2018 Capital Program & 2017 Results

February 14, 2018

Forward-Looking Statements and Other Matters

This presentation (and oral statements made regarding the subjects of this presentation) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including, without limitation: the Company's future performance, business strategy, asset quality, production guidance, drilling plans, 2018 capital plans, cost and expense estimates, cash flows, returns, including CROIC and CFPDAS, cash margins, asset sales and acquisitions, future financial position, and other plans and objectives for future operations. 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 results to differ materially from those projected, including, without limitation: 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, including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions; capital available for exploration and development; risks related to our hedging activities; well production timing; the inability of any party to satisfy closing conditions with respect to our Canadian subsidiary disposition; drilling and operating risks; 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 contractual obligations; unforeseen hazards such as weather conditions; acts of war or terrorism, 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 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.

Reconciliations of the differences between non-GAAP financial measures used in this presentation and their most directly comparable GAAP financial measures are available at www.Marathonoil.com in the 4Q 2017 Investor Packet.

2018 Capital Program Overview

- Year over year improvement in corporate cash returns significantly outpaces production growth
- Margins naturally expand as U.S. resource plays increase to almost 70% of production mix
- >90% of $2.3B development capital budget allocated to high-return U.S. resource plays
- Self-funding development capital at $50 WTI incl. dividend; meaningful free cash flow at $60 WTI
- 2018 total annual oil growth of 18% at the midpoint, divestiture adjusted, driven by 20 - 25% oil growth in U.S. resource plays

Strong Rate of Change on Corporate Performance Metrics

2018 vs 2017 Metrics	At $50 WTI	At $60 WTI
CROIC[1] improvement:	Δ 30%	Δ 50%
CFPDAS[2] improvement:	Δ 10%	Δ 30%
Total production Boe growth:	Δ 10 - 14%	
Oil growth:	Δ 16 - 20%	

- CROIC and CFPDAS adopted as executive compensation metrics in 2018

[1]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)

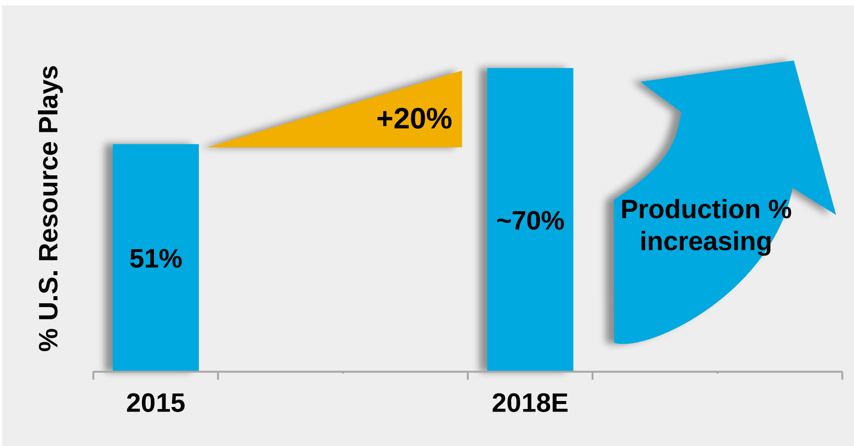
[2]CFPDAS = Cash flow per debt adjusted share; calculated by taking cash flow (Operating Cash Flow before working capital + net interest after tax) divided by total shares including debt shares. Debt shares is the average net debt during a calendar year divided by the average annual stock price.

Metrics exclude Libya in 2018. See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

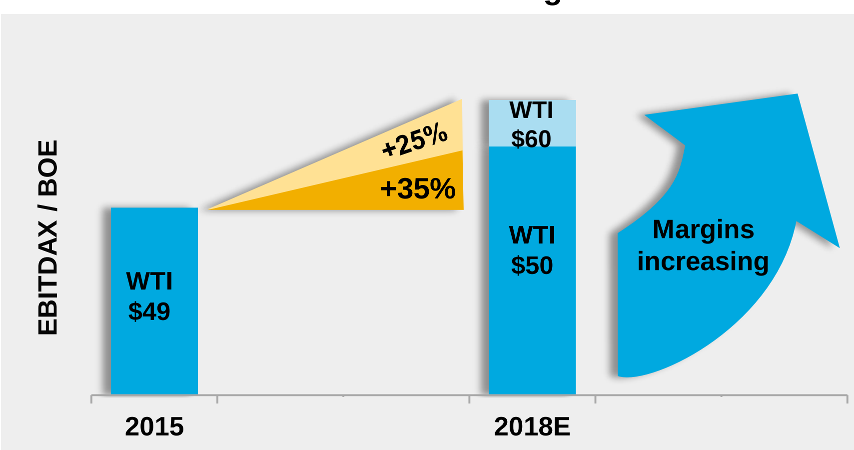
Marathon Oil

Production Mix Drives Margin Enhancement

U.S. Resource Plays % of Total Production Mix



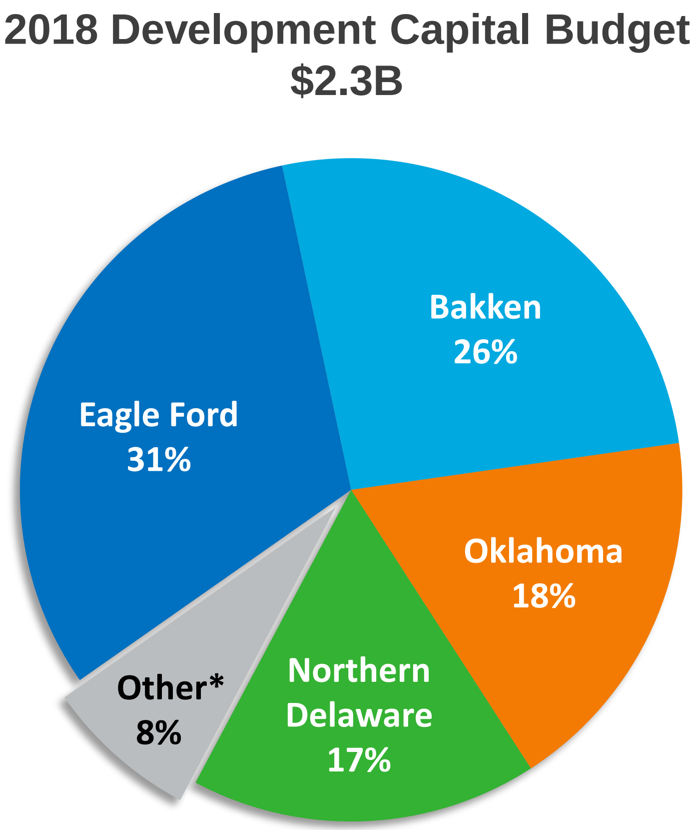
MRO EBITDAX Margins



- U.S. resource plays production contribution **up significantly** from 2015
- **~70%** of 2018 production mix from higher margin U.S. resource plays and trending higher
- Estimated 2018 EBITDAX unit margins **up ~35%** from 2015 on a price normalized basis
  - Grows to **~60% increase** at $60 WTI
  - Reflects portfolio transformation and reset of cost structure

Excluding Libya

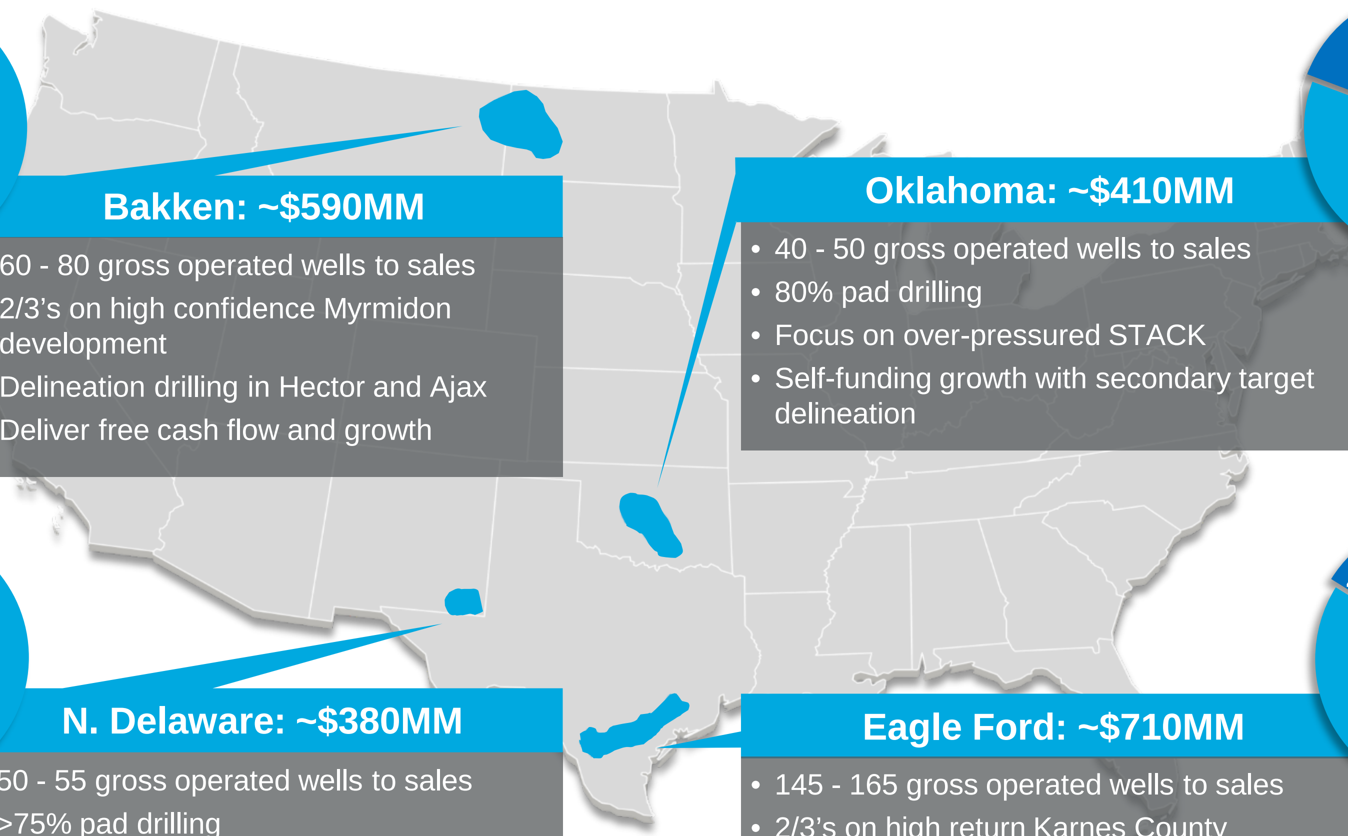
>90% 2018 Development Capital to U.S. Resource Plays

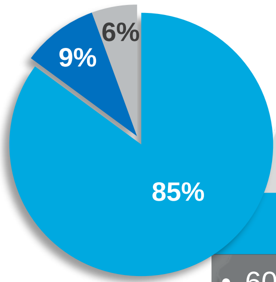


- Disciplined capital program balances returns and strategic objectives with growth as an outcome
- **$2.3B** Development Capital Budget in 2018; cash flow neutral at $50 WTI
- Uses of excess cash from higher commodity prices or divestiture proceeds:
  - Balance sheet strength
  - Resource play leasing and exploration (REx)
  - Bolt-on acquisitions in core basins
  - Additional return of capital to shareholders

**Other includes International and corporate capex*

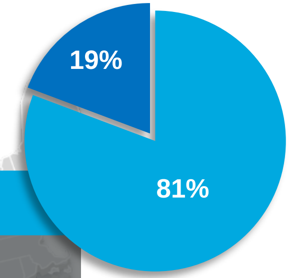
Differentiated Position in 4 Lowest Cost Resource Plays





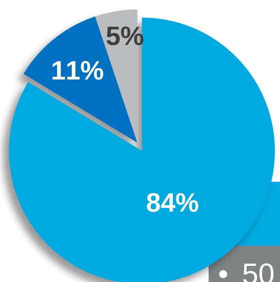
Bakken: ~$590MM

- 60 - 80 gross operated wells to sales
- 2/3's on high confidence Myrmidon development
- Delineation drilling in Hector and Ajax
- Deliver free cash flow and growth



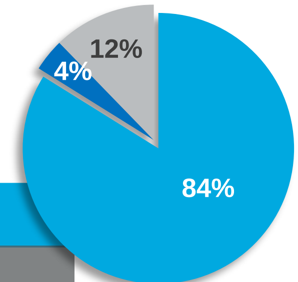
Oklahoma: ~$410MM

- 40 - 50 gross operated wells to sales
- 80% pad drilling
- Focus on over-pressured STACK
- Self-funding growth with secondary target delineation



N. Delaware: ~$380MM

- 50 - 55 gross operated wells to sales
- >75% pad drilling
- 60 - 65% average WI
- Focus on Wolfcamp X-Y & 3rd Bone Spring
- Deliver growth while delineating and defining upside



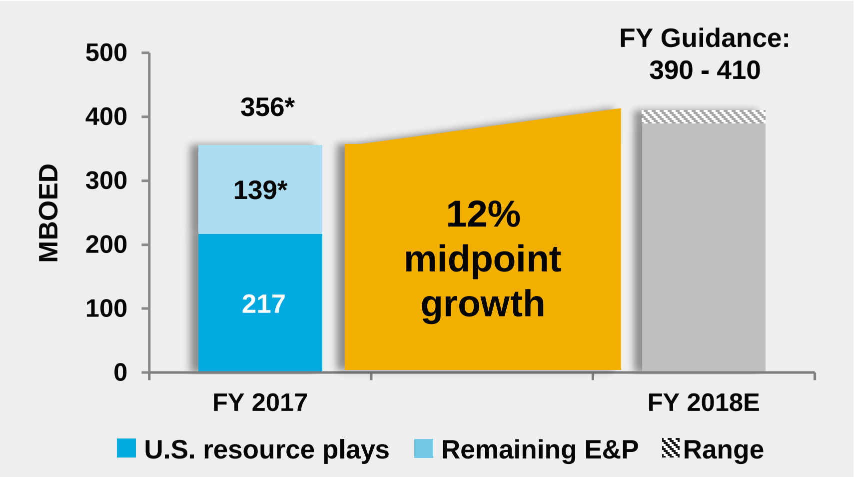
Eagle Ford: ~$710MM

- 145 - 165 gross operated wells to sales
- 2/3's on high return Karnes County
- 1/3 in Atascosa County
- Maintain flat production and generate free cash flow

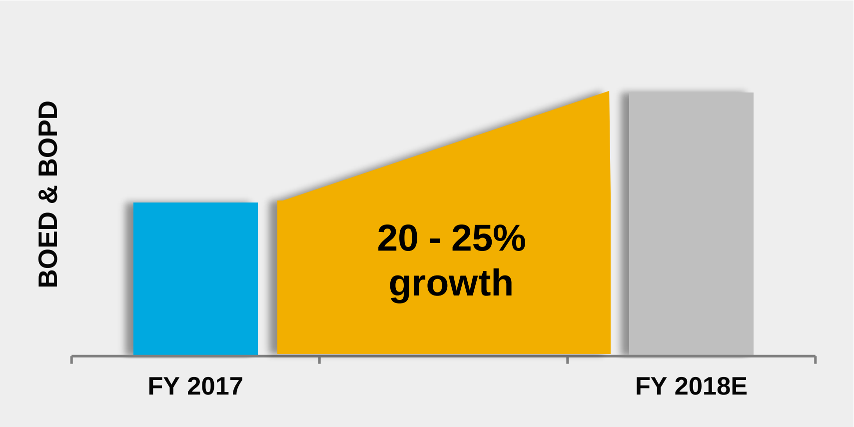
2018 Capital Legend: D&C Co-Op D&C Non-Op Facilities & Other

2018 Returns Driven by Oil Focused Growth

Total Available for Sale Volumes



U.S. Resource Play Production



2018 Annual Production Guidance:

- Total growth of **12%** at the midpoint, divestiture adjusted
  - **18%** oil growth at the midpoint
  - **20 - 25%** oil & boe growth in U.S. resource plays
  - 8 - 10% decline rates in EG
- Total MRO and resource play growth consistent with 4-year benchmark CAGRs

2018 1Q Production Guidance:

- U.S.: 265,000 – 275,000 BOED
- International: 105,000 – 115,000 BOED
  - Lower sequentially due to planned turnaround in EG

**Adjusted for divestitures of 2 MBOED in FY17*
Excluding Libya and discontinued operations

2017 Results Highlight Execution Focus

	2017 Guidance	2017 Actuals
Full-Year Capital Program[1]	$2.1B	**$2.1B** ✓
Total Production (MBOED)[2]	350 - 360	**358** ✓
Production Oil & BOE Growth[2,3]	9% midpoint	**9%** ✓
U.S. Resource Plays Exit-to-Exit Oil Growth	25 - 30%	**31%** ✓
United States Production expense	$5.00 - $6.00	**$5.57** ✓
International Production expense[2]	$4.50 - $5.50	**$4.13** ✓

- Met or exceeded all commitments through consistent operational excellence across all assets
- Entered Northern Delaware basin and divested Canadian oil sands business
- Organic reserve replacement of 121% at ~$12.81 adjusted drillbit F&D costs (excluding acquisitions and dispositions)

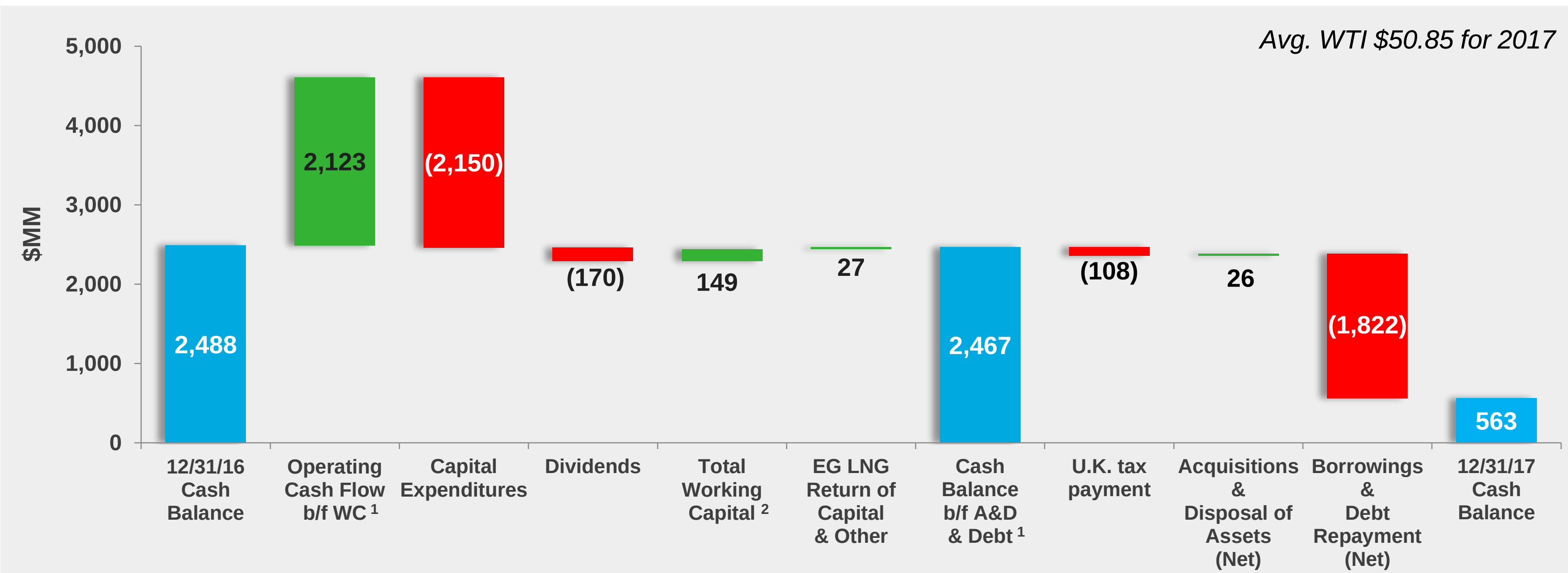
[1]Does not include acquisition costs of $1.8B, net of cash, or ~$110MM for resource play leasing and exploration capex (REx)
[2]Excluding Libya [3]Divestiture adjusted
See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

Marathon Oil

Total Company Cash Flow for FY17

Year-end liquidity of $4.0B

- Achieved free cash flow neutrality in 2017, including dividends and working capital[1]
- Reduced gross debt by **~$1.75B**, lowering annualized interest expense by **$115MM**
- Competitive dividend of **$170MM** returned to shareholders
- **~$110MM** invested in resource play leasing and exploration capex (REx)
- Final **$750MM** OSM payment expected in March 2018, not reflected below



[1]*Excludes one time U.K. tax payment under appeal of $108MM*

[2]*Total working capital includes $(27)MM and $176MM of working capital changes associated with operating activities and investing activities, respectively*

Free cash flow = Operating cash flows b/f changes in working capital - capital expenditures & dividends + total working capital + EG LNG return of capital & other

See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

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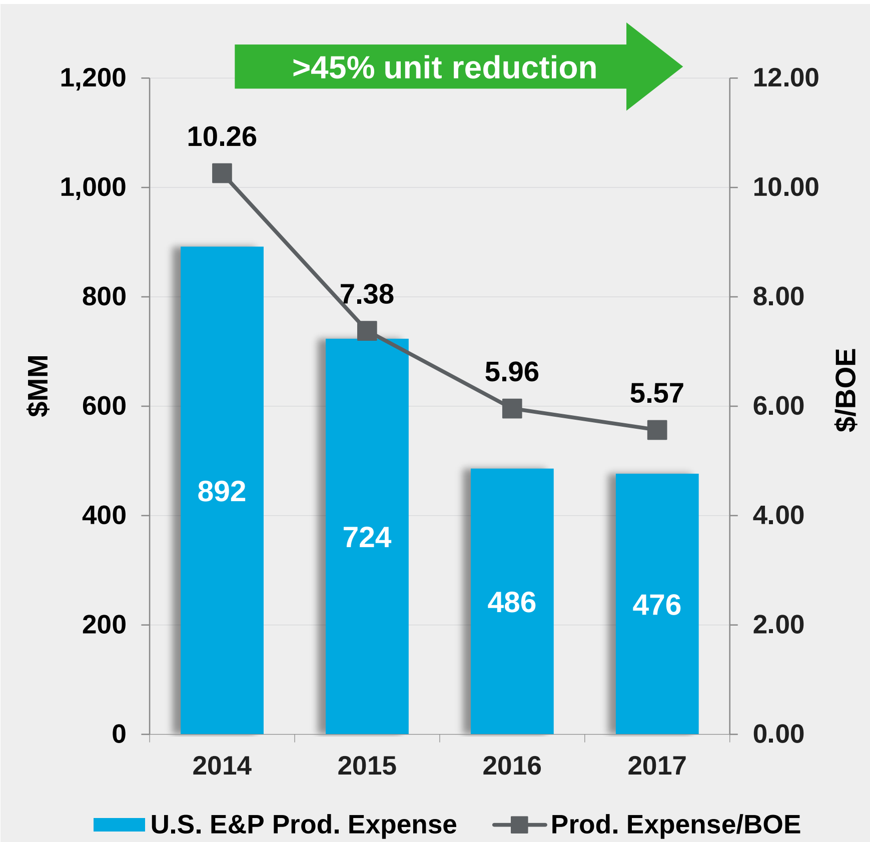
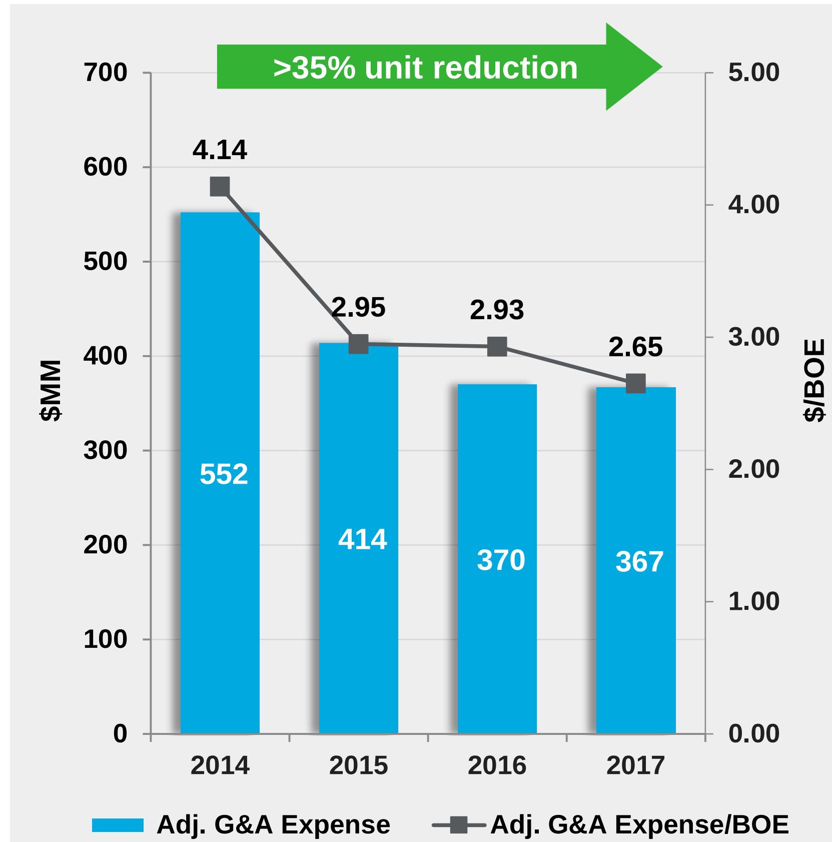
2017 U.S. Production Unit Expense At Record Low*

U.S. Production Expense



Adjusted G&A Expense



**Since becoming an independent E&P in 2011*

See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

Fourth Quarter 2017 Highlights

Production

- Total Company production (ex. Libya) of 383 MBOED, **up 4%** sequentially*; Libya 33 MBOED
- U.S. resource plays production **grew 10%** sequentially to 249 MBOED; oil **up 31%** exit to exit
- Bakken and Oklahoma production **grew 17%** and **10%** sequentially

4 Basin Execution

- Williston **Basin record** for IP 30 oil rate of **3,005 BOPD**
- Eagle Ford production **up 4%** sequentially with fewer wells to sales
- STACK infill development pad averaged IP 30 of **1,840 BOED**
- Two well N. Delaware pad averaged IP 30 of **3,265 BOED**

"We ended the quarter with outstanding results across our four U.S. resource plays and achieved cash flow neutrality for 2017. In 2018, we'll continue to focus on high-return investments and expect to deliver meaningful free cash flow at $60 WTI…"

-- Lee Tillman, President & CEO

**On a divestiture-adjusted basis*

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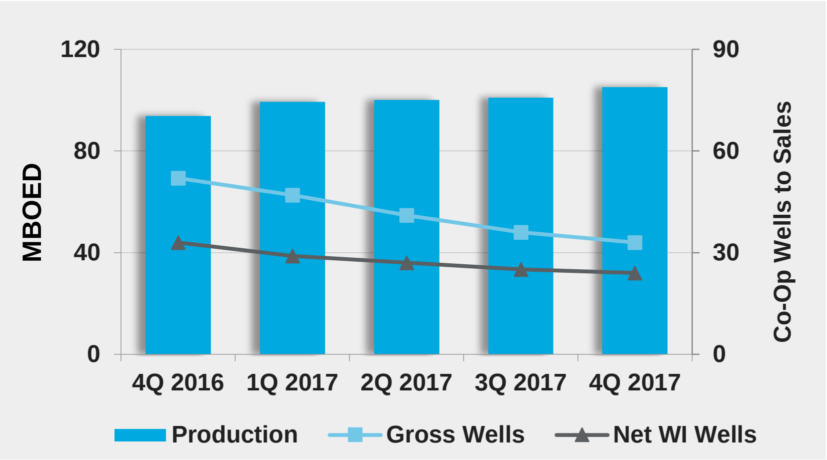
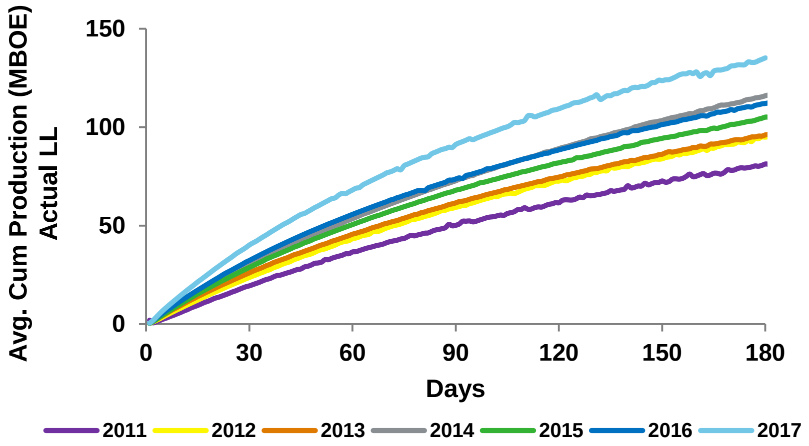
Another Quarter of Eagle Ford Outperformance

Production Volumes and Wells to Sales



180 day Cumulative Well Production



- Production averaged **105** net MBOED; **up 4%** from 3Q 2017
- **33** gross operated wells to sales
  - Average IP 30 rates of **1,800 BOED** (73% oil), including two Austin Chalk wells that averaged IP 30 of **2,415 BOED** (75% oil)
- Atascosa County wells continue to outperform
  - Middle McCowen 3-well pad averaged IP 30 of **2,080 BOED** (87% oil), 9,915 ft LL
  - Guajillo Unit 8 South 5-well pad averaged IP 30 of **1,730 BOED** (77% oil), 6,300 ft LL
- 2017 180d cumulative well production increased **~20%** from last year; up **~65%** since 2011

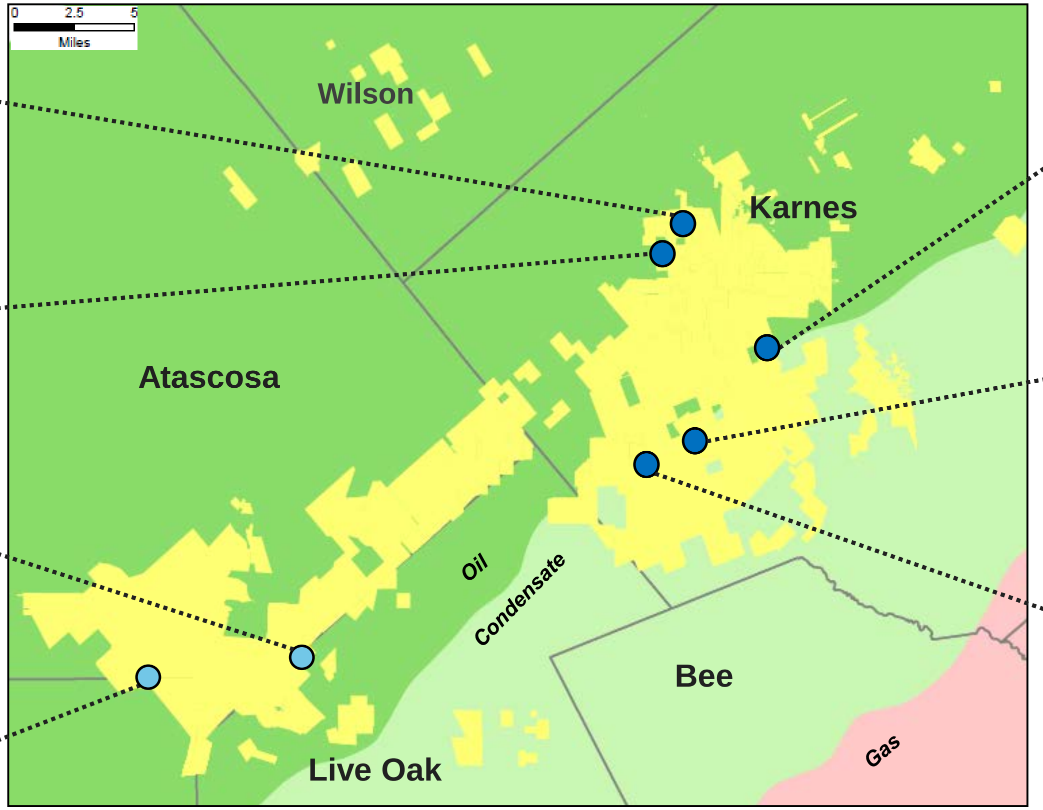
Positive 4Q Results Across Eagle Ford Position

Challenger Unit C
7 well pad
Avg: 1,698 BOED (79% oil)
~5,500' LL

Labus Pittman
4 well pad
Avg: 1,969 BOED (83% oil)
~5,200' LL

Guajillo Unit 8 South
5 well pad
Avg: 1,730 BOED (77% oil)
~6,300' LL

Middle McCowen
3 well pad
Avg: 2,080 BOED (87% oil)
~9,915' LL



Rogers Foester
5 well pad
Avg: 1,678 BOED (65% oil)
~5,060' LL

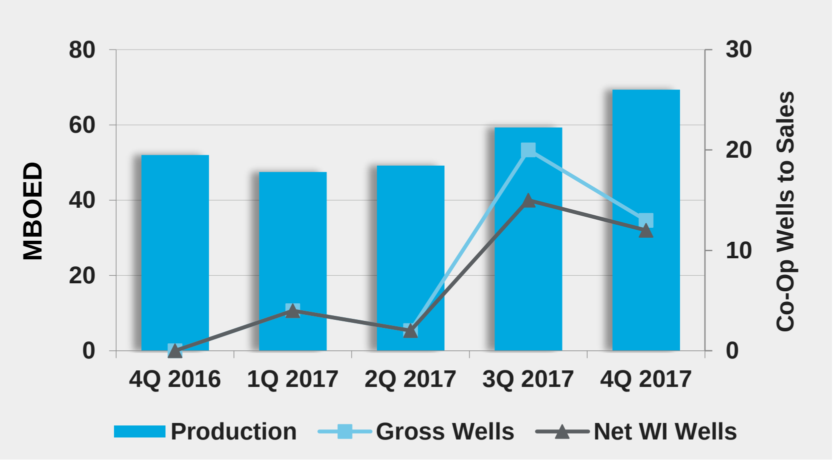
Morgan/Direct Assets
6 well pad
Avg: 1,492 BOED (57% oil)
~6,285' LL

Rancho Grande
3 well pad
Avg: 2,429 BOED (67% oil)
~8,080' LL

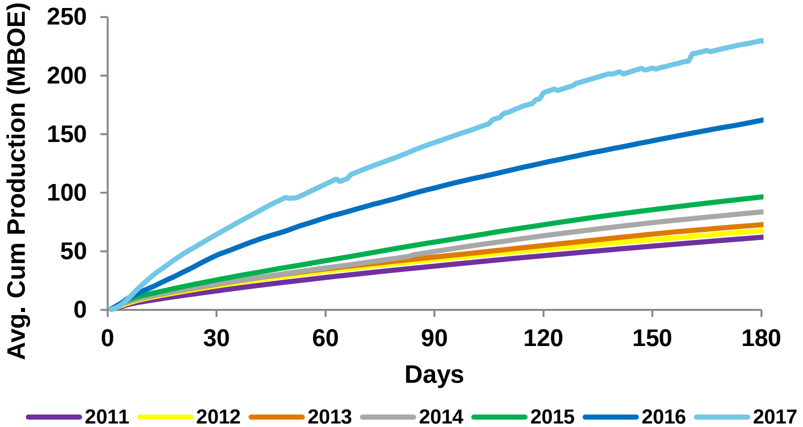
Light blue boxes indicate outside core Karnes County
IPs shown are 30 day (includes oil, NGL and gas)

Bakken Delivers Another Year of Step Change Performance

Production Volumes and Wells to Sales



Well Performance History*



- Production averaged **69** net MBOED, **up 17%** from 3Q 2017
- **13** gross operated wells to sales
  - Nine West Myrmidon wells reached IP 30 rates averaging **2,935 BOED** (78% oil)
- W. Myrmidon Forsman well sets new basin record with IP 30 oil rate of **3,005 BOPD**
- Eastern Hector step-out wells delivering promising initial results
  - 3 wells on Chapman pad averaged IP 30 of **1,810 BOED** (85% oil)
- 2017 well performance increased **>40%** from last year's step change in results

**Includes all MRO operated wells across all formations*

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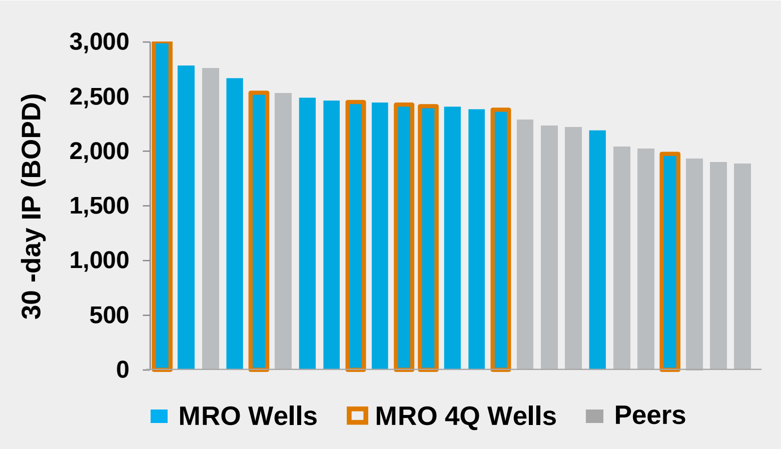
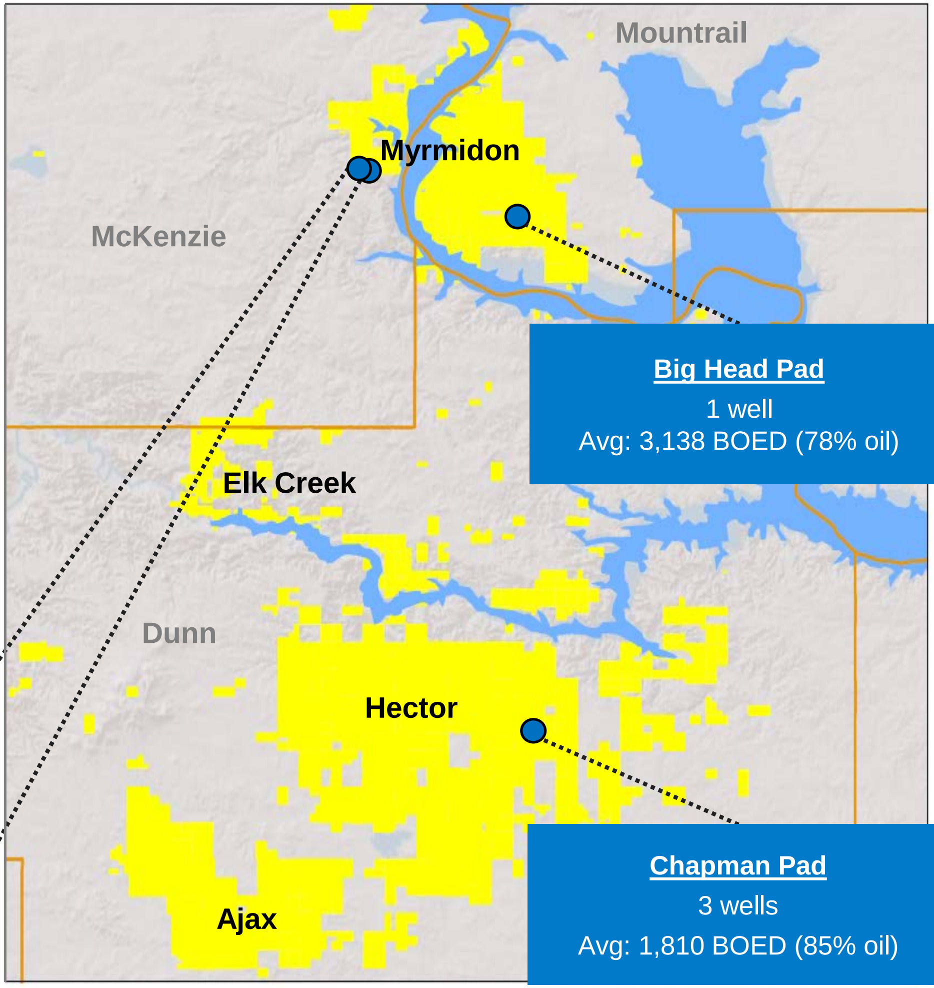
Bakken Best in Basin Performance Continues

Historic Industry Middle Bakken Well Performance



Source: Drilling info, competitor presentations and internal data.
External data available through 3Q 2017.



Big Head Pad
1 well
Avg: 3,138 BOED (78% oil)

Veronica Pad
5 wells
Avg: 3,048 BOED (78% oil)

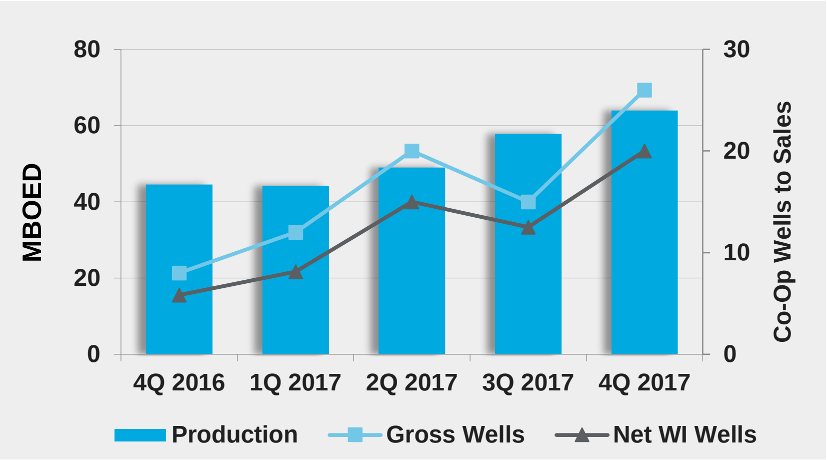
TAT 34 Pad
4 wells (includes Forsman)
Avg: 2,789 BOED (78% oil)

Chapman Pad
3 wells
Avg: 1,810 BOED (85% oil)

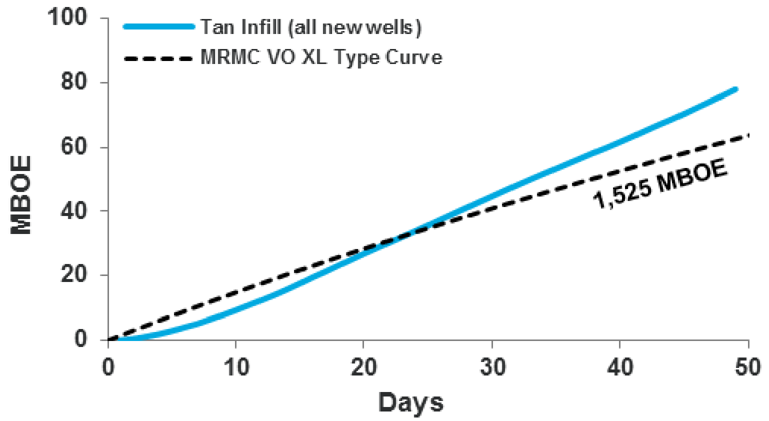
IPs shown are 30 day (includes oil, NGL and gas)

Oklahoma Delivers Impressive Volatile Oil Infill Development

Production Volumes and Wells to Sales



Tan Infill Cumulative Production



- Production averaged **64** net MBOED; **up 10%** from 3Q 2017
- **26** gross operated wells to sales
- Successful STACK volatile oil infill development; 9 new wells (8 XLs and 1 SL) averaged IP 30 of **1,840 BOED** (60% oil)
- STACK black oil infill pilot with 5 new wells averaged IP 30 of 715 BOED (65% oil), 5,000 ft LL
- 4Q gas and gas condensate wells driven by leasehold requirements

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Oklahoma 4Q Activity Focused on Infills and Leasehold

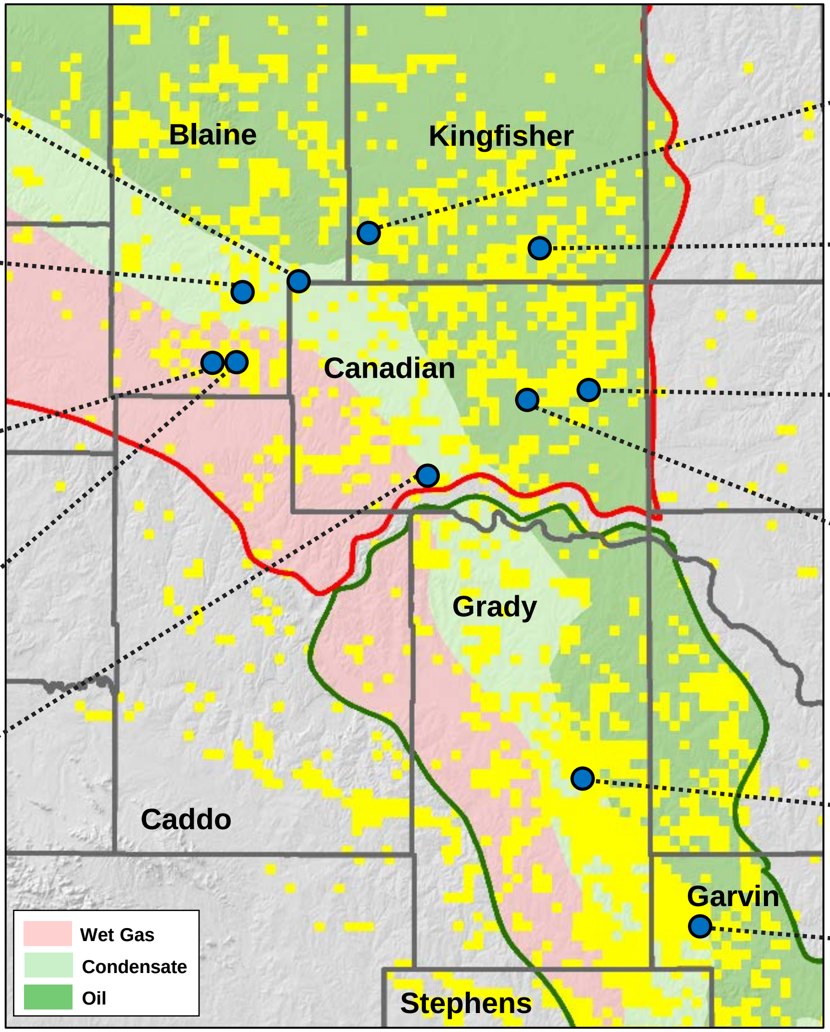
Willie Left Hand BIA 1-5H
IP30: 1,396 BOED (16% oil)

Londyn BIA 1411 1-9MH
IP30: 2,533 BOED (6% oil)

Hicks BIA 1-13-12XH
IP30: 14.8 MMCFED

Tom BIA 1311 1-17-8MXH
IP30: 21.9 MMCFED

Rafter J Ranch 1108 1-16MH
IP30: 1,017 BOED (27% oil)



Tan Infill Development
(9 new wells)
Avg IP30: 1,840 BOED (60% oil)

Eve Infill Pilot
(5 new wells)
Avg IP30: 715 BOED (65% oil)

Brenda Chapman 1306 1-25-26MXH
IP30: 632 BOED (59% oil)

Wilds 1207 1-1MH
IP30: 1,327 BOED (35% oil)

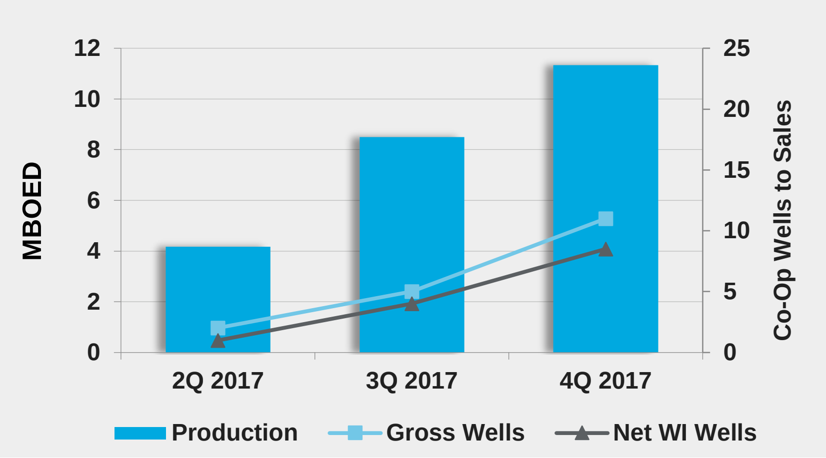
Winter Creek 0606 1-25-24MXH
(Sycamore)
IP30: 1,484 BOED (43% oil)

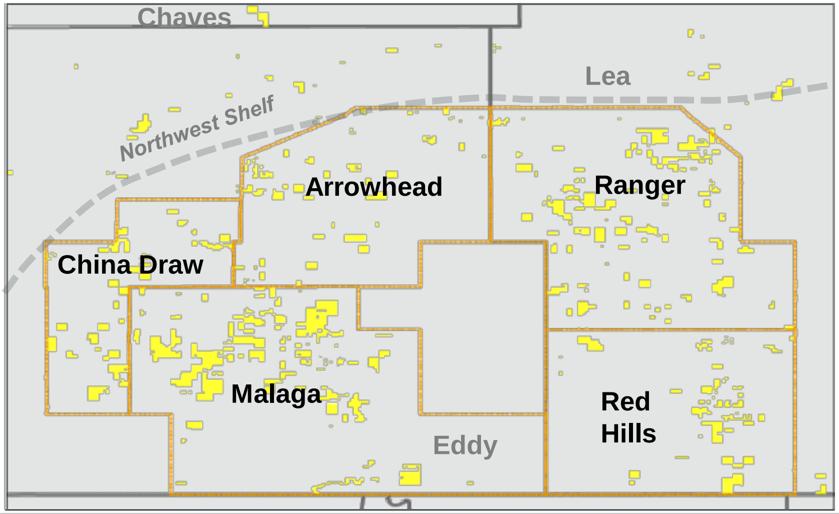
Ralph 0304 1-11-2WXH
IP30: 1,729 BOED (40% oil)

IPs shown are 30 day (includes oil, NGL and gas)

Northern Delaware Producing Outstanding Well Results

Production Volumes and Wells to Sales





- Production averaged **11** net MBOED; **up** from 3Q 2017
- **11** gross operated wells to sales
  - Average IP 30 rates of **1,835 BOED** (66% oil)
- Encouraging results from multiple Wolfcamp & Bone Spring wells, incl. first 7,500 ft LL tests:
  - Two well pad average IP 30 of **3,265 BOED** (62% oil)
  - Nearby third well averaged IP 30 of **2,910 BOED** (63% oil)
- Successfully drilled multi-horizon Cypress spacing pilot; to sales in 2Q
- Continue to pursue bolt-on acquisitions, acreage swaps and greenfield leasing

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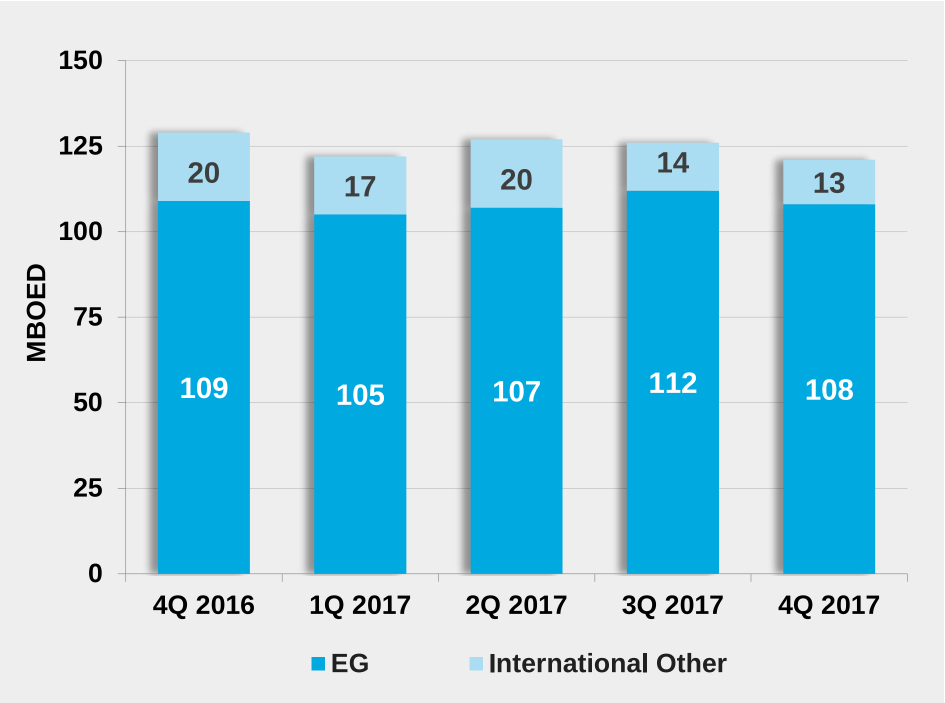
International 4Q Highlights

Intl Production Volumes (Excl. Libya)



Total EG EBITDAX	**$163MM**	**$161MM**	**$134MM**	**$183MM**	**$186MM**

- International production* **121** net MBOED; down sequentially due to:
  - Forties pipeline shutdown
  - Planned TAR at Brae and Foinaven
  - Natural field declines
- EG delivered **$186MM** of EBITDAX in 4Q
- Libya production averaged 33 net MBOED; continue to exclude from guidance

**Excluding Libya*

See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

Key 4Q and Full Year 2017 Takeaways

Outperformed in 2017 While Maintaining Cash Flow Neutrality*

9%	31%	121%
2017 oil and boe production growth**	U.S. resource plays exit to exit oil growth	Organic reserve replacement

Eagle Ford

Up 4% sequentially with fewer wells to sales

N. Delaware

3,265 BOED
average IP 30 of two well pad

Bakken

3,005 BOPD
Williston Basin record

Oklahoma

1,840 BOED
average IP 30 on STACK infill

Reduced debt $1.75B
$115MM annualized interest savings

$4.0B total liquidity
including ~$560MM cash

$5.57/boe
Record low 2017 U.S. production expense

*Including dividends and working capital, excluding the U.K tax payment under appeal
**Excluding Libya and divestiture adjusted

APPENDIX

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Volumes, Exploration Expenses & Effective Tax Rate

2017 (excluding Libya)

	1Q	2Q	3Q	4Q	Full Year
United States Net Sales Volumes:					
- Liquid Hydrocarbons (MBD)	158	165	183	199	176
- Natural Gas (MMCFD)	304	341	369	376	348
- United States Total (MBOED)	208	222	244	262	234
International Net Sales Volumes:					
- Liquid Hydrocarbons (MBD)	38	44	58	42	45
- Natural Gas (MMCFD)	461	478	507	479	481
- International Total (MBOED)	114	124	142	122	125
Total Sales Volumes (MBOED)	322	346	386	384	359
Total Available for Sale (MBOED)	330	349	371	383	358
- Disc. operations synthetic crude oil production (MBD)*	45	29	-	-	18
Equity Method Investment Net Sales Volumes:					
- LNG (metric tonnes/day)	6,147	6,243	6,943	6,353	6,423
- Methanol (metric tonnes/day)	1,307	1,182	1,366	1,637	1,374
- Condensate and LPG (BOED)	14,546	11,608	17,216	14,605	14,501
Exploration Expenses (Pre-tax):**					
- United States ($ millions)	26	30	41	61	158
- International ($ millions)	2	-	3	-	5
Consolidated Effective Tax Rate (ex. Libya) Provision (Benefit)	(16)%	7%	7%	8%	5%

*Upgraded bitumen excluding blendstocks

**Excludes exploratory dry well costs, unproved property impairments and other of $250MM in 3Q and FY reported as special items

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2018 Production Estimates

	Available for Sale 1QE	Available for Sale Year Estimate
United States Total (MBOED)	265 – 275	
- Crude Oil (MBD)	150 – 160	
International Total (MBOED)*	105 – 115	
- Crude Oil (MBD)*	30 – 40	
Total Segments (MBOED)*	370 – 390	390 – 410
- Crude Oil (MBD)*	180 – 200	190 – 200

** Excluding Libya*

2018 Estimates

Exploration expenses & annual production operating costs per BOE

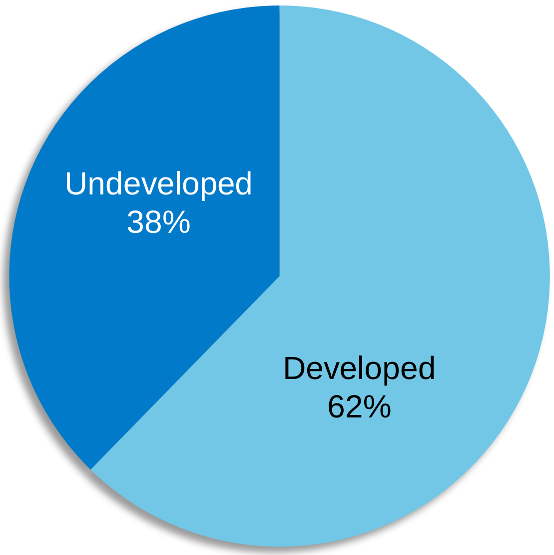
	1QE	Year Estimate
Total Exploration Expenses (Pre-tax, $MM)*:	40 – 50	
United States Cost Data		
Production Operating		$4.75 – 5.75
DD&A		$20.75 – 23.25
S&H and Other**		$3.75 – 4.25
International Cost Data*		
Production Operating		$4.75 – 5.75
DD&A		$4.25 – 5.75
S&H and Other**		$1.25 – 1.75
Expected Tax Rates by Jurisdiction:		
U.S. and Corporate Tax Rate		0%
Equatorial Guinea Tax Rate		25%
United Kingdom Tax Rate		40%
Libya Tax Rate		93.5%

**Excludes Libya*

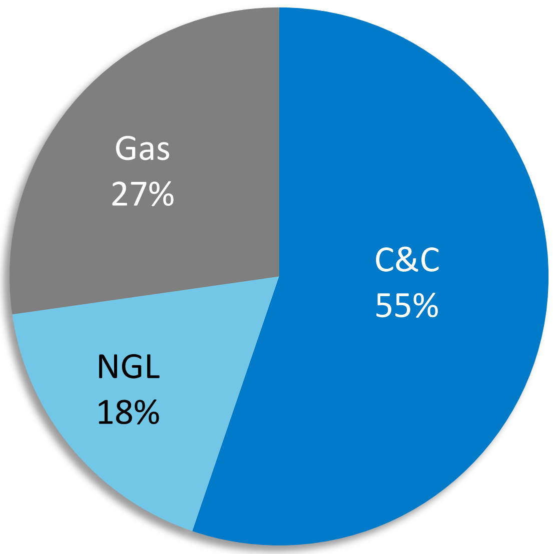
***Excludes G&A expense*

Year End 2017 Estimated Net Proved Reserves 1.4 BBOE

62% Proved Developed YE 2017



73% Liquids YE 2017



See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

121% Organic Reserve Replacement in 2017

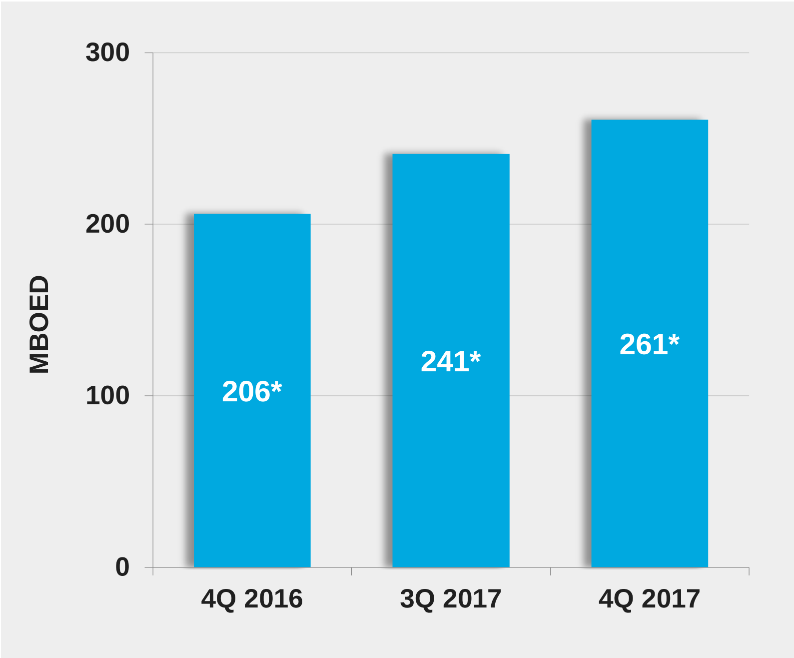
	United States	International	Canada – Disc Ops	TOTAL	F&D Costs
Category	(MMBOE)	(MMBOE)	SCO (MMBBL)	(MMBOE)	($/BOE)
As of Dec 31, 2016	948	456	692	2,096	
Additions	98	18	-	116	
Revisions	42	7	-	49	
Acquisitions	28	-	-	28	
Dispositions	(10)	-	(685)	(695)	
Production	(86)	(52)	(7)	(145)	
As of Dec 31, 2017	**1,020**	**429**	**0**	**1,449**	
Reserve Replacement Ratio (excluding dispositions)				140%	$19.97
Organic Reserve Replacement Ratio (excluding acquisitions & dispositions)				121%	$12.81

See the 4Q 2017 Investor Packet at www.Marathonoil.com for non-GAAP reconciliations

Marathon Oil

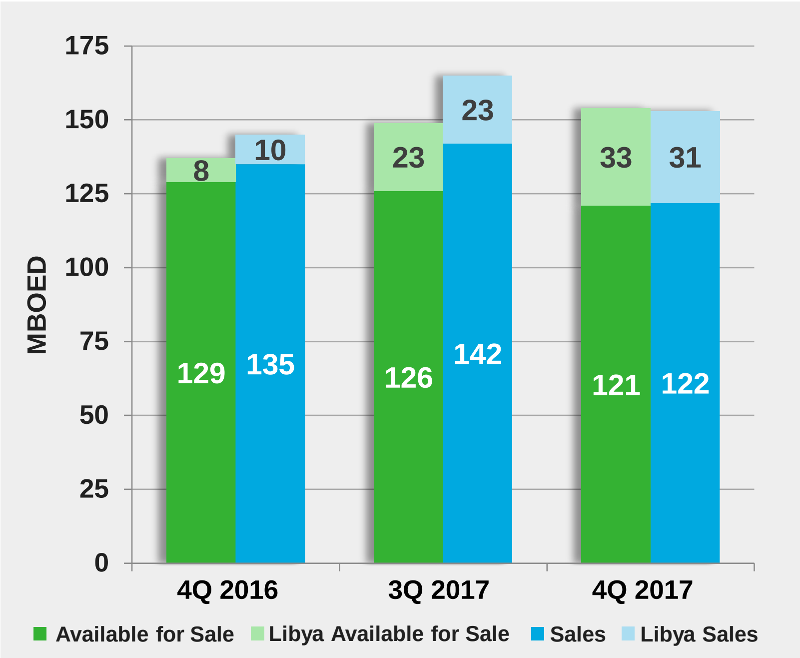
Production Performance

U.S. Divestiture-Adj. Sales Volumes



Avg C&C Realizations ($/BBL)			
Excluding Derivatives	$45.89	$46.65	$55.46
Including Derivatives	$46.21	$49.07	$54.70

Intl Production & Sales Volumes



Avg C&C Realizations ($/BBL)			
	$46.14	$51.23	$61.32

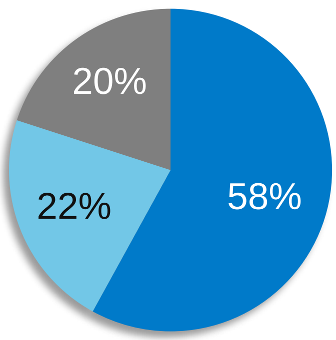
**Adjusted for divestitures of 6 MBOED in 4Q16, 3 MBOED in 3Q17 and 1 MBOED in 4Q17*

Cumulative underlift of (1,967) MBOE in Libya, (40) MBOE in EG and a cumulative overlift of 7 MBOE in UK

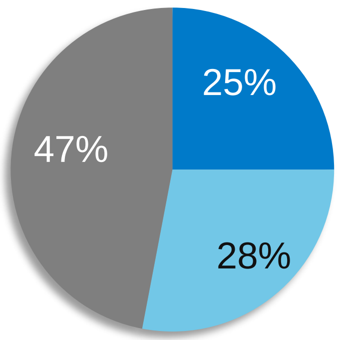
Marathon Oil

2017 4Q Production Mix

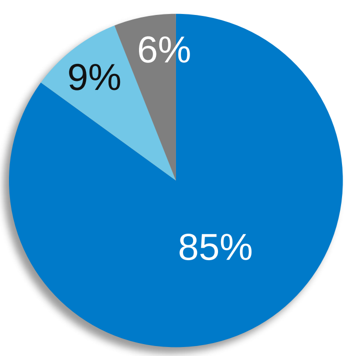
Eagle Ford



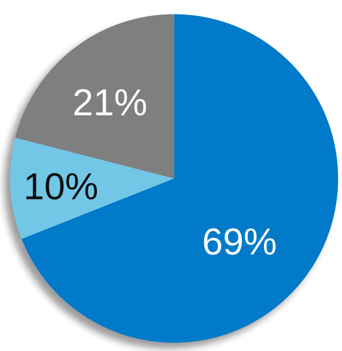
Oklahoma Resource Basins



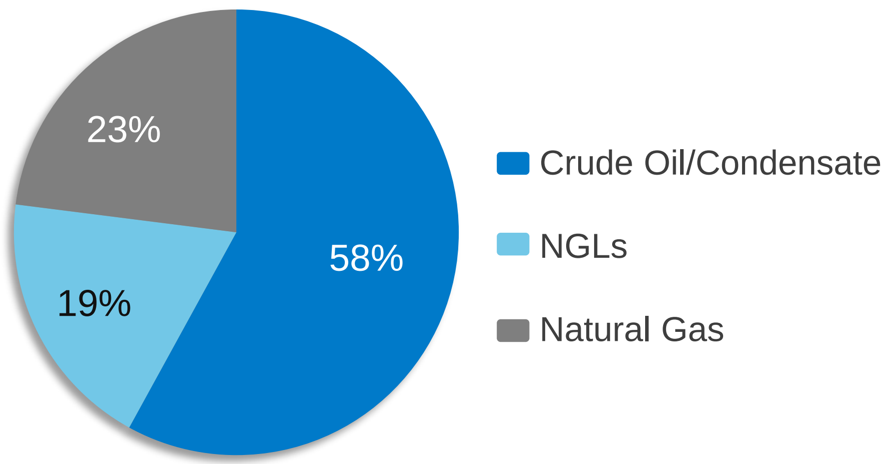
Bakken



Northern Delaware



Total U.S. Resource Plays



Marathon Oil

United States Crude Oil Derivatives

As of February 12, 2018

Crude Oil (Benchmark to NYMEX WTI)								
	1Q 2018	**2Q 2018**	**3Q 2018**	**4Q 2018**	**1Q 2019**	**2Q 2019**	**3Q 2019**	**4Q 2019**
Three-Way Collars								
Volume (Bbls/day)	85,000	85,000	95,000	95,000	30,000	30,000	-	-
Weighted Avg 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 Avg Price per Bbl	$55.12	$55.12	-	-	-	-	-	-
Midland to Cushing Basis Swaps								
Volume (Bbls/day)	5,000	5,000	10,000	10,000	10,000	10,000	10,000	10,000
Weighted Avg Price per Bbl	$(0.60)	$(0.60)	$(0.67)	$(0.67)	$(0.82)	$(0.82)	$(0.82)	$(0.82)

United States Natural Gas Derivatives

As of February 12, 2018

Natural Gas (Benchmark to NYMEX HH)				
	1Q 2018	**2Q 2018**	**3Q 2018**	**4Q 2018**
Three-Way Collars				
Volume (MMBtu/day)	200,000	160,000	160,000	160,000
Weighted Avg 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

Capital, Investment & Exploration

2017 budget reconciliation $MM

	2017 Revised Budget	2017 Actual
Capital expenditures	2,100	2,150
M&S Inventory	0	(10)
Investments in equity method investees & others	0	0
Exploration costs other than well costs[1]	39	75
Capital, Investment & Exploration Budget[2]	**2,139**	**2,215**

[1]Excludes $35MM of accruals not associated with well costs

[2]Includes ~$110MM of REx (resource play leasing and exploration capex); does not include discontinued operations or acquisition costs