Marathon Oil Announces 2018 Development Capital Budget; Reports Fourth Quarter and Full-Year 2017 Results

HOUSTON, Feb. 14, 2018 (GLOBE NEWSWIRE) -- Marathon Oil Corporation (NYSE:MRO) today announced a $2.3 billionreturns-driven development capital budget for 2018, which is self-funding at $50 average WTI, including dividends, and generates meaningful free cash flow at $60 average WTI. More than 90 percent will be directed to the four U.S. resource plays, with corporate cash return on invested capital (CROIC) expected to increase by about 30 percent year over year at $50 average WTI.

Almost 60 percent of the 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 the Company's Northern Delaware and Oklahoma assets, where the majority of drilling activity will be transitioning to multi-well pads, while continuing strategic delineation and appraisal.

As a result of this concentrated capital allocation, the U.S. resource plays will increase to about 70 percent of the total Company production mix, driving a natural expansion in margins. Additionally, Marathon Oil expects to deliver a strong annual rate of change on the key corporate performance metrics of CROIC and cash flow per debt adjusted share (CFPDAS), both of which are now integrated into the executive compensation structure.

2018 Production Guidance
For full year 2018, the Company forecasts total production available for sale, excluding Libya, to average 390,000 to 410,000 net barrels of oil equivalent per day (boed), up 12 percent at the midpoint compared to 2017 on a divestiture-adjusted basis. Total annual oil production available for sale, excluding Libya, is expected to increase about 18 percent at the midpoint on a divestiture-adjusted basis, driven by 20 - 25 percent annual oil growth in the U.S. resource plays.

For first quarter 2018, U.S. production is expected to average 265,000 to 275,000 net boed. International production, excluding Libya, is expected to average 105,000 to 115,000 net boed, which reflects planned turnaround activity in EG.

2017 Review

- Achieved cash flow neutrality*, including dividends and working capital, with$51 average WTI
- Total production (excluding Libya) of 358,000 net boed; up 9% year over year on a divestiture-adjusted basis
- U.S. resource plays exited 2017 with oil production 31% higher than fourth quarter 2016
- Entered Northern Delaware basin and divested Canadian oil sands business
- Reduced unit production costs 7% for U.S. E&P and 6% for International E&P (excludingLibya) compared to the prior year
- Reduced gross debt by approximately $1.75 billion, lowering annualized interest expense by $115 million
- Organic reserve replacement of 121%, excluding acquisitions and dispositions, at a drillbit finding and development cost of $12.81 per boe

** Excludes a one-time $108 millionU.K. tax payment that is currently under appeal.*

"We finished 2017 with another quarter of outstanding operational execution across all four resource plays," said Marathon Oil President and CEO Lee Tillman. "We delivered some of the most productive unconventional wells in our Company's history in our high-return Eagle Ford and Bakken assets, while achieving strong rates from our nine-well STACK infill development and excellent well results across the Northern Delaware. Last year we reached key milestones in our portfolio transformation, further strengthened our balance sheet, drove costs even lower and delivered production near the top of our production guidance, all while maintaining cash flow neutrality. In 2018, we expect to improve corporate-level returns from our disciplined development capital program that's self-funding at $50 and will generate meaningful free cash flow at $60 average WTI, including the dividend."

Marathon Oil reported a fourth quarter 2017 net loss of $28 million, or $0.03 per diluted share, which includes the impact of certain items not typically represented in analysts' earnings estimates and that would otherwise affect comparability of results. Adjusted net income was $56 million, or $0.07 per diluted share. Net operating cash flow was $501 million, or $637 million before changes in working capital and the one-time U.K. tax payment.

Fourth Quarter 2017 Highlights

- Total Company production excluding Libya averaged 383,000 net boed, up 4% sequentially on a divestiture-adjusted basis; 33,000 net boed from Libya
- U.S. resource play production averaged 249,000 net boed, up 10% sequentially
- Eagle Ford production averaged 105,000 net boed; up 4% sequentially with fewer wells to sales
- Bakken production increased 17% sequentially to 69,000 net boed; set newWilliston Basin 30-day IP oil record at 3,005 bpd
- Oklahoma production up 10% sequentially to 64,000 net boed; nine-well STACK infill development averaged 30-day IP rates of 1,840 boed (60% oil)
- Northern Delaware production averaged 11,000 net boed; two-well pad averaged 30-day IP rates of 3,265 boed (62% oil)

U.S. E&P
U.S. E&P production available for sale averaged 262,000 net boed for fourth quarter 2017. On a divestiture-adjusted basis, production was up 8 percent compared to the prior quarter and up 27 percent from the year-ago quarter. Fourth quarter unit production costs were $5.33 per barrel of oil equivalent (boe), down from $5.38 in the previous quarter, and a new record low for the Company since becoming an independent E&P in 2011. Full-year unit production costs averaged $5.57 per boe.

EAGLE FORD: Marathon Oil's production in the Eagle Ford averaged 105,000 net boed in the fourth quarter, up from 101,000 net boed in the prior quarter. The Company brought 33 gross Company-operated wells to sales in the fourth quarter with average 30-

day initial production (IP) rates of 1,800 boed (73% oil). The testing of enhanced completion designs in Atascosa County continued to deliver encouraging results. The five-well Guajillo Unit 8 South pad delivered average 30-day IP rates of 1,730 boed (77% oil, 6,300-foot average lateral length) and the three-well Middle McCowen pad, the Company's western-most test of 2017, achieved average 30-day IP rates of 2,080 boed (87% oil, 9,915-foot average lateral length). In Karnes County, average 30-day IP rates from two Austin Chalk wells on the Challenger pad were 2,415 boed (75% oil, 5,350-foot average lateral length).

BAKKEN: In fourth quarter 2017, Marathon Oil's Bakken production averaged 69,000 net boed, up 17 percent compared to 59,000 net boed in the prior quarter. The Company brought 13 gross Company-operated wells to sales in the fourth quarter, nine of which came in West Myrmidon with average 30-day IP rates of 2,935 boed. The Forsman Middle Bakken well in West Myrmidon set a new Williston Basin 30-day IP oil record with a rate of 3,005 barrels per day. The testing of enhanced completion designs continued to deliver encouraging results, with the three-well Chapman pad on the eastern side of Hector achieving average 30-day IP rates of 1,810 boed (85% oil).

OKLAHOMA: The Company's production in Oklahoma increased 10 percent to 64,000 net boed during fourth quarter 2017, up from 58,000 net boed in the prior quarter. The Company brought 26 gross Company-operated wells to sales during the quarter predominately focused in the STACK on Meramec infill wells and leasehold activity. The Company's first STACK volatile oil infill development, the Tan, in southwest Kingfisher County averaged 30-day IP rates of 1,840 boed (60% oil). The nine new infills were comprised of eight XL wells (10,400-foot average lateral length) and one SL well (5,400-foot lateral length). The Eve, the Company's third and farthest east infill spacing pilot in Kingfisher County’s black oil window, averaged 30-day IP rates from the five new wells of 715 boed (65% oil, 5,000-foot average lateral length).

NORTHERN DELAWARE: The Company's Northern Delaware production averaged 11,000 net boed in fourth quarter 2017, up from 9,000 net boed in the prior quarter. The Company brought 11 gross Company-operated wells to sales in Eddy and Lea Counties, which had 30-day IP rates that averaged 1,835 boed (66% oil). A two-well pad achieved average 30-day IP rates of 3,265 boed (62% oil) and a nearby third well averaged a 30-day rate of 2,910 boed (63% oil).

International E&P
International E&P production available for sale (excluding Libya) averaged 121,000 net boed for fourth quarter 2017. This compares to 126,000 net boed in the prior quarter, and 129,000 net boed in the year-ago quarter. The decrease was due to the temporary shut-down of the outside-operated Forties Pipeline System and planned turn-around activity in the U.K, as well as natural field declines. Libya production available for sale averaged 33,000 net boed in the fourth quarter. Fourth quarter 2017 International E&P unit production costs (excluding Libya) averaged $3.85 per boe. Full-year 2017 unit production costs (excluding Libya) were $4.13 per boe, below the low end of guidance of $4.50 to $5.50 per boe.

Corporate and Special Items
Net cash provided by continuing operations was $501 million during fourth quarter 2017, or $637 million before changes in working capital and the one-time U.K. tax payment under appeal. Fourth quarter 2017 cash additions to property, plant and equipment (PP&E) were $669 million, up sequentially due to the timing of invoice payments and resource play exploration leasing.

As previously disclosed, Marathon Oil received an adverse ruling from the U.K. first-tier tax tribunal during fourth quarter 2017 related to the timing of deductibility for certain Brae area decommissioning costs. While the Company is appealing the ruling, the Company was required to pay the disputed tax amount of $108 million in order to pursue the appeal.

Total liquidity as of Dec. 31 was approximately $4 billion, which consisted of $560 million in cash and cash equivalents and an undrawn revolving credit facility of $3.4 billion. Remaining proceeds of $750 million from the sale of the Company's Canadian subsidiary are scheduled to be received in March.

The adjustments to net income from continuing operations for fourth quarter 2017 totaled $96 million before tax, and include an unrealized loss of $145 million on commodity derivatives and $24 million proved property impairment, partially offset by a $32 million gain from dispositions.

Reserves
During 2017, Marathon Oil added proved reserves of 193 million boe for a reserve replacement ratio of 140 percent excluding dispositions. Virtually all of the additions were in U.S. E&P. The Company's organic reserve replacement ratio, excluding acquisitions and dispositions, was 121 percent at a drillbit finding and development (F&D) cost of $12.81. Net proved reserves were approximately 1.45 billion boe at year-end 2017, down from year-end 2016 primarily due to the sale of the Canadian Oil Sands business.

A slide deck and Quarterly Investor Packet will be posted to the Company's website at https://www.marathonoil.com/Investors following this release today, Feb. 14. The Company will conduct a question and answer webcast/call on Thursday, Feb. 15, at 9:00 a.m. ET. The commentary and answers to questions will include forward-looking information. To listen to the live webcast, visit the Marathon Oil website at https://www.marathonoil.com. The audio replay of the webcast will be posted by Feb. 16.

Definitions
CROIC - Cash return on invested capital; calculated by taking cash flow (operating cash flow before working capital + net interest after tax) divided by (average stockholder's equity + average net debt).

CFPDAS - Cash flow per debt adjusted share; calculated by taking cash flow (operating cash flow before working capital + net interest after tax) divided by total shares including debt shares. Debt shares is the average net debt during a calendar year divided by the average annual stock price.

Non-GAAP Measures
In analyzing and planning for its business, Marathon Oil supplements its use of GAAP financial measures with non-GAAP financial measures, including adjusted net income (loss), net cash provided by operations before changes in working capital and the one-time U.K. tax payment under appeal, CROIC and CFPDAS to evaluate the Company's financial performance between periods and to compare the Company's performance to certain competitors. Management also uses net cash provided by operations before changes in working capital and the one-time U.K. tax payment under appeal to demonstrate the Company's ability to internally fund capital expenditures, pay dividends and service debt. The Company considers adjusted net income (loss) as another way to meaningfully represent our operational performance for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges, dispositions, pension settlements, and other items that could be considered “non-operating” or “non-core” in nature. CROIC and CFPDAS will be integrated into our executive compensation structure and

management will use this information for purposes of comparing its financial performance with the financial performance of other companies in the industry. These non-GAAP financial measures reflect an additional way of viewing aspects of the business that, when viewed with GAAP results may provide a more complete understanding of factors and trends affecting the business and are a useful tool to help management and investors make informed decisions about Marathon Oil's financial and operating performance. These measures should not be considered substitutes for their most directly comparable GAAP financial measures. See the tables below for reconciliations between each of adjusted net income (loss) and net cash provided by operations before changes in working capital and the one-time U.K. tax payment under appeal and its most directly comparable GAAP financial measure. A reconciliation of CROIC's components to their most directly comparable GAAP financial measures can be found in our investor package on our website at www.marathonoil.com. Marathon Oilstrongly encourages investors to review the Company's consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

Forward-looking Statements

This release 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. All statements, other than statements of historical fact, including without limitation statements regarding the Company's 2018 capital budget and allocations, future performance, free cash flow, corporate cash return on invested capital, business strategy, asset quality, cash margins, production, rates of change for CROIC and CFPDAS, future payments for the Canadian disposition, and other plans and objectives for future operations, are forward-looking statements. Words such as "anticipate," "believe," "could," "estimate," "expect," "forecast," "guidance," "intend," "may," "plan," "project," "seek," "should," "target," "will," "would," or similar words may be used to identify forward-looking statements; however, the absence of these words does not mean that the statements are not forward-looking. While the Company believes its assumptions concerning future events are reasonable, a number of factors could cause actual results to differ materially from those projected, including, but not limited to: conditions in the oil and gas industry, including supply/demand levels and the resulting impact on price; changes in expected reserve or production levels; changes in political or economic conditions in the jurisdictions in which the Company operates; risks related to the Company's hedging activities; capital available for exploration and development; the inability for any party to satisfy closing conditions with respect to the Canadian subsidiary disposition; drilling and operating risks; well production timing; availability of drilling rigs, materials and labor, including associated costs; difficulty in obtaining necessary approvals and permits; non-performance by third parties of contractual obligations; unforeseen hazards such as weather conditions, acts of war or terrorist acts and the government 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 2016 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 undertakes no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise.

Media Relations Contact:
Lee Warren: 713-296-4103

Investor Relations Contacts:
Zach Dailey: 713-296-4140
John Reid: 713-296-4380

Consolidated Statements of Income (Unaudited)	**Three Months Ended**			**Year Ended**	
(In millions, except per share data)	**Dec. 31 2017**	**Sept. 30 2017**	**Dec. 31 2016**	**Dec. 31 2017**	**Dec. 20**
Revenues and other income:					
Sales and other operating revenues, including related party	$ 1,185	$ 1,114	$ 898	$ 4,211	$ 2,
Marketing revenues	45	48	38	162	[illegible]
Income from equity method investments	73	63	65	256	[illegible]
Net gain (loss) on disposal of assets	32	19	108	58	[illegible]
Other income	47	8	15	78	
Total revenues and other income	1,382	1,252	1,124	4,765	3,
Costs and expenses:					
Production	185	194	180	706	[illegible]
Marketing, including purchases from related parties	47	49	44	168	[illegible]
Other operating	122	109	111	431	[illegible]
Exploration	57	294	34	409	[illegible]
Depreciation, depletion and amortization	583	641	573	2,372	2,
Impairments	24	201	19	229	
Taxes other than income	55	44	38	183	[illegible]
General and administrative	101	97	95	400	[illegible]
Total costs and expenses	1,174	1,629	1,094	4,898	4,
Income (loss) from operations	208	(377)	30	(133)	(
Net interest and other	(71)	(35)	(76)	(270)	(
Loss on early extinguishment of debt	(5)	(46)	—	(51)	
Income (loss) from continuing operations before income taxes	132	(458)	(46)	(454)	(1,
Provision (Benefit) for income taxes	160	141	1,337	376	[illegible]
Income (loss) from continuing operations	(28)	(599)	(1,383)	(830)	(2,
Discontinued operations (a)	—	—	12	(4,893)	
Net income (loss)	$ (28)	$ (599)	$ (1,371)	$ (5,723)	$ (2,
Adjusted Net Income					
Income (loss) from continuing operations	(28)	(599)	(1,383)	(830)	(2,
Adjustments for special items from continuing operations (pre-tax):					
Net (gain) loss on dispositions	(32)	(19)	(108)	(57)	(
Proved property impairments	24	201	—	225	
Exploratory dry well costs, unproved property impairments and other	—	250	—	250	[illegible]
Pension settlement	7	8	10	32	[illegible]
Unrealized (gain) loss on derivative instruments	145	56	21	81	[illegible]
Gain on termination of interest rate swaps	—	(47)	—	(47)	
Loss on extinguishment of debt	5	46	—	51	
Rig termination payment	—	—	—	—	[illegible]
Other	(53)	(4)	(4)	(59)	
Provision (benefit) for income taxes related to special items from continuing operations	(12)	(1)	23	(13)	
Valuation Allowance	—	41	1,346	41	1,
Adjusted net income (loss) from continuing operations (b)	$ 56	$ (68)	$ (95)	$ (326)	$ (
Income (loss) from discontinued operations (a)	—	—	12	(4,893)	
Adjustments for special items from discontinued operations (pre-tax):					
Canadian oil sands business impairment (a)	—	—	—	6,636	

Net (gain) loss on disposition (a)		—		—		—		43	
Provision (benefit) for income taxes related to special items from discontinued operations (a)		—		—		—		(1,674)	
Adjusted net income (loss) (b)	$	56	$	(68)	$	(83)	$	(214)	$ ((
Per diluted share:									
Income (loss) from continuing operations	$	(0.03)	$	(0.70)	$	(1.63)	$	(0.97)	$ (2
Net Income (loss)	$	(0.03)	$	(0.70)	$	(1.62)	$	(6.73)	$ (2
Adjusted net income (loss) from continuing operations (b)	$	0.07	$	(0.08)	$	(0.11)	$	(0.38)	$ (0
Adjusted net income (loss) (b)	$	0.07	$	(0.08)	$	(0.10)	$	(0.25)	$ (0
Weighted average diluted shares		850		850		847		850	8

(a) The Company closed on its sale of the Canadian oil sands business in the second quarter of 2017. The Canadian oil sands business is reflected as discontinued operations in all peri presented
(b) Non-GAAP financial measure. See "Non-GAAP Measures" above for further discussion.

Supplemental Statistics (Unaudited)	Three Months Ended			Year Ended	
(in millions)	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 2(
Segment income (loss)					
United States E&P	$ 76	$ (38)	$ (91)	$ (148)	$ (
International E&P	118	104	110	374	
Segment income (loss)	194	66	19	226	(
Not allocated to segments	(222)	(665)	(1,402)	(1,056)	(1,
Loss from continuing operations	(28)	(599)	(1,383)	(830)	(2,
Discontinued operations (a)	—	—	12	(4,893)	
Net income (loss)	$ (28)	$ (599)	$ (1,371)	$ (5,723)	$ (2,
Exploration expenses					
United States E&P	$ 57	$ 41	$ 37	$ 154	$
International E&P	—	3	(3)	5	
Segment exploration expenses	57	44	34	159	
Not allocated to segments	—	250	—	250	
Total	$ 57	$ 294	$ 34	$ 409	$
Cash flows					
Net cash provided by operating activities from continuing operations	$ 501	$ 564	$ 375	$ 1,988	$
Minus: changes in working capital	(28)	62	12	(27)	
Minus: U.K. tax payment	(108)	—	—	(108)	
Total net cash provided from continuing operations before changes in working capital and the U.K. tax payment (b)	$ 637	$ 502	$ 363	$ 2,123	$
Net cash provided by operating activities from discontinued operations (a)	—	—	80	141	
Cash additions to property, plant and equipment	$ (669)	$ (530)	$ (255)	$ (1,974)	$ (1,

(a) The Company closed on its sale of the Canadian oil sands business in the second quarter of 2017. The Canadian oil sands business is reflected as discontinued operations in all peric presented
(b) Non-GAAP financial measure. See "Non-GAAP Measures" above for further discussion.

	Three Months Ended			Year Ended	
(mboed)	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 20
Net production available for sale					
United States E&P (a)	262	245	212	235	2
International E&P excluding Libya (b)	121	126	129	123	1
Total continuing operations, excluding Libya (b)	383	371	341	358	3
Libya	33	23	8	19	
Total continuing operations	416	394	349	377	3

(a) The Company closed on the sale of certain Oklahoma and Colorado assets in September 2017 and October 2017, respectively. The sales of certain Wyoming assets closed in 2016.
(b) Libya is excluded because of the timing of future production and sales levels.

	Three Months Ended			Year Ended	
(mboed)	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 20
Net production available for sale					
United States E&P	262	245	212	235	2
Less: Divestitures (a)	(1)	(3)	(6)	(2)	(
Divestiture-adjusted United States E&P	261	242	206	233	2
Divestiture-adjusted total continuing operations	415	391	343	375	3
Discontinued operations (b)	—	—	47	18	

(a) Divestitures include the sale of certain conventional assets in Oklahoma in September 2017 and Colorado in October 2017. These production volumes have been removed from all periods shown in arriving at divestiture-adjusted United States E&P net production available for sale.
(b) The Company closed on its sale of the Canadian oil sands business on May 31, 2017. The Canadian oil sands business is reflected as discontinued operations in all periods presentec

Supplemental Statistics (Unaudited)	Three Months Ended			Year Ended	
	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 2(
United States E&P - net sales volumes					
Liquid hydrocarbons (mbbld)	**199**	**183**	**160**	**176**	1
Oklahoma	34	31	24	29	
Eagle Ford	84	80	74	80	
Bakken	64	55	47	52	
Northern Delaware	9	6	—	5	
Other United States (a)	8	11	15	10	
Crude oil and condensate (mbbld)	**150**	**139**	**121**	**133**	1
Oklahoma	16	17	13	15	
Eagle Ford	61	58	54	59	
Bakken	58	49	41	46	
Northern Delaware	8	6	—	4	
Other United States (a)	7	9	13	9	
Natural gas liquids (mbbld)	**49**	**44**	**39**	**43**	
Oklahoma	18	14	11	14	
Eagle Ford	23	22	20	21	
Bakken	6	6	6	6	
Northern Delaware	1	—	—	1	

Other United States (a)	1	2	2	1	
Natural gas (mmcfd)	**376**	**369**	**315**	**348**	**3**
Oklahoma	180	161	123	149	
Eagle Ford	127	126	119	125	
Bakken	26	26	26	25	
Northern Delaware	14	15	—	9	
Other United States (a)	29	41	47	40	
Total United States E&P (mboed)	**262**	**244**	**212**	**234**	**2**
International E&P - net sales volumes					
Liquid hydrocarbons (mbbld)	**71**	**81**	**64**	**64**	
Equatorial Guinea	32	39	32	32	
Libya	29	23	10	19	
United Kingdom	6	16	22	11	
Other International	4	3	—	2	
Crude oil and condensate (mbbld)	**58**	**68**	**52**	**52**	
Equatorial Guinea	20	27	20	21	
Libya	29	23	10	19	
United Kingdom	5	15	22	10	
Other International	4	3	—	2	
Natural gas liquids (mbbld)	**13**	**13**	**12**	**12**	
Equatorial Guinea	12	12	12	11	
United Kingdom	1	1	—	1	
Natural gas (mmcfd)	**493**	**507**	**482**	**485**	**4**
Equatorial Guinea	464	482	454	459	4
Libya	14	—	—	4	
United Kingdom (b)	15	25	28	22	
Total International E&P (mboed)	**153**	**165**	**145**	**145**	**1**
Total Company continuing operations - net sales volumes (mboed)	**415**	**409**	**357**	**379**	**3**
Net sales volumes of equity method investees					
LNG (mtd)	6,353	6,943	6,743	6,423	5,
Methanol (mtd)	1,637	1,366	1,316	1,374	1,
Condensate and LPG (boed)	14,605	17,216	15,381	14,501	13,

(a) Includes production from conventional onshore assets sold in the applicable periods. The sale of certain Oklahoma and Colorado assets closed in September 2017 and October 2017 respectively. The sales of certain Wyoming assets closed in 2016.
(b) Includes natural gas acquired for injection and subsequent resale.

Supplemental Statistics (Unaudited)	Three Months Ended			Year Ended	
	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 20
United States E&P - average price realizations (a)					
Liquid hydrocarbons ($ per bbl)	**$ 47.61**	**$ 40.48**	**$ 39.00**	**$ 42.31**	**$ 32.**
Oklahoma	38.41	35.84	34.28	36.07	28
Eagle Ford	48.32	39.87	38.16	41.86	31
Bakken	51.38	43.09	41.96	45.83	35
Northern Delaware	50.35	44.00	—	46.08	
Other United States (b)	46.26	43.23	41.69	43.82	33
Crude oil and condensate ($ per bbl) (c)	**$ 55.46**	**$ 46.65**	**$ 45.89**	**$ 49.35**	**$ 38.**
Oklahoma	53.90	46.39	46.30	48.79	41
Eagle Ford	57.82	47.56	45.96	49.93	38
Bakken	54.42	46.06	46.28	49.28	39
Northern Delaware	53.74	44.49	—	48.84	
Other United States (b)	48.87	45.83	43.78	46.98	34
Natural gas liquids ($ per bbl)	**$ 23.60**	**$ 20.86**	**$ 17.31**	**$ 20.55**	**$ 13.**
Oklahoma	24.16	23.58	20.79	22.74	15
Eagle Ford	22.54	19.52	16.34	19.32	12
Bakken	24.09	17.89	11.97	18.38	8
Northern Delaware	26.79	30.23	—	24.04	
Other United States (b)	30.06	24.94	24.56	24.61	23
Natural gas ($ per mcf) (d)	**$ 2.65**	**$ 2.71**	**$ 2.87**	**$ 2.84**	**$ 2.**
Oklahoma	2.54	2.69	2.90	2.82	2
Eagle Ford	2.82	2.83	2.91	2.89	2
Bakken	2.82	2.08	2.63	2.80	2
Northern Delaware	2.37	3.00	—	2.70	
Other United States (b)	2.56	2.67	2.82	2.82	2
International E&P - average price realizations					
Liquid hydrocarbons ($ per bbl)	**$ 51.13**	**$ 43.69**	**$ 37.85**	**$ 43.36**	**$ 32.**
Equatorial Guinea	33.56	32.78	26.60	29.62	25
Libya	68.31	56.93	57.69	60.72	57
United Kingdom	59.11	51.12	45.02	53.52	42
Other International	48.89	40.67	—	44.73	
Crude oil and condensate ($ per bbl)	**$ 61.32**	**$ 51.23**	**$ 46.14**	**$ 53.05**	**$ 41.**
Equatorial Guinea	52.92	46.91	41.60	46.02	38
Libya	68.31	56.93	57.69	60.72	57
United Kingdom	61.94	51.72	45.18	54.51	43
Other International	48.89	40.67	—	44.73	
Natural gas liquids ($ per bbl)	**$ 4.66**	**$ 2.25**	**$ 1.72**	**$ 3.15**	**$ 2.**
Equatorial Guinea (e)	1.00	1.00	1.00	1.00	1
United Kingdom	45.71	32.58	32.58	39.65	26
Natural gas ($ per mcf)	**$ 0.59**	**$ 0.51**	**$ 0.53**	**$ 0.55**	**$ 0.**
Equatorial Guinea (e)	0.24	0.24	0.24	0.24	0
Libya	5.03	—	—	5.03	
United Kingdom	7.20	5.71	5.39	6.28	4
Benchmark					
WTI crude oil (per bbl)	$ 55.30	$ 48.20	$ 49.29	$ 50.85	$ 43
Brent (Europe) crude oil (per bbl)(f)	$ 61.53	$ 52.11	$ 49.19	$ 54.25	$ 43
Henry Hub natural gas (per mmbtu)(g)	$ 2.93	$ 3.00	$ 2.98	$ 3.11	$ 2

(a) Excludes gains or losses on derivative instruments.
(b) Includes production from conventional onshore assets sold in the applicable periods. The sale of certain Oklahoma and Colorado assets closed in September 2017 and October 2017 respectively. The sales of certain Wyoming assets closed in 2016.
(c) Inclusion of crude oil derivative instruments would have affected liquid hydrocarbons average price realizations by a realized loss of $0.76, and realized gains of $2.42, $0.32, $0.75 $0.92, for the fourth and third quarter of 2017, fourth quarter of 2016, and the years 2017 and 2016, respectively.
(d) Inclusion of realized gains (losses) on natural gas derivative instruments would have a minimal impact on average price realizations for the periods presented.
(e) Represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and/or Equatorial Guinea LNG Holdings Limited, which are equity method investees. The Alba Plant LLC processes the NGLs and then sells secondary condensate, propane, and butane at market prices. Marathon Oil includes its share of income from of these equity method investees in the International E&P segment.
(f) Average of monthly prices obtained from Energy Information Administration ("EIA") website.

(g) Settlement date average per mmbtu.

Estimated Net Proved Reserves from Continuing Operations (mmboe)	**U.S E&P**	**Intl. E&P**	**Total**
As of Dec. 31, 2016	948	456	1,40
Additions	98	18	11
Revisions	42	7	4
Acquisitions	28	—	2
Dispositions	(10)	—	(1
Production	(86)	(52)	(13
As of Dec. 31, 2017	**1,020**	**429**	**1,44**

Changes in Reserves (excluding dispositions) (mmboe)	19
Production (mmboe)	13
Reserve Replacement Ratio (excluding dispositions) (a)	14
Organic Changes in Reserves (excluding acquisitions, dispositions) (mmboe)	16
Production (mmboe)	13
Organic Reserve Replacement Ratio (excluding acquisitions, dispositions) (a)	12

Finding Costs ($ in millions, except as indicated)		**2017**
Property Acquisition Costs - Proved	$	19
Property Acquisition Costs - Unproved		1,74
Exploration		92
Development		99
Total Company - Costs Incurred from Continuing Operations	**$**	**3,85**
Cost Incurred	$	3,85
Changes in Reserves (excluding dispositions) (mmboe)		19
Finding and development costs per BOE	**$**	**19.9**
Costs Incurred	$	3,85
Property Acquisition Costs		(1,93
Capitalized Asset Retirement Costs		19
Adjusted finding and development costs (a)	**$**	**2,11**
Organic Changes in Reserves (excluding acquisitions, dispositions) (mmboe)		16
Adjusted finding and development costs per BOE (a)	**$**	**12.8**

(a) Non-GAAP financial measure. See "Non-GAAP Measures" above for further discussion.

The following tables set forth outstanding derivative contracts as of February 12, 2018 and the weighted average prices for those contracts:

Crude Oil

	2018				**2019**			
(unaudited)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarte**
Three-Way Collars [(a)]								
Volume (Bbls/day)	85,000	85,000	95,000	95,000	30,000	30,000	—	
Weighted average price per Bbl:								
Ceiling	$ 56.38	$ 56.38	$ 57.65	$ 57.65	$ 65.27	$ 65.27	$ —	$
Floor	$ 51.65	$ 51.65	$ 52.11	$ 52.11	$ 54.00	$ 54.00	$ —	$
Sold put	$ 45.00	$ 45.00	$ 45.21	$ 45.21	$ 46.67	$ 46.67	$ —	$
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	10,000	10,000	10,000	10,(
Weighted average price per Bbl	$ (0.60)	$ (0.60)	$ (0.67)	$ (0.67)	$ (0.82)	$ (0.82)	$ (0.82)	$ (C

(a) Includes contracts we entered into between January 1, 2018 and February 12, 2018, of 10,000 Bbls/day of three-way collars for July - December 2018 with an average ceiling price c $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. We entered into 10,000 Bbls/day of basis swaps for 2019 subsequent to December 31, 2017.

Natural Gas

	2018			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Three-Way Collars				
Volume (MMBtu/day)	200,000	160,000	160,000	16(
Weighted average price per MMBtu				
Ceiling	$ 3.79	$ 3.61	$ 3.61	$
Floor	$ 3.08	$ 3.00	$ 3.00	$
Sold put	$ 2.55	$ 2.50	$ 2.50	$