QEP RESOURCES®

Investor Presentation

May 2017

Forward-Looking Statements & Non-GAAP Financial Measures

This presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by words such as "anticipates," "believes," "forecasts," "plans," "estimates," "expects," "should," "will," or other similar expressions. Such statements are based on management's current expectations, estimates and projections, which are subject to a wide range of uncertainties and business risks. These statements are not guarantees of future performance. These forward-looking statements include statements regarding: estimated proved reserves; estimated production split among oil, gas and NGL; proven and unproven zones; forecasted oil production; growth strategy; portfolio optimization; allocation of capital; potential drilling locations; evaluating well density; development strategy, plans and timeline; completion methodology; minimizing well interference issues and maximizing production through drilling and completion program; guidance for 2017 production, LOE and transportation expense, DD&A, production taxes, general and administrative expense, and capital investment; and assumptions related to our guidance.

Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: the availability and cost of capital; changes in local, regional, national and global demand for oil, natural gas, and NGL; oil, natural gas and NGL prices; changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions, natural resources, and fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures; elimination of federal income tax deductions for oil and gas exploration and development; drilling results; liquidity constraints; availability of refining and storage capacities; shortages or increased costs of oilfield equipment, services and personnel; operating risks such as unexpected drilling conditions; weather conditions; permitting delays; actions taken by third-party operators, processors and transporters; demand for oil and natural gas storage and transportation services; technological advances affecting energy supply and consumption; competition from the same and alternative sources of energy; natural disasters; and the other risks discussed in the Company's periodic filings with the Securities and Exchange Commission (SEC), including the Risk Factors section of QEP's Annual Report on Form 10-K for the year ended December 31, 2016 (the "2016 Form 10-K"). QEP undertakes no obligation to publicly correct or update the forward-looking statements in this presentation, in other documents, or on its website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or through reliable technology to be economically and legally producible at specific prices and existing economic and operating conditions. The SEC permits optional disclosure of probable and possible reserves calculated in accordance with SEC guidelines; however, QEP has made no such disclosures in its filings with the SEC. "Resources" refers to QEP's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and are not proved, probable or possible reserves within the meaning of the rules of the SEC. Probable and possible reserves and resources are by their nature more speculative than estimates of proved reserves and, accordingly, are subject to substantially more risks of actually being realized. Actual quantities of natural gas, oil and NGL that may be ultimately recovered from QEP's interests may differ substantially from the estimates contained in this presentation. Factors affecting ultimate recovery include the scope of QEP's drilling program, which will be directly affected by the availability of capital; oil, gas and NGL prices; drilling and production costs; availability of drilling services and equipment; drilling results; geological and mechanical factors affecting recovery rates; lease expirations; transportation constraints; changes in local, regional, national and global demand for natural gas, oil and NGL; changes in, adoption of and compliance with laws and regulations; regulatory approvals; and other factors. Investors are urged to consider carefully the disclosures and risk factors about QEP's reserves in the 2016 Form 10-K.

QEP refers to Adjusted EBITDA, Adjusted Net Income (Loss) and other non-GAAP financial measures that management believes are good tools to assess QEP's operating results. For definitions of these terms and reconciliations to the most directly comparable GAAP measures, see the recent earnings press release and SEC filings at the Company's website at www.qepres.com under "Investor Relations."

QEP Resources – *A Leading Independent E&P Company*

Balanced & Diversified Upstream Portfolio

- Focused investment in core (onshore) oil and natural gas plays

Financial Strength

- $338.4 million of cash and cash equivalents as of March 31, 2017
- Undrawn $1.8 billion unsecured revolving credit facility
- Solid oil & gas derivative portfolio through 2018 to help maximize downside protection

Portfolio Optimization

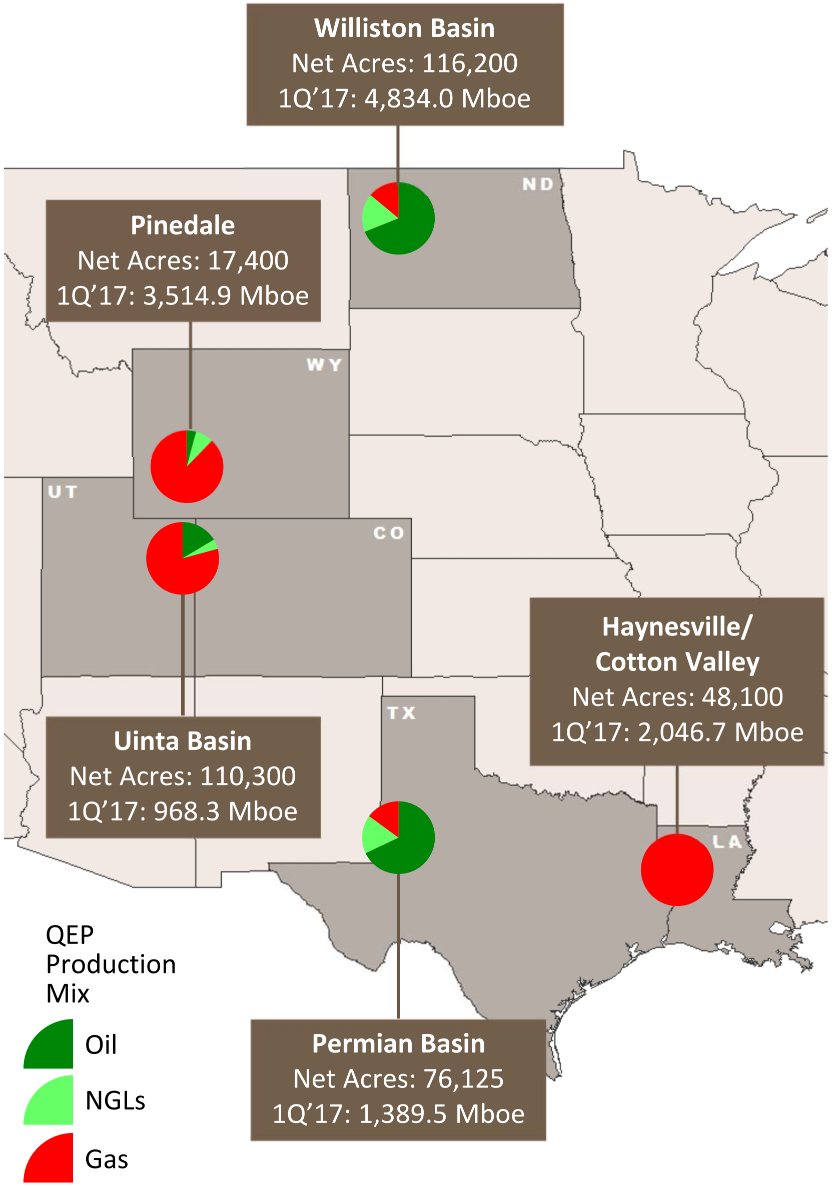
- Actively working to increase oil development drilling inventory through acquisitions, acreage swaps and organic growth opportunities
- Simplification of the QEP story through rationalization of mature assets

Capital & Operational Efficiency

- Allocate capital to highest rate of return projects
- Optimize well completion design and placement with “tank-style” completions to maximize economic recovery of oil in place

QEP Resources – *1Q 2017 Financial & Operational Overview*

Asset Overview(1)



1Q 2017 Highlights

- Total Equivalent Production: 13,090.3 Mboe
  - Oil Production: 4,682.7 Mbbl
  - Gas Production: 42.3 Bcf
  - NGL Production: 1,355.4 Mbbl
- Strong results from five high-density Spraberry Shale test wells on County Line acreage utilizing "tank-style" completion design
  - Average peak 24 hour IP: 1,803 Boed (average 9,900' lateral, 88% oil)
  - Validates Permian Basin go forward development plans
- Parent wells at Mustang Springs exceeding expectations
  - Average peak 24 hour IP: 1,384 Boed (average 7,345' lateral , 85% oil)
  - Two wells reached peak rate without artificial lift - Wolfcamp A and Wolfcamp B
- Notable Williston Basin well results on South Antelope
  - Average peak 24 hour IP: 2,817 Boed (average 9,575' lateral , 73% oil)
- Ongoing successful Haynesville refrac program
  - Added five high-rate wells during 1Q 2017
  - Average incremental 24-hour rate increase of 11.5 MMcfed
- Currently operating seven rigs
  - Horizontal: Permian (5), Williston (1)
  - Vertical: Pinedale (1)

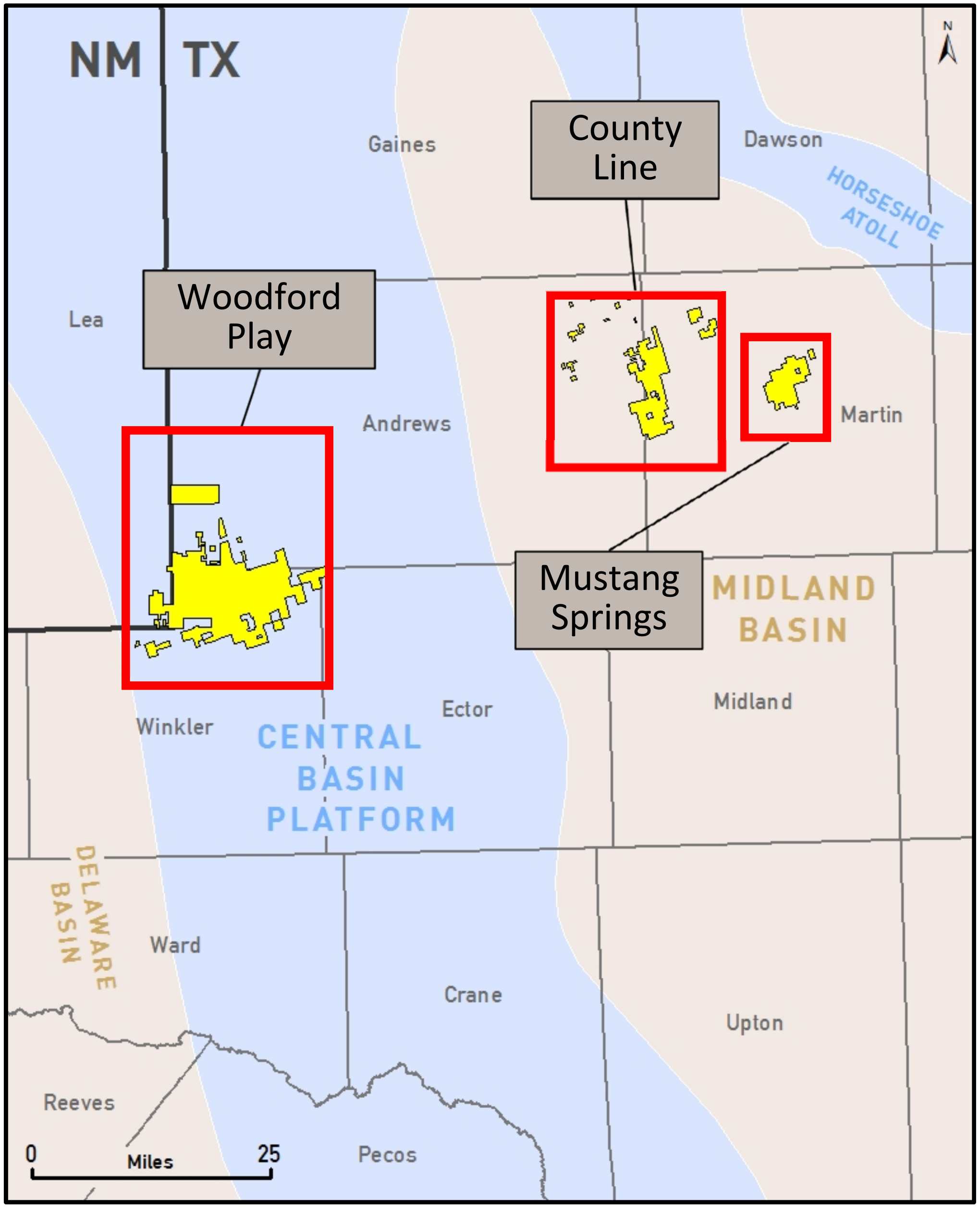
(1) Equivalent production excludes 336.9 Mboe from Other Northern & Other Southern regions

QEP Resources – *2017 Guidance*(1)

	2017 Current Forecast
Oil production (MMBbl)	21.0 - 22.0
Gas Production (Bcf)	180.0 - 190.0
NGL Production (MMBbl)	5.75 - 6.25
Total oil equivalent production (MMBoe)	57.0 - 60.0
Lease operating and transportation expense (per Boe)	$9.50 - $10.50
Depletion, depreciation and amortization (per Boe)	$16.00 - $17.00
Production and property taxes (% of field-level revenue)	8.50%
(in millions)	
General and administrative expense(2)	$160 - $170
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip(3)	$890 - $930
Infrastructure	$50 - $60
Corporate	$10
Total Capital Investment (excluding property acquisitions)	**$950 - $1,000**

(1) As of April 26, 2017: assumes an average of seven rigs for the remainder of 2017, with five rigs in the Permian Basin (horizontal), one rig in the Williston Basin (horizontal) and one rig in Pinedale (vertical/directional); no property acquisitions or divestitures; ethane rejection for the entire year where QEP can elect to make such an election.
(2) General and administrative expense includes approximately $32.0 million of non-cash share-based compensation expense.
(3) Drilling, Completion and Equip includes approximately $50.0 million of non-operated well completion costs.

Permian Basin



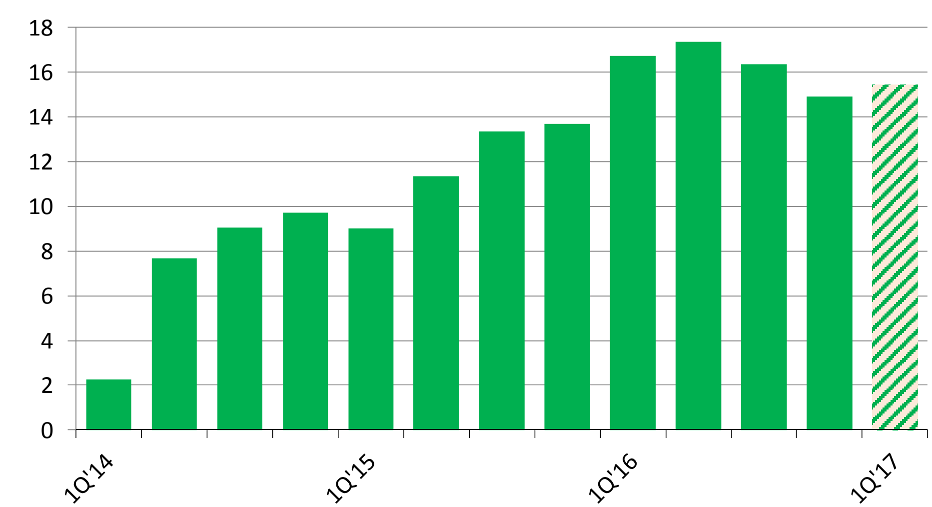
QEP Acreage as of 3/31/2017

Profile[1]

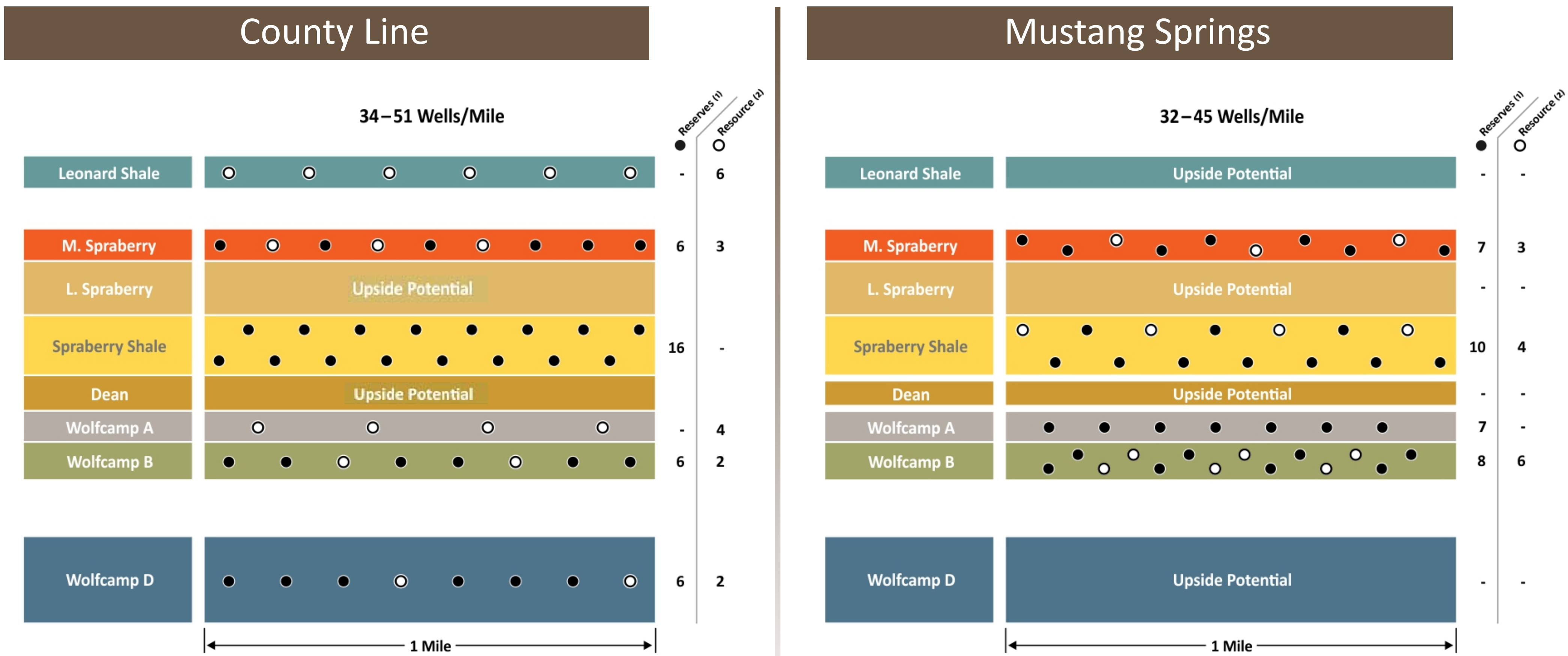
Net acres	76,125
Gross operated producing wells	495
Average WI/average NRI	96% / 73%
Proved reserves (MMboe)/% liquids[2]	148 / 88%
Production Split – oil/gas/NGL	72/14/14%
Current rig count	5

[1] As of March 31, 2017
[2] As of December 31, 2016, SEC Pricing

Net Production - Mboed



Permian Basin – *Well Density Assumptions*

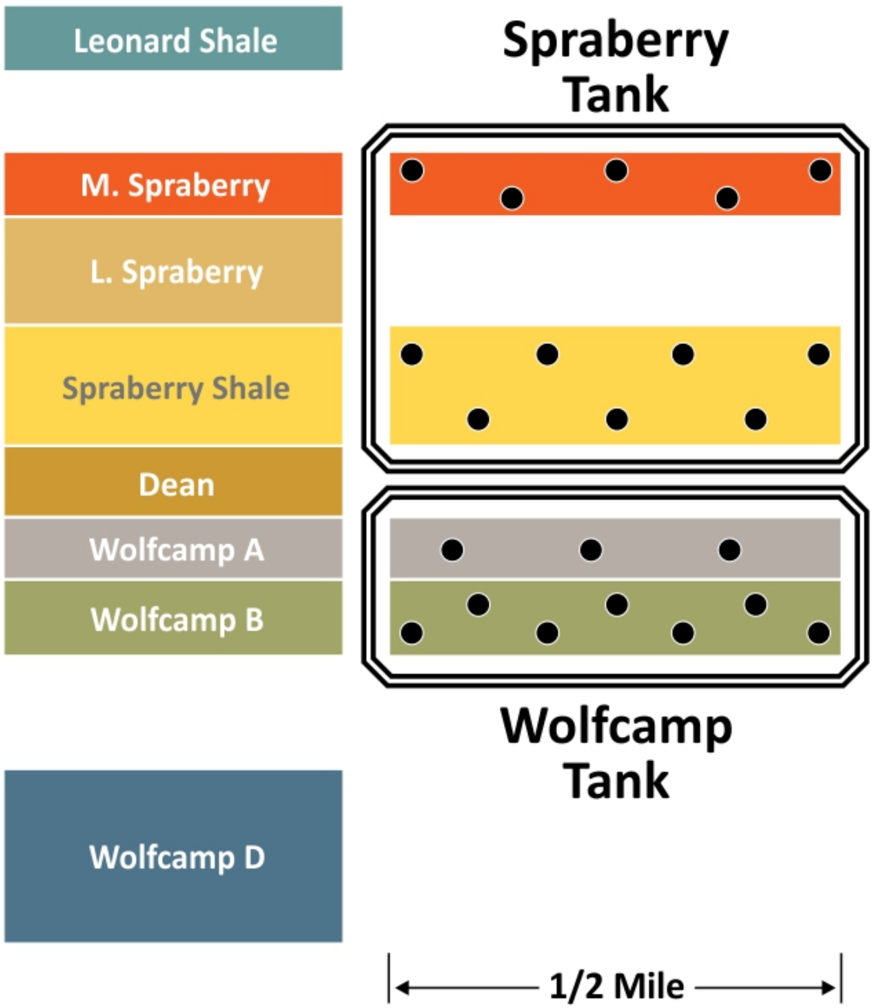


- Stacked pay opportunity across core Permian acreage position
- Large upside opportunity in both proven and unproven zones
- More than 1,150 potential future locations of 7,500’ and 10,000’ laterals
  - Excludes zones labeled as upside potential

(1) Includes proven, probable and possible locations
(2) Includes non-reserve locations

Permian Basin – *"Tank-Style" Completion Design*

Example of "Tank-Style" Completion Design



"Tank-Style" Completion Methodology

- Two "tanks" used in design – Spraberry "tank" and Wolfcamp "tank"
- Drill and complete all wells in "tank" before placing any well in "tank" on production
- Complete wells closest to offset producing wells first

"Tank-Style" Completion Benefits

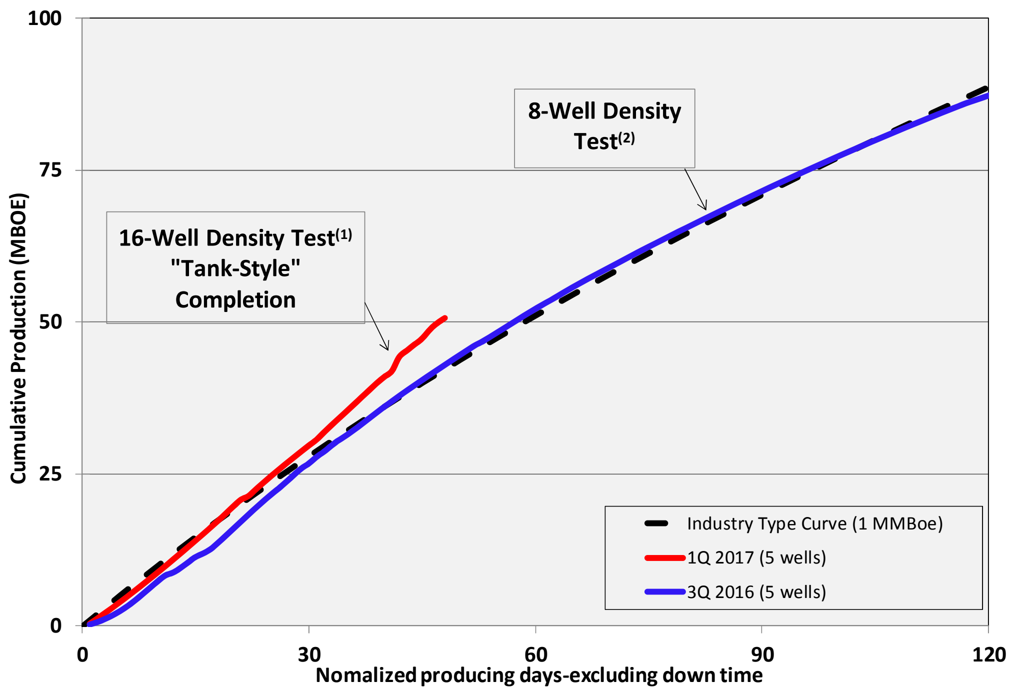
- Less interference and shorter shut-in times for offset producing wells
- Improved results from increased stimulated rock volume

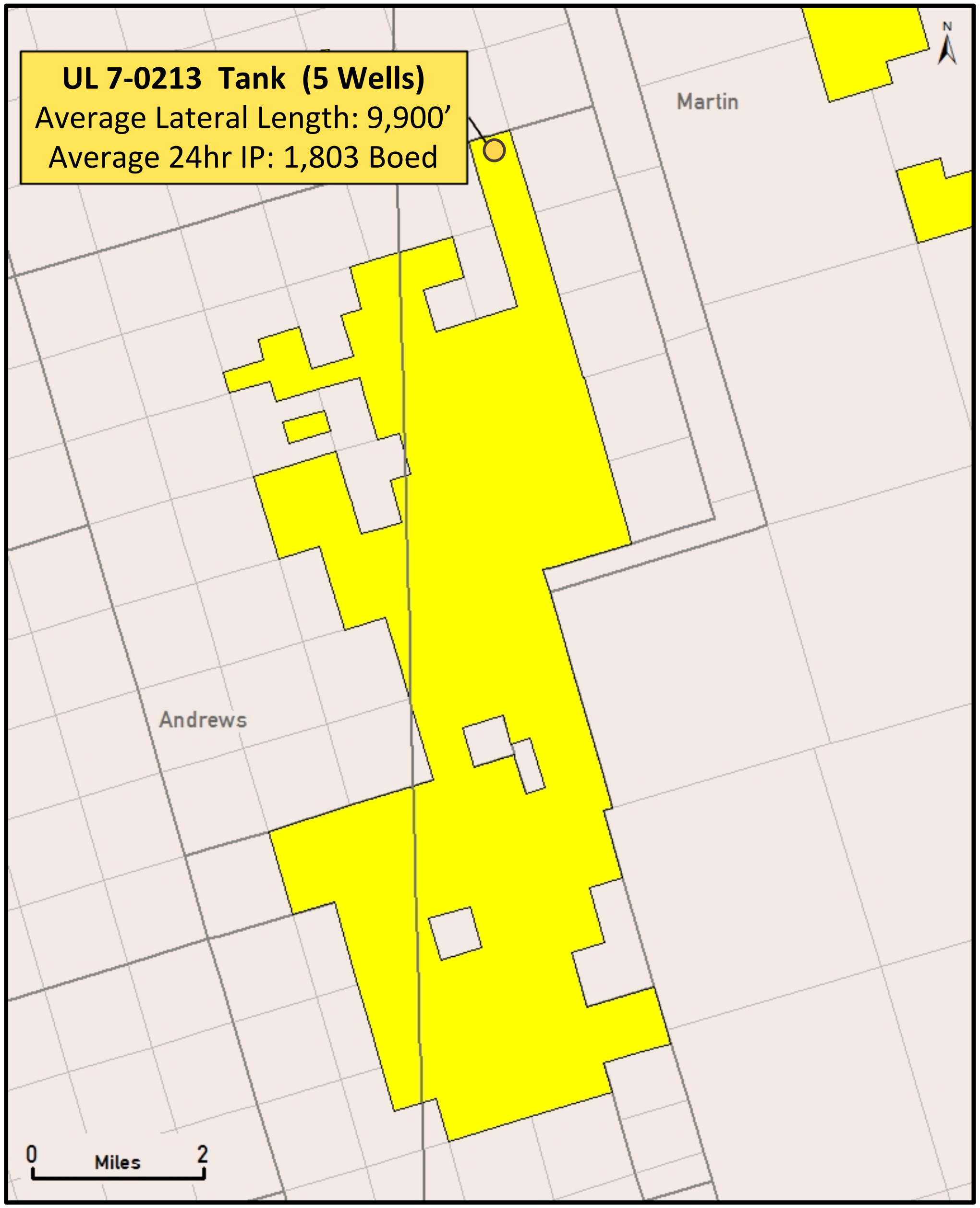
1Q 2017 "Tank-Style" Results

- Five high-density wells completed in Spraberry Shale
- Average peak 24-hour IP: 1,803 Boed

Permian Basin – *County Line 1Q 2017 Activity*

- **Net Acres:** ~20,300
- **Rig Count:** 2 (horizontal)
- **Completions:** 5
  - Spraberry Shale
- **Waiting on Completion:** 13
  - Leonard Shale (1)
  - Middle Spraberry (4)
  - Spraberry Shale (8)





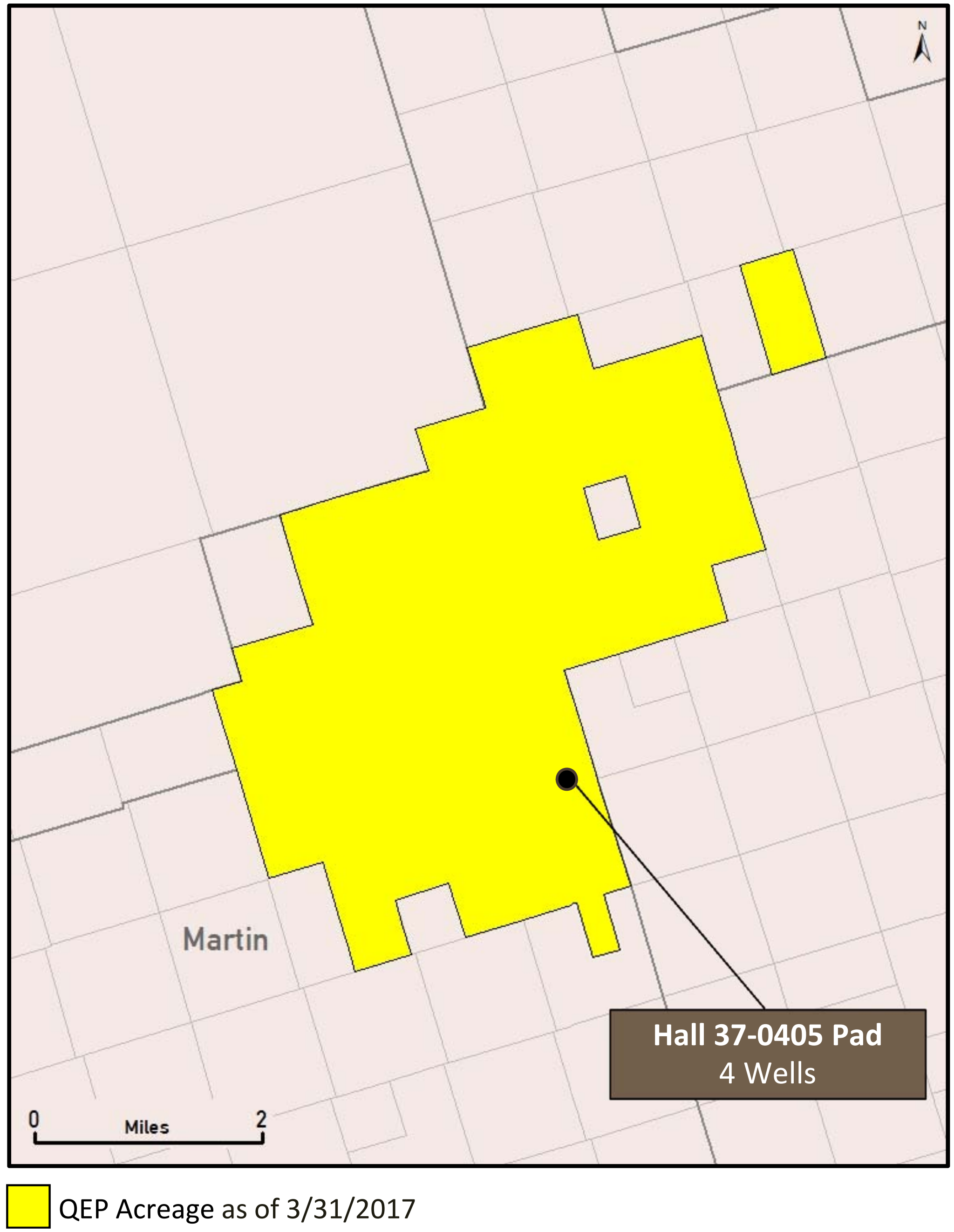
QEP Acreage as of 3/31/2017

(1) Normalized for 7,500' lateral length – five wells drilled in wine rack pattern testing 16 wells per one mile drilling spacing unit (DSU) utilizing "tank-style" completion
(2) Normalized for 7,500' lateral length – five wells drilled in wine rack pattern testing eight wells per one mile DSU

Permian Basin – *Mustang Springs 1Q 2017 Activity*

- **Net Acres:** ~10,000
- **Rig Count:** 3 (horizontal)
- **Completions:** 4
  - Middle Spraberry (MS) (1)
  - Spraberry Shale (SS) (1)
  - Wolfcamp A (WA) (1)
  - Wolfcamp B (WB) (1)
- **Waiting on Completion**: 2
  - Wolfcamp A

Well Name	Target Formation	Lateral Length	Avg. Peak 24hr IP Boed
Hall 37-0405 AL 1 S 03MB	MS	7,368'	N/A[1]
Hall 37-0405 AL 2 S 08SC	SS	7,375'	1,102
Hall 37-0405 AL 4 S 06WA	WA	7,238'	1,343
Hall 37-0405 AL 3 S 02BU	WB	7,420'	1,707



(1) Hall 37-0405 AL 1 S 03MB in early stages of cleanup as of 3/31/2017

Permian Basin – *Mustang Springs Optimization & Pilot Tests*

	West Pilot Density/Section	East Pilot Density/Section
	Low WA & WB High MS & SS	High WA & WB Low MS & SS
Leonard Shale		
M. Spraberry	10-well density	6-well density
L. Spraberry		
Spraberry Shale	14-well density	8-well density
Dean		
Wolfcamp A	4-well density	7-well density
Wolfcamp B	8-well density	14-well density
Wolfcamp D		

1 Mile

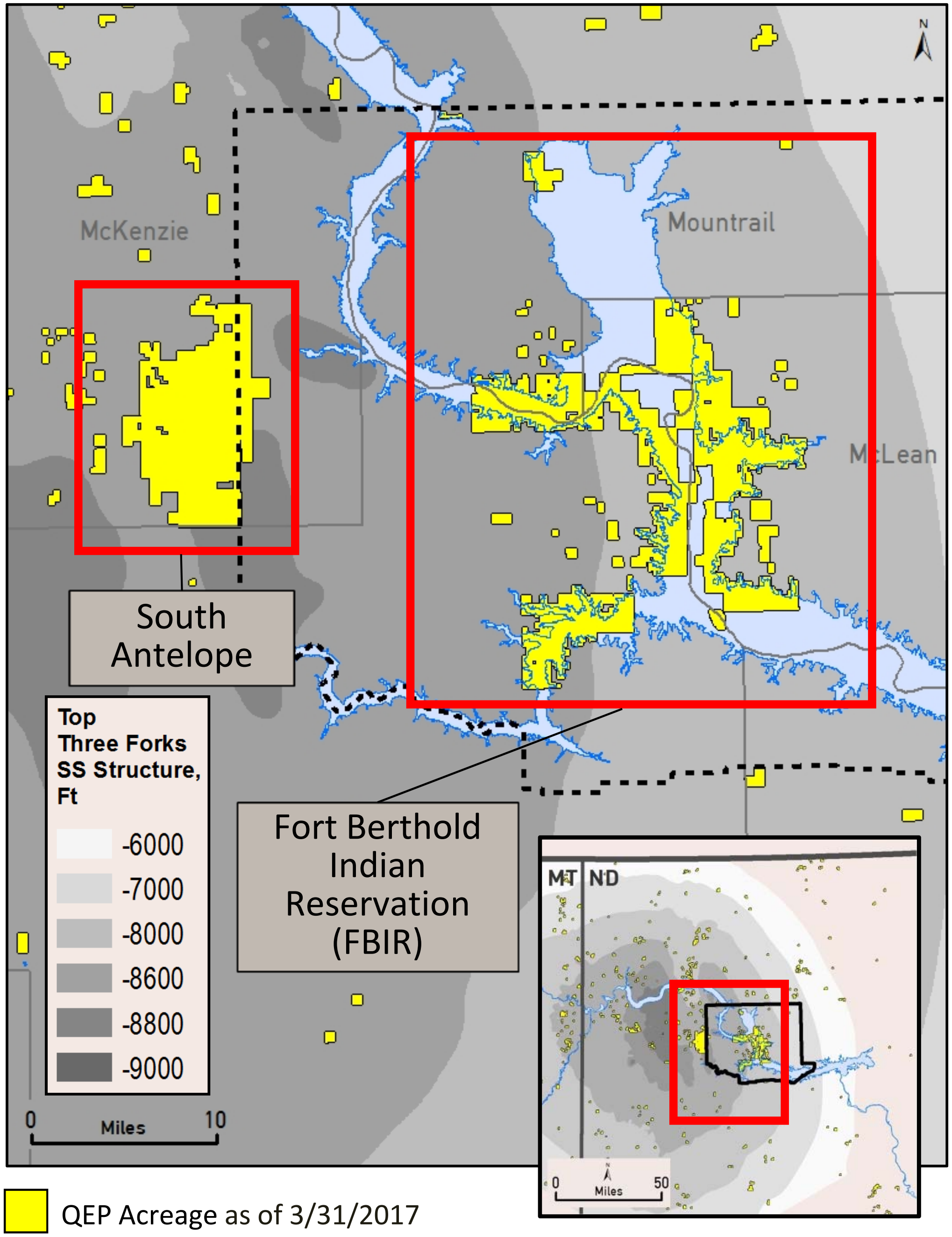
Development Optimization

- Parent well tests
  - Provide baseline well performance in four zones MS, SS, WA and WB
- Density tests
  - Drive ultimate spacing of each reservoir and sequencing of development
  - Establish optimum drilling and completion program to maximize production and minimize well interference

Density Pilot Tests

- Two pilot tests planned
  - Evaluate a continuum of wells across all four target horizons
- West Pilot – *estimated completion August 2017*
  - Evaluate higher well density in MS & SS and lower density in WA and WB, Estimated completion in Aug. 2017
- East Pilot – *estimated completion November 2017*
  - Evaluate higher well density in WA & WB and lower density in MS and SS, Estimated completion in Oct. 2017

Williston Basin

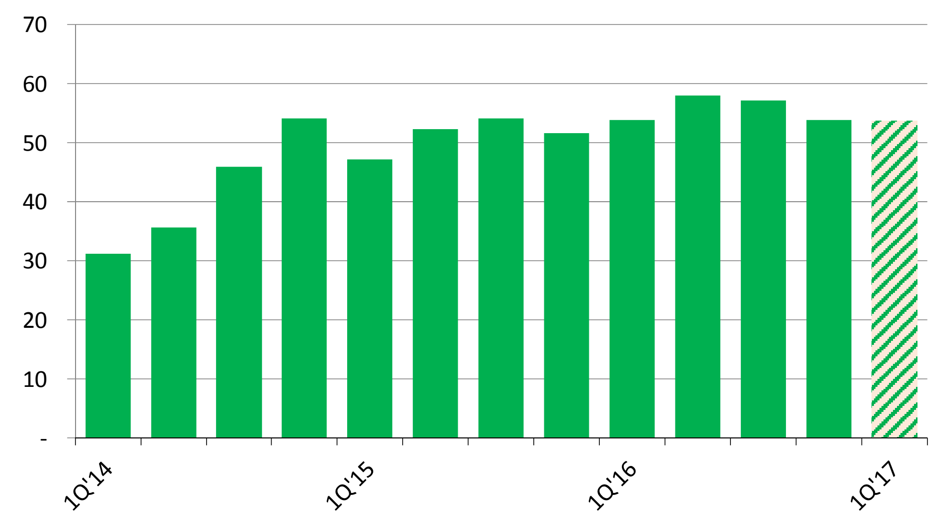


Profile(1)

Net acres	116,200
Gross operated producing wells	369
Average WI/average NRI	87/70%
Proved reserves (MMboe)/% liquids(2)	160 / 86%
Production Split – oil/gas/NGL	69/14/17%
Current rig count	1

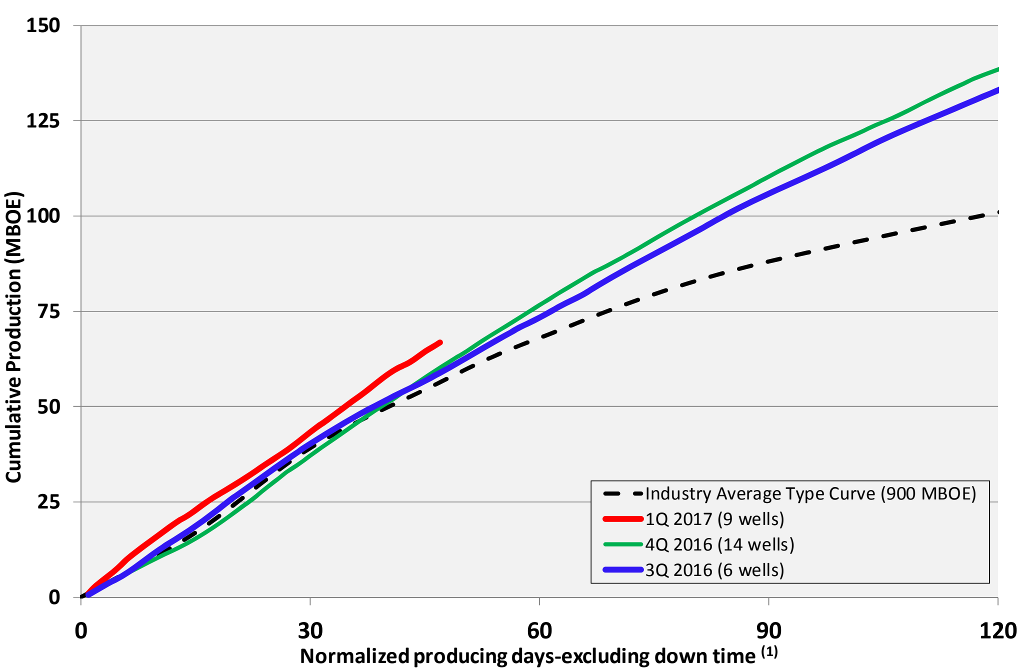
(1) As of March 31, 2017
(2) As of December 31, 2016, SEC Pricing

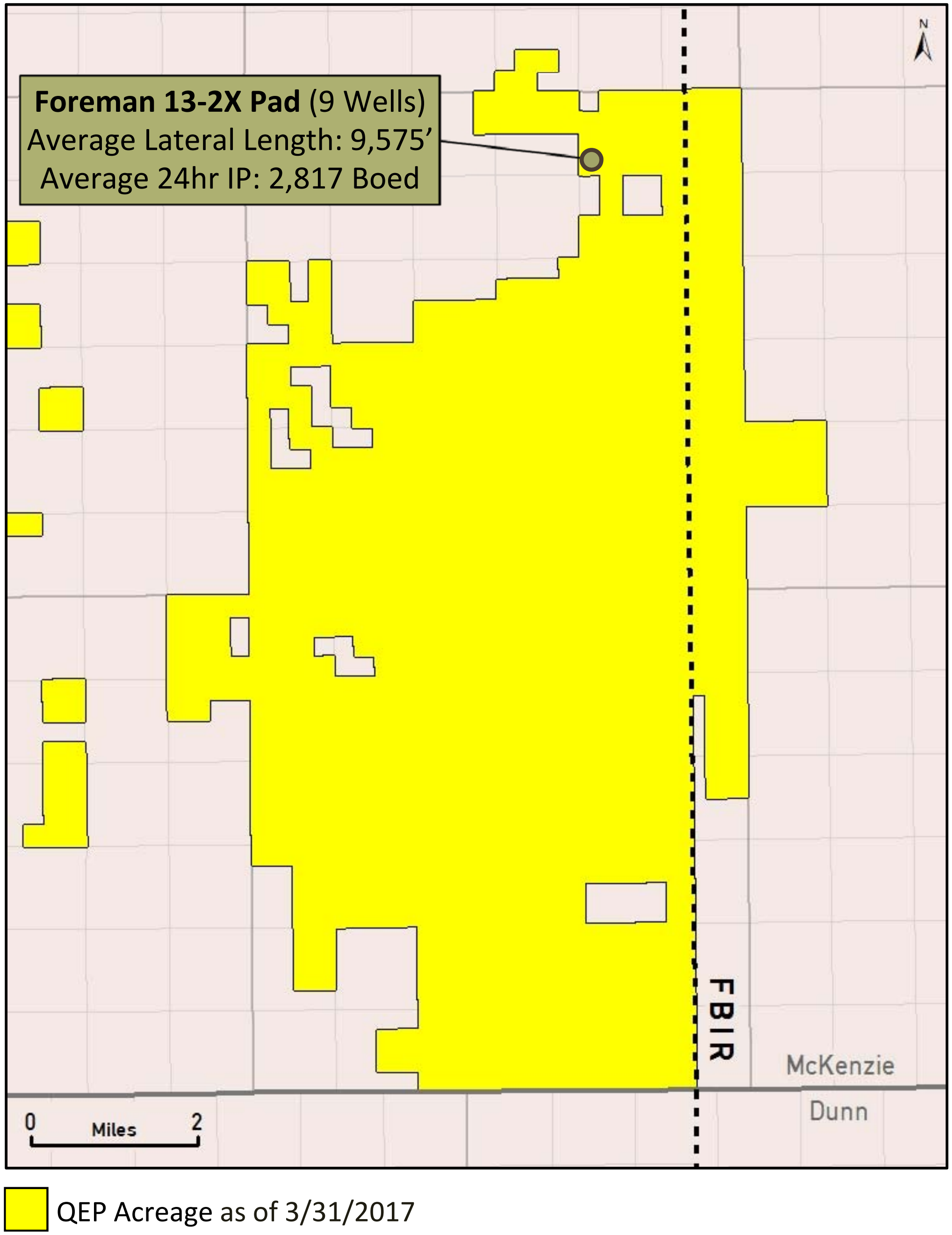
Net Production - Mboed



Williston Basin – *South Antelope 1Q 2017 Activity*

- **Net Acres:** ~30,900
- **Rig Count:** 1 (horizontal)
- **Completions:** 9
  - Bakken (5)
  - Three Forks 1 (2), Three Forks 2 (1), Three Forks 3 (1)
- **Waiting on Completion**: 3
  - Middle Bakken (2)
  - Three Forks 2 (1)

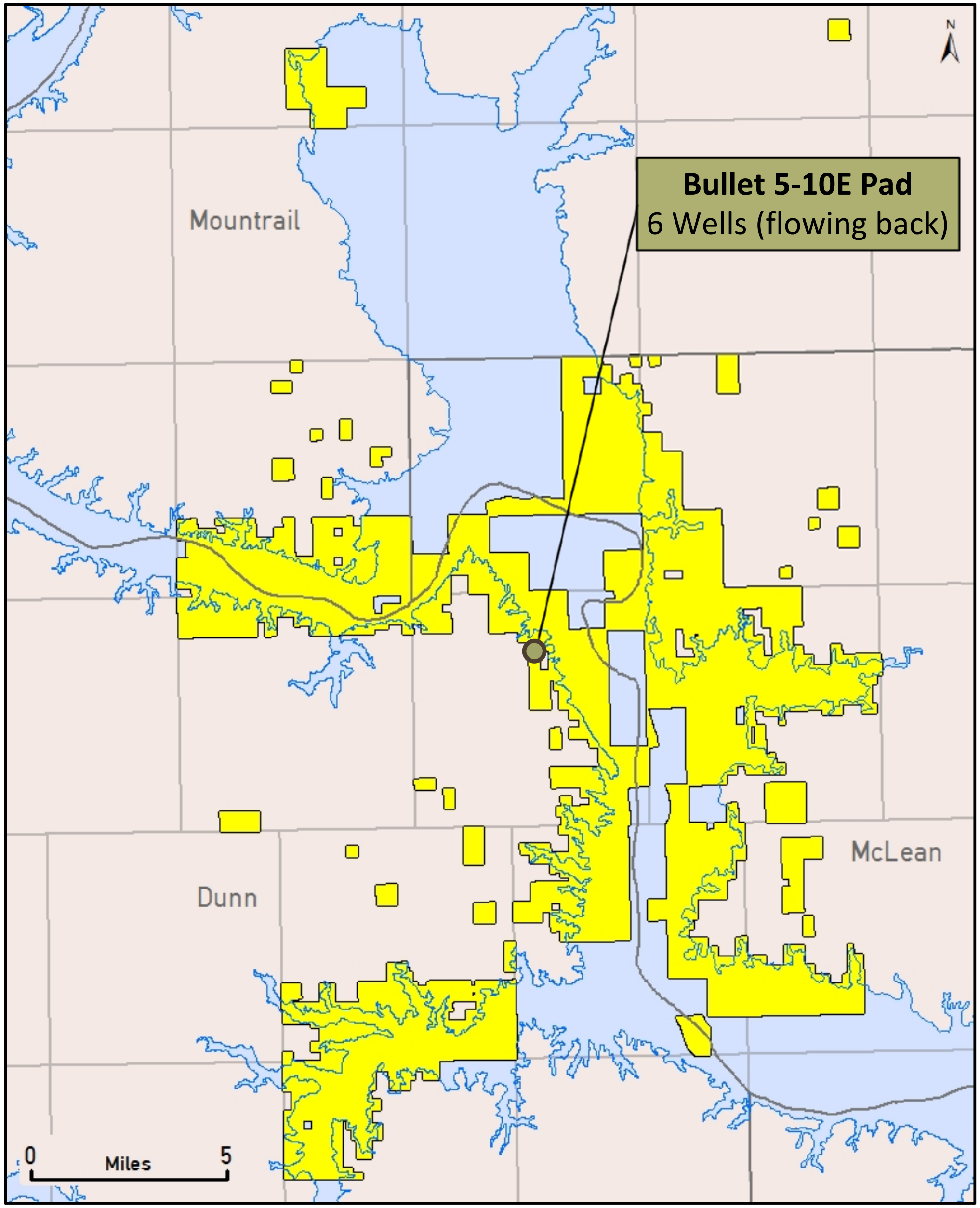




(1) Average 10,000' lateral length, high-density infill wells at 600' spacing

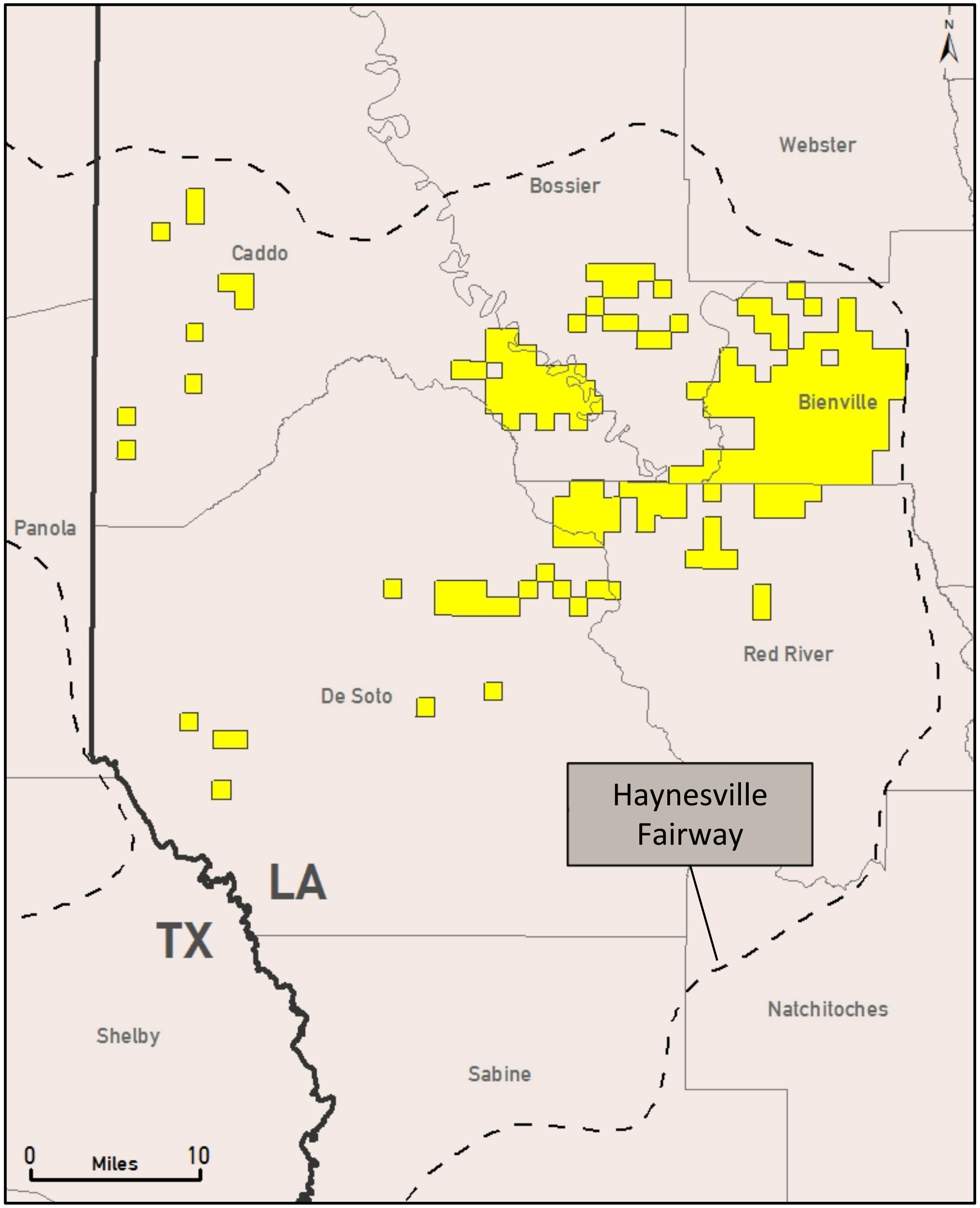
Williston Basin – *FBIR 1Q 2017 Activity*

- **Net Acres:** ~66,200
- **Rig Count:** N/A
- **Completions:** 6
  - Bakken (3)
  - Three Forks 1 (3)
  - All wells in early stages of flowback at the end of 1Q'17 and did not have measurable production during the quarter
  - First production expected in early 2Q'17
- **Waiting on Completion:** 3
  - Middle Bakken (2)
  - Three Forks 2 (1)



QEP Acreage as of 3/31/2017

Haynesville



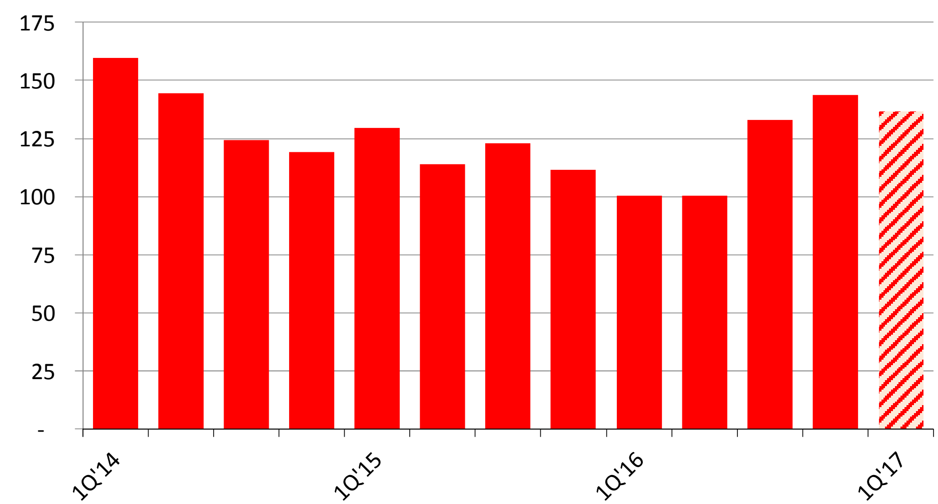
QEP Units as of 3/31/2017

Profile[1]

Net acres	48,100
Gross operated producing wells	130
Average WI/average NRI	74/57% (op) 37/29% (all)
Proved reserves (Bcfe)/% liquids[2]	866 / 0%
Production Split – oil/gas/NGL	0/100/0%

[1] As of March 31, 2017
[2] As of December 31, 2016, SEC Pricing

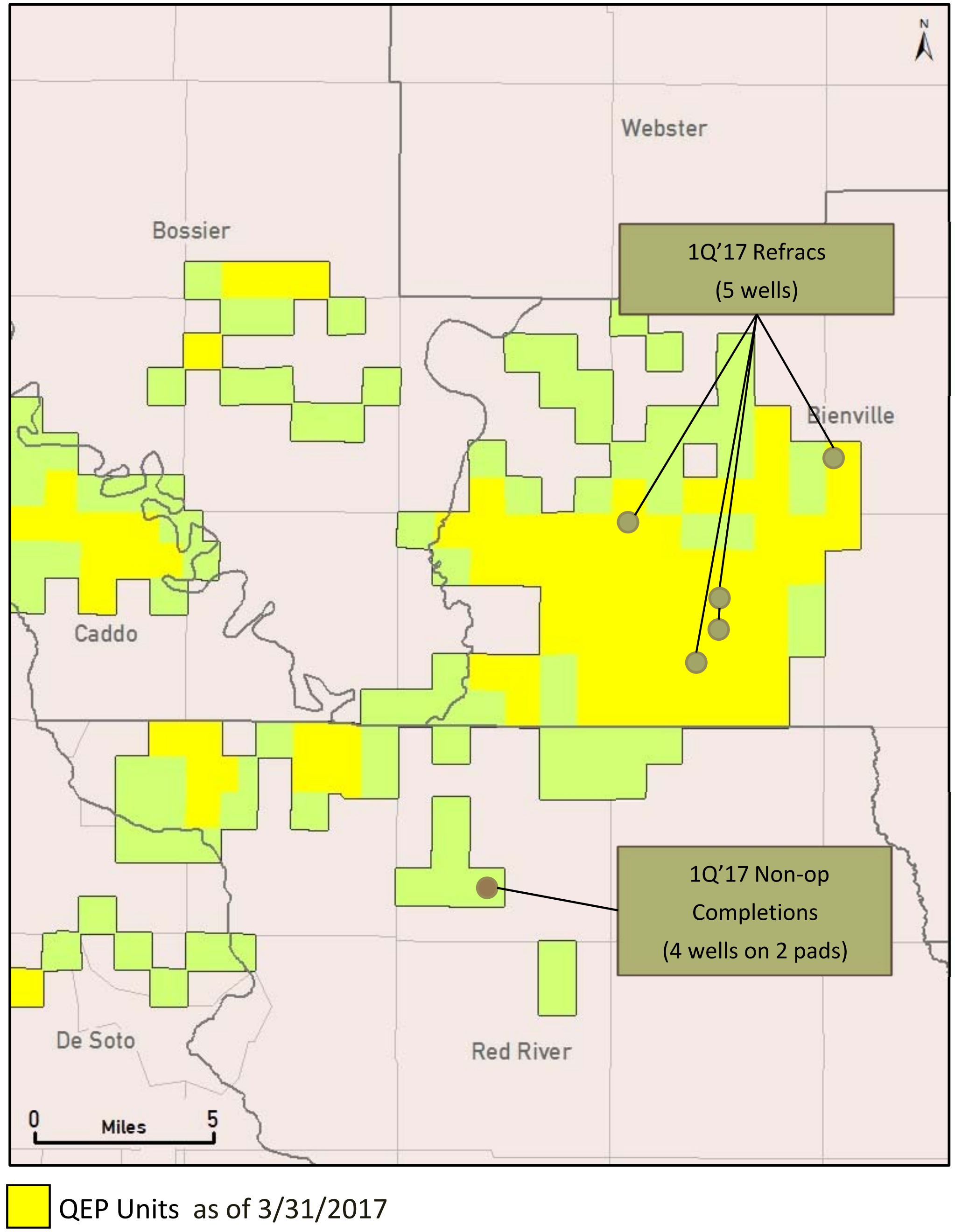
Net Production - MMcfed



Haynesville – *1Q 2017 Activity*

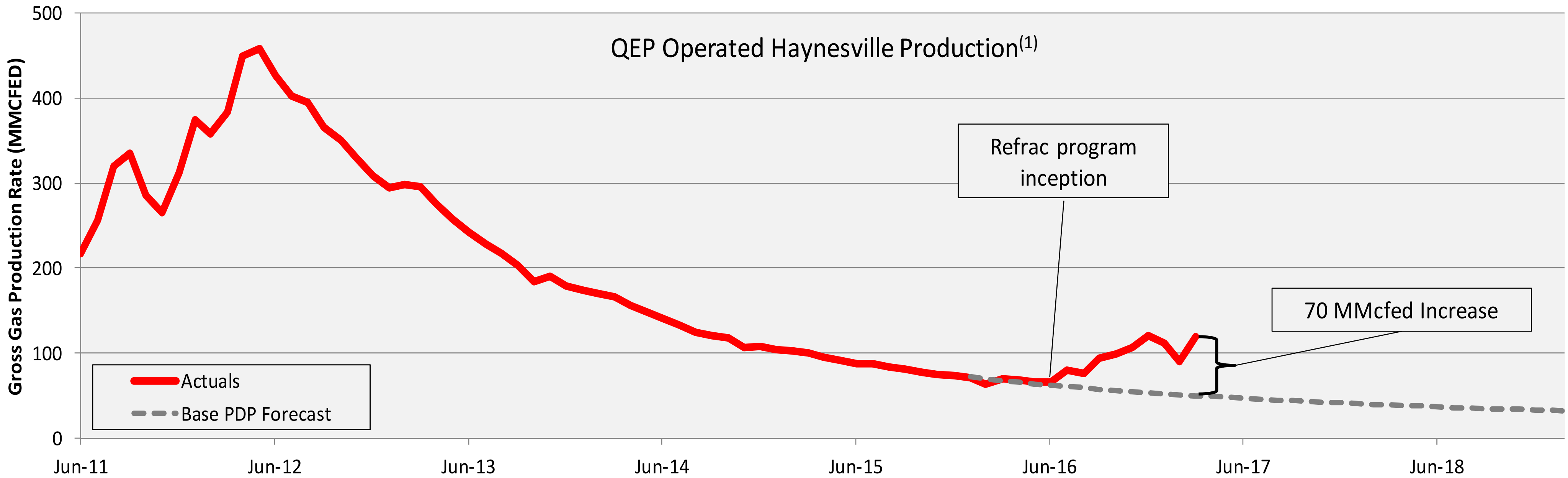
- Completed five refracs
  - Average incremental 24-hour rate increase of 11.5 MMcfed
- Eight new non-op wells brought online in 1Q'17
- Refrac program has increased Haynesville gross production by ~70.0 MMcfed since inception

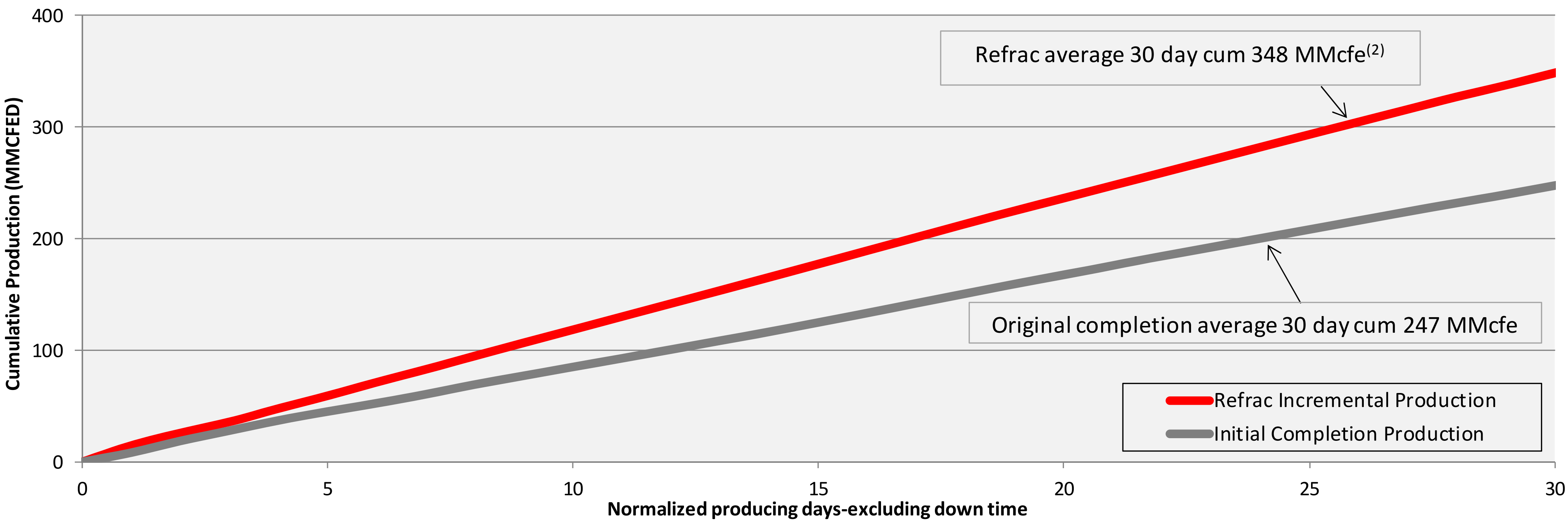
Well Name	Restimulated Lateral Length (ft)	Proppant (lbs/ft)	Pre Refrac (MMcfed) Last 10-day	Post Refrac (MMcfe) 30-day Cum	90-day Cum	180-day Cum
WAERSTAD 003	2,243	2,386	0.22	197.9	494.3	777.9
B HARPER 23-15-9 H 001	4,352	2,532	0.34	257.7	687.9	1,166.5
BILLY R HARPER 14 H 001	4,323	2,508	0.44	277.6	747.3	1,271.3
MOSLEY 5-15-9 H 001	4,269	2,596	0.46	276.9	743.7	1,191.0
J WOODARD 27-15-9H 001	1,451	3,441	0.47	175.1	446.3	719.9
J WOODARD 34-15-9 H 001	4,211	2,481	0.33	241.5	650.7	1,150.9
SANDERS 8-15-9 H 001	4,560	4,048	0.53	274.8	766.2	
J SALTER H 001	2,971	2,861	0.45	271.9	736.5	
RADZIKOWSKI 17-15-9 H 001	4,440	3,976	0.53	339.0	953.7	
L PARKER 10-15-9 H 001	4,371	5,092	0.28	312.5	906.4	
THOMAS 6-15-9 H 001[(1)]	4,533	3,925	0.34	392.1		
MARAK 15-15-9 H 001-ALT[(1)]	1,534	3,912	0.54			
MARAK 22-15-9 H 001[(1)]	4,472	4,076	0.28			
BECKETT 28-15-9 H 001[(1)]	3,289	4,048	0.44			
THRASH 30-16-8H 001[(1)]	4,388	3,977	0.26			



(1) 1Q 2017 refracs

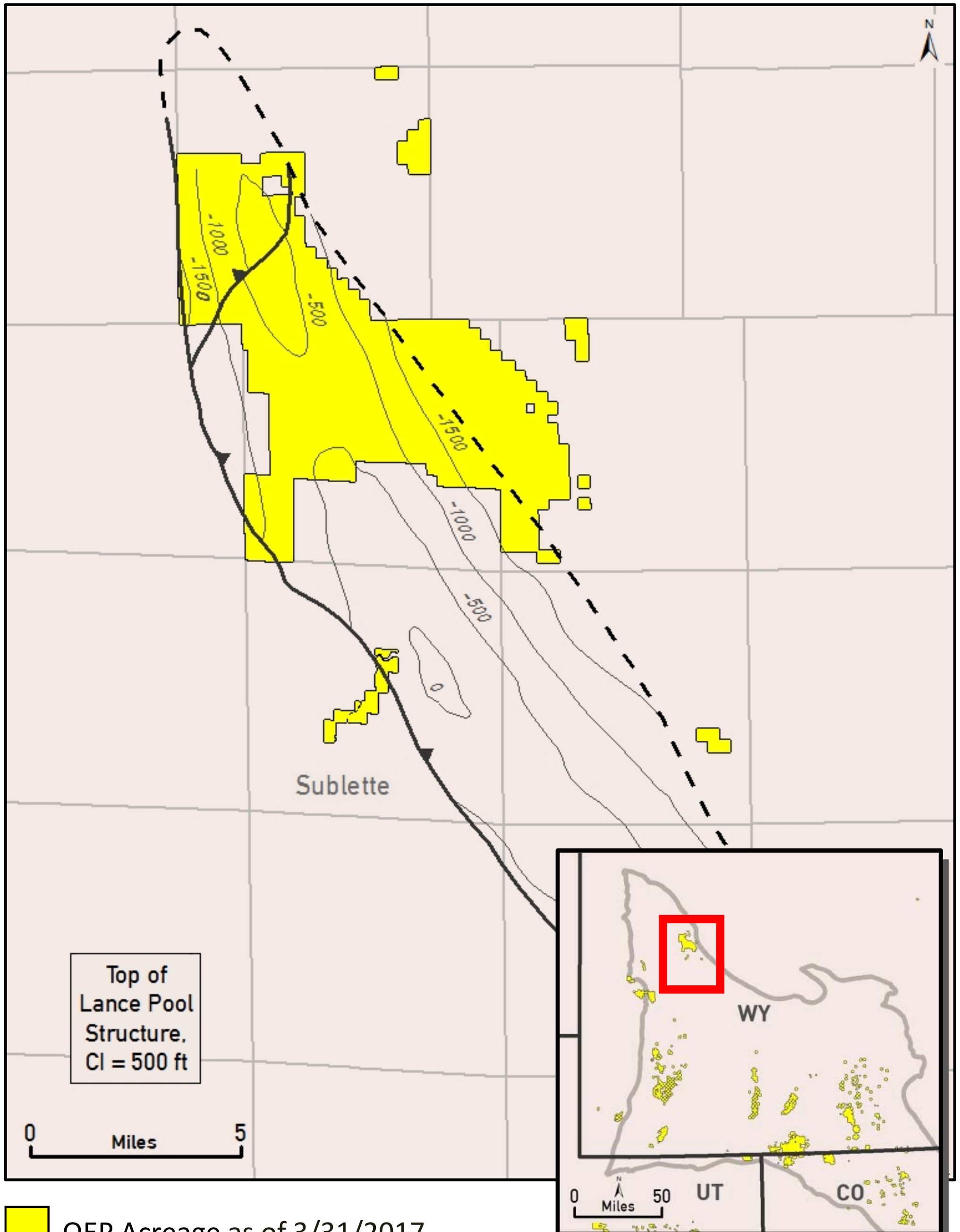
Haynesville – *Well Refrac Performance*





(1) 130 gross operated wells
(2) Represents wells put online after 12/1/2016 with ~4,000 lbs/ft of proppant

Pinedale



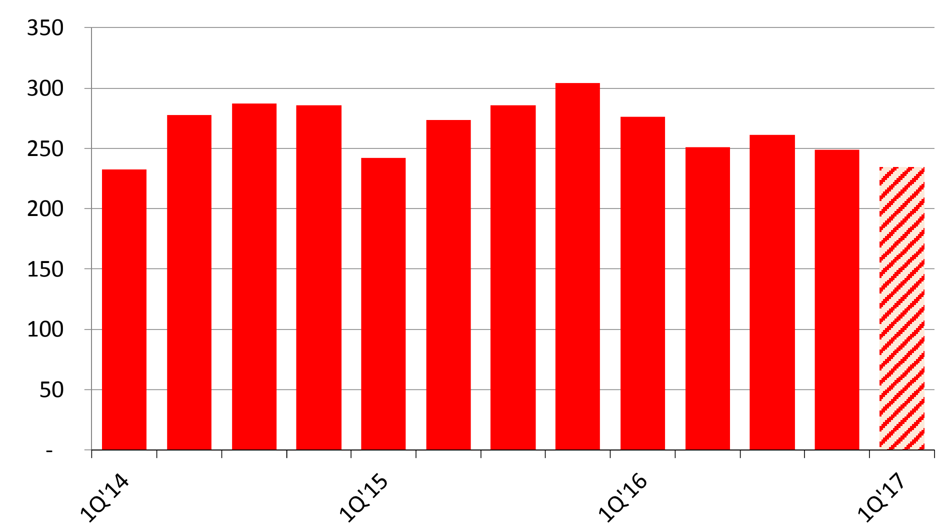
QEP Acreage as of 3/31/2017

Profile(1)

Net acres	17,400
Gross operated producing wells	1,113
Average WI/average NRI	59/45%
Proved reserves (Bcfe)/% liquids(2)	964 / 13%
Production Split – oil/gas/NGL	4/88/8%
Current rig count	1

(1) As of March 31, 2017
(2) As of December 31, 2016, SEC Pricing

Net Production - MMcfed



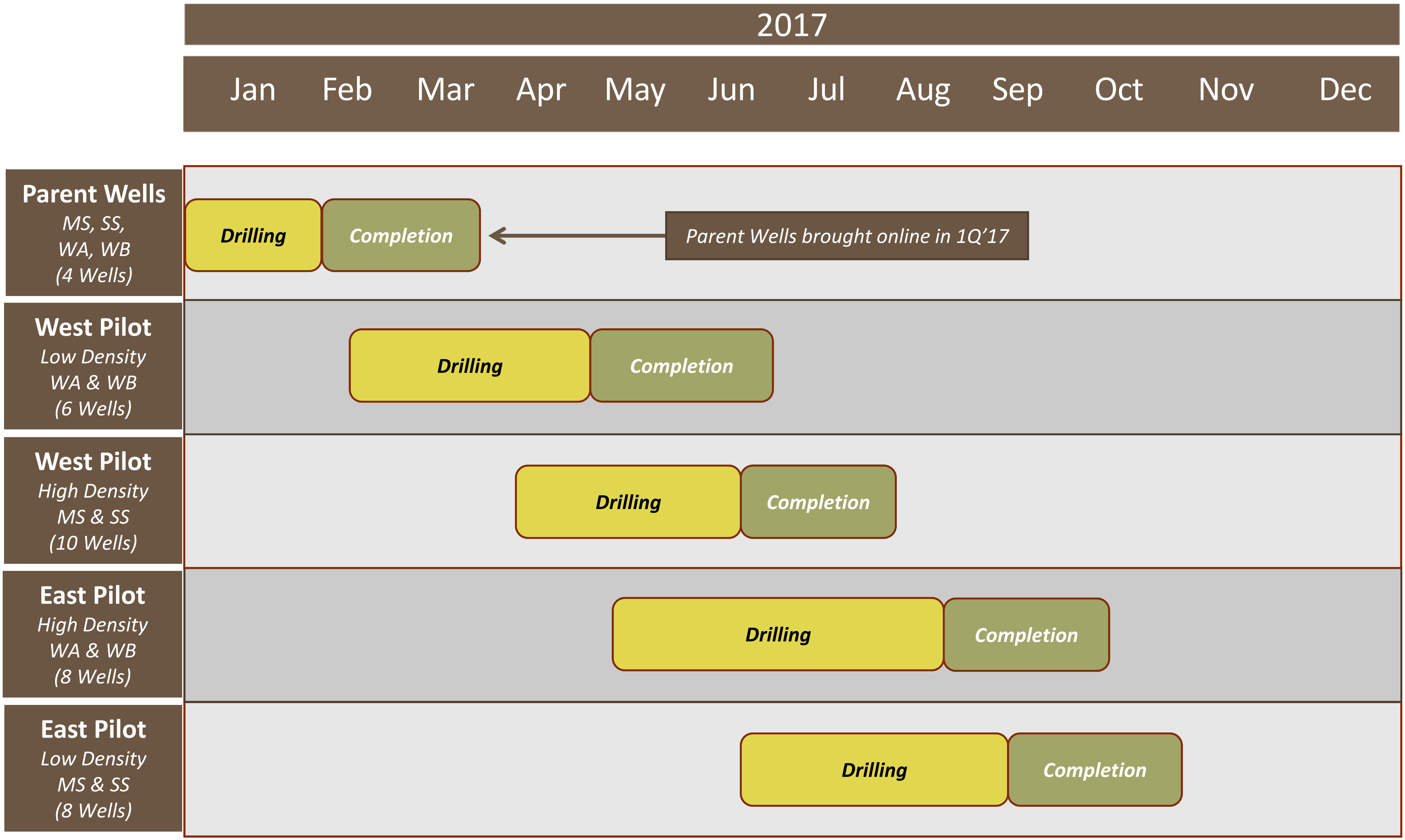
Appendix

Permian & Williston Basins – *Detailed Well Cost Summary*

Permian Gross Well Costs (AFE)				
Area	**Target Formation**	**Lateral Length (ft.)**	**Drill & Complete ($mm)**	**Facilities & Artificial Lift ($mm)**
County Line	Spraberry Shale	7,500	$5.0	$0.8
	Spraberry Shale	10,000	$6.3	$0.8
Mustang Springs	Middle Spraberry	7,500	$5.0	$0.7
	Spraberry Shale	7,500	$5.0	$0.7
	Wolfcamp A	7,500	$6.3	$0.7
	Wolfcamp B	7,500	$6.6	$0.7

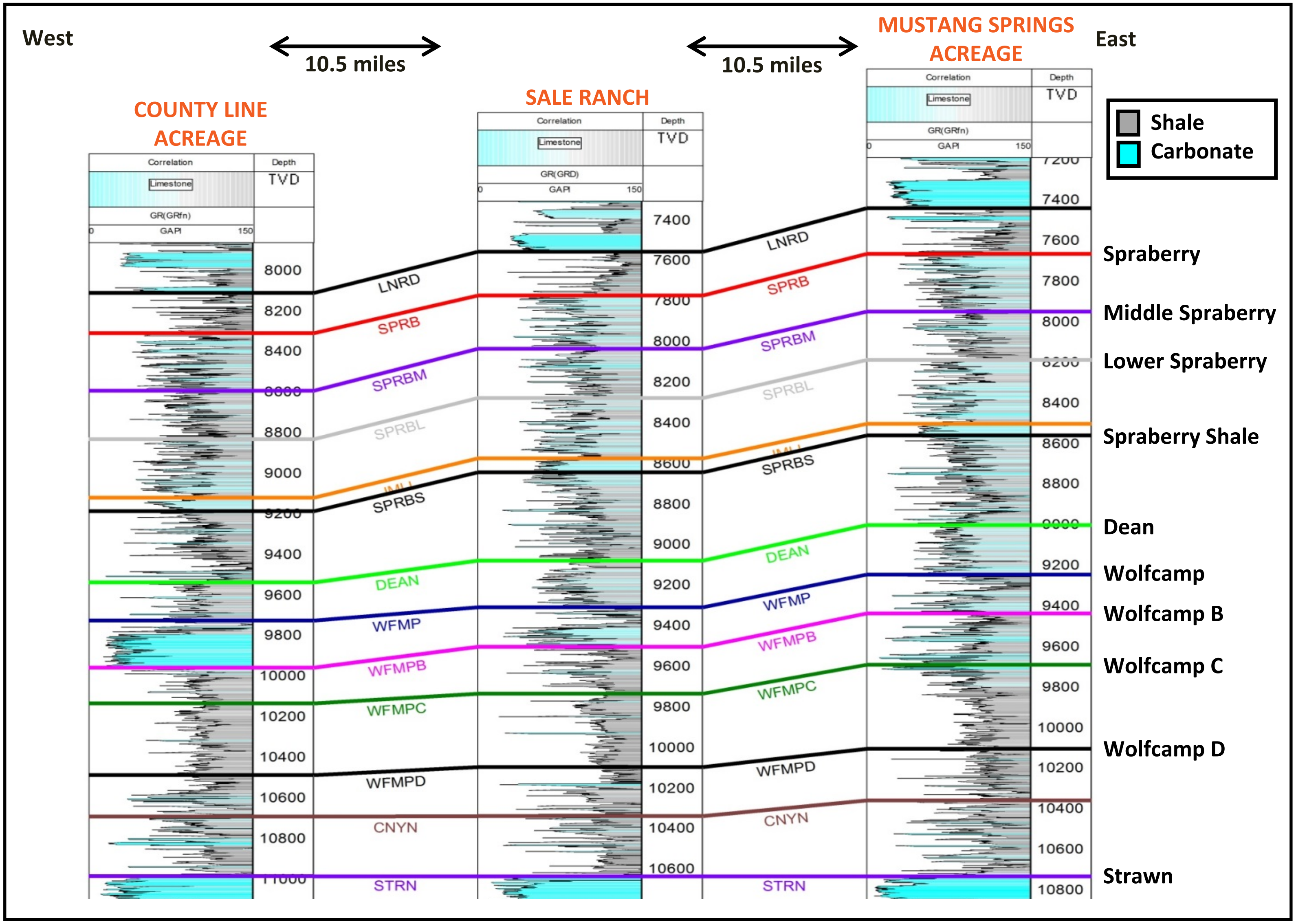
Williston Basin Gross Well Costs (AFE)				
Area	**Target Formation**	**Lateral Length (ft.)**	**Drill & Complete ($mm)**	**Facilities & Artificial Lift ($mm)**
South Antelope	Middle Bakken / Three Forks	10,000	$5.6	$0.8
FBIR	Middle Bakken / Three Forks	10,000	$6.2	$1.3

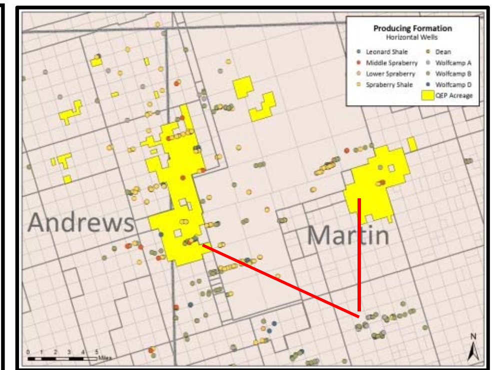
Permian Basin – *Mustang Springs Optimization & Pilot Test Timeline*



Note: Assumes four rigs, two frac crews, and two drill-out crews

Permian Basin – *Predictable Geology Across Acreage*





County Line, Sale Ranch, and Mustang Springs acreage have similar reservoir characteristics in the Spraberry and Wolfcamp intervals

QEP Resources – *Derivative Positions*

The following tables present QEP's volumes and average prices for its open derivative positions as of April 21, 2017:

Production Commodity Derivative Swap Positions

Year	Index	Total Volumes	Average Price per Unit
Oil Sales		**(MMBbls)**	**($/Bbl)**
2017	NYMEX WTI	10.7	$51.50
2018	NYMEX WTI	9.9	$53.59
Gas Sales		**(million MMBtus)**	**($/MMBtu)**
2017	NYMEX HH	66.2	$2.87
2017	IFNPCR	22.1	$2.51
2018	NYMEX HH	91.3	$2.98

Production Commodity Derivative Gas Collars

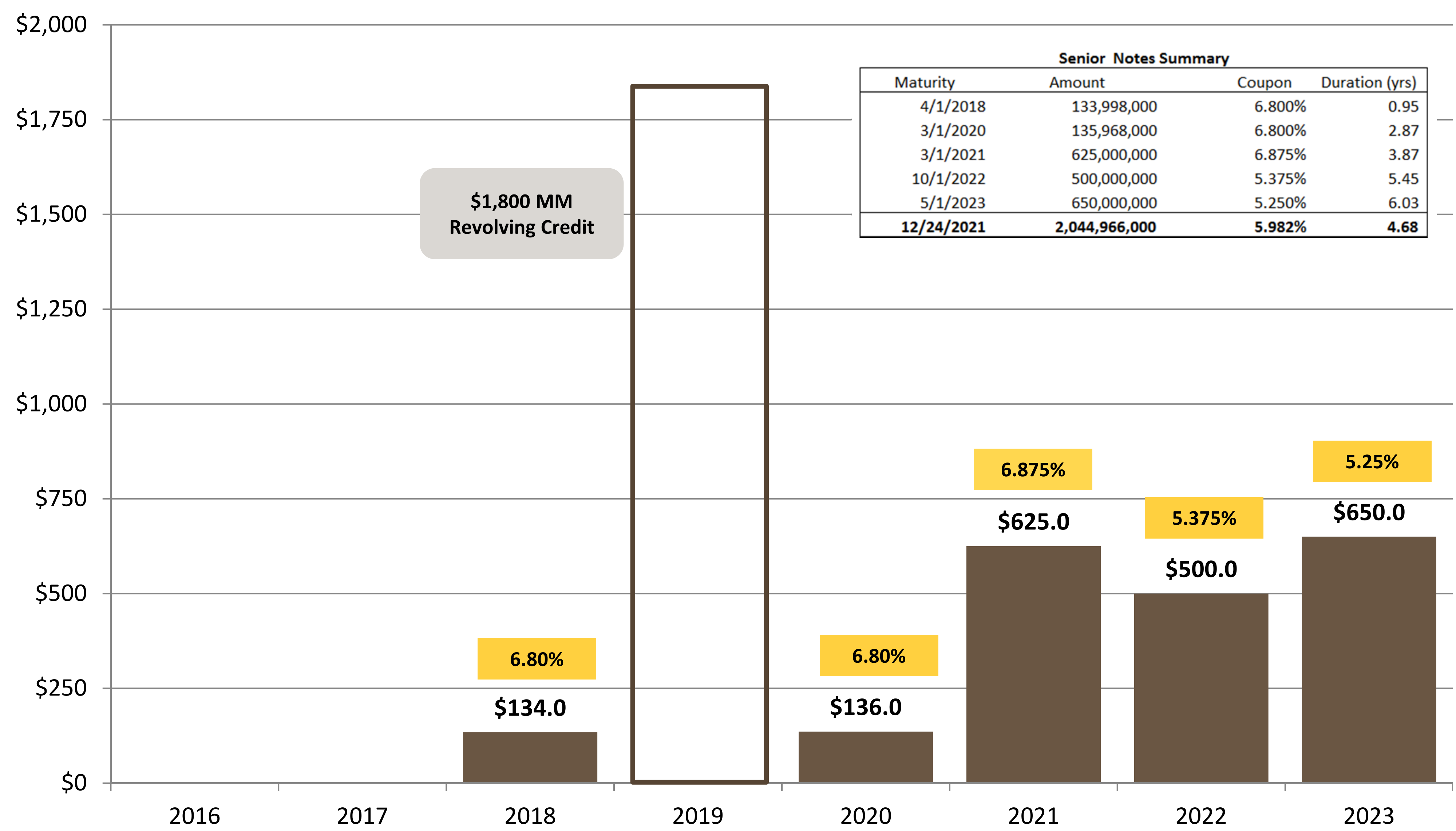
Year	Index	Total Volume (million MMbtu)	Average Price Floor ($/MMBtu)	Average Price Celing ($/MMBtu)
2017	NYMEX HH	7.4	$2.50	$3.50

Production Commodity Derivative Basis Swaps

Year	Index less Differential	Index	Total Volumes	Weighted Average Differential
Oil Sales			**(MMBbls)**	**($/Bbl)**
2017	NYMEX WTI	Argus WTI Midland(1)	3.2	($0.66)
2018	NYMEX WTI	Argus WTI Midland(1)	3.7	($1.01)
Gas Sales			**(million MMBtus)**	**($/MMBtu)**
2017	NYMEX HH	IFNPCR	34.3	($0.18)
2018	NYMEX HH	IFNPCR	7.3	($0.16)

(1) Argus WTI Midland is an index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, TX

QEP Resources – *Debt Maturity Schedule*



Senior Notes Summary

Maturity	Amount	Coupon	Duration (yrs)
4/1/2018	133,998,000	6.800%	0.95
3/1/2020	135,968,000	6.800%	2.87
3/1/2021	625,000,000	6.875%	3.87
10/1/2022	500,000,000	5.375%	5.45
5/1/2023	650,000,000	5.250%	6.03
12/24/2021	**2,044,966,000**	**5.982%**	**4.68**

QEP Resources – *Estimated Proved Reserves*

Estimated Proved Reserves	Oil (MMBbl)	Gas (Bcf)	NGL (MMBbl)	Total (MMBoe) (1)
Balance at December 31, 2015	193.1	2,108.9	58.8	603.4
Revisions of previous estimates	(9.7)	412.8	(0.3)	58.8
Extensions and discoveries	13.0	158.1	3.3	42.6
Purchase of reserves in place	62.7	54.6	11.5	83.3
Sale of reserves in place	(0.2)	(3.6)	(0.1)	(0.9)
Production	(20.3)	(177.0)	(6.0)	(55.8)
Balance at December 31, 2016	**238.6**	**2,553.8**	**67.2**	**731.4**

Total Costs Incurred (December 31, 2016)	($MM)
Proved Property Acquisitions	$431.6
Unproved Property Acquisitions	$208.7
Exploration (capitalized and expensed)	$13.4
Development	$509.2
Total Costs Incurred	**$1,162.9**

(1) Natural gas is converted to crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

Estimated Proved Reserves - by operating area	Total (MMBoe)	% of Total	PUD %	Liquids %
For the year ended December 31, 2016				
Northern Region				
Williston Basin	160.2	22%	37%	86%
Pinedale	160.7	22%	14%	13%
Uinta Basin	106.1	14%	62%	5%
Other Northern	12.3	2%	0%	6%
Southern Region				
Permian Basin	147.8	20%	81%	88%
Haynesville/Cotton Valley	144.3	20%	74%	0%
Other Southern	-	0%	0%	0%
Total Proved Reserves	**731.4**	**100%**	**51%**	**42%**
For the year ended December 31, 2015				
Northern Region				
Williston Basin	181.0	30%	39%	86%
Pinedale	187.5	31%	27%	13%
Uinta Basin	93.1	16%	55%	18%
Other Northern	12.4	2%	0%	8%
Southern Region				
Permian Basin	62.4	10%	66%	87%
Haynesville/Cotton Valley	66.1	11%	57%	0%
Other Southern	0.9	0%	0%	32%
Total Proved Reserves	**603.4**	**100%**	**42%**	**42%**