Dear fellow shareholders,

2017 was truly a pivotal year for Marathon Oil, as we solidified high quality, differentiated positions in the four lowest-cost, highest-margin U.S. oil plays. We made significant progress across every element of our playbook, and ended the year with a stronger balance sheet, a lower cost structure, a more concentrated portfolio, and an outstanding track record of consistent execution across all our assets.

A remarkable 2017 has positioned us well for future success. We've transitioned from portfolio transformation to execution delivery at scale across our U.S. resource plays. Our 2018 capital allocation philosophy is fully consistent with how we managed the business in 2017, which is to deliver a returns-focused program that balances cash flow with our CapEx and dividend, and achieves that at a moderate oil price of $50 WTI while generating meaningful free cash flow at $60. With over 90 percent of our 2018 development capital allocation associated with the U.S. resource plays, our margins will naturally expand as a greater percentage of our production is sourced from these high quality assets.

This margin expansion story, coupled with outstanding financial flexibility, will help drive improvements in corporate cash returns and cash flow per debt-adjusted share. Our actions will always be driven by seeking the greatest long-term value for our shareholders, while remaining steadfast in our core values that include first and foremost being a safe and responsible operator.

We thank all our dedicated employees and contractors who have made such a difference in 2017, driving execution excellence in every asset, every quarter. Their talent and innovation will continue to position us favorably to outperform the competition through 2018 and beyond.

Lee M. Tillman
President and Chief Executive Officer

Dennis H. Reilley
Chairman of the Board of Directors

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2017

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 and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 ☐ (Do not check if a smaller reporting company)
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, 2017: $10,050 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 849,755,866 shares of Marathon Oil Corporation Common Stock outstanding as of February 14, 2018.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2018 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 Development Program – 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.

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.

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.

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 and its consolidated subsidiaries: 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.

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 2018 capital development program 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 relating to our hedging activities;
- capital available for exploration and development;
- drilling and operating risks;
- well production timing;
- availability of drilling rigs, materials and labor, including the costs associated therewith;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, 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 assume no duty to revise or update any forward-looking statements whether 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

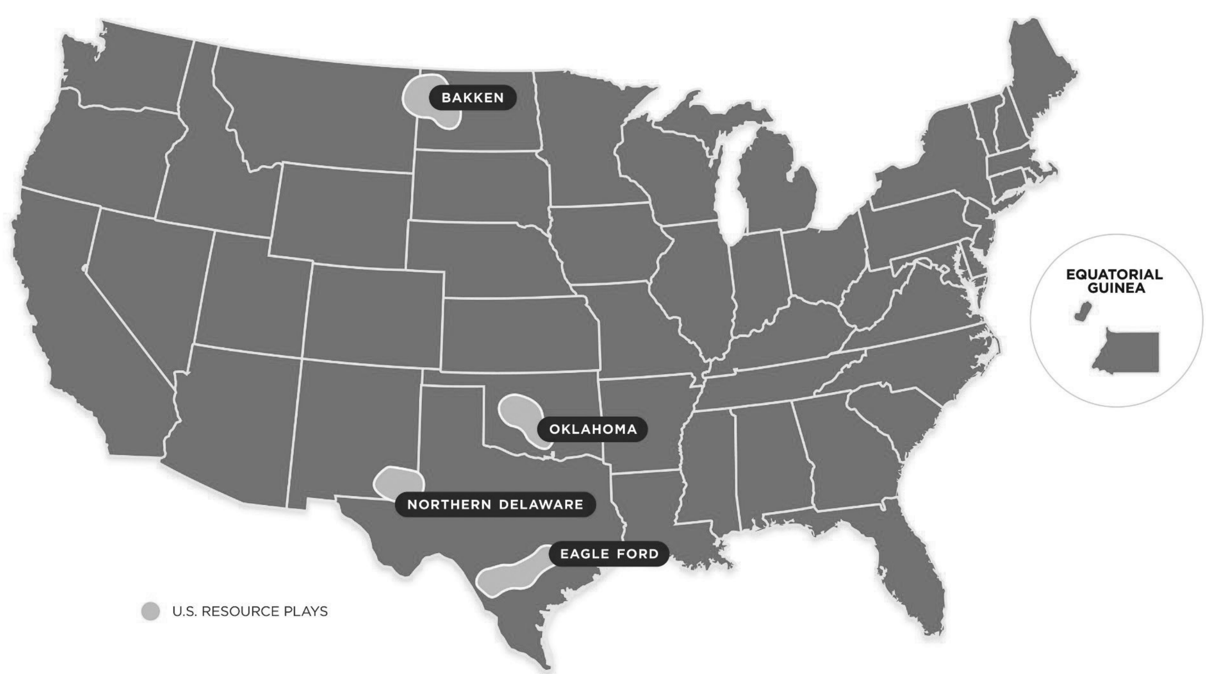
Marathon Oil Corporation (NYSE: MRO) is an independent exploration and production company based in Houston, Texas, focused on U.S. unconventional resource plays with operations in the United States, Europe and Africa. Our corporate headquarters is located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our two reportable operating segments are organized and managed based upon geographic location and the nature of the products and services offered. The two segments are:

- United States E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;
- International E&P – 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.

Our strategy is to deliver competitive returns by focusing on the lowest cost, highest margin U.S. resource plays while maintaining a peer-leading balance sheet. 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.

We are concentrated on our core operations in our U.S. unconventional resource plays and E.G. The map below shows the locations of our core operations:



* Our additional locations include the Gulf of Mexico, U.K., Libya, Gabon and the Kurdistan Region of Iraq.

Segment and Geographic Information

In the second quarter of 2017, we closed on the sale of our Canadian business which includes our Oil Sands Mining segment and exploration stage in-situ leases. The Canadian business is reflected as discontinued operations in all periods presented. Additionally, we have renamed our North America E&P segment to United States E&P segment, effective June 30, 2017. See Item 8. Financial Statements and Supplementary Data – Note 1 to the consolidated financial statements for further detail. For reportable operating segment and geographic financial information, see Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements.

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

United States E&P Segment

We are engaged in oil and gas exploration, development and production activities in the U.S. Our primary focus in the United States E&P segment is concentrated within our four high quality unconventional 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 E&P-- Unconventional 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 County and Atascosa County. We operate 32 central gathering and treating facilities across the field that support more than 1,500 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, Atascosa and Bee Counties.

Bakken – We have been operating in North Dakota and eastern Montana since 2006. The majority of our acreage is in core prospects within McKenzie, Mountrail, and Dunn Counties in North Dakota. We continue focusing on the high-return Myrmidon area building on the successes from our enhanced completion designs, as well as delineating our position in Hector.

Oklahoma – Our primary focus in Oklahoma has been delineation and leasehold protection in the Meramec play in the STACK and delineation of the Woodford and Springer plays in the SCOOP, as we move toward infill development. We hold net acreage with rights to the Woodford, Springer, Meramec, Osage, Oswego, Granite Wash and other Pennsylvanian and Mississippian plays, with a majority of this in the SCOOP and STACK.

Northern Delaware – We closed on multiple Permian acquisitions during 2017, with a majority of the acreage in Northern Delaware. These acquisitions give us a strong foundational footprint in the region where we have begun developing the Wolfcamp and Bone Spring plays. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for further detail.

Other United States

Our remaining properties in the United States primarily consist of outside operated assets in the Gulf of Mexico, including the Gunflint field where we hold an 18% non-operated working interest.

International E&P Segment

We are engaged in oil and gas development and production across our international locations primarily in E.G., U.K. and Libya. We include the results of our LPG processing plant, gas liquefaction operations and methanol production operations in E.G. in our International E&P segment.

International E&P

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. Block D was unitized with the Alba field in second quarter 2017. Operational availability from our company-operated facilities averaged approximately 99% in 2017.

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 3.95 mmta in 2017. AMPCO had gross sales totaling approximately 1,100 mt in 2017. Methanol production is sold to customers in Europe and the U.S.

United Kingdom – Our operated asset in the U.K. sector of the North Sea is 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 – We hold a 16% non-operated working interest in the Waha concessions, which includes acreage located in the Sirte Basin of eastern Libya. While civil and political unrest has interrupted operations in recent years, our production resumed in October 2016 at our Waha concession. During December 2016, liftings resumed from the Es Sider crude oil terminal. During 2017 sales volumes and production continued, except for a brief interruption in March 2017 due to civil unrest.

Other International

Kurdistan Region of Iraq – We have non-operated interests in two blocks located north-northwest of Erbil: Atrush with a 15% working interest and Sarsang with a 20% working interest. In 2016, we relinquished to the Kurdistan Regional Government our 45% operated working interest in the Harir block located northeast of Erbil.

Gabon – We hold a 100% participating interest and operatorship in the Tchicuate block where we have an exploration and production sharing agreement.

In the third quarter 2017, we entered into separate agreements to sell certain non-core properties in our International E&P segment, and a portion of this transaction closed during the 4th quarter 2017. 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 72% of our proved reserves are located in OECD countries, with 70% 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, 2017.

		Africa				
December 31, 2017	**U.S.**	**E.G.**	**Libya**	**Total**	**Other Int'l**	**Total from Cont Ops**
Proved Developed Reserves						
Crude oil and condensate *(mmbbl)*	263	39	165	204	17	484
Natural gas liquids *(mmbbl)*	118	25	—	25	—	143
Natural gas *(bcf)*	726	833	94	927	2	1,655
Total proved developed reserves *(mmboe)*	502	203	181	384	17	903
Proved Undeveloped Reserves						
Crude oil and condensate (*mmbbl*)	307	—	—	—	9	316
Natural gas liquids (*mmbbl*)	111	—	—	—	—	111
Natural gas (*bcf*)	598	—	110	110	6	714
Total proved undeveloped reserves (*mmboe*)	518	—	18	18	10	546
Total Proved Reserves						
Crude oil and condensate (*mmbbl*)	570	39	165	204	26	800
Natural gas liquids (*mmbbl*)	229	25	—	25	—	254
Natural gas (*bcf*)	1,324	833	204	1,037	8	2,369
Total proved reserves (*mmboe*)	1,020	203	199	402	27	1,449

Of the total estimated proved reserves, approximately 55% was crude oil and condensate. As of December 31, 2017, our estimated proved developed reserves totaled 903 mmboe or 62% and estimated proved undeveloped reserves totaling 546 mmboe or 38% 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 E&P and International E&P segments, the following table sets forth gross and net productive wells, service wells and drilling wells as of December 31 for the years presented.

	Productive Wells				Service Wells		Drilling Wells	
	Oil		Natural Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2017								
U.S.	5,132	1,905	1,690	676	799	70	33	13
E.G.	—	—	19	12	—	—	—	—
Libya	1,071	175	7	2	94	16	—	—
Total Africa	1,071	175	26	14	94	16	—	—
Other International	61	22	19	7	23	8	—	—
Total	6,264	2,102	1,735	697	916	94	33	13
2016								
U.S. [(a)]	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		
2015								
U.S.	7,198	2,878	1,796	750	2,727	747		
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	59	21	39	16	24	8		
Total	8,328	3,074	1,859	778	2,847	772		

(a) Reduction in December 31, 2016 gross and net productive wells and service wells is primarily due to the dispositions of certain conventional West Texas and Wyoming assets in 2016. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Drilling Activity

For our United States E&P and International E&P 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
2017									
U.S.	107	27	—	134	88	16	—	104	238
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	—	—	—
Total Africa	—	—		—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	107	27	—	134	88	16	—	104	238
2016									
U.S.	64	12	—	76	70	27	—	97	173
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	—	—	—
Total Africa	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	64	12	—	76	70	27	—	97	173
2015									
U.S.	135	36	11	182	49	48	1	98	280
E.G.	—	1	—	1	—	—	1	1	2
Libya	—	—	—	—	—	—	—	—	—
Total Africa	—	1	—	1	—	—	1	1	2
Other International	1	—	—	1	—	—	—	—	1
Total	136	37	11	184	49	48	2	99	283

Acreage

We believe we have satisfactory title to our United States E&P and International E&P 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 E&P and International E&P segments as of December 31, 2017.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,529	1,008	388	322	1,917	1,330
E.G.	82	67	54	36	136	103
Libya	12,909	2,108	—	—	12,909	2,108
Other Africa	—	—	277	277	277	277
Total Africa	12,991	2,175	331	313	13,322	2,488
Other International	86	31	171	32	257	63
Total	14,606	3,214	890	667	15,496	3,881

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, additional undeveloped acreage will expire in future years. We plan to continue the terms of certain of these licenses and concession areas or retain leases through operational or administrative actions.

Net Sales Volumes

		Africa					
	U.S.	E.G.	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31,							
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
2015							
Crude and condensate *(mbbld)*[a]	171	19	—	14	204	—	204
Natural gas liquids *(mbbld)*	39	10	—	—	49	—	49
Natural gas *(mmcfd)*[b]	351	410	—	21	782	—	782
Synthetic crude oil *(mbbld)*[c]	—	—	—	—	—	45	45
Total sales volumes *(mboed)*	269	97	—	18	384	45	429

(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
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
2015	10.65	2.37	N.M.	27.23	9.54	38.42	12.62

(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]

(Dollars per unit)	U.S.	Africa E.G.	Africa Libya	Africa Total	Other Int'l	Disc Ops	Total
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
2015							
Crude and condensate *(bbl)*	$ 43.50	$ 42.83	$ —	$ 42.83	$ 53.91	$ —	$ 44.14
Natural gas liquids *(bbl)*	13.37	1.00 [b]	—	1.00	32.53	—	11.16
Natural gas *(mcf)*	2.66	0.24 [b]	—	0.24	6.85	—	1.50
Synthetic crude oil *(bbl)*	—	—	—	—	—	40.13	40.13

(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 E&P 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, 2017, the contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to the following commitments:

	2018	2019	2020	Thereafter	Commitment Period Through
Eagle Ford					
Crude and condensate *(mbbld)*	95	65	51	—	2020
Natural gas liquids *(mbbld)*	1	1	—	—	2020
Natural gas *(mmcfd)*	168	168	168	46 - 70	2022
Bakken					
Crude and condensate *(mbbld)*	10	10	10	5 - 10	2027
Natural gas *(mmcfd)*	2	2	2	2 - 25	2027
Oklahoma					
Natural gas *(mmcfd)*	—	90	118	110 - 148	2030

All of these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate. 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 have filed lawsuits in California and New York 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 six of these lawsuits in California, 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. This more stringent ozone NAAQS could result in additional areas being designated 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. The EPA anticipates promulgating final area designations under the new standard in the first half of 2018. 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 and has indicated that the requirements could be rescinded or significantly revised in the future. If not withdrawn or significantly revised, this rule is expected to result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities. If we are unable to comply with the terms of these regulations, we could be required to forego certain operations. These regulations may also result in administrative, civil and/or criminal penalties for non-compliance.

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 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. If this 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 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. In 2015, sales to Shell Oil and its affiliates accounted for approximately 10% of our total revenues.

Trademarks, Patents and Licenses

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

Employees

We had approximately 2,300 active, full-time employees as of December 31, 2017.

Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2018, are as follows:

Lee M. Tillman	56	President and Chief Executive Officer
Dane E. Whitehead	56	Executive Vice President and Chief Financial Officer
T. Mitch Little	54	Executive Vice President—Operations
Reginald D. Hedgebeth	50	Senior Vice President, General Counsel and Secretary
Patrick J. Wagner	53	Executive Vice President-Corporate Development and Strategy
Catherine L. Krajicek	56	Vice President—Conventional
Gary E. Wilson	56	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed president and chief executive officer in August 2013. Mr. Tillman is also a member of our Board of Directors. 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 company), and vice president of legal for The Home Depot, Inc. (home improvement supplies retailing company).

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

Ms. Krajicek was appointed vice president—conventional assets in August 2016 after having served as vice president of technology and innovation since December 2015. Prior to that, Ms. Krajicek served as vice president, health, environment, safety and security from January 2015 through December 2015. In January 2018 Ms. Krajicek announced her plans to retire effective April 1, 2018. Ms. Krajicek joined Marathon Oil in 2007 and has since held a number of positions of increasing responsibility. Prior to joining the Company, Ms. Krajicek spent 22 years with Conoco and then ConocoPhillips (a multinational energy corporation), where she held a variety of reservoir engineering and asset management and development management positions for upstream and mid-stream businesses under development, both in the U.S. and internationally.

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.

The public may read and copy any materials we file with the SEC at its Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also 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. Prior to 2016, the synthetic crude oil reserves estimates, included in discontinued operations, were prepared by GLJ, a third-party consulting firm experienced in working with oil sands. Reserves were valued based on SEC pricing for the periods ended December 31, 2017, 2016 and 2015, as well as other conditions in existence at those dates. The table below provides the 2017 SEC pricing for certain benchmark prices:

	SEC Pricing 2017	
WTI Crude oil (per bbl)	$	51.34
Henry Hub natural gas (per mmbtu)	$	2.98
Brent crude oil (per bbl)	$	54.39
Mont Belvieu NGLs (per bbl)	$	22.03

If commodity prices were to decrease by approximately 10% below average prices used to estimate 2017 proved reserves (see table above), 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 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 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 to fund their portion of the costs under our joint venture 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 deepwater areas may pose incrementally greater risks because of water depths that limit intervention capability and 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 venting or 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.

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 recently 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 recently 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.

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 38% of our crude oil and condensate, NGLs and natural gas related to continuing operations in 2017 was derived from production outside the U.S. and 30% of our proved reserves of crude oil and condensate, NGLs and natural gas as of December 31, 2017 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., Gabon, the Kurdistan Region of Iraq and Libya, and in global markets 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.

For the past several years, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence and numerous incidences of terrorist acts, within some countries in the Middle East and Africa. Some political regimes in these countries are threatened or have changed as a result of such unrest.

If such unrest continues to spread, conflicts could result in civil wars, regional conflicts, and regime changes resulting in governments that are hostile to the U.S. These may have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates and reduced demand for our products;
- negative impact on the world crude oil supply if transportation avenues are disrupted;
- security concerns leading to the prolonged evacuation of our personnel;
- damage to, or the inability to access, production facilities or other operating assets; and
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations.

Continued hostilities in the Middle East and Africa and 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.

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 level of indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2017, our total debt was $5.5 billion, with no debt due within the next 24 months. 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 15 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 decline in crude oil and U.S. natural gas prices in recent years, credit rating agencies reviewed companies in the energy industry, including us. At December 31, 2017, our corporate credit ratings were: Standard & Poor's Global Ratings Services BBB- (stable); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (stable). The credit rating process is contingent upon a number of factors, many of which are beyond our control. A downgrade of our credit ratings 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 program, 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.

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 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 with partners, 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 partners 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 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 E&P and International E&P 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 have filed lawsuits in California and New York 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 six of these lawsuits in California, 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 are set forth in Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities – Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business – Reserves.

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 24 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, 2017, under federal and state environmental laws.

Government entities have filed lawsuits in California and New York 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 six of these lawsuits in California, 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, 2017, 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"). As of January 31, 2018, there were 31,472 registered holders of Marathon Oil common stock.

The following table reflects high and low sales prices for Marathon Oil common stock and the related dividend per share by quarter for the past two years:

	2017			2016		
(Dollars per share)	**High Price**	**Low Price**	**Dividends**	**High Price**	**Low Price**	**Dividends**
First Quarter	$18.18	$14.61	$0.05	$12.82	$6.73	$0.05
Second Quarter	$16.60	$11.35	$0.05	$15.27	$10.53	$0.05
Third Quarter	$13.73	$10.77	$0.05	$16.80	$12.90	$0.05
Fourth Quarter	$17.26	$13.48	$0.05	$18.80	$12.78	$0.05
Full Year	$18.18	$10.77	$0.20	$18.80	$6.73	$0.20

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, 2017, 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)]
10/01/17 – 10/31/17	49,046	$13.38	—	$ 1,500,285,529
11/01/17 – 11/30/17	2,813	$14.62	—	$ 1,500,285,529
12/01/17 – 12/31/17	—	—	—	$ 1,500,285,529
Total	51,859	$13.45	—	

(a) 51,859 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. The remaining share repurchase authorization as of December 31, 2017 is $1.5 billion. No repurchases were made under the program in 2017.

Item 6. Selected Financial Data

(In millions, except per share data)	Year Ended December 31, 2017	2016	2015	2014	2013
Statement of Income Data[(a)(b)(c)]					
Revenues	$ 4,373	$ 3,170	$ 4,635	$ 9,238	$ 9,731
Income (loss) from continuing operations	(830)	(2,087)	(1,701)	710	710
Discontinued operations	(4,893)	(53)	(503)	2,336	1,043
Net income (loss)	(5,723)	(2,140)	(2,204)	3,046	1,753
Per Share Data[(a)(b)(c)]					
Basic:					
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)	$ 1.04	$ 1.01
Discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)	$ 3.44	$ 1.48
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)	$ 4.48	$ 2.49
Diluted:					
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)	$ 1.04	$ 1.00
Discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)	$ 3.42	$ 1.47
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)	$ 4.46	$ 2.47
Statement of Cash Flows Data[(b)]					
Additions to property, plant and equipment related to continuing operations	$ (1,974)	$ (1,204)	$ (3,485)	$ (4,937)	$ (4,170)
Dividends paid	170	162	460	543	508
Dividends per share	$ 0.20	$ 0.20	$ 0.68	$0.80	$0.72
Balance Sheet Data at December 31					
Total assets	$ 22,012	$ 31,094	$ 32,311	$ 35,983	$ 35,588
Total long-term debt, including capitalized leases	5,494	6,581	7,268	5,285	6,352

(a) Includes impairments to producing properties of $229 million, $67 million, $381 million, $132 million and $96 million in 2017, 2016, 2015, 2014 and 2013 and impairments to unproved properties of $246 million, $195 million, $655 million, $306 million and $572 million in 2017, 2016, 2015, 2014 and 2013 (see Item 8. Financial Statements and Supplementary Data – Note 10 to the consolidated financial statements). Includes a goodwill impairment of $340 million in 2015 related to the U.S. E&P reporting unit (see Item 8. Financial Statements and Supplementary Data – Note 12 to the consolidated financial statements).

(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 (see Item 8. Financial Statements and Supplementary Data – Note 9 to the consolidated financial statements).

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 segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- United States E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States
- International E&P – 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 Summary

During 2017, we continued to strengthen our balance sheet, transform our portfolio and manage our capital and operating costs. Through multiple financing transactions in 2017, we have reduced total debt by approximately $1.75 billion which will result in a reduction to our future annual interest expense of approximately $115 million. Additionally, we closed on the sale of our Canadian business for approximately $2.5 billion and acquired acreage in the Permian basin, including over 70,000 net acres in Northern Delaware for approximately $1.9 billion.

As discussed in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements, we closed on the sale of our Canadian business, which has been reflected as discontinued operations and is excluded from operations in all periods presented.

Key highlights include the following:

Liquidity and corporate financing

- Ended 2017 with liquidity of $4.0 billion, comprised of $563 million in cash and cash equivalents and an undrawn $3.4 billion revolving credit facility, which was increased from $3.3 billion in July 2017. Remaining proceeds of $750 million from the sale of our Canadian business are scheduled to be received in the first quarter of 2018.
- In third quarter 2017, we issued $1 billion of 4.4% senior unsecured notes due in 2027 and redeemed approximately $1.75 billion of debt due in 2017, 2018 and 2019. This offering and redemption reduced our future annual interest expense by approximately $64 million.
- In December 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. This redemption reduced our future annual interest expense by approximately $51 million.

Simplifying our portfolio

- We closed on the sale of our Canadian business for approximately $2.5 billion with over $1.8 billion in proceeds received to date and $750 million to be received in first quarter 2018.
- We closed on multiple Permian basin acquisitions for approximately $1.9 billion of cash on hand.

Financial and Operational results

- Total 2017 net sales volumes from continuing operations are 379 mboed, including Libya, which is 10% higher compared to 2016. This includes a 12% increase in sales volumes from the U.S resource plays to 217 mboed within our United States E&P segment.
- Due to improved cost structure and higher sales volumes, our production expense rate in our United States E&P segment decreased 7% to $5.57 per boe in 2017 compared to last year. In our International E&P segment, our production expense rate decreased 14% to $4.33 per boe in 2017 primarily due to an increase in sales volumes in E.G. and Libya.
- Added proved reserves of 193 mmboe for a reserve replacement ratio from continuing operations of 140%.
- Net cash provided by operating activities in 2017 was $2.0 billion, compared to $901 million in 2016 primarily as a result of improved price realizations, increased sales volumes and lower unit production expenses.

- Our net loss per share from continuing operations was $0.97 in 2017 as compared to a net loss per share of $2.55 last year. Included in the 2017 net loss are:
    - An increase in sales and other operating revenues of over 40% to $4.2 billion primarily due to improved price realizations and increased sales volumes.
    - Our sales volumes from continuing operations increased 10% while production expense remained flat during 2017 as a result of improved cost structure.
    - Depreciation, depletion and amortization expense increased 10% to $2.4 billion due to our increase in sales volumes from continuing operations.
    - Exploration and impairment expenses increased by $248 million to $638 million, year over year, primarily due to non-cash impairment charges on proved and unproved properties primarily as a result of the anticipated sales of certain non-core international assets and due to lower forecasted long-term commodity prices.
    - Our provision for income taxes was $376 million in 2017 primarily as 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 7 to the consolidated financial statements for a discussion of the effects of U.S. Tax Reform Legislation.

Outlook

Capital Development Program

Our $2.3 billion 2018 Capital Development Program will be over 90% allocated to our U.S. resource plays. Almost 60% of this development budget will be allocated to the high-return Eagle Ford and Bakken assets, which have demonstrated step-change performance improvements while operating at scale. Approximately one-third of the development budget will be allocated to our Northern Delaware and Oklahoma assets, where the majority of drilling activity will be transitioning to multi-well pads, while continuing strategic delineation and appraisal.

Our 2018 Capital Development Program is broken down by reportable operating segment in the table below:

(In millions)		**Capital Development Program**
United States E&P		
Eagle Ford	$	710
Bakken		590
Oklahoma		410
Northern Delaware		380
Total United States E&P	$	2,090
International E&P and corporate other [a]		210
Total Capital Development Program	$	2,300

[a] International E&P and corporate other includes our International E&P segment and other corporate items

Operations

Our net sales volumes from continuing operations, including Libya, averaged 379 mboed, 345 mboed and 385 mboed for 2017, 2016 and 2015, respectively. This 10% increase in 2017 was primarily due to new wells to sales in our U.S. resource plays, our acquisitions in Northern Delaware and the resumption of sales in Libya.

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	**2017**	**Increase (Decrease)**	**2016**	**Increase (Decrease)**	**2015**
United States E&P *(mboed)*	234	5%	223	(17)%	269
International E&P [a] *(mboed)*	145	19%	122	5 %	116
Total Continuing Operations *(mboed)*	379	10%	345	(10)%	385

[a] Years ended December 31, 2017, 2016 and 2015 include net sales volumes relating to Libya of 20 mboed, 3 mboed and none, respectively.

United States E&P

The following tables provide additional detail regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

Net Sales Volumes	2017	Increase (Decrease)	2016	Increase (Decrease)	2015
Equivalent Barrels *(mboed)*					
Oklahoma	54	54%	35	40%	25
Eagle Ford	101	(4)%	105	(22)%	134
Bakken	56	4%	54	(8)%	59
Northern Delaware	6	100%	—	—%	—
Other United States[(a)]	17	(41)%	29	(43)%	51
Total United States E&P (mboed)	234	5%	223	(17)%	269

(a) 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. Year ended December 31, 2016 decreases relating to assets sold were 23 mboed, primarily consisting of Wyoming, West Texas, East Texas, North Louisiana and certain Gulf of Mexico assets. 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 - 2017	Oklahoma	Eagle Ford	Bakken	Northern Delaware	Total
Crude oil and condensate	28%	58%	83%	66%	57%
Natural gas liquids	26%	21%	10%	8%	19%
Natural gas	46%	21%	7%	26%	24%

Drilling Activity - U.S. Resource Plays	2017	2016	2015
Gross Operated			
Oklahoma:			
Wells drilled to total depth	86	33	20
Wells brought to sales	73	28	21
Eagle Ford:			
Wells drilled to total depth	182	168	251
Wells brought to sales	157	168	276
Bakken:			
Wells drilled to total depth	90	3	35
Wells brought to sales	39	13	56
Northern Delaware			
Wells drilled to total depth	27	—	—
Wells brought to sales	18	—	—

- *Eagle Ford* – Our net sales volumes were 101 mboed in 2017, 4% lower compared to 2016. We brought fewer wells to sales in 2017, while we increased well productivity through completion optimization and efficiency gains.
- *Bakken* – Our net sales volumes were 56 mboed in 2017 compared to 54 mboed in 2016. In 2017, we improved well performance with continued application of high intensity completions. During the year, we set a new record in the Williston Basin for the highest 30-day initial production oil rate.
- *Oklahoma* – Our net sales volumes in 2017 increased by 54% to 54 mboed compared to year ended 2016. Our activity during 2017 was concentrated in the STACK and was focused on leasehold capture, delineation drilling and infill spacing pilots.
- *Northern Delaware* – Our net sales volumes were 6 mboed in 2017 which reflected a partial year of production following the second quarter 2017 closing of the BC Operating and Black Mountain assets. During 2017 we focused our activity on delineation and leasehold capture across our position in Eddy and Lea Counties, New Mexico.

International E&P

The following table provides net sales volumes from continuing operations within this segment:

Net Sales Volumes	**2017**	**Increase (Decrease)**	**2016**	**Increase (Decrease)**	**2015**
Equivalent Barrels *(mboed)*					
Equatorial Guinea	109	7%	102	5%	97
United Kingdom[(a)]	14	(18)%	17	(11)%	19
Libya	20	567%	3	100%	—
Other International	2	100%	—	—%	—
Total International E&P *(mboed)*	145	19%	122	5%	116
Equity Method Investees					
LNG *(mtd)*	6,423	9%	5,874	—%	5,884
Methanol *(mtd)*	1,374	1%	1,358	45%	937
Condensate & LPG *(boed)*	14,501	8%	13,430	10%	12,208

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

- *Equatorial Guinea* – Net sales volumes in 2017 were higher than 2016 as a result of the completion and start-up of our Alba field compression project in mid-2016 and lower volumes in first quarter 2016 due to a planned turnaround. Additionally, in April 2017 we received host government approval to develop Block D offshore E.G. through unitization with the Alba field.
- *United Kingdom* – Net sales volumes in 2017 decreased compared to 2016 primarily as a result of planned turn-around activity at the Brae and Foinaven complexes and the temporary shut-down of the outside-operated Forties Pipeline System during fourth quarter 2017.
- *Libya* – While civil and political unrest has interrupted operations in recent years, our production resumed in October 2016. During December 2016, liftings resumed from the Es Sider crude oil terminal. During 2017, sales volumes and production continued, except for a brief interruption in March 2017 due to civil unrest.

Market Conditions

Crude oil, natural gas and NGL benchmarks increased in 2017 as compared to the same period in 2016. As a result, we experienced increased price realizations associated with those benchmarks. We continue to expect crude oil, natural gas and NGLs benchmark prices to remain volatile based on global supply and demand, which will result in increases or decreases in our price realizations. 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, NGLs and natural gas relative to our operating segments, follows.

United States E&P

The following table presents our average price realizations and the related benchmarks for crude oil, NGLs and natural gas for 2017, 2016 and 2015:

	2017	Increase (Decrease)	2016	Increase (Decrease)	2015
Average Price Realizations [(a)]					
Crude Oil and Condensate *(per bbl)* [(b)]	$49.35	28%	$38.57	(11)%	43.50
Natural Gas Liquids *(per bbl)*	20.55	56%	13.15	(2)%	13.37
Total Liquid Hydrocarbons *(per bbl)*	42.31	29%	32.71	(14)%	37.85
Natural Gas *(per mcf)* [(c)]	2.84	19%	2.38	(11)%	2.66
Benchmarks					
WTI crude oil average of daily prices *(per bbl)*	$50.85	17%	$43.47	(11)%	48.76
LLS crude oil average of daily prices *(per bbl)*	54.04	20%	45.02	(14)%	52.33
Mont Belvieu NGLs *(per bbl)* [(d)]	23.76	37%	17.40	3 %	16.94
Henry Hub natural gas settlement date average (per *mmbtu)*	3.11	26%	2.46	(8)%	2.66

(a) Excludes gains or losses on commodity derivative instruments.
(b) Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon price realizations per barrel by $0.75, $0.92, and $1.24 for 2017, 2016, and 2015.
(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 – Our crude oil and condensate price realizations may differ from the benchmark due to the quality and location of the product.

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

Natural gas – A significant portion of our natural gas production in the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas.

International E&P

The following table presents our average price realizations and the related benchmark for crude oil for 2017, 2016 and 2015:

	2017	Increase (Decrease)	2016	(Decrease)	2015
Average Price Realizations					
Crude Oil and Condensate *(per bbl)*	$53.05	27%	$41.70	(12)%	$47.50
Natural Gas Liquids *(per bbl)*	3.15	49%	2.11	(25)%	2.81
Total Liquid Hydrocarbons *(per bbl)*	43.36	35%	32.10	(12)%	36.67
Natural Gas *(per mcf)*	0.55	6%	0.52	(24)%	0.68
Benchmark					
Brent (Europe) crude oil *(per bbl)*[(a)]	$54.25	25%	$43.55	(17)%	$52.35

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

Our U.K. liquid hydrocarbon production is generally sold in relation to the Brent crude benchmark. Our production from the Alba field in E.G. is condensate and gas. Condensate is sold at market prices and the gas is shipped to the onshore Alba Plant. The Alba Plant extracts NGLs and secondary condensate, which have been supplied under a long-term contract at a fixed price, leaving dry natural gas. The extracted NGLs and secondary condensate are sold by Alba Plant at market prices, with our share of its income/loss reflected in income from equity method investments, and the dry natural gas from Alba Plant is supplied to AMPCO and EGHoldings under long-term contracts at fixed prices. Therefore, our reported average realized prices for condensate, NGLs and natural gas will not fully track market price movements. Because of the location and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, EGHoldings and AMPCO to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. EGHoldings and AMPCO process the gas into LNG and methanol, which are sold at market prices, with our share of their income/loss reflected in the income from equity method investments line item on the Consolidated Statements of Income. Although uncommon, any dry gas not sold is returned offshore and re-injected into the Alba field for later production.

Consolidated Results of Operations: 2017 compared to 2016

Sales and other operating revenues, including related party are summarized by segment in the following table:

(In millions)	Year Ended December 31, 2017	2016
Sales and other operating revenues, including related party		
United States E&P	$ 3,138	$ 2,375
International E&P	1,154	665
Segment sales and other operating revenues, including related party	4,292	3,040
Unrealized gain (loss) on commodity derivative instruments	(81)	(110)
Sales and other operating revenues, including related party	$ 4,211	$ 2,930

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 Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2017
United States E&P Price-Volume Analysis (a)				
Liquid hydrocarbons	$ 2,041	$ 619	$ 66	$ 2,726
Natural gas	274	58	29	361
Realized gain on commodity derivative instruments	44			45
Other sales	16			6
Total	$ 2,375			$ 3,138
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 546	$ 264	$ 205	$ 1,015
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 CO2 and waterflood assets in West Texas and New Mexico in 2016.

Marketing revenues decreased $78 million in 2017 from 2016, primarily as a result of lower marketed volumes in the United States E&P 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 11 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 E&P was lower primarily due to the disposition of higher cost non-core assets in Wyoming. The International E&P 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		
United States E&P	$5.57	$5.96
International E&P	$4.33	$5.05

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

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 during 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 E&P segment. In 2017, we recorded non-cash charges of $159 million comprised of $95 million in unproved property impairments in our International E&P segment and $64 million in 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 expenses are also discussed in Item 8. Financial Statements and Supplementary Data - Note 10 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 E&P 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 E&P 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 E&P 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 International E&P 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 E&P	$23.51	$22.49
International E&P	$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 E&P 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 10 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	$ 183	$ 151

General and administrative expenses decreased $81 million in 2017 primarily due to reduced pension settlement charges of $32 million in 2017 compared to $103 million in 2016.

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 $47 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 15 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 approximately $1.75 billion in senior unsecured notes. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for further detail.

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 7 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 operations excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. A portion of our corporate and operations support general and administrative 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 that affect comparability also 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 E&P	$ (148)	$ (415)
International E&P	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 6 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 *E&P 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 E&P 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.

Consolidated Results of Operations: 2016 compared to 2015

Sales and other operating revenues, including related party are summarized by segment in the following table:

(In millions)	Year Ended December 31, 2016	2015
Sales and other operating revenues, including related party		
United States E&P	$ 2,375	$ 3,358
International E&P	665	728
Segment sales and other operating revenues, including related party	3,040	4,086
Unrealized gain on crude oil derivative instruments	(110)	50
Sales and other operating revenues, including related party	$ 2,930	$ 4,136

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, 2015	Increase (Decrease) Related to Price Realizations	Net Sales Volumes	Year Ended December 31, 2016
United States E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 2,905	$ (321)	$ (543)	$ 2,041
Natural gas	341	(32)	(35)	274
Realized gain on crude oil derivative instruments	78			44
Other sales	34			16
Total	$ 3,358			$ 2,375
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 578	$ (78)	$ 46	$ 546
Natural gas	108	(25)	4	87
Other sales	42			32
Total	$ 728			$ 665

Marketing revenues decreased $259 million in 2016 from 2015. 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. The decreases are primarily related to lower marketed volumes in the United States, which were further compounded by a lower commodity price environment.

Income from equity method investments increased $30 million primarily due to higher net sales volumes in the second half of 2016 in E.G. as a result of the completion of the Alba field compression project. Additionally, a partial impairment of our investment in an equity method investee in 2015 of $12 million contributed to the increase in the current year.

Net gain on disposal of assets increased $269 million in 2016 from 2015. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses decreased $267 million in 2016 from 2015. United States E&P declined $238 million primarily due to lower operational, maintenance and labor costs, coupled with lower net sales volumes resulting from the impact of our non-core asset dispositions and lower activity levels. International E&P declined $29 million largely due to lower operational and maintenance costs as well as a more favorable exchange rate on expenses.

The 2016 production expense rate (expense rate per boe) for United States E&P declined primarily due to cost reductions that occurred at a rate faster than our production decline. The International E&P expense rate decreased in 2016 primarily due to reduced maintenance and project costs in the U.K. and benefited from the favorable exchange rate. The following table provides production expense rates for each segment:

($ per boe)	2016	2015
Production Expense Rate		
United States E&P	$5.96	$7.38
International E&P	$5.05	$5.99

Marketing expenses decreased $255 million in 2016 from the prior year, consistent with the decrease in marketing revenues discussed above.

Other operating expenses increased $74 million primarily as a result of the termination payment of our Gulf of Mexico deepwater drilling commitment.

Exploration expenses decreased $648 million in 2016 compared to 2015, reflecting our strategic decision to transition out of conventional exploration. In 2016, unproved property impairments primarily consisted of non-cash charges related to our decision to not drill our remaining Gulf of Mexico leases and also included certain other unproved properties in the United States. In 2015, unproved property impairments are due to changes in our conventional exploration strategy (Gulf of Mexico and the Harir block in the Kurdistan Region of Iraq), and the sale of certain properties in the Gulf of Mexico, as well as our unproved property in Colorado.

Dry well costs in 2015 included the operated Solomon exploration well in the Gulf of Mexico and our operated Sodalita West #1 exploratory well in E.G.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	2016	2015
Exploration Expenses		
Unproved property impairments	$ 195	$ 655
Dry well costs	25	212
Geological and geophysical	5	31
Other	98	73
Total exploration expenses	$ 323	$ 971

Exploration expense are also discussed in Item 8. Financial Statements and Supplementary Data - Note 10 to the consolidated financial statements.

Depreciation, depletion and amortization decreased $565 million in 2016 from the prior year primarily as a result of net sales volume decreases in the United States E&P segment, including the impact of non-core asset dispositions, and volume declines due to base declines and lower completion activity. 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 following table provides DD&A rates for each segment. The DD&A rate for United States E&P decreased primarily due to a higher proved reserve base. The DD&A rate for International E&P declined primarily due to sales volume mix changes in E.G. and the U.K. for 2016.

($ per boe)	2016	2015
DD&A rate		
United States E&P	$22.49	$24.24
International E&P	$6.21	$6.95

Impairments decreased $654 million in 2016 versus 2015. Impairments in 2016 were primarily the result of lower forecasted commodity prices in conventional properties in Oklahoma and the Gulf of Mexico, and were also the result of revisions to estimated abandonment costs. Impairments in 2015 included $340 million for the goodwill impairment of the United States E&P reporting unit, and $335 million related to proved properties (primarily in Colorado and the Gulf of Mexico) as a result of lower forecasted commodity prices, and $44 million associated with our disposition of natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma.

See Item 8. Financial Statements and Supplementary Data - Note 10 and Note 12 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. The decline in revenue and sales volumes during 2016 resulted in a decline of $65 million compared to 2015. The following table summarizes the components of taxes other than income:

	Year Ended December 31,	
(In millions)	**2016**	**2015**
Taxes other than income		
Production and severance	$ 91	$ 131
Ad valorem	23	39
Other	37	46
Total taxes other than income	$ 151	$ 216

General and administrative expenses decreased $107 million primarily due to cost savings realized from the 2015 workforce reductions including corresponding severance expenses.

Net interest and other increased $46 million primarily due to an increase in interest expense as a result of the increase in long-term debt in the second quarter of 2015. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - Note 20 to the consolidated financial statements.

Provision (benefit) for income taxes reflects an effective tax rate of 79% and a benefit of 30% for 2016 and 2015. The increase in the 2016 effective tax rate was primarily due to the valuation allowance increase of $1,346 million related to our U.S. benefits on foreign taxes and other federal deferred taxes.

See Item 8. Financial Statements and Supplementary Data - Note 7 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: 2016 compared to 2015

Segment income (loss)

Segment income (loss) represents income (loss) from operations excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. A portion of our corporate and operations support general and administrative 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 that affect comparability also are not allocated to operating segments

The following table reconciles segment income (loss) to net income (loss):

	Year Ended December 31,	
(In millions)	**2016**	**2015**
United States E&P	$ (415)	$ (452)
International E&P	228	112
Segment income (loss)	(187)	(340)
Items not allocated to segments, net of income taxes [(a)]	(1,900)	(1,361)
Income (loss) from continuing operations	(2,087)	(1,701)
Income (loss) from discontinued operations [(b)]	(53)	(503)
Net income (loss)	$ (2,140)	$ (2,204)

(a) See Item 8. Financial Statements and Supplementary Data - Note 6 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 E&P segment loss decreased $37 million in 2016 compared to 2015 as a result of lower DD&A expense, production costs, taxes other than income, and exploration expense, with these expense reductions more than offsetting the lower revenues as a result of decreases in both price realizations and net sales volumes.

International E&P segment income increased $116 million in 2016 compared to 2015. The increase was largely due to lower exploration expenses in 2016, as our 2015 expense included costs relating to our transition out of our conventional exploration program. The remainder of the increase was due to lower production costs and DD&A as a result of lower asset retirement costs and sales mix, and an increase in income from equity method investments, partially offset by lower price realizations.

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 2017, we experienced an increase in operating cash flows primarily due to improvements in the commodity price environment which resulted in an increase to consolidated average liquid hydrocarbons price realizations by over 30% to $42.59. Additionally, we closed on the sale of our Canadian business and other non-core assets resulting in net proceeds of $1.79 billion, which allowed us to be opportunistic with our high quality acquisitions in the Permian basin. Beyond the proceeds the non-core asset sales generated, the portfolio changes enhanced our profitability by disposing of higher unit cost operations and allowing for a more efficient allocation of our Capital Development Program to the higher return opportunities in the U.S. resource plays.

Steps taken in 2017 to continue our operating cash flow growth include the following actions:

- Improved cost structure by reducing production expense per boe in 2017.
    - United States E&P - 7% reduction to $5.57 per boe
    - International E&P - 14% reduction to $4.33 per boe
- Total 2017 net sales volumes from continuing operations increased 10% compared to 2016.

Other 2017 cash flow highlights include:

- Divested certain non-core assets resulting in net proceeds of $1.79 billion.
- We closed on multiple Permian basin acquisitions for $1.89 billion with cash on hand.
- Through multiple financing transactions we have reduced total debt by approximately $1.75 billion which will result in a reduction to our future annual interest expense of approximately $115 million.
- Expect to receive $750 million in remaining proceeds from the sale of our Canadian business by March 1, 2018.
- Expanded the capacity of the revolving credit facility from $3.3 billion to $3.4 billion.

At December 31, 2017, we had approximately $4.0 billion of liquidity consisting of $563 million in cash and cash equivalents and $3.4 billion available under our revolving credit facility. As previously discussed in our Outlook section, we are targeting a $2.3 billion Capital Development Program for 2018. We believe our current liquidity level and balance sheet, along with our non-core asset disposition program 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 2018.

Cash Flows

The following table presents sources and uses of cash and cash equivalents from continuing operations for 2017, 2016 and 2015:

	Year Ended December 31,		
(In millions)	2017	2016	2015
Sources of cash and cash equivalents			
Operating activities - continuing operations	$ 1,988	$ 901	$ 1,537
Disposals of assets, net of cash transferred to the buyer	1,787	1,219	225
Common stock issuance	—	1,236	—
Borrowings	988	—	1,996
Other	68	56	101
Total sources of cash and cash equivalents	$ 4,831	$ 3,412	$ 3,859
Uses of cash and cash equivalents			
Cash additions to property, plant and equipment	$ (1,974)	$ (1,204)	$ (3,485)
Acquisitions, net of cash acquired	(1,891)	(902)	—
Purchases of common stock	(11)	(6)	(11)
Debt repayments	(2,764)	(1)	(1,069)
Debt extinguishment costs	(46)	—	—
Dividends paid	(170)	(162)	(460)
Other	(30)	(4)	(8)
Total uses of cash and cash equivalents	$ (6,886)	$ (2,279)	$ (5,033)

Cash flows generated from operating activities in 2017 were higher as commodity prices and price realizations improved compared to 2016. This increase in price realization coupled with our increased sales volumes and continued focus on cost reductions resulted in an increase to cash flows generated from operating activities.

Proceeds from the disposals of assets for 2017 are primarily a result of the disposal of our Canadian business, and proceeds from disposals of assets in 2016 are primarily from the sale of our Wyoming upstream and midstream assets, as well as the sale of certain other non-operated CO2 and waterflood assets in West Texas and New Mexico. Disposals of assets in 2015 pertain to the sale of certain of our operated and non-operated producing properties in the Gulf of Mexico as well as natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma. 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 March 2016 from our public sale of common stock. See Item 8. Financial Statements and Supplementary Data - Note 22 to the consolidated financial statements for additional information.

Borrowings in 2017 are a result of the issuance of $1 billion of 4.4% senior unsecured notes due in 2027. Our 2015 borrowings reflect net proceeds received from the issuance of senior notes in June 2015. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 15 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 for 2017, 2016 and 2015:

	Year Ended December 31,		
(In millions)	2017	2016	2015
United States E&P	$ 2,081	$ 936	$ 2,553
International E&P	42	82	368
Corporate	27	18	25
Total capital expenditures	2,150	1,036	2,946
Change in capital expenditure accrual	(176)	168	539
Additions to property, plant and equipment	$ 1,974	$ 1,204	$ 3,485

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 $902 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 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. In November 2015, we repaid our $1 billion 0.90% senior notes upon maturity. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for additional information.

During 2017, the Board of Directors approved a $0.05 per share quarterly dividend. See Capital Requirements below for additional information about the fourth quarter dividend. During 2015 we announced an adjustment to our quarterly dividend starting in third quarter 2015, with the full-year impact resulting in a decrease of dividends paid in 2017 and 2016.

Liquidity and Capital Resources

In June 2017, we extended the maturity date of our Credit Facility from May 28, 2020, to May 28, 2021. In July 2017, we increased our $3.3 billion unsecured Credit Facility by $93 million to a total of $3.4 billion. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unaffected by the increase and term extension. We have the ability to request two additional 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, 2017, we had approximately $4.0 billion of liquidity consisting of $563 million in cash and cash equivalents and $3.4 billion available under our revolving credit facility. During the first quarter of 2018, we expect to receive $750 million in remaining proceeds from the sale of our Canadian business. 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 programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, and other amounts that may ultimately be paid in connection with contingencies.

General economic conditions, commodity prices, and financial, business and other factors could affect our operations and our ability to access the capital markets. Our corporate credit ratings as of December 31, 2017 are: Standard & Poor's Ratings Services BBB- (stable); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (stable). A downgrade in our credit ratings could increase our future cost of financing or limit our ability to access capital, and result in additional collateral requirements. See Item 1A. Risk Factors for a discussion of how a downgrade in our credit ratings could affect us.

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, 2017, we had no borrowings against our revolving credit facility.

At December 31, 2017, 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 closed on $1.8 billion of non-core asset sales during 2017, with the largest transaction being the disposal of our Canadian business. During the third quarter of 2017, we entered into separate agreements to sell certain non-core properties in our International E&P segment for combined proceeds of $53 million, before closing adjustments. We have closed on one of these agreements in 2017, and we expect the remainder of the agreements to close during 2018.

See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for additional discussion of these dispositions.

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 32% at December 31, 2017 and 29% at December 31, 2016.

(Dollars in millions)	**2017**	**2016**
Long-term debt due within one year	$ —	$ 686
Long-term debt	5,494	6,581
Total debt	$ 5,494	$ 7,267
Equity	$ 11,708	$ 17,541
Calculation		
Total debt	$ 5,494	$ 7,267
Total debt plus equity (total capitalization)	$ 17,202	$ 24,808
Debt-to-capital ratio	32%	29%

Capital Requirements

Capital Spending

Our approved Capital Development Program for 2018 is $2.3 billion. Additional details were previously discussed in Outlook.

Share Repurchase Program

The remaining share repurchase authorization as of December 31, 2017 is $1.5 billion.

Other Expected Cash Outflows

On January 30, 2018, our Board of Directors approved a dividend of $0.05 per share for the fourth quarter of 2017. The dividend is payable on March 12, 2018 to shareholders on record on February 21, 2018.

We plan to make contributions of up to $65 million to our funded pension plans during 2018. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $6 million and $21 million in 2018.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2017.

(In millions)	Total	2018	2019-2020	2021-2022	Later Years
Short and long-term debt (includes interest)[(a)]	$ 8,776	$ 256	$ 1,103	$ 1,512	$ 5,905
Lease obligations	119	29	55	31	4
Purchase obligations:					
Oil and gas activities[(b)]	108	94	8	4	2
Service and materials contracts[(c)]	115	65	48	2	—
Transportation and related contracts	1,581	313	483	241	544
Drilling rigs and fracturing crews[(d)]	21	21	—	—	—
Other	42	13	24	5	—
Total purchase obligations	1,867	506	563	252	546
Other long-term liabilities reported in the consolidated balance sheet[(e)]	486	141	77	63	205
Total contractual cash obligations[(f)]	$ 11,248	$ 932	$ 1,798	$ 1,858	$ 6,660

(a) Includes anticipated cash payments for interest of $256 million for 2018, $503 million for 2019-2020, $477 million for 2021-2022 and $2,003 million for the remaining years for a total of $3,239 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) Some contracts may be canceled at an amount less than the contract amount. Were we to elect that option where possible at December 31, 2017 our minimum commitment would be $14 million.

(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 $1,483 million. See Item 8. Financial Statements and Supplementary Data – Note 11 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, 2017, 2016 and 2015 aggregated $89 million, $166 million and $53 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.

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 2017 SEC pricing for certain benchmark prices:

		SEC Pricing 2017
WTI Crude oil (per bbl)	$	51.34
Henry Hub natural gas (per mmbtu)	$	2.98
Brent crude oil (per bbl)	$	54.39
Mont Belvieu NGLs (per bbl)	$	22.03

When determining the December 31, 2017 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 commodity prices were to decrease by approximately 10%, below average prices used to estimate 2017 proved reserves (see table above), 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 2017 proved reserves based on 2017 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 E&P	$ (2.14)	$ 183	$ 2.61	$ (224)
International E&P	$ (0.56)	$ 30	$ 0.69	$ (36)

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. 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 future impairment charges or in the recognition of income. See Item 8. Financial Statements and Supplementary Data – Note 11 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 14 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 Development Program, 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 2017 lower forecasted long-term commodity prices and the anticipated sales of certain non-core proved properties in our International E&P segment 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 an income and market approach and recognized impairments. As of December 31, 2017 our estimated undiscounted cash flows relating to our remaining long-lived assets significantly exceeded their carrying values. Long-lived assets most at risk for future impairment had estimated undiscounted cash flows that exceeded their $66 million carrying value by $22 million. See Item 8. Financial Statements and Supplementary Data Note 10 and Note 14 to the consolidated financial statements for discussion of impairments recorded in 2017, 2016 and 2015 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 development 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 of a reporting unit with goodwill 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 E&P includes goodwill. We performed our annual impairment test in the second quarter of 2017 for the International E&P reporting unit and no impairment was required. As of the date of our last goodwill impairment assessment, our International E&P reporting unit fair value exceeded its book value by over 40%.

We estimate the fair values of our International E&P reporting unit using a combination of market and income approaches. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. The market approach referenced 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. 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 12 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 13 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.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act ("Tax Reform Legislation"), which made significant changes to U.S. federal income tax law. We expect that certain aspects of the Tax Reform Legislation will positively impact our future after-tax earnings in the U.S., primarily due to the lower federal statutory tax rate. The Tax Reform Legislation is a comprehensive bill containing several other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, that are not expected to have a material effect on our results. The ultimate impact of the Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us, as well as additional regulatory guidance that may be issued. Item 8. Financial Statements and Supplementary Data – Note 7 to the consolidated financial statements for further disclosure regarding Tax Reform Legislation.

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, 2017, we reflect a valuation allowance in our Consolidated Balance Sheet of $926 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 $898 million, which will expire in 2035, 2036 and 2037. 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 is 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.

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
- health care cost projections.

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 $250 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, 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 3.55% for our U.S. pension plans and 3.54% 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	$ (4)	$ —	$ 4	$ —
Other U.S. postretirement benefit plans	$ (5)	$ —	$ 5	$ —

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 17 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 and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

See Item 8. Financial Statements and Supplementary Data – Notes 13 and 14 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 2017 and 2016 were impacted by crude oil and natural gas derivatives related to a portion of our forecasted United States E&P sales. The table below provides a summary of open positions as of December 31, 2017 and the weighted average price for those contracts:

Crude Oil

	2018				2019	
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter
Three-Way Collars [(a)]						
Volume (Bbls/day)	85,000	85,000	85,000	85,000	10,000	10,000
Weighted average price per Bbl:						
Ceiling	$56.38	$56.38	$56.96	$56.96	$60.00	$60.00
Floor	$51.65	$51.65	$51.53	$51.53	$55.00	$55.00
Sold put	$45.00	$45.00	$44.65	$44.65	$47.00	$47.00
Swaps						
Volume (Bbls/day)	20,000	20,000	—	—	—	—
Weighted average price per Bbl	$55.12	$55.12	$—	$—	$—	$—
Basis Swaps [(b)]						
Volume (Bbls/day)	5,000	5,000	10,000	10,000	—	—
Weighted average price per Bbl	$(0.60)	$(0.60)	$(0.67)	$(0.67)	$—	$—

(a) Between January 1, 2018 and February 12, 2018, we entered into 10,000 Bbls/day of three-way collars for July - December 2018 with an average ceiling price of $63.51, a floor price of $57.00, and a sold put price of $50.00 and 20,000 Bbls/day of three-way collars for January - June 2019 with an average ceiling price of $67.92, a floor price of $53.50, and a sold put price of $46.50.

(b) The basis differential price is between WTI Midland and WTI Cushing.

Natural Gas

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Three-Way Collars				
Volume (MMBtu/day)	200,000	160,000	160,000	160,000
Weighted average price per MMBtu				
Ceiling	$3.79	$3.61	$3.61	$3.61
Floor	$3.08	$3.00	$3.00	$3.00
Sold put	$2.55	$2.50	$2.50	$2.50

The following table provides a sensitivity analysis of the projected incremental effect on income (loss) from operations of a hypothetical 10% change in NYMEX WTI and Henry Hub prices on our open commodity derivative instruments as of December 31, 2017:

(In millions)	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Crude oil derivatives	$ (180)	$ 149
Natural gas derivatives	(8)	7
Total	$ (188)	$ 156

Interest Rate Risk

At December 31, 2017, our portfolio of long-term debt was substantially comprised of fixed rate instruments. 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. Sensitivity analysis of the incremental effect of a hypothetical 10% change in interest rates on our financial assets and liabilities as of December 31, 2017, is provided in the following table.

(In millions)	Fair Value	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Financial assets (liabilities): [(a)]			
Long-term debt, including amounts due within one year	$ (5,976) [(b)(c)]	$ 190	$ (202)

[(a)] Fair values of cash and cash equivalents, receivables, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.
[(b)] Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.
[(c)] Excludes capital leases.

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
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, 2017.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2017 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
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 as of December 31, 2017 and 2016, 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, 2017, 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, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

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 22, 2018

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, 2017	2016	2015
Revenues and other income:			
Sales and other operating revenues, including related party	$ 4,211	$ 2,930	$ 4,136
Marketing revenues	162	240	499
Income from equity method investments	256	175	145
Net gain (loss) on disposal of assets	58	389	120
Other income	78	53	53
Total revenues and other income	4,765	3,787	4,953
Costs and expenses:			
Production	706	712	979
Marketing, including purchases from related parties	168	245	500
Other operating	431	484	410
Exploration	409	323	971
Depreciation, depletion and amortization	2,372	2,156	2,721
Impairments	229	67	721
Taxes other than income	183	151	216
General and administrative	400	481	588
Total costs and expenses	4,898	4,619	7,106
Income (loss) from operations	(133)	(832)	(2,153)
Net interest and other	(270)	(332)	(286)
Loss on early extinguishment of debt	(51)	—	—
Income (loss) from continuing operations before income taxes	(454)	(1,164)	(2,439)
Provision (benefit) for income taxes	376	923	(738)
Income (loss) from continuing operations	(830)	(2,087)	(1,701)
Income (loss) from discontinued operations	(4,893)	(53)	(503)
Net income (loss)	$ (5,723)	$ (2,140)	$ (2,204)
Per Share Data			
Basic:			
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)
Income (loss) from discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)
Diluted:			
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)
Income (loss) from discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)
Dividends	$ 0.20	$ 0.20	$ 0.68
Weighted average shares:			
Basic	850	819	677
Diluted	850	819	677

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Net income (loss)	$ (5,723)	$ (2,140)	$ (2,204)
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	21	16	228
Income tax provision (benefit)	7	(4)	(86)
Postretirement and postemployment plans, net of tax	28	12	142
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	2	1	—
Other comprehensive income (loss)	21	52	142
Comprehensive income (loss)	$ (5,702)	$ (2,088)	$ (2,062)

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, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 563	$ 2,488
Receivables, less reserve of $12 and $6	1,082	748
Notes receivable	748	—
Inventories	126	136
Other current assets	36	66
Current assets held for sale	11	227
Total current assets	2,566	3,665
Equity method investments	847	931
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,564 and $20,255	17,665	16,727
Goodwill	115	115
Other noncurrent assets	764	558
Noncurrent assets held for sale	55	9,098
Total assets	$ 22,012	$ 31,094
Liabilities		
Current liabilities:		
Accounts payable	$ 1,395	$ 967
Payroll and benefits payable	108	129
Accrued taxes	177	94
Other current liabilities	288	243
Long-term debt due within one year	—	686
Current liabilities held for sale	—	121
Total current liabilities	1,968	2,240
Long-term debt	5,494	6,581
Deferred tax liabilities	833	769
Defined benefit postretirement plan obligations	362	345
Asset retirement obligations	1,428	1,602
Deferred credits and other liabilities	217	225
Noncurrent liabilities held for sale	2	1,791
Total liabilities	10,304	13,553
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 937 million and 937 million shares, respectively (par value $1 per share, 1.1 billion shares authorized)	937	937
Held in treasury, at cost – 87 million and 90 million shares	(3,325)	(3,431)
Additional paid-in capital	7,379	7,446
Retained earnings	6,779	12,672
Accumulated other comprehensive loss	(62)	(83)
Total stockholders' equity	11,708	17,541
Total liabilities and stockholders' equity	$ 22,012	$ 31,094

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	Year Ended December 31, 2017	2016	2015
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income (loss)	$ (5,723)	$ (2,140)	$ (2,204)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations	4,893	53	503
Depreciation, depletion and amortization	2,372	2,156	2,721
Impairments	229	67	721
Exploratory dry well costs and unproved property impairments	323	220	867
Net (gain) loss on disposal of assets	(58)	(389)	(120)
Deferred income taxes	(61)	828	(804)
Net (gain) loss on derivative instruments	(11)	63	(126)
Net cash received (paid) in settlement of derivative instruments	98	61	55
Stock based compensation	50	48	45
Equity method investments, net	20	17	33
Changes in:			
Current receivables	(334)	67	790
Inventories	10	64	25
Current accounts payable and accrued liabilities	297	(137)	(906)
All other operating, net	(117)	(77)	(63)
Net cash provided by operating activities from continuing operations	1,988	901	1,537
Investing activities:			
Additions to property, plant and equipment	(1,974)	(1,204)	(3,485)
Acquisitions, net of cash acquired	(1,891)	(902)	—
Disposal of assets, net of cash transferred to the buyer	1,787	1,219	225
Equity method investments - return of capital	64	55	77
Purchases of short term investments	—	—	(925)
Maturities of short term investments	—	—	925
All other investing, net	(30)	(1)	24
Net cash used in investing activities from continuing operations	(2,044)	(833)	(3,159)
Financing activities:			
Borrowings	988	—	1,996
Debt repayments	(2,764)	(1)	(1,069)
Debt extinguishment costs	(46)	—	—
Common stock issuance	—	1,236	—
Purchases of common stock	(11)	(6)	(11)
Dividends paid	(170)	(162)	(460)
All other financing, net	—	1	(5)
Net cash provided by (used in) financing activities	(2,003)	1,068	451
Cash Flow from Discontinued Operations:			
Operating activities	141	177	39
Investing activities	(13)	(41)	(43)
Changes in cash included in current assets held for sale	2	100	90
Net increase in cash and cash equivalents of discontinued operations	130	236	86
Effect of exchange rate changes on cash and cash equivalents:	4	(3)	(3)
Net increase (decrease) in cash and cash equivalents	(1,925)	1,369	(1,088)
Cash and cash equivalents at beginning of period	2,488	1,119	2,207
Cash and cash equivalents at end of period	$ 563	$ 2,488	$ 1,119

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

(In millions)	Total Equity of Marathon Oil Stockholders: Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Equity
December 31, 2014 Balance	$ —	$ 770	$ (3,642)	$ 6,531	$ 17,638	$ (277)	$ 21,020
Shares issued - stock-based compensation	—	—	96	(32)	—	—	64
Shares repurchased	—	—	(8)	—	—	—	(8)
Stock-based compensation	—	—	—	(1)	—	—	(1)
Net loss	—	—	—	—	(2,204)	—	(2,204)
Other comprehensive loss	—	—	—	—	—	142	142
Dividends paid	—	—	—	—	(460)	—	(460)
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	—	—	—	—	(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	—	—	—	—	(170)	—	(170)
Common stock issuance	—	—	—	—	—	—	—
December 31, 2017 Balance	$ —	$ 937	$ (3,325)	$ 7,379	$ 6,779	$ (62)	$ 11,708

(Shares in millions)	Preferred Stock	Common Stock	Treasury Stock
December 31, 2014 Balance	—	770	95
Shares issued - stock-based compensation	—	—	(2)
Shares repurchased	—	—	—
December 31, 2015 Balance	—	770	93
Shares issued - stock-based compensation	—	—	(3)
Shares repurchased	—	—	—
Common stock issuance	—	167	—
December 31, 2016 Balance	—	937	90
Shares issued - stock-based compensation	—	—	(3)
Shares repurchased	—	—	—
Common stock issuance	—	—	—
December 31, 2017 Balance	—	937	87

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

1. Summary of Principal Accounting Policies

We are a global energy 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 include the accounts of our controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

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

As discussed above 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 2017. The characteristics and composition of our North America E&P reporting segment remained unchanged and there was no effect on previously reported segment information. As all our remaining properties within the segment are located within the United States, we concluded that our North America E&P segment would be renamed United States E&P segment, effective June 30, 2017. During the year, no changes occurred to our International E&P segment. See Note 6 for further information on our reportable segments.

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 – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

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.

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.

Short-term Investments - Our short-term investments are comprised of bank time deposits with original maturities of greater than three months but less than twelve months. They are classified as held-to-maturity investments, which are recorded at amortized cost.

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 - We hold two notes receivable from the sale of our Canadian business, which closed in the second quarter of 2017. Both notes receivable were initially recorded at fair value and are reported at amortized cost. The notes receivable are evaluated for collectability on an individual basis each reporting period, based on the financial condition of the debtor. No allowances for credit losses were established for the notes receivable as of December 31, 2017. 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 14 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.

During the first quarter of 2017, we adopted the accounting standards update issued by the FASB in March 2016 pertaining to share-based payment transactions. As a result of this adoption, all cash payments for withheld shares made to taxing authorities on the employees' behalf are presented within the financing activities section instead of the operating activities section of the statement of cash flows. We elected the retrospective method for adoption of this update and the change in the statement of cash flows is not material for the years ended December 31, 2016 or 2015. Excess tax benefits were classified as an operating activity within the statement of cash flows on a prospective basis beginning in 2017; as such, prior periods were not adjusted. See Note 2 for additional discussion.

2. Accounting Standards

Not Yet Adopted

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. This standard is effective for us in the first quarter of 2018 and 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 will adopt this new standard in the first quarter of 2018 using the modified retrospective method. The adoption of this ASU will not have a material impact on our consolidated results of operations, financial position or cash flows. However, as a result of this standard we will change our presentation of marketing revenues and marketing expenses from the current gross presentation to a net presentation for a portion of our international contracts. For the years ended December 31, 2017 and 2016, we expect the impact of this change to be a reduction of approximately $130 million and $100 million, respectively, in marketing revenue and expenses in our consolidated results of operations. We will 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, beginning in the first quarter of 2018.

In March 2017, the FASB issued a new accounting standards update that will change how employers that sponsor defined pension and/or other postretirement benefit plans present the net periodic benefit cost in the income statement. Employers will 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. Only the service cost component will be eligible for capitalization in assets. We will adopt this standard in the first quarter of 2018 on a retrospective basis, and will reclassify certain amounts from general and administrative expense to the exploration, production and our new other net periodic benefit costs expense categories on our consolidated statements of income.

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 will adopt this standard during the first quarter of 2018 on a retrospective basis with no significant impact on our consolidated results of operations, financial position or 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, entities will 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. We will adopt this standard in the first quarter of 2018 on a retrospective basis and do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

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. We will adopt this standard in the first quarter of 2018 using the modified retrospective approach with no material impact on our consolidated results of operations, financial position or cash flows.

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 an entity 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. We will adopt this standard in the first quarter of 2018 on a prospective basis. Since we adopted the standard on a prospective basis, adoption of this standard will not have a significant impact on our consolidated results of operations, financial position or cash flows for prior periods.

In January 2016, the FASB issued an accounting standards update that addresses certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. We plan to adopt this standard in the first quarter of 2018 and do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

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. While we will have to recognize a right of use asset and lease liability on the adoption date, we continue to evaluate the provisions of this accounting standards update and assessing the effects it will have on our consolidated results of operations, financial position or cash flows.

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. Early adoption is permitted in any interim or annual period. The amendment mandates modified retrospective adoption when accounting for hedge relationships in effect as of the adoption date. We are evaluating the provisions of this accounting standards update, including transition requirements, and are assessing the impact it may have on our results of operations, financial position, or cash flows.

In January 2017, the FASB issued a new accounting standards update that eliminates the requirement to calculate the implied fair value of the goodwill (i.e., Step 2 of goodwill impairment test under the current guidance) to measure a goodwill impairment charge. The standard will require entities to record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value (i.e., 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. Since we will adopt the standard on a prospective basis, we do not expect an impact on our consolidated results of operations, financial position or cash flows for prior periods.

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

In March 2016, the FASB issued a new accounting standards update that changes several aspects of accounting for share-based payment transactions, including a requirement to recognize all excess tax benefits and tax deficiencies as income tax expense or benefit in the income statement, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This standard was effective for us in the first quarter of 2017. The new standard requires a company to make a policy election on how it accounts for forfeitures; we elected to continue estimating forfeitures using the same methodology practiced prior to adoption of this standard. See Note 1 for the impact this standard has on the presentation of our financial statements.

In July 2015, the FASB issued an update that requires an entity to measure inventory at the lower of cost or net realizable value. This excludes inventory measured using LIFO or the retail inventory method. This standard was effective for us in the first quarter of 2017, 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.

3. Income (Loss) 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 years, provided the effect is not antidilutive. The per share calculations below exclude 11 million, 13 million and 13 million stock options in 2017, 2016 and 2015 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	**2017**	**2016**	**2015**
Income (loss) from continuing operations	$ (830)	$ (2,087)	$ (1,701)
Income (loss) from discontinued operations	(4,893)	(53)	(503)
Net income (loss)	$ (5,723)	$ (2,140)	$ (2,204)
Weighted average common shares outstanding	850	819	677
Per basic share:			
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)
Income (loss) from discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)
Per diluted share:			
Income (loss) from continuing operations	$ (0.97)	$ (2.55)	$ (2.51)
Income (loss) from discontinued operations	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ (6.73)	$ (2.61)	$ (3.26)

4. Acquisitions

2017 - United States E&P

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 our acquisitions of approximately 91,000 net acres in the Permian basin, including over 70,000 net acres in the Northern Delaware basin of New Mexico. On May 1, 2017, we closed on our acquisition with BC Operating, Inc. and other entities for $1.1 billion in cash, subject to post-closing adjustments, to acquire approximately 70,000 net surface acres and current production of approximately 5,000 net barrels of oil equivalent per day. On June 1, 2017, we closed on our acquisition with Black Mountain Oil & Gas and other private sellers for approximately $700 million in cash, subject to post-closing adjustments, to acquire approximately 21,000 net surface acres. The purchase price for these acquisitions was paid with cash on hand. We accounted for these transactions as asset acquisitions, with substantially all of the purchase price allocated to unproved property within property, plant and equipment.

2016 - United States E&P

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

Oil Sands Mining Segment

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 ("CNRL") for $2.5 billion, excluding closing adjustments. Under the terms of the agreement, $1.8 billion was paid to us upon closing and the remaining proceeds will be paid in the first quarter of 2018. At closing we received two notes receivable for the remaining proceeds, each with a face value of $375 million. We recorded these notes receivable at fair value, see Note 14 for fair value measurements. Our notes receivable are with 10084751 Canada Limited ("Canada Limited"), an affiliate of Shell Canada Limited, and CNRL. The Canada Limited note receivable is guaranteed by Shell Canada Limited and the CNRL note receivable is guaranteed by Toronto Dominion Bank. In the first quarter of 2017, we recorded an after-tax non-cash impairment charge of $4.96 billion primarily related to the property, plant and equipment of our Canadian business. 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 second quarter results of operations from our Canadian business that were recorded in our financial statements but 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 consolidated statements of income as discontinued operations:

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Total sales and other revenues and other income	$ 431	$ 863	$ 908
Net gain (loss) on disposal of assets	(43)	—	—
Total revenues and other income	388	863	908
Costs and expenses:			
Production expenses	254	601	715
Exploration expenses	—	7	347
Depreciation, depletion and amortization	40	239	236
Impairments	6,636	—	31
Other	25	87	98
Total costs and expenses	6,955	934	1,427
Pretax income (loss) from discontinued operations	(6,567)	(71)	(519)
Provision (benefit) for income taxes	(1,674)	(18)	(16)
Income (loss) from discontinued operations	$ (4,893)	$ (53)	$ (503)

The following table presents the carrying value of the major categories of assets and liabilities of our Canadian business reported as discontinued operations and other non-core international assets and liabilities from continuing operations, that are reflected as held for sale on our consolidated balance sheets at December 31, 2017 and December 31, 2016:

(In millions)	**December 31, 2017**	**December 31, 2016**
Assets held for sale		
Current assets:		
Cash and cash equivalents	$ —	$ 2
Accounts receivables	—	129
Inventories	—	91
Other	—	4
Total current assets held for sale—discontinued operations	—	226
Total current assets held for sale—continuing operations	11	1
Total current assets held for sale	$ 11	$ 227
Noncurrent assets:		
Property, plant and equipment, net	$ —	$ 8,991
Other	—	106
Total noncurrent assets held for sale—discontinued operations	—	9,097
Total noncurrent assets held for sale—continuing operations	55	1
Total noncurrent assets held for sale	$ 55	$ 9,098
Liabilities associated with assets held for sale		
Current liabilities:		
Accounts payable	$ —	$ 111
Other	—	10
Total current liabilities held for sale—discontinued operations	—	121
Total current liabilities held for sale—continuing operations	—	—
Total current liabilities held for sale	$ —	$ 121
Noncurrent liabilities:		
Asset retirement obligations	$ —	$ 95
Deferred tax liabilities	—	1,669
Other	—	20
Total noncurrent liabilities held for sale—discontinued operations	—	1,784
Total noncurrent liabilities held for sale—continuing operations	2	7
Total noncurrent liabilities held for sale	$ 2	$ 1,791

United States E&P Segment

As disclosed above, we closed on the sale of our Canadian business in May of 2017. This sale included interests in our exploration stage in-situ leases which were included within our historically named North America E&P Segment. See Note 6 for further detail on our segments. These interests have been reflected as discontinued operations and are included within the disclosure above.

In July 2017, we entered into an agreement to sell certain conventional assets in Oklahoma. We closed on the sale in September 2017 for proceeds of $25 million, and recognized a pre-tax gain of $21 million.

In September 2016, we entered into an agreement to sell certain non-operated CO2 and waterflood assets in West Texas and New Mexico. The sale closed in late October for proceeds of $235 million, and we recognized a total 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.

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

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.

In November 2015, we entered into an agreement to sell 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. The transaction closed in December 2015, excluding the Neptune field, for proceeds of $111 million. A $228 million pretax gain was recorded in the fourth quarter of 2015. The Neptune field transaction closed during the first quarter of 2016 for cash proceeds of $4 million.

In August 2015, we closed the sale of our East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets for proceeds of $100 million and recorded a pretax loss of $1 million. During the second quarter of 2015, we recorded a non-cash impairment charge of $44 million related to these assets (see Note 14).

International E&P Segment

In the third quarter of 2017, we entered into separate agreements to sell certain non-core properties in our International E&P segment for combined proceeds of $53 million, before closing adjustments. We closed on one of the asset sales in the second half of 2017 and recognized no net pre-tax gain or loss on sale. The remaining asset sale is expected to close during 2018 and is classified as held for sale in the consolidated balance sheet as of December 31, 2017, with total assets of $66 million and total liabilities of $2 million. See Note 10 for further detail on impairment expenses recognized concurrently with these agreements.

In the third quarter of 2015, we entered into agreements to sell our East Africa exploration acreage in Ethiopia and Kenya. A pretax loss of $109 million was recorded in the third quarter of 2015. This transaction closed during the first quarter of 2016.

6. Segment Information

We have two reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers.

- United States E&P ("U.S. E&P") – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States
- International E&P ("Int'l E&P") – 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 segments, net of income taxes, attributable to the operating segments. A portion of our corporate and operations support general and administrative costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Additionally, items which affect comparability such as gains or losses on dispositions, certain impairments, change in tax expense associated with a tax rate change, changes in our valuation allowance, unrealized gains or losses on 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 periods presented. Additionally, we renamed our North America E&P segment to United States E&P segment effective June 30, 2017 in all periods presented. See Note 1 for further information.

Year Ended December 31, 2017 *(In millions)*	U.S. E&P	Int'l E&P	Not Allocated to Segments	Total
Sales and other operating revenues	$ 3,138	$ 1,154	$ (81) [b]	$ 4,211
Marketing revenues	29	133	—	162
Total revenues	3,167	1,287	(81)	4,373
Income from equity method investments	—	256	—	256
Net gain on disposal of assets and other income	13	6	117 [c]	136
Less:				
Production expenses	476	229	1	706
Marketing costs	36	132	—	168
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	32	249 [f]	400
Net interest and other	—	—	270 [g]	270
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.
(c) Primarily related to 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 E&P segment. (See Note 10).
(e) Primarily related to proved property impairments associated with certain non-core properties within our International E&P segment. (See Note 10).
(f) Includes pension settlement loss of $32 million (see Note 17).
(g) Includes a gain of $47 million resulting from the termination of our forward starting interest rate swaps. (See Note 13.)
(h) Primarily related to the make-whole call provisions paid upon redemption of our senior unsecured notes. (See Note 15.)

Year Ended December 31, 2016 *(In millions)*	U.S. E&P	Int'l E&P	Not Allocated to Segments	Total
Sales and other operating revenues	$ 2,375	$ 665	$ (110) [b]	$ 2,930
Marketing revenues	135	105	—	240
Total revenues	2,510	770	(110)	3,170
Income (loss) from equity method investments	—	175	—	175
Net gain on disposal of assets and other income	28	32	382 [c]	442
Less:				
Production expenses	486	226	—	712
Marketing costs	142	103	—	245
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	35	352 [g]	481
Net interest and other	—	—	332	332
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.
(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 decision to not drill remaining Gulf of Mexico undeveloped leases (See Note 10).
(f) Proved property impairments (see Note 10).
(g) Includes pension settlement loss of $103 million and severance related expenses associated with workforce reductions of $8 million (see Note 17).
(h) Increased valuation allowance on certain of our deferred tax assets $1,346 million (see Note 7).

Year Ended December 31, 2015 *(In millions)*	U.S. E&P	Int'l E&P	Not Allocated to Segments	Total
Sales and other operating revenues	$ 3,358	$ 728	$ 50 [b]	$ 4,136
Marketing revenues	396	103	—	499
Total revenues	3,754	831	50	4,635
Income from equity method investments	—	157	(12) [c]	145
Net gain on disposal of assets and other income	24	27	122 [d]	173
Less:				
Production expenses	724	255	—	979
Marketing costs	401	99	—	500
Other operating	335	48	27	410
Exploration	314	101	556 [e]	971
Depreciation, depletion and amortization	2,377	295	49	2,721
Impairments	2	—	719 [f]	721
Taxes other than income	215	—	1	216
General and administrative	127	44	417 [g]	588
Net interest and other	—	—	286	286
Income tax provision (benefit)	(265)	61	(534)	(738)
Segment income (loss) / Income (loss) from continuing operations	$ (452)	$ 112	$ (1,361)	$ (1,701)
Capital expenditures [a]	$ 2,553	$ 368	$ 25	$ 2,946

(a) Includes accruals.
(b) Unrealized gain on commodity derivative instruments.
(c) Partial impairment of investment in equity method investee (See Note 14).
(d) Primarily related to gain on sale of our properties and interests in the Gulf of Mexico, partially offset by the loss on sale of East Africa exploration acreage (see Note 5).
(e) Unproved property impairments associated with lower forecasted commodity prices and change in conventional exploration strategy (See Note 10).

(f) Includes goodwill impairment (see Note 12) and proved property impairments (see Note 10).
(g) Includes pension settlement loss of $119 million (see Note 17) and severance related expenses associated with workforce reductions of $55 million.

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

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
United States	$ 3,086	$ 2,400	$ 3,804
Equatorial Guinea	530	444	444
Libya	431	54	—
U.K.	289	263	380
Other international	37	9	7
Total revenues	$ 4,373	$ 3,170	$ 4,635

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. In 2015, sales to Shell Oil and its affiliates accounted for approximately 10% of our total revenues.

The following summarizes revenues by product line.

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Crude oil and condensate	$ 3,477	$ 2,605	$ 3,963
Natural gas liquids	338	198	203
Natural gas	510	356	464
Other	48	11	5
Total revenues	$ 4,373	$ 3,170	$ 4,635

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

	December 31,	
(In millions)	**2017**	**2016**
United States	$ 15,971	$ 14,272
Equatorial Guinea	1,582	1,794
Other international	959	1,592
Total long-lived assets	$ 18,512	$ 17,658

7. Income Taxes

Income (loss) before tax expense for continuing operations was:

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
United States	$ (783)	$ (1,449)	$ (2,384)
Foreign	329	285	(55)
Total	$ (454)	$ (1,164)	$ (2,439)

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2017			2016			2015		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (32)	$ 41	$ 9	$ 2	$ 836	$ 838	$ (41)	$ (684)	$ (725)
State and local	(14)	2	(12)	2	8	10	(8)	(18)	(26)
Foreign	483	(104)	379	91	(16)	75	115	(102)	13
Total	$ 437	$ (61)	$ 376	$ 95	$ 828	$ 923	$ 66	$ (804)	$ (738)

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)	2017	2016	2015
Total pre-tax income (loss) from continuing operations	$ (454)	$ (1,164)	$ (2,439)
Total income tax expense (benefit)	$ 376	$ 923	$ (738)
Effective income tax expense (benefit) rate on continuing operations	83%	79%	(30)%
Income taxes at the statutory tax rate of 35% [(a)]	$ (159)	$ (407)	$ (854)
Effects of foreign operations	140	47	(55)
Adjustments to valuation allowances	446	1,270	95
State income taxes	(19)	9	(15)
Tax law change	(35)	6	(3)
Goodwill impairment	—	—	94
Other federal tax effects	3	(2)	—
Income tax expense (benefit) on continuing operations	$ 376	$ 923	$ (738)

[(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.

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 appears in the "Not Allocated to Segments" column of the tables in Note 6.

Effects of foreign operations – The effects of foreign operations increased our tax expense in 2017, 2016, and 2015 due to the mix of pretax income between high and low tax jurisdictions. This increase primarily relates to increased sales volumes in Libya during 2017 where the tax rate is 93.5%. Excluding Libya, the effective tax rates on continuing operations would be an expense of 5% in 2017, an expense of 79% in 2016, and a benefit of 29% in 2015.

Adjustments to valuation allowances - Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. In 2017, we recorded a $446 million valuation allowance primarily related to current year activity in the U.S. Included within the $446 million is a $41 million out-of-period adjustment as a result of identifying certain deferred tax assets for which the impact should have been recorded to other comprehensive income, but had been recorded to income from continuing operations in 2016.

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 changes 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 standards. 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. We recorded a net benefit of $35 million, classified as a receivable within other noncurrent assets on the consolidated balance sheet, during the fourth quarter of 2017 related to the repeal of the corporate AMT. Although the $35 million net benefit represents what we believe is a reasonable estimate of the impact of the income tax effects of the Act on our consolidated financial statements as of December 31, 2017, it should be considered provisional. We do not expect to pay U.S. federal cash taxes on the deemed repatriation due to an accumulated deficit in foreign earnings for tax purposes.

Once we finalize certain tax positions when we file our 2017 federal tax return, we will be able to conclude whether any further adjustments are required to our net tax position as of December 31, 2017. Any adjustments to these provisional amounts will be reported as a component of income tax expense (benefit) in the reporting period in which any such adjustments are determined, which will be no later than the fourth quarter of 2018.

Deferred tax assets and liabilities resulted from the following:

(In millions)	Year Ended December 31, 2017	2016
Deferred tax assets:		
Employee benefits	$ 111	$ 228
Operating loss carryforwards	1,030	1,065
Capital loss carryforwards	3	4
Foreign tax credits	611	4,430
Other credit carryforwards	—	35
Investments in subsidiaries and affiliates	174	91
Other	69	86
Subtotal	1,998	5,939
Valuation Allowance	(926)	(4,301)
Total deferred tax assets	1,072	1,638
Deferred tax liabilities:		
Property, plant and equipment	1,332	3,672
Accrued revenue	81	75
Other	3	(7)
Total deferred tax liabilities	1,416	3,740
Net deferred tax liabilities	$ 344	$ 2,102

Foreign Tax Credits - As a result of U.S. tax reform, we have reduced our foreign tax credits at December 31, 2017, which are offset by a corresponding reduction in valuation allowance, by $3,819 million due to the remote likelihood these credits will be utilized before expiration. We have not elected any of our foreign earnings to be permanently reinvested abroad. Additionally due to U.S. tax reform, we do not expect future foreign earnings from operations to be subject to tax in the U.S. The remaining foreign tax credits, which are offset by a valuation allowance, expire in 2022 through 2027.

Operating loss carryforwards - At December 31, 2017, our operating loss carryforwards before valuation allowance includes $898 million from the U.S. that expire in 2035-2037. Foreign operating loss carryforwards include $13 million that begin to expire in 2018. State operating loss carryforwards of $119 million expire in 2018 through 2037.

Valuation allowances – At December 31, 2017, we reflect a valuation allowance in our consolidated balance sheet of $926 million against our net deferred tax assets in various jurisdictions in which we operate. The reduction primarily related to the reduction of foreign tax credits in the U.S. In 2016 and 2015, we increased our valuation allowance by $1,268 million and $99 million respectively.

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

(In millions)	December 31, 2017	2016
Assets:		
Other noncurrent assets	$ 489	$ 336
Liabilities:		
Noncurrent deferred tax liabilities	833	769
Noncurrent liabilities held for sale	—	1,669
Net deferred tax liabilities	$ 344	$ 2,102

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 2010-11. 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 adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. See Note 24 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, 2017, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2008-2016
Equatorial Guinea	2007-2016
Libya	2012-2016
United Kingdom	2008-2016

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2017	2016	2015
Beginning balance	$ 66	$ 65	$ 80
Additions for tax positions of prior years	83	6	1
Reductions for tax positions of prior years	(3)	(5)	—
Settlements	(20)	—	(7)
Statute of limitations	—	—	(9)
Ending balance	$ 126	$ 66	$ 65

If the unrecognized tax benefits as of December 31, 2017 were recognized, $10 million would affect our effective income tax rate. As of December 31, 2017, there are $83 million uncertain tax positions for which it is reasonably possible that the amount could significantly change during the next twelve months. If this were to significantly change, we estimate that any revisions to current and deferred tax liabilities would have no cumulative adverse earnings impact on our consolidated results of operations.

The U.K. tax authorities have challenged the timing of deductibility for certain Brae area decommissioning costs. In the fourth quarter of 2017, we received an adverse ruling from the U.K. first-tier tax tribunal. As a result of the adverse ruling, in the fourth quarter of 2017 we established an uncertain tax position. We have appealed the ruling, but were required to pay the disputed tax amount and associated interest in order to pursue the appeal. The payment of the disputed tax and interest, approximately $108 million, is not considered a settlement of the tax dispute with the U.K. tax authorities. If we prevail in appeals, we will be refunded the tax and interest paid, however, if we do not prevail no further material cash payments are expected due to the initial payment required to appeal the adverse ruling. See Note 24 for further detail.

Interest and penalties are recorded as part of the tax provision and were $2 million, $1 million and $1 million related to unrecognized tax benefits in 2017, 2016 and 2015. As of December 31, 2017 and 2016, $25 million and $15 million of interest and penalties were accrued related to income taxes.

8. 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)	2017	2016
Crude oil and natural gas	$ 9	$ 6
Supplies and other items	117	130
Inventories	$ 126	$ 136

9. Property, Plant and Equipment

	December 31,	
(In millions)	2017	2016
United States E&P	$ 15,867	$ 14,158
International E&P	1,710	2,470
Corporate	88	99
Net property, plant and equipment	$ 17,665	$ 16,727

At December 31, 2017, 2016 and 2015 we had total deferred exploratory well costs as follows:

	December 31,		
(In millions)	2017	2016	2015
Amounts capitalized less than one year after completion of drilling	$ 263	$ 131	$ 352
Amounts capitalized greater than one year after completion of drilling	32	118	85
Total deferred exploratory well costs	$ 295	$ 249	$ 437
Number of projects with costs capitalized greater than one year after completion of drilling	1	3	2

(In millions)	2017	2016	2015
Beginning balance	$ 249	$ 437	$ 573
Additions	212	299	610
Charges to expense [(a)]	(64)	(23)	(111)
Transfers to development	(102)	(388)	(635)
Dispositions[(b)]	—	(76)	—
Ending balance	$ 295	$ 249	$ 437

(a) Includes $64 million in exploratory well costs being expensed as a result of our agreement to sell Diaba License G4-223 in the Republic of Gabon in August of 2017. See Note 10 for further detail.

(b) Includes sale of GOM assets in 2016.

Exploratory well costs capitalized greater than one year after completion of drilling are associated with one project in E.G. with costs of $32 million as of December 31, 2017. Management believes this project with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development based on current plans. For this project in E.G., drilling was completed on the Rodo well in Alba Block Sub Area B, offshore E. G. in the first quarter of 2015, and we have since completed a seismic feasibility study. In 2017, we received approval for and proceeded to perform a seismic reprocessing program. After completion of this program we will evaluate drilling opportunities within Sub Area B.

10. Impairments and Exploration Expenses

Impairments

As a result of our announced disposition of our Canadian business in the first quarter of 2017, we recorded a pre-tax non-cash impairment charge of $6.6 billion primarily related to property, plant and equipment. This impairment in 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 summarizes impairment charges of proved properties:

	Year Ended December 31,		
(in millions)	2017	2016	2015
Total impairments	$ 229	$ 67	$ 721

- **2017** - Impairments were primarily a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core proved properties in our International E&P segment of $136 million. Additionally, included in proved property impairments was $89 million relating to the Gulf of Mexico and certain conventional Oklahoma assets primarily as a result of lower forecasted long-term commodity prices.

- **2016** - Impairments of $67 million consisted primarily of proved properties in Oklahoma and the Gulf of Mexico as a result of lower forecasted commodity prices and revisions to estimated abandonment costs.
- **2015** - Impairments included $340 million for the goodwill impairment of the United States E&P reporting unit, and $335 million related to proved properties (primarily in Colorado and the Gulf of Mexico) as a result of lower forecasted commodity prices, and $44 million associated with our disposition of natural gas assets in East Texas, North Louisiana and Wilburton, Oklahoma.

See Note 6 for relevant detail regarding segment presentation, Note 12 for further detail regarding the goodwill impairment and Note 14 for fair value measurements related to impairments of proved properties and long-lived assets.

Exploration expense

The following table summarizes the components of exploration expenses:

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Exploration Expenses			
Unproved property impairments	$ 246	$ 195	$ 655
Dry well costs	77	25	212
Geological and geophysical	25	5	31
Other	61	98	73
Total exploration expenses	$ 409	$ 323	$ 971

Unproved property impairments and dry well costs

- **2017** - As a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core properties in our International E&P segment, we recorded a non-cash charge of $159 million comprised of $95 million in unproved property impairments; and $64 million in dry well costs related to our Diaba License G4-223 in the Republic of Gabon. Also, because of our decision not to develop the Tchicuate offshore Block in the Republic of Gabon, we recorded a non-cash impairment charge of $43 million to unproved property.
- **2016** - Unproved property impairments recorded of $195 million were primarily a result of our decision to not drill any of our remaining Gulf of Mexico undeveloped leases and also includes certain other unproved properties in the United States. Lower dry well expense was a result of the strategic decision to transition out of our conventional exploration program during 2015.
- **2015** - Primarily due to changes in our conventional exploration strategy (Gulf of Mexico, Canadian in-situ assets and Harir block in the Kurdistan Region of Iraq), relinquishment of certain properties in the Gulf of Mexico, the operated Solomon exploration well in the Gulf of Mexico and our unproved property in Colorado as a result of the proved property impairment mentioned above. Dry well costs include the operated Solomon exploration well in the Gulf of Mexico, and our operated Sodalita West #1 exploratory well in E.G.

See Note 6 for relevant detail regarding segment presentation of unproved property impairments.

11. 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 were as follows:

	For Year Ended December 31,	
(In millions)	2017	2016
Beginning balance	$ 1,652	$ 1,544
Incurred liabilities, including acquisitions	25	14
Settled liabilities, including dispositions	(50)	(74)
Accretion expense (included in depreciation, depletion and amortization)	85	79
Revisions of estimates	(227)	96
Held for sale	(2)	(7)
Ending balance	$ 1,483	$ 1,652

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* includes $55 million classified as short-term at December 31, 2017.

2016

- *Settled liabilities* include dispositions, primarily related to the Gulf of Mexico and Wyoming as well as retirements in the Gulf of Mexico.
- *Revisions of estimates* were primarily due to changes in timing of abandonment activities as well as changes in cost estimated in the U.K.
- *Ending balance* includes $50 million classified as short-term at December 31, 2016.

12. Goodwill

Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value of a reporting unit with goodwill 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 E&P includes goodwill. We estimate the fair value of our International E&P reporting unit using a combination of market and income approaches. The market approach referenced 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 utilized discounted cash flows, which were 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. These valuation methodologies represent Level 3 fair value measurements. We performed our annual impairment test in the second quarter of 2017 and concluded no impairment was required. As of the date of our last impairment assessment, the fair value of our International E&P reporting unit exceeded its book value by over 40%. 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.

The table below displays the allocated beginning goodwill balances by segment along with changes in the carrying amount of goodwill for 2017 and 2016:

(In millions)	U.S. E&P	Int'l E&P	Total
2016			
Beginning balance, gross	$ —	$ 115	$ 115
Less: accumulated impairments	—	—	—
Beginning balance, net	—	115	115
Dispositions	—	—	—
Impairment	—	—	—
Ending balance, net	$ —	$ 115	$ 115
2017			
Beginning balance, gross	$ —	$ 115	$ 115
Less: accumulated impairments	—	—	—
Beginning balance, net	—	115	115
Dispositions	—	—	—
Impairment	—	—	—
Ending balance, net	$ —	$ 115	$ 115

13. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 14. See Note 1 for discussion of the types of derivatives we use and the reasons for them. All of our commodity derivatives and historical interest rate derivatives are subject to enforceable master netting arrangements or similar agreements under which we may 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, 2017			
(In millions)	Asset	Liability	Net Asset	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)	
Total	$ —	$ 140	$ (140)	

	December 31, 2016			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 3	$ —	$ 3	Other current assets
Interest rate	1	—	1	Other noncurrent assets
Cash Flow Hedges				
Interest rate	$ 64	$ —	$ 64	Other noncurrent assets
Total Designated Hedges	$ 68	$ —	$ 68	
Not Designated as Hedges				
Commodity	$ —	$ 60	$ (60)	Other current liabilities
Total Not Designated as Hedges	$ —	$ 60	$ (60)	
Total	$ 68	$ 60	$ 8	

Derivatives Designated as Fair Value Hedges

During the third quarter of 2017, we terminated all of our interest rate swaps designated as fair value hedges. The pretax effects of derivative instruments designated as hedges of fair value in our consolidated statements of income has a gross impact that is not material to net interest and other in all periods presented. Additionally, there is no ineffectiveness related to fair value hedges in all periods presented.

The following table presents, by maturity date, information about our interest rate swap agreements, including the weighted average, London Interbank Offer Rate ("LIBOR") based, floating rate.

	December 31, 2017		**December 31, 2016**	
Maturity Dates	**Aggregate Notional Amount (in millions)**	**Weighted Average, LIBOR-Based, Floating Rate**	**Aggregate Notional Amount (in millions)**	**Weighted Average, LIBOR-Based, Floating Rate**
October 1, 2017	$ —	—%	$ 600	5.10%
March 15, 2018	$ —	—%	$ 300	5.04%

The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income is summarized in the table below. There is no ineffectiveness related to the historical fair value hedges.

		Gain (Loss)		
		Year Ended December 31,		
(In millions)	**Income Statement Location**	**2017**	**2016**	**2015**
Derivative				
Interest rate	Net interest and other	$ —	$ (4)	$ —
Hedged Item				
Debt	Net interest and other	$ —	$ 4	$ —

Derivatives Not Designated as Hedges

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. We designated these derivative instruments as cash flow hedges. 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. See Note 15 for further detail. As a result, we terminated our forward starting interest rate swaps receiving proceeds of $54 million. We recognized a gain of $47 million, related to deferred gains reclassified from accumulated other comprehensive income, in net interest and other during 2017.

The following table presents, by maturity date, information about our terminated forward starting interest rate swap agreements, including the rate.

	December 31, 2017		**December 31, 2016**	
Maturity Dates	**Aggregate Notional Amount** *(in millions)*	**Weighted Average, LIBOR** Fixed Rate	**Aggregate Notional Amount** *(in millions)*	**Weighted Average, LIBOR** Fixed Rate
March 15, 2018	$ —	—%	$ 750	1.57%

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)	2017	2016	2015
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 E&P sales through 2019. These commodity derivatives consist of three-way collars, swaps, and basis swaps. Three-way collars consist of a sold call (ceiling), a purchased put (floor) and a sold put. The ceiling price is the maximum we will receive for the contract volumes, the floor is the minimum price we will receive, unless the market price falls below the sold put strike price. In this case, we receive the NYMEX WTI/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, 2017 and the weighted average prices for those contracts:

Crude Oil

	2018				2019	
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter
Three-Way Collars [(a)]						
Volume (Bbls/day)	85,000	85,000	85,000	85,000	10,000	10,000
Weighted average price per Bbl:						
Ceiling	$56.38	$56.38	$56.96	$56.96	$60.00	$60.00
Floor	$51.65	$51.65	$51.53	$51.53	$55.00	$55.00
Sold put	$45.00	$45.00	$44.65	$44.65	$47.00	$47.00
Swaps						
Volume (Bbls/day)	20,000	20,000	—	—	—	—
Weighted average price per Bbl	$55.12	$55.12	$—	$—	$—	$—
Basis Swaps [(b)]						
Volume (Bbls/day)	5,000	5,000	10,000	10,000	—	—
Weighted average price per Bbl	$(0.60)	$(0.60)	$(0.67)	$(0.67)	$—	$—

(a) Between January 1, 2018 and February 12, 2018, we entered into 10,000 Bbls/day of three-way collars for July - December 2018 with an average ceiling price of $63.51, a floor price of $57.00, and a sold put price of $50.00 and 20,000 Bbls/day of three-way collars for January - June 2019 with an average ceiling price of $67.92, a floor price of $53.50, and a sold put price of $46.50.

(b) The basis differential price is between WTI Midland and WTI Cushing.

Natural Gas

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Three-Way Collars				
Volume (MMBtu/day)	200,000	160,000	160,000	160,000
Weighted average price per MMBtu				
Ceiling	$3.79	$3.61	$3.61	$3.61
Floor	$3.08	$3.00	$3.00	$3.00
Sold put	$2.55	$2.50	$2.50	$2.50

The mark-to-market impact and settlement of these commodity derivative instruments appears in sales and other operating revenues in our consolidated statements of income for the years ended December 31, 2017, 2016, and 2015. The December 31, 2017, 2016, and 2015 impact was a net loss of $36 million, a net loss of $66 million, and a net gain of $128 million, respectively. Net settlements of commodity derivative instruments for the years ended December 31, 2017, 2016, and 2015 were gains of $45 million, $44 million, and $78 million, respectively.

14. 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, 2017			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	—	—	—	—
Derivative instruments, assets	$ —	$ —	$ —	$ —
Derivative instruments, liabilities				
Commodity [(a)]	$ (20)	$ (120)	$ —	$ (140)
Derivative instruments, liabilities	$ (20)	$ (120)	$ —	$ (140)

	December 31, 2016			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$ —	$ 68	$ —	$ 68
Derivative instruments, assets	$ —	$ 68	$ —	$ 68
Derivative instruments, liabilities				
Commodity [(a)]	$ —	$ 60	$ —	$ 60
Derivative instruments, liabilities	$ —	$ 60	$ —	$ 60

(a) Derivative instruments are recorded on a net basis in our balance sheet (see Note 13).

Commodity derivatives include three-way collars, swaps, and basis swaps. These instruments are measured at fair value using either a Black-Scholes or a modified Black-Scholes Model. For swaps and basis swaps, inputs to the models include 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, interest rates, 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 are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See Note 13 for additional discussion of the types of derivative instruments we use.

Fair values – Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2017		2016		2015	
(In millions)	**Fair Value**	**Impairment**	**Fair Value**	**Impairment**	**Fair Value**	**Impairment**
Long-lived assets held for use	$ 179	$ 229	$ 15	$ 67	$ 56	$ 386

Long-lived assets held for use that were impaired are discussed below. The fair values, unless otherwise noted, were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. 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.

United States E&P

In the third quarter of 2017, impairments of $65 million were recorded consisting of certain proved properties in the Gulf of Mexico as a result of lower forecasted long-term commodity prices, to an aggregate fair value of $66 million.

In the third quarter of 2016, impairments of $47 million were recorded consisting primarily of conventional non-core proved properties in Oklahoma as a result of lower forecasted long-term commodity prices, to an aggregate fair value of $15 million. During the fourth quarter of 2016, we recorded an impairment of $17 million as a result of abandonment cost revisions related to the Ozona development in the Gulf of Mexico which ceased productions in 2013.

In the third quarter of 2015, impairments of $333 million were recorded primarily related to certain producing assets in Colorado and the Gulf of Mexico as a result of lower forecasted commodity prices, to an aggregate fair value of $41 million.

During the second quarter of 2015, we recorded an impairment charge of $44 million related to East Texas, North Louisiana and Wilburton, Oklahoma natural gas assets as a result of the anticipated sale. The fair values were measured using a probability weighted income approach based on both the anticipated sale price and held-for-use model.

International E&P

In the third quarter of 2017, we recorded proved property impairments of $136 million, to an aggregate fair value of $103 million, on certain non-core properties in our International E&P segment primarily as a result of lower forecasted long-term commodity prices and as a result of the anticipated sales of certain non-core international assets. The 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. This resulted in a Level 2 classification. See Note 5 for further information about the divestment of certain non-core properties in our International E&P segment.

In the third quarter of 2015, a partial impairment of $12 million was recorded to an investment in an equity method investee as a result of lower forecasted commodity prices, to a fair value of $604 million. The impairment was reflected in income from equity method investments in our consolidated statement of income.

Canadian discontinued operations

As a result of our announced disposition of our Canadian business in the first quarter of 2017, we recorded a pre-tax non-cash impairment charge of $6.6 billion primarily related to property, plant and equipment. 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. See Note 5 for relevant detail regarding dispositions

Fair values – Financial instruments

Our current assets and liabilities include financial instruments, the most significant of which are receivables, 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 value by individual balance sheet line item at December 31, 2017 and 2016.

	December 31,			
	2017		2016	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets [(a)]	$ 762	$ 761	$ 7	$ 7
Other noncurrent assets	159	161	105	108
Total financial assets	$ 921	$ 922	$ 112	$ 115
Financial liabilities				
Other current liabilities	$ 32	$ 43	$ 68	$ 75
Long-term debt, including current portion [(b)]	5,976	5,526	7,449	7,292
Deferred credits and other liabilities	110	103	114	107
Total financial liabilities	$ 6,118	$ 5,672	$ 7,631	$ 7,474

(a) Includes our two notes receivable relating to the sale of our Canadian business as of December 31, 2017, see note 5 for further information.
(b) Excludes capital leases, debt issuance costs and historical interest rate swap adjustments.

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.

Most 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 such debt. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

15. Debt

Short-term debt

As of December 31, 2017, we had no borrowings against our $3.4 billion unsecured revolving credit facility (as amended, the "Credit Facility"), as described below.

Revolving Credit Facility

In June 2017, we extended the maturity date of our Credit Facility from May 28, 2020 to May 28, 2021. In July 2017, we increased our $3.3 billion unsecured Credit Facility by $93 million to a total of $3.4 billion. Fees on the unused commitment of each lender, as well as the borrowing options under the Credit Facility, remain unaffected by the increase and term extension. We have the ability to request two additional 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, 2017, we were in compliance with this covenant with a debt-to-capitalization ratio of 32%.

Long-term debt

The following table details our long-term debt:

	December 31,	
(In millions)	**2017**	**2016**
Senior unsecured notes:		
6.000% notes due 2017	—	682
5.900% notes due 2018	—	854
7.500% notes due 2019	—	228
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	—
6.800% notes due 2032[a]	550	550
6.600% notes due 2037[a]	750	750
5.200% notes due 2045[a]	500	500
Capital leases:		
Capital lease obligation expiring in 2018	—	1
Other obligations:		
5.125% obligation relating to revenue bonds due 2037	—	1,000
Total[b]	5,536	7,301
Unamortized discount	(10)	(9)
Fair value adjustments[c]	—	7
Unamortized debt issuance cost	(32)	(35)
Amounts due within one year	—	(683)
Total long-term debt	$ 5,494	$ 6,581

(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, 2017 may be declared immediately due and payable.
(c) See Notes 13 and 14 for information on historical interest rate swaps.

Debt Issuance

On July 24, 2017, we issued $1 billion of 4.4% 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. During the third quarter of 2017, 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

During the year ended 2017, 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 $47 million into earnings in 2017. See Note 13 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.

The following table shows future debt payments:

(In millions)	
2018	$ —
2019	—
2020	600
2021	—
2022	1,035
Thereafter	3,901
Total long-term debt, including current portion	$ 5,536

16. 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, 2017, 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 (2) the value of our common stock on the date vesting is determined by the Compensation Committee of the Board of Directors. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of our Board of Directors. Dividend equivalents may accrue during the performance period and would be paid in cash at the end of the performance period based on the number of shares that would represent the value of the units.

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 $50 million, $51 million and $57 million in 2017, 2016 and 2015, while the total related income tax benefits were $19 million and $20 million in 2016 and 2015. Due to the full valuation allowance on our net federal deferred tax assets, we realized no tax benefit during 2017. During 2016 and 2015, cash received upon exercise of stock option awards was $1 million and $9 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 2017, 2016 and 2015.

Stock option awards – During 2017, 2016 and 2015 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:

	2017	2016	2015
Exercise price per share	$15.80	$7.22	$29.06
Expected annual dividend yield	1.3%	2.8%	2.9%
Expected life in years	6.4	6.3	6.2
Expected volatility	42%	36%	32%
Risk-free interest rate	2.1%	1.4%	1.7%
Weighted average grant date fair value of stock option awards granted	$6.07	$1.97	$6.84

The following is a summary of stock option award activity in 2017.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value *(in millions)*
Outstanding at beginning of year	11,915,533	$27.71		
Granted	799,591	$15.80		
Exercised	(8,666)	$7.22		
Canceled	(2,375,682)	$33.31		
Outstanding at end of year	10,330,776	$25.52	4 years	$ 13
Exercisable at end of year	8,661,893	$27.91	3 years	$ 5
Expected to vest	1,650,737	$13.08	9 years	$ 8

The intrinsic value of stock option awards exercised during 2017 and 2016 were not material. The intrinsic value of stock awards exercised during 2015 was $6 million.

As of December 31, 2017, unrecognized compensation cost related to stock option awards was $4 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 2017.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	6,933,533	$14.44
Granted	4,198,624	$16.13
Vested & Exercised	(2,472,367)	$17.67
Canceled	(1,086,945)	$15.03
Unvested at end of year	7,572,845	$14.24

The vesting date fair value of restricted stock awards which vested during 2017, 2016 and 2015 was $30 million, $16 million and $26 million. The weighted average grant date fair value of restricted stock awards was $14.24, $14.44 and $30.76 for awards unvested at December 31, 2017, 2016 and 2015.

As of December 31, 2017 there was $67 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 2017, 2016 and 2015 we granted 563,631, 1,205,517 and 382,335 stock-based performance unit awards to officers. At December 31, 2017, there were 1,510,823 units outstanding. Total stock-based performance unit awards expense was $8 million in 2017 and $6 million in 2016. We had no stock-based performance unit awards expense in 2015.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2017, 2016 and 2015 were:

	2017	2016	2015 [(a)]
Valuation date stock price	$16.93	$16.93	$16.93
Expected annual dividend yield	1.2%	1.2%	1.2%
Expected volatility	54%	34%	33%
Risk-free interest rate	1.9%	1.7%	1.4%
Fair value of stock-based performance units outstanding	$21.63	$19.86	$0.00

[(a)] As of December 31, 2017, there were no 2015 performance unit awards outstanding.

17. 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	
	2017		2016		2017	2016
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.
Accumulated benefit obligation	378	599	386	583	221	227
Change in benefit obligations:						
Beginning balance	$ 397	$ 583	$ 525	$ 579	$ 227	$ 260
Service cost	22	—	25	—	2	2
Interest cost	13	17	16	23	8	11
Plan amendment	—	—	—	1	—	(38)
Actuarial loss (gain)	42	(7)	78	139	5	11
Foreign currency exchange rate changes	—	52	—	(108)	—	—
Divestiture	—	—	—	—	—	—
Settlements paid	(84)	(31)	(240)	(36)	—	—
Benefits paid	(6)	(15)	(7)	(15)	(21)	(19)
Ending balance	$ 384	$ 599	$ 397	$ 583	$ 221	$ 227
Change in fair value of plan assets:						
Beginning balance	$ 227	$ 595	$ 354	$ 608	$ —	$ —
Actual return on plan assets	27	47	25	129	—	—
Employer contributions	52	17	95	18	21	20
Foreign currency exchange rate changes	—	57	—	(109)	—	—
Divestiture	—	—	—	—	—	—
Settlements paid	(84)	(31)	(240)	(36)	—	—
Benefits paid	(6)	(15)	(7)	(15)	(21)	(20)
Ending balance	$ 216	$ 670	$ 227	$ 595	$ —	$ —
Funded status of plans at December 31	$ (168)	$ 71	$ (170)	$ 12	$ (221)	$ (227)
Amounts recognized in the consolidated balance sheets:						
Noncurrent assets	—	71	—	12	—	—
Current liabilities	(6)	—	(4)	—	(21)	(21)
Noncurrent liabilities	(162)	—	(166)	—	(200)	(206)
Accrued benefit cost	$ (168)	$ 71	$ (170)	$ 12	$ (221)	$ (227)
Pretax amounts in accumulated other comprehensive loss:						
Net loss (gain)	$ 122	$ 58	$ 130	$ 81	$ 30	$ 25
Prior service cost (credit)	(45)	3	(55)	4	(56)	(63)

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,		
	2017		2016		2015		2017	2016	2015
(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	$ 22	$ —	$ 25	$ —	$ 29	$ 14	$ 2	$ 2	$ 3
Interest cost	13	17	16	23	25	25	8	11	11
Expected return on plan assets	(13)	(30)	(18)	(35)	(30)	(37)	—	—	—
Amortization:									
- prior service cost (credit)	(10)	—	(10)	1	(7)	1	(7)	(3)	(4)
- actuarial loss	8	1	14	—	22	2	—	—	1
Net curtailment loss (gain)[(a)]	—	—	—	—	(5)	4	—	—	(7)
Net settlement loss[(b)]	28	4	97	6	119	—	—	—	—
Net periodic benefit cost[(c)]	$ 48	$ (8)	$ 124	$ (5)	$ 153	$ 9	$ 3	$ 10	$ 4
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ 28	$ (26)	$ 70	$ 41	$ 30	$ (25)	$ 5	$ 11	$ (21)
Amortization of actuarial gain (loss)	(36)	(4)	(111)	(6)	(134)	(2)	—	—	(1)
Prior service cost (credit)	—	—	—	1	(89)	1	—	(38)	—
Amortization of prior service credit (cost)	10	—	10	(1)	7	(5)	7	3	13
Total recognized in other comprehensive (income) loss	$ 2	$ (30)	$ (31)	$ 35	$(186)	$ (31)	$ 12	$ (24)	$ (9)
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 50	$ (38)	$ 93	$ 30	$ (33)	$ (22)	$ 15	$ (14)	$ (5)

(a) Related to workforce reductions, which reduced the future expected years of service for employees participating in the plans and the impact of discontinuing accruals for future benefits under the U.K. pension plan effective December 31, 2015.
(b) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period.
(c) 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 2018 are $13 million and $10 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 2018 are $1 million and $7 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 2017, 2016 and 2015.

	Pension Benefits						Other Benefits		
	2017		2016		2015		2017	2016	2015
(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	3.55%	2.50%	4.02%	2.70%	4.04%	3.90%	3.54%	3.98%	4.36%
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	3.86%	2.70%	3.66%	3.90%	3.79%	3.70%	3.98%	4.36%	3.93%
Expected long-term return on plan assets	6.50%	4.50%	6.75%	5.50%	6.75%	5.70%	—	—	—
Rate of compensation increase [(a)]	4.00%	—	4.00%	—%	4.00%	3.60%	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

	2017	2016	2015
Initial health care trend rate	8.00%	8.25%	8.00%
Ultimate trend rate	4.70%	4.50%	4.50%
Year ultimate trend rate is reached	2025	2025	2024

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. 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.

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, 2017 and 2016.

Cash and cash equivalents – Cash and cash equivalents are valued using a market approach and are considered Level 1. This investment also includes a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2.

Equity securities - Investments in common stock and preferred 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. These private equity investments are considered Level 3. Investments in pooled funds are valued using a market approach at the net asset value ("NAV") of units held. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These 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, non-U.S. government bonds, private placements, taxable municipals, GNMA/FNMA pools, and Yankee bonds 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, and interest rate swaps. The investment in the commingled funds is valued using the NAV 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. Pooled funds 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, real estate and U.S. treasury futures. All are considered Level 3, as significant inputs to determine fair value are unobservable.

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, 2017 and 2016.

	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	—
Mutual and pooled funds	—	151	—	115	—	—	—	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	152	8	518	38	—	157	670
Commingled funds [(a)]	—	—	—	—	—	—	59	—
Total investments	$ 111	$ 152	$ 8	$ 518	$ 38	$ —	$ 216	$ 670

	December 31, 2016							
(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	$ 8	$ 5	$ —	$ —	$ —	$ —	$ 8	$ 5
Equity securities:								
Common stock	82	—	—	—	—	—	82	—
Private equity	—	—	—	—	20	—	20	—
Mutual and pooled funds	—	201	—	159	—	—	—	360
Fixed income securities:								
Corporate	—	—	52	—	—	—	52	—
Exchange traded funds	5	—	—	—	—	—	5	—
Government	6	—	19	—	—	—	25	—
Pooled funds	—	—	—	230	—	—	—	230
Other	—	—	—	—	21	—	21	—
Total investments, at fair value	101	206	71	389	41	—	213	595
Commingled funds [(a)]	—	—	—	—	—	—	14	—
Total investments	$ 101	$ 206	$ 71	$ 389	$ 41	$ —	$ 227	$ 595

(a) 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, 2017 and 2016, 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, 2017 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.
2018	$ 43	$ 17	$ 21
2019	40	18	20
2020	37	17	20
2021	33	19	19
2022	30	21	18
2023 through 2027	123	118	74

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $65 million in 2018. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $6 million and $21 million in 2018.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $20 million, $20 million and $20 million in 2017, 2016 and 2015.

18. Reclassifications Out of Accumulated Other Comprehensive Loss

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

	Year Ended December 31,		
(In millions)	2017	2016	Income Statement Line
Postretirement and postemployment plans			
Amortization of actuarial loss	$ (9)	$ (14)	General and administrative
Net settlement loss	(32)	(103)	General and administrative
Derivative hedges			
Recognized gain on terminated derivative hedge	46	—	Net interest and other
Ineffective portion of derivative hedge	1	4	Net interest and other
	6	(113)	Income (loss) from operations
	(40)	41	(Provision) benefit for income taxes
Total reclassifications to expense, net of tax	$ (34)	$ (72)	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	$ (64)	$ (72)	

19. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Net cash used in operating activities:			
Interest paid (net of amounts capitalized)	$ (379)	$ (375)	$ (325)
Income taxes paid to taxing authorities [(a)]	(391)	(84)	(171)
Noncash investing activities, related to continuing operations:			
Changes in asset retirement costs	$ (202)	$ 110	$ (95)
Asset retirement obligations assumed by buyer	14	40	251
Increase in capital expenditure accrual	176	—	—
Notes receivable for disposition of assets	748	—	—

[(a)] Includes a payment of $108 million made to U.K. taxing authorities to preserve our appeal rights, see Note **7** - Income Taxes for additional discussion.

20. Other Items

Net interest and other

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Interest:			
Interest income	$ 34	$ 14	$ 9
Interest expense	(380)	(398)	(350)
Income on interest rate swaps	53	13	11
Interest capitalized	3	18	19
Total interest	(290)	(353)	(311)
Other:			
Net foreign currency gain (loss)	8	6	4
Other	12	15	21
Total other	20	21	25
Net interest and other	$ (270)	$ (332)	$ (286)

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

	Year Ended December 31,		
(In millions)	**2017**	**2016**	**2015**
Net interest and other	$ 8	$ 6	$ 4
Provision for income taxes	57	(32)	(11)
Aggregate foreign currency gains (losses)	$ 65	$ (26)	$ (7)

21. Equity Method Investments and Related Party Transactions

During 2017, 2016 and 2015 only our equity method investees were considered related parties and they 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, 2017**	**December 31, 2017**	**December 31, 2016**
EGHoldings	60%	$ 456	$ 550
Alba Plant LLC	52%	214	215
AMPCO	45%	177	165
Other investments		—	1
Total		$ 847	$ 931

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $276 million in 2017, $192 million in 2016 and $178 million in 2015.

Summarized financial information for equity method investees is as follows:

(In millions)	**2017**	**2016**	**2015**
Income data – year [(a)]:			
Revenues and other income	$ 1,294	$ 770	$ 769
Income from operations	631	346	313
Net income	508	313	280
Balance sheet data – December 31:			
Current assets	$ 586	$ 525	
Noncurrent assets	1,044	1,173	
Current liabilities	221	218	
Noncurrent liabilities	94	47	

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

Revenues from related parties were $60 million, $54 million and $51 million in 2017, 2016 and 2015, with the majority related to EGHoldings in all years. Purchases from related parties were $132 million, $103 million and $207 million in 2017, 2016 and 2015 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2017 and 2016, were $24 million, and $23 million. Payables to related parties were $14 million and $11 million at December 31, 2017 and 2016, with the majority related to Alba Plant LLC.

22. Stockholders' Equity

In March 2016, we issued 166,750,000 shares of our common stock, par value $1 per share, at a price of $7.65 per share, excluding underwriting discounts and commissions, for net proceeds of $1,236 million. The proceeds were used to strengthen our balance sheet and for general corporate purposes, including funding a portion of our Capital Development Program.

There were no share repurchases during 2017 or 2016 under our publicly announced plans or programs. As of December 31, 2017 the total remaining share repurchase authorization was $1.5 billion. Purchases under the program 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.

23. 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**
2018	$ 29
2019	28
2020	27
2021	26
2022	5
Later years	4
Sublease rentals	—
Total minimum lease payments	$ 119

* Future minimum commitments for capital lease obligations are nil as of December 31, 2017.

Operating lease rental expense related to continuing operations was $87 million, $87 million and $99 million in 2017, 2016 and 2015.

24. 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 third quarter of 2017, a hearing took place at the U.K.'s First-tier Tribunal with respect to this tax deduction. In the fourth quarter of 2017, we received notification from the U.K.'s First-tier Tribunal that the judge sided with the U.K. tax authorities with respect to the timing of the decommissioning cost deductions. We intend to appeal this decision and estimate that any revisions to current and deferred tax liabilities, if we do not prevail in the appeals process, would have no cumulative adverse earnings impact on our consolidated results of operations. In accordance with U.K. regulations, we have paid the amount of tax and interest in question, approximately $108 million, prior to our appeal. As a result of the negative ruling we no longer consider this position to be more-likely-than-not to be sustained and have created an uncertain tax position related to the Brae area decommissioning costs. The payment of the tax and interest to the U.K. tax authorities is not to settle the position, but a regulatory requirement to appeal in the U.K. If we ultimately prevail in appeals, the U.K. tax authorities will refund the tax and interest, however, if we ultimately lose in appeals no material future payments related to this issue will be required. See Note 7 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.

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 federal, state, local and foreign laws and regulations relating to the environment. 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. 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, 2017 and 2016, 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 – We have entered into a performance guarantee related to asset retirement obligations with aggregate maximum potential undiscounted payments totaling $35 million as of December 31, 2017. Under the terms of this guarantee arrangement, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

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, 2017 and 2016, contractual commitments to acquire property, plant and equipment totaled $102 million and $144 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)

	2017				2016			
(In millions, except per share data)	**1st Qtr.**	**2nd Qtr.**	**3rd Qtr.**	**4th Qtr.**	**1st Qtr.**	**2nd Qtr.**	**3rd Qtr.**	**4th Qtr.**
Revenues	$ 988	$ 993	$ 1,162	$ 1,230	$ 612	$ 761	$ 861	$ 936
Income (loss) from continuing operations before income taxes [(a)]	(16)	(112)	(458)	132	(613)	(192)	(313)	(46)
Income (loss) from continuing operations	(50)	(153)	(599)	(28)	(360)	(138)	(206)	(1,383)
Discontinued operations [(b)]	(4,907)	14	—	—	(47)	(32)	14	12
Net income (loss) [(c)]	$(4,957)	$ (139)	$ (599)	$ (28)	$ (407)	$ (170)	$ (192)	$ (1,371)
Income (loss) per share:								
Continuing operations	$ (0.06)	$ (0.18)	$ (0.70)	$ (0.03)	$ (0.49)	$ (0.16)	$ (0.24)	$ (1.63)
Discontinued operations [(b)]	$ (5.78)	$ 0.02	$ —	$ —	$ (0.07)	$ (0.04)	$ 0.01	$ 0.01
Basic net income (loss)	$ (5.84)	$ (0.16)	$ (0.70)	$ (0.03)	$ (0.56)	$ (0.20)	$ (0.23)	$ (1.62)
Dividends paid per share	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05

[(a)] Includes impairments to proved properties of $24 million and $201 million in the fourth and third quarter of 2017 and $47 million in the third quarter of 2016. Also includes unproved property impairments and exploratory dry well costs of $215 million in the third quarter of 2017 and $118 million in the second quarter of 2016. (See Item 8. Financial Statements and Supplementary Data – Note 13 to the consolidated financial statements).

[(b)] 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.

[(c)] Includes the increase of a valuation allowance on certain of our deferred tax assets for $1,346 million in the fourth quarter of 2016 (see Item 8. Financial Statements and Supplementary Data – Note 9 to the consolidated financial statements).

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; E.G.; Libya; Other Africa, which includes Gabon; and Other International ("Other Int'l"), which includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Canada business in 2017 and have reflected this business as discontinued operations ("Disc Ops") in all periods presented. See Note 5 for further details on our Canadian disposition.

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 31 years with Marathon Oil, he has held numerous engineering and management positions, including more recently 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.

Historical estimates of synthetic crude oil reserves were prepared by GLJ Petroleum Consultants of Calgary, Alberta, Canada, third-party consultants for 2015. Their report was filed as an exhibit to the prior year Annual Report on Form 10-K. The individual responsible for the estimates of our synthetic crude oil reserves had 15 years of experience in petroleum engineering, has conducted surface mineable oil sands evaluations since 2009 and is a registered Practicing Professional Engineer in the Province of Alberta.

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, 2017, with 84% 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 2017, 2016 or 2015.

During 2017, 2016 and 2015, Netherland, Sewell & Associates, Inc. prepared a reserves certification for the Alba field in E.G. The NSAI summary reports are 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 13 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 11 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 2017, 2016 and 2015. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 35 years of industry experience, having worked for a major financial advisory services group before joining Ryder Scott. He is a 26 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, Cash Flows and Liquidity – Critical Accounting Estimates – Estimated Quantities of Net Reserves for the table providing our 2017 SEC pricing of benchmark prices and the underlying assumptions used.

The table below provides the 2017 SEC pricing for certain benchmark prices:

	SEC Pricing 2017	
WTI Crude oil (per bbl)	$	51.34
Henry Hub natural gas (per mmbtu)	$	2.98
Brent crude oil (per bbl)	$	54.39
Mont Belvieu NGLs (per bbl)	$	22.03

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 - 2015	634	57	208	29	928	—	928
Revisions of previous estimates	(57)	2	(7)	(2)	(64)	—	(64)
Improved recovery	1	—	—	—	1	—	1
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	70	—	—	—	70	—	70
Production	(62)	(7)	—	(5)	(74)	—	(74)
Sales of reserves in place	(6)	—	—	—	(6)	—	(6)
End of year - 2015	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
Proved developed reserves:							
Beginning of year - 2015	294	30	175	19	518	—	518
End of year - 2015	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
Proved undeveloped reserves:							
Beginning of year - 2015	340	27	33	10	410	—	410
End of year - 2015	253	27	28	6	314	—	314
End of year - 2016	325	—	—	9	334	—	334
End of year - 2017	307	—	—	9	316	—	316

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 - 2015	161	30	—	1	192	—	192
Revisions of previous estimates	(7)	2	—	(1)	(6)	—	(6)
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	33	—	—	—	33	—	33
Production	(14)	(4)	—	—	(18)	—	(18)
Sales of reserves in place	(1)	—	—	—	(1)	—	(1)
End of year - 2015	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
Proved developed reserves:							
Beginning of year - 2015	68	15	—	—	83	—	83
End of year - 2015	92	12	—	—	104	—	104
End of year - 2016	78	24	—	—	102	—	102
End of year - 2017	118	25	—	—	143	—	143
Proved undeveloped reserves:							
Beginning of year - 2015	93	15	—	1	109	—	109
End of year - 2015	80	16	—	—	96	—	96
End of year - 2016	92	—	—	—	92	—	92
End of year - 2017	111	—	—	—	111	—	111

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 - 2015	1,144	1,205	209	22	2,580	—	2,580
Revisions of previous estimates	(22)	35	(3)	1	11	—	11
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	1	—	—	—	1	—	1
Extensions, discoveries and other additions	225	—	—	—	225	—	225
Production [b]	(128)	(150)	—	(8)	(286)	—	(286)
Sales of reserves in place	(69)	—	—	—	(69)	—	(69)
End of year - 2015	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
Proved developed reserves:							
Beginning of year - 2015	575	664	94	17	1,350	—	1,350
End of year - 2015	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
Proved undeveloped reserves:							
Beginning of year - 2015	569	541	115	5	1,230	—	1,230
End of year - 2015	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

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 - 2015	—	—	—	—	—	648	648
Revisions of previous estimates	—	—	—	—	—	67	67
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—	—	—	—
Production	—	—	—	—	—	(17)	(17)
Sales of reserves in place	—	—	—	—	—	—	—
End of year - 2015	—	—	—	—	—	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	—	—	—	—	—	—	—
Proved developed reserves:							
Beginning of year - 2015	—	—	—	—	—	644	644
End of year - 2015	—	—	—	—	—	698	698
End of year - 2016	—	—	—	—	—	692	692
End of year - 2017	—	—	—	—	—	—	—
Proved undeveloped reserves:							
Beginning of year - 2015	—	—	—	—	—	4	4
End of year - 2015	—	—	—	—	—	—	—
End of year - 2016	—	—	—	—	—	—	—
End of year - 2017	—	—	—	—	—	—	—

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 - 2015	986	288	243	33	1,550	648	2,198
Revisions of previous estimates	(67)	8	(8)	(2)	(69)	67	(2)
Improved recovery	1	—	—	—	1	—	1
Purchases of reserves in place	1	—	—	—	1	—	1
Extensions, discoveries and other additions	139	1	—	—	140	—	140
Production [b]	(98)	(36)	—	(6)	(140)	(17)	(157)
Sales of reserves in place	(18)	—	—	—	(18)	—	(18)
End of year - 2015	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
Proved developed reserves:							
Beginning of year - 2015	458	155	191	22	826	644	1,470
End of year - 2015	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
Proved undeveloped reserves:							
Beginning of year - 2015	528	133	52	11	724	4	728
End of year - 2015	418	132	46	7	603	—	603
End of year - 2016	524	—	18	10	552	—	552
End of year - 2017	518	—	18	10	546	—	546

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

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

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.

2015 proved reserves decreased by 35 mmboe primarily due to the following:

- *Revisions of previous estimates:* Decreased by 2 mmboe primarily resulting from an increase of 105 mmboe associated with drilling programs in U.S. resource plays and an increase of 67 mmboe in discontinued operations due to technical reevaluation and lower royalty percentages related to lower realized prices, offset by a decrease of 173 mmboe which was largely due to reductions to our capital development program and adherence to the SEC 5-year rule.
- *Extensions, discoveries, and other additions:* Increased by140 mmboe as a result of drilling programs in our U.S. resource plays.
- *Production:* Decreased by 157 mmboe.
- *Sales of reserves in place:* U.S. conventional assets sales contributed to a decrease of 18 mmboe.

Changes in Proved Undeveloped Reserves

As of December 31, 2017, 546 mmboe of proved undeveloped reserves were reported, a decrease of 6 mmboe from December 31, 2016. The following table shows changes in proved undeveloped reserves for 2017:

(mmboe)	
Beginning of year	552
Revisions of previous estimates	5
Improved recovery	—
Purchases of reserves in place	15
Extensions, discoveries, and other additions	57
Dispositions	—
Transfers to proved developed	(83)
End of year	546

Revisions of prior estimates. Revisions of prior estimates increased 5 mmboe during 2017, primarily due to a 44 mmboe increase in the Bakken from an acceleration of higher economic wells into the 5-year plan, offset by a decrease of 40 mmboe in Oklahoma due to the removal of less economic wells from the 5-year plan.

Extensions, discoveries and other additions. Increased 57 mmboe through expansion of proved areas in Oklahoma.

Transfers to proved developed. 83 mmboe of PUD reserves were converted to proved developed status during 2017, primarily from assets in our U.S. resource plays. This 2017 transfer equates to a 15% PUD conversion rate and a 5-year average annual PUD conversion rate during the 2013-2017 period of 18%. All proved undeveloped reserve drilling locations are scheduled to be drilled prior to the end of 2022.

A total of 25 mmboe of proved undeveloped reserves, or less than 2% of the company's total proved reserves, have been on the books beyond 5 years as of year-end 2017.

As of year-end 2017, there were 18 mmboe of proved undeveloped reserves, initially disclosed in 2012, associated with the Faregh Phase II project in Libya. Drilling operations and construction of the associated gas plant were completed in 2010. Final commissioning was halted in 2011 and again in 2013 due to civil unrest and subsequent declaration of Force Majeure. In 2017, teams conducted an assessment of the facilities to determine the state of the equipment and developed a plan to recommission the plant and initiate production in 2018, at which time, all associated proved undeveloped reserves will be transferred to proved developed.

As of year-end 2017, there were 7 mmboe of proved undeveloped reserves, initially disclosed in 2011, associated with the Fuel Gas Deficiency project in the U.K. The project includes the design, procurement and installation of the Brae Bravo gas by-pass, which will ensure continued operations at the existing Brae Alpha and East Brae platforms. The project has been approved and work is underway with completion expected in 2018, at which time, all associated proved undeveloped reserves will be transferred to proved developed.

Costs Incurred & Future Costs to Develop

Costs incurred in 2017, 2016 and 2015 relating to the development of proved undeveloped reserves were $842 million, $359 million and $1,415 million. As of December 31, 2017, 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 2018 through 2022 are projected to be $1,425 million, $1,348 million, $1,409 million, $1,458 million and $1,028 million.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	Year Ended December 31,					
(In millions)	U.S.	E.G.	Libya	Other Africa	Other Int'l	Total
2017 Capitalized Costs:						
Proved properties	$ 27,477	$ 1,990	830	$ —	$ 5,050	$ 35,347
Unproved properties	2,755	110	217	43	33	3,158
Total	30,232	2,100	1,047	43	5,083	38,505
Accumulated depreciation, depletion and amortization:						
Proved properties	14,254	1,348	289	—	4,850	20,741
Unproved properties [(a)]	206	—	—	43	33	282
Total	14,460	1,348	289	43	4,883	21,023
Net capitalized costs	$ 15,772	$ 752	$ 758	$ —	$ 200	$ 17,482
2016 Capitalized Costs:						
Proved properties	$ 25,497	$ 1,978	$ 756	$ —	$ 5,864	$ 34,095
Unproved properties	1,473	119	281	136	183	2,192
Total	26,970	2,097	1,037	136	6,047	36,287
Accumulated depreciation, depletion and amortization:						
Proved properties	12,526	1,216	268	1	5,246	19,257
Unproved properties [(a)]	382	2	—	—	113	497
Total	12,908	1,218	268	1	5,359	19,754
Net capitalized costs	$ 14,062	$ 879	$ 769	$ 135	$ 688	$ 16,533

(a) Includes unproved property impairments (see Note 10).

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

(In millions)	U.S.	E.G.	Libya	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
December 31, 2017								
Property acquisition:								
Proved	$ 191	$ 1	$ —	$ —	$ —	$ 192	$ —	$ 192
Unproved	1,746	—	—	1	—	1,747	—	1,747
Exploration	882	1	—	37	3	923	—	923
Development	1,122	5	10	—	(144) [(b)]	993	6	999
Total	$ 3,941	$ 7	$ 10	$ 38	$ (141)	$ 3,855	$ 6	$ 3,861
December 31, 2016								
Property acquisition:								
Proved	$ 276	$ —	$ —	$ —	$ —	$ 276	$ —	$ 276
Unproved	642	—	—	1	(11)	632	—	632
Exploration	525	1	—	10	3	539	—	539
Development	456	55	3	—	121 [(b)]	635	31	666
Total	$ 1,899	$ 56	$ 3	$ 11	$ 113	$ 2,082	$ 31	$ 2,113
December 31, 2015								
Property acquisition:								
Proved	$ 4	$ —	$ —	$ —	$ —	$ 4	$ —	$ 4
Unproved	61	—	—	1	—	62	—	62
Exploration	959	60	1	37	50	1,107	1	1,108
Development	1,477	150	13	—	31	1,671	—	1,671
Total	$ 2,501	$ 210	$ 14	$ 38	$ 81	$ 2,844	$ 1	$ 2,845

(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.

Results of Operations for Oil and Gas Producing Activities

	U.S.	E.G.	Libya	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
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)	—	—	(171)	(83)	(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)	(7)	(18)	(61)	—	(61)
Total expenses	(3,271)	(222)	(69)	(178)	(526)	(4,266)	(6,948)	(11,214)
Results before income taxes	(147)	167	362	(178)	(206)	(2)	(6,568)	(6,570)
Income tax provision	(1)	(50)	(333)	—	13	(371)	1,674	1,303
Results of operations	$ (148)	$ 117	$ 29	$ (178)	$ (193)	$ (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)	(8)	(2)	(323)	(7)	(330)
Depreciation, depletion and amortization[c]	(1,901)	(114)	(7)	—	(132)	(2,154)	(239)	(2,393)
Technical support and other	(21)	(4)	—	(3)	(2)	(30)	(1)	(31)
Total expenses	(3,180)	(200)	(49)	(11)	(276)	(3,716)	(791)	(4,507)
Results before income taxes	(544)	133	5	(11)	(37)	(454)	(67)	(521)
Income tax provision [d]	195	(26)	(2)	—	57	224	15	239
Results of operations	$ (349)	$ 107	$ 3	$ (11)	$ 20	$ (230)	$ (52)	$ (282)
Year Ended December 31, 2015								
Revenues and other income:								
Sales	$ 3,374	$ 40	$ —	$ —	$ 329	$ 3,743	$ 700	$ 4,443
Transfers	—	296	—	—	—	296	—	296
Other income[a]	230	—	—	(109)	1	122	—	122
Total revenues and other income	3,604	336	—	(109)	330	4,161	700	4,861
Expenses:								
Production costs	(1,259)	(84)	(31)	—	(177)	(1,551)	(660)	(2,211)
Exploration expenses[b]	(750)	(41)	—	(36)	(143)	(970)	(348)	(1,318)
Depreciation, depletion and amortization[c]	(2,758)	(92)	(5)	—	(163)	(3,018)	(266)	(3,284)
Technical support and other	(47)	(6)	(1)	(1)	(3)	(58)	(2)	(60)
Total expenses	(4,814)	(223)	(37)	(37)	(486)	(5,597)	(1,276)	(6,873)
Results before income taxes	(1,210)	113	(37)	(146)	(156)	(1,436)	(576)	(2,012)
Income tax provision	437	(33)	37	50	86	577	31	608
Results of operations	$ (773)	$ 80	$ —	$ (96)	$ (70)	$ (859)	$ (545)	$ (1,404)

(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 10).
(c) Includes long-lived asset impairments (see Note 10).
(d) Discontinued operations activity includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase.

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)	**2017**	**2016**	**2015**
Results of operations	$ (5,267)	$ (282)	$ (1,404)
Discontinued operations	4,894	52	545
Results of continuing operations	(373)	(230)	(859)
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	(107)	(39)	(102)
Income from equity method investments	229	142	127
Items not allocated to segment income, net of tax:			
Loss (gain) on asset dispositions and other income	(79)	(248)	(76)
Long-lived asset impairments	475	148	602
Unrealized loss (gain) on derivatives	81	72	(32)
Deferred tax valuation allowance increase	—	(32)	—
Segment income	$ 226	$ (187)	$ (340)

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, 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
Year Ended December 31, 2015					
Future cash inflows	$ 31,026	$ 2,671	$ 12,157	$ 1,281	$ 47,135
Future production and support costs	(12,270)	(1,095)	(901)	(902)	(15,168)
Future development costs	(6,637)	(94)	(689)	(1,537)	(8,957)
Future income tax expenses	(778)	(369)	(9,857)	602	(10,402)
Future net cash flows	$ 11,341	$ 1,113	$ 710	$ (556) [(a)]	$ 12,608
10% annual discount for timing of cash flows	(6,082)	(380)	(441)	352	(6,551)
Standardized measure of discounted future net cash flows-related to continuing operations	$ 5,259	$ 733	$ 269	$ (204)	$ 6,057
Standardized measure of discounted future net cash flows-related to discontinued operations					$ 165

[(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)	**2017**	**2016**	**2015**
Sales and transfers of oil and gas produced, net of production and support costs	$ (2,853)	$ (1,634)	$ (2,422)
Net changes in prices and production and support costs related to future production	4,916	(3,621) [b]	(21,309) [b]
Extensions, discoveries and improved recovery, less related costs	661	(2,174)	6
Development costs incurred during the period	1,027	669	1,693
Changes in estimated future development costs	183	2,534	7,247
Revisions of previous quantity estimates[a]	497	654	(5,682)
Net changes in purchases and sales of minerals in place	102	(651)	(460)
Accretion of discount	698	1,005	2,719
Net change in income taxes	(1,245)	1,038	9,989
Net change for the year	3,986	(2,180)	(8,219)
Beginning of the year related to continuing operations	3,877	6,057	14,276
End of the year related to continuing operations	$ 7,863	$ 3,877	$ 6,057
Net change for the year related to discontinued operations	$ —	$ 911	$ (2,115)

[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, 2017.

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 2017, 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 2018 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2017 (the "2018 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 2018 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 2018 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2017 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	11,915,472 [a]	$25.52	43,840,884 [d]
Equity compensation plans not approved by stockholders	12,291 [b]	N/A	—
Total	11,927,763	N/A	43,840,884

[a] Includes the following:

- 736,199 stock options outstanding under the 2016 Plan; 3,991,905 stock options outstanding under the 2012 Plan; 5,591,708 stock options outstanding under the 2007 Plan;
- 399,114 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 69,556, 142,724, 152,839 and 33,995, respectively;

- 1,196,546 restricted stock units granted to non-officers under the 2012 Plan and 2016 Plan and outstanding as of December 31, 2017.
- In addition to the awards reported above, 2,850,798 and 3,525,501 shares of restricted stock were issued and outstanding as of December 31, 2017, 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 18,496,714 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 2018 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 2018" in the 2018 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

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

Item 16. Form 10-K Summary

None.

SIGNATURES

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

February 22, 2018 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 22, 2018 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ LEE M. TILLMAN Lee M. Tillman	President and Chief Executive Officer and Director
/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/ DENNIS H. REILLEY Dennis H. Reilley	Chairman of the Board
/s/ GAURDIE E. BANISTER, JR. Gaurdie E. Banister, Jr.	Director
/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/ PHILIP LADER Philip Lader	Director
/s/ MICHAEL E. J. PHELPS Michael E. J. Phelps	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.			
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	10-Q	3.1	8/8/2013
3.2	Marathon Oil Corporation By-laws (Amended and restated as of February 24, 2016)	8-K	3.1	3/1/2016
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†	Marathon Oil Corporation 2016 Incentive Compensation Plan	DEF 14A	App. A	4/7/2016
10.7†	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
10.8†	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
10.9†	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
10.10†	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
10.11†	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			
10.13*	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Officers			
10.14†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012
10.15†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.16†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.1	5/7/2014
10.17†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.2	5/7/2014
10.18†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Initial CEO Option Grant Agreement	10-Q	10.1	11/6/2013

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.19†	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
10.20†	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
10.21†	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
10.22†	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
10.23†	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
10.24†	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
10.25†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.26†	Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers	10-K	10.6	2/29/2012
10.27†	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
10.28†	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
10.29†	Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.9	2/26/2010
10.30†	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
10.31†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.32†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.33†*	Marathon Oil Corporation Officer Change in Control Severance Benefits Plan (as amended, effective January 1, 2018)			
10.34†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.35†	Marathon Oil Corporation Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009
10.36	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
12.1*	Computation of Ratio of Earnings to Fixed Charges			
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 GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists			

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
23.4*	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists			
23.5*	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	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2015	10-K	99.1	2/25/2016
99.2*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016			
99.3*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016			
99.4*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016			
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 2015	10-K	99.4	2/24/2017
99.7*	Summary report performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2016			
99.8	Summary report performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2015	10-K	99.6	2/24/2017
99.9*	Alba Plant, LLC audited financial statements as of December 31, 2017			
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.			

Corporate Information

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

Marathon Oil Corporation Web Site
www.marathonoil.com

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

Zach Dailey, VP Investor Relations
+1 713-296-4140

Notice of Annual Meeting
The 2018 Annual Meeting of Stockholders will be held in Houston, Texas, on May 30, 2018.

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

Stock Exchange Listing
New York Stock Exchange

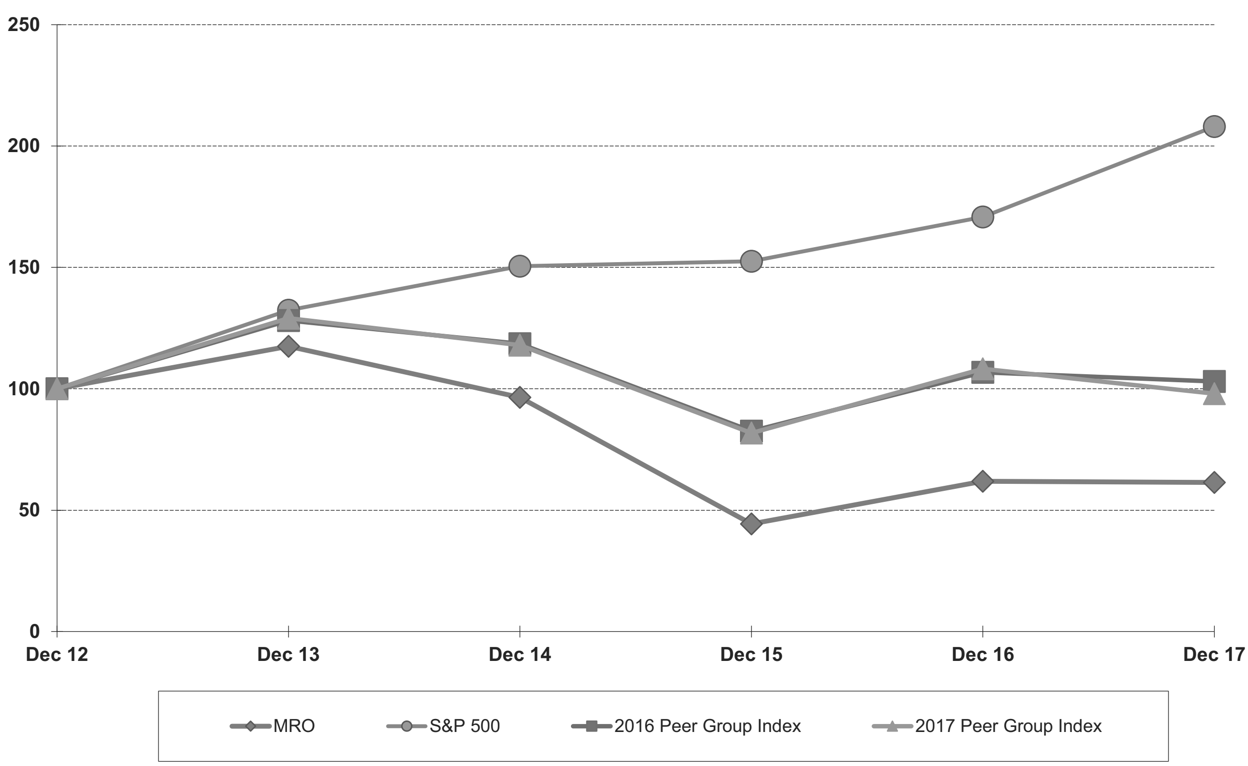
Common Stock Symbol
MRO

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

Dividends
Dividends on common stock, as declared by the board of directors, are normally paid on the 10th day of March, June, September and December.

Stockholder Return Performance Graph
The line graph below compares the yearly change in cumulative total stockholder return for our common stock with the cumulative total return of the Standard & Poor's 500 Stock Index ("S&P 500"), the Peer Group Index shown in our 2016 Annual Report (the "2016 Peer Group"), and the new Peer Group Index that replaces it (the "2017 Peer Group"). In order to reflect a peer group more comparable in size and operations, the 2017 Peer Group Index reflects the removal of ConocoPhillips Co. and Occidental Petroleum Corporation, and the addition of Continental Resources, Inc. We use a Peer Group Index because there is no relevant published industry or line-of-business index that reflects the companies against which we compete as an independent exploration and production company. The 2017 Peer Group Index is comprised of Anadarko Petroleum Corporation, Apache Corporation, Chesapeake Energy Corporation, Continental Resources, Inc., Devon Energy Corporation, Encana Corp., EOG Resources, Inc., Hess Corporation, Murphy Oil Corporation, Noble Energy, Inc., and Pioneer Natural Resources Company.

Comparison of Cumulative Total Return on $100
Invested in Marathon Oil Common Stock on December 31, 2012
vs.
***S&P 500 and Peer Group Index**



***Total return assumes reinvestment of dividends**

Forward-Looking Statements

This letter to stockholders contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: the Company's 2018 capital development program and the allocation thereof; returns, cash flow per debt adjusted share, cash flow, margins and asset quality.

While the Company believes that its assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to: conditions in the oil and gas industry, including supply/demand levels for crude oil and condensate, NGLs, natural gas and synthetic crude oil and the resulting impact on price; changes in expected reserve or production levels; changes in political or economic conditions in the jurisdictions in which we operate, including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions; risks relating to our hedging activities; capital available for exploration and development; drilling and operating risks; well production timing; availability of drilling rigs, materials and labor, including the costs associated therewith; difficulty in obtaining necessary approvals and permits; non-performance by third parties of their contractual obligations; unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto; cyber-attacks; changes in safety, health, environmental, tax and other regulations; other geological, operating and economic considerations; and the risk factors, forward-looking statements and challenges and uncertainties described in the Company's 2017 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases available at www.marathonoil.com. Except as required by law, the Company assumes no duty to revise or update any forward-looking statements whether as a result of new information, future events or otherwise.