Investor Presentation

December 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; large upside potential in proven and unproven zones; rationalization of mature assets; stacked pay opportunity across core Permian acreage position; allocation of capital investment; potential drilling locations; evaluating well density; development strategy, plans and timeline; anticipated benefits of tank-style development in the Permian Basin; 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 and property taxes, general and administrative expense, non-cash share-based compensation 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 and other 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; actions of operators on properties where we own an interest but are not the operator; and the other risks discussed in the Company’s periodic filings with the Securities and Exchange Commission (SEC), including the Risk Factors sections of QEP’s Annual Report on Form 10-K for the year ended December 31, 2016 (the “2016 Form 10-K”), and QEP’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2017. 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; 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 – *At A Glance*

Balanced & Diversified Upstream Portfolio

- Focused investment in core crude oil and natural gas plays

Financial Strength

- $782.6 million of cash and cash equivalents as of September 30, 2017(1)
- Undrawn $1.8 billion unsecured revolving credit facility
- Solid oil & gas derivative portfolio through 2018 to help mitigate cash-flow risk

Portfolio Optimization

- Actively working to increase crude oil development drilling inventory through acreage swaps and organic growth opportunities
  - *2017 Permian Basin Acquisition of ~13,000 net acres in Martin County, TX for $683.5 million – completed on Oct. 24, 2017*(2)
- Simplification of the QEP story through rationalization of mature assets
  - *Divestiture of Pinedale Anticline for $718.2 million – completed on Sept. 20, 2017*

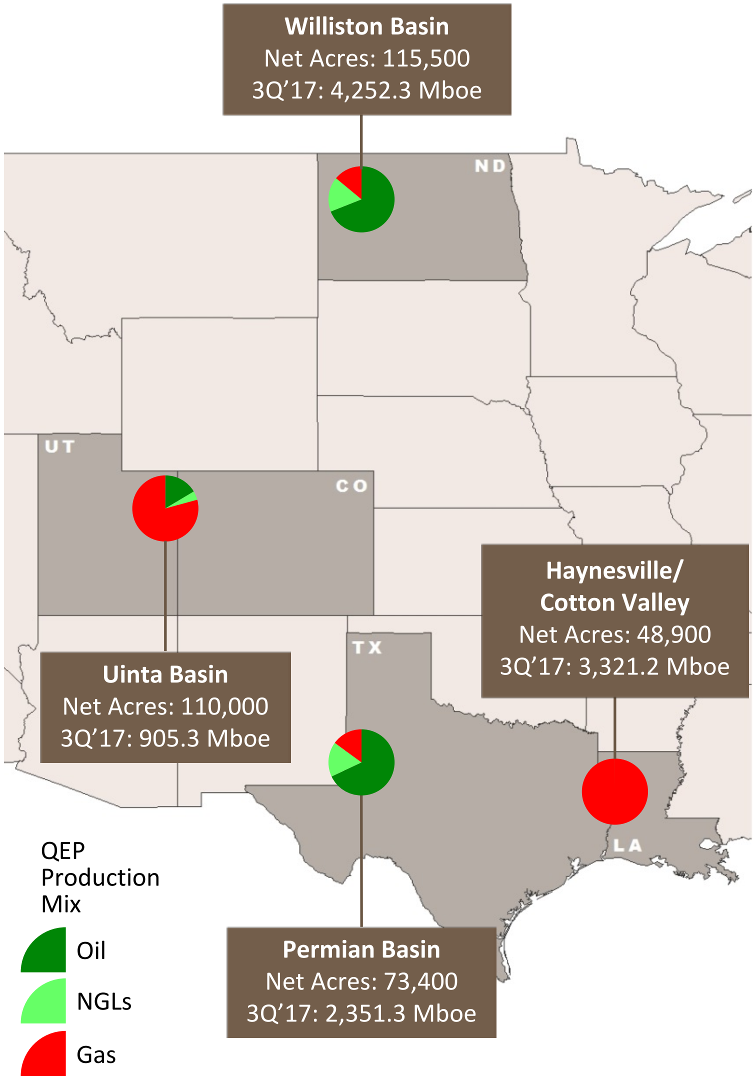
Capital & Operational Efficiency Strategy

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

(1) Pro-forma for the 2017 Permian Basin Acquisition, the Company would have approximately $136 million of cash and cash equivalents as of September 30, 2017.
(2) Approximately 700 additional acres contracted for in the transaction were not included in the closing, but are expected to be acquired by the Company within the next 30 days for an aggregate purchase price not to exceed $38 million.

QEP Resources – *3Q 2017 Financial & Operational Overview*

Asset Overview[1]



3Q 2017 Highlights

- Total Net Equivalent Production: 14,124.1 Mboe
  - Oil Production: 4,827.1 Mbbl
  - Gas Production: 46.7 Bcf
  - NGL Production: 1,516.1 Mbbl
- Increased net equivalent production in the Permian Basin to a record 25.6 Mboed, a 57% year-over-year increase
- Increased net equivalent production in the Haynesville/Cotton Valley to 216.6 MMcfed, a 63% year-over-year increase
- Completed four Williston Basin refracs with a nearly six fold increase in average 30-day incremental oil production
- Completed the sale of Pinedale Anticline assets for net proceeds of $718.2 million

(1) Equivalent production excludes 3,010.8 Mboe from Pinedale and 283.2 Mboe from Other Northern & Other Southern regions

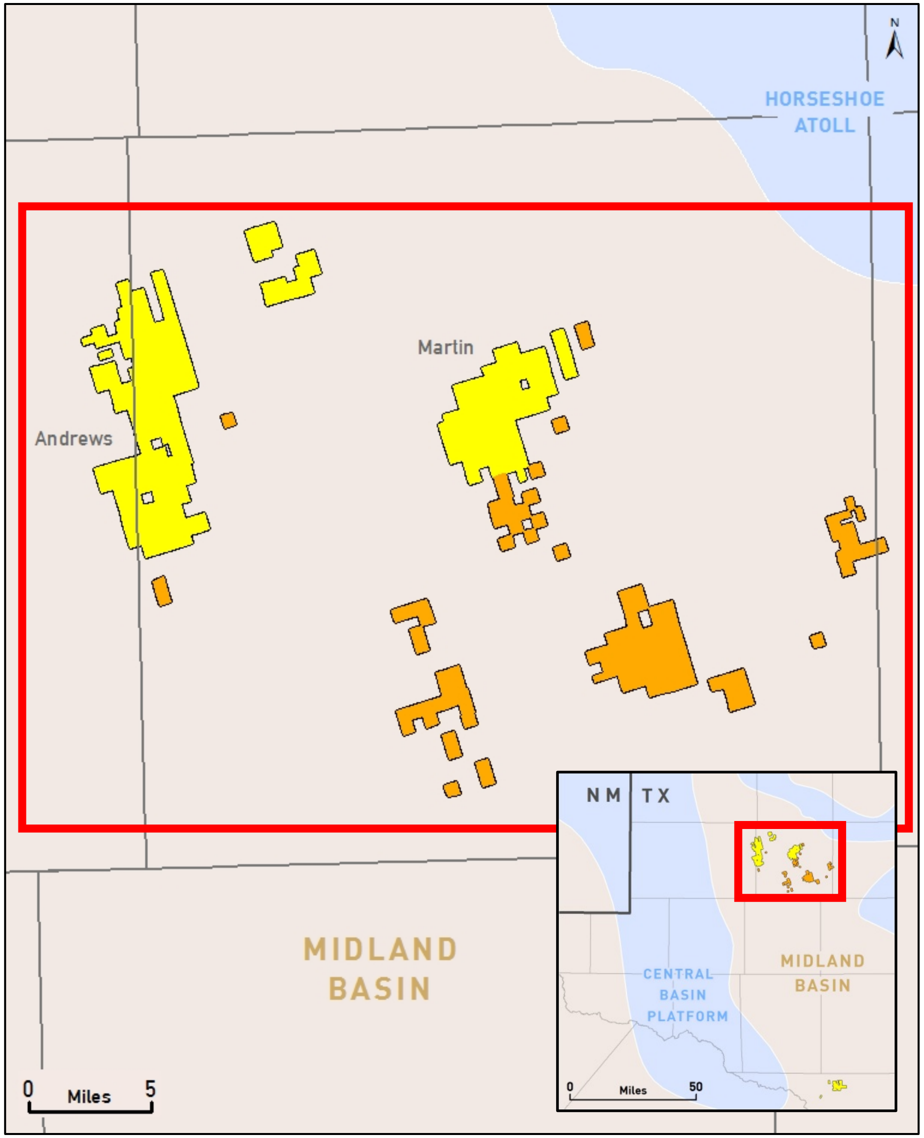
QEP Resources – *2017 Guidance*[(1)]

	2017 Current Forecast
Oil Production (MMBbl)	19.5 - 20.0
Gas Production (Bcf)	165.0 - 170.0
NGL Production (MMBbl)	5.25 - 5.75
Total oil equivalent production (MMBoe)	52.3 - 54.1
Lease operating and transportation expense (per Boe)	$10.25 - $10.75
Depletion, depreciation and amortization (per Boe)	$14.00 - $15.00
Production and property taxes (% of field-level revenue)	8.5%
(in millions)	
General and administrative expense[(2)]	$150 - $160
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip[(3)]	$970 - $1,010
Infrastructure	$70 - $80
Corporate	$10
Total Capital Investment (excluding property acquisitions)	**$1,050 - $1,100**

(1) As of October 25, 2017: The Company's guidance has been updated for the Pinedale Divestiture and the 2017 Permian Basin Acquisition, assumes no additional property acquisitions or divestitures and assumes that QEP will elect to reject ethane from its produced gas for the entire year where QEP has the right to make such an election. Assumes an average of eight rigs for the remainder of 2017, with six rigs in the Permian Basin, one rig in the Williston Basin and one rig in the Haynesville.
(2) General and administrative expense includes approximately $25.0 million of non-cash share-based compensation expense.
(3) Drilling, Completion and Equip includes approximately $20.0 million of non-operated well completion costs.

Asset Overview

Midland Basin



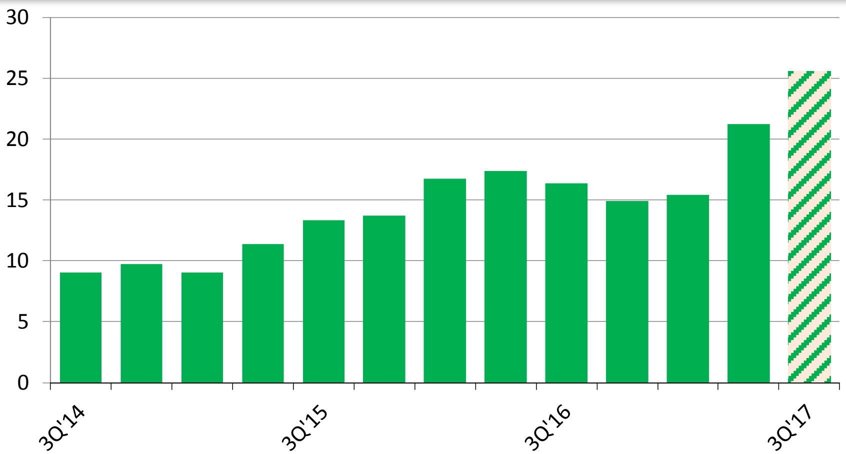
QEP Acreage as of 9/30/2017
2017 Permian Basin Acquisition

Profile[1]

Net acres[2]	49,100
Gross operated producing wells	499
Average WI/average NRI	96 / 73%
Proved reserves (MMboe)/% liquids[3]	148 / 88%
Production Split – oil/gas/NGL	72/13/15%
Rig Count[4]	6

(1) As of September 30, 2017, except for reserve estimates
(2) Includes 2017 Permian Basin Acquisition and leasehold in Crocket County, TX
(3) As of December 31, 2016, SEC Pricing
(4) Excludes one rig drilling salt water disposal wells

Net Production - Mboed



Midland Basin – *Tank-style Development*

Methodology

- Multiple stacked horizons from a single surface location
- Large multi-well pads and advanced completion designs
- Wells completed in a top-down pattern
- "Pressure Wall" separates producing wells from completing wells
- "Buffer" minimizes interference between completed and drilling wells

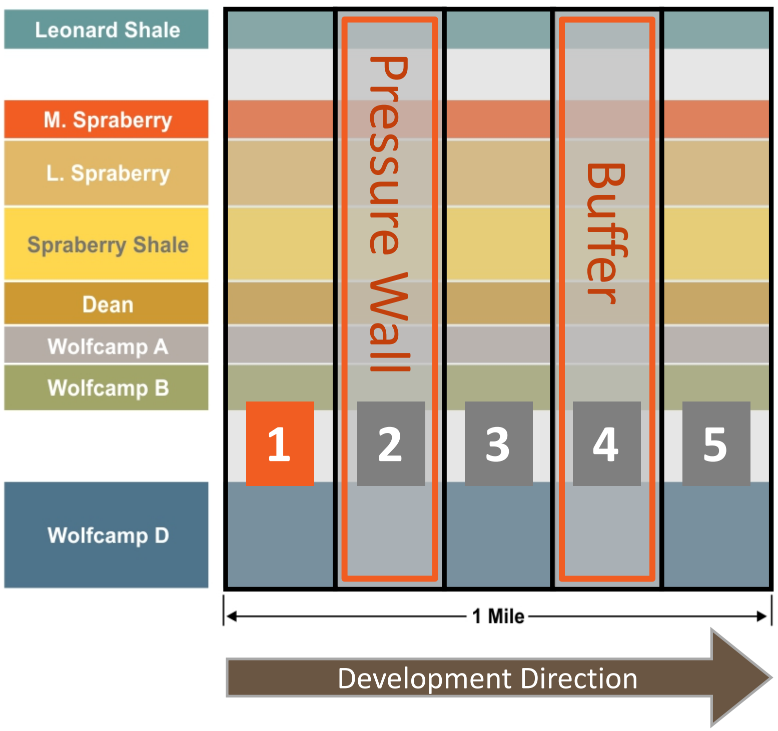
Anticipated Benefits

Above Ground

- Improves efficiency and utilization of surface equipment, crews and infrastructure
- Simultaneous use of multiple drilling rigs reduces cycle time and allows for the sharing of services
- Integrated infrastructure provides cost savings through the recycling of water and the reduction of well site facility and pipeline costs

Below Ground

- Improves production and ultimate resource recovery
- Maintains "super-charged" reservoir pressure during completion and optimizes rock stimulation and conservation of completion energy
- Reduces the risk of interference and shut-in times for offset producing wells



LEGEND:

- 1 Producing wells
- 2 Completed wells waiting to be turned-to-sales ("Pressure Wall")
- 3 Wells being completed (active frac crew)
- 4 Wells waiting-on-completion ("Buffer")
- 5 Wells being drilled (rigs)

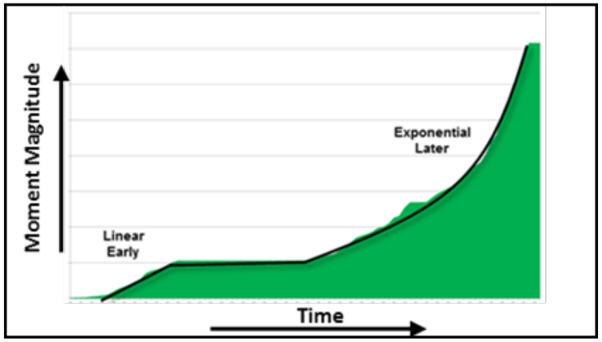
Midland Basin – *Tank-Style Development Allowing for Increased Densities*

Microseismic Study & Production Support 16 well/mile Density with Tank-Style Development

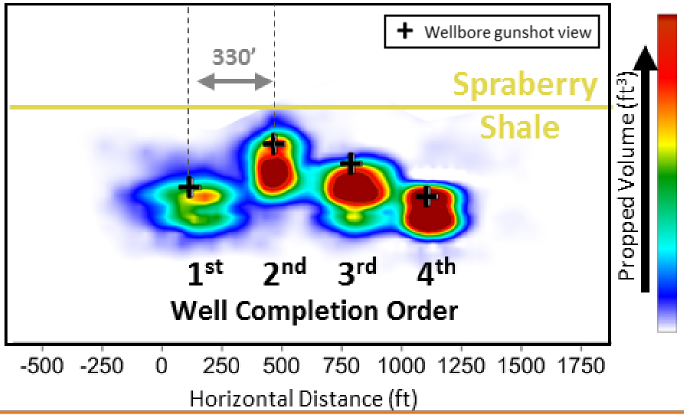
Microseismic Study

As tank-style development advances:

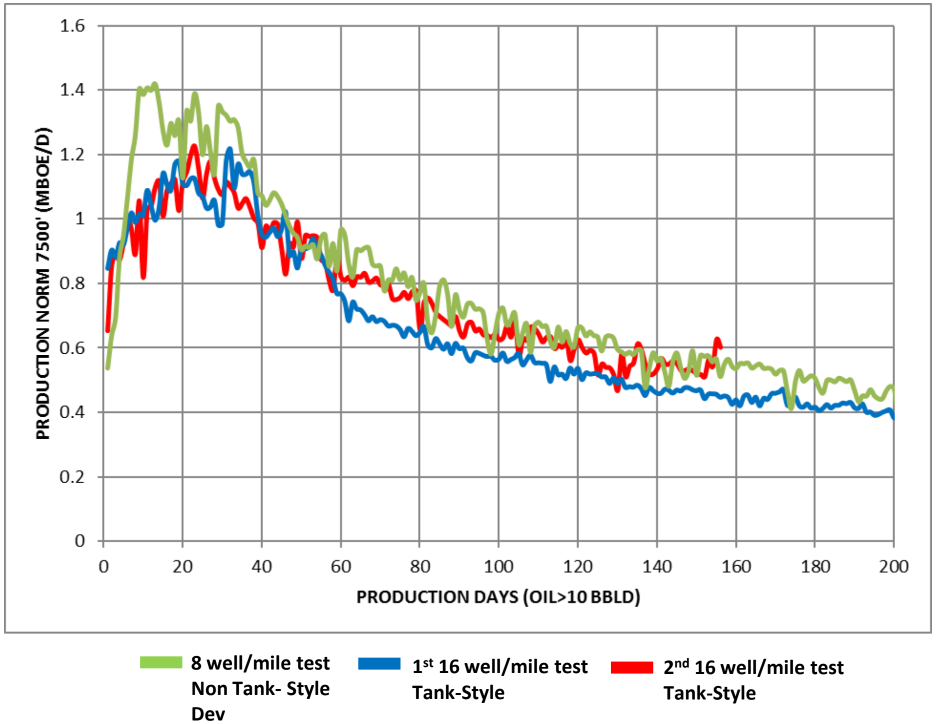
- Evidence of "breaking more rock" with increased event count and moment magnitudes



- Increased fracture complexity for later wells in the tank-style development sequence and illustrates "pressure wall"



Performance of Well Density Tests

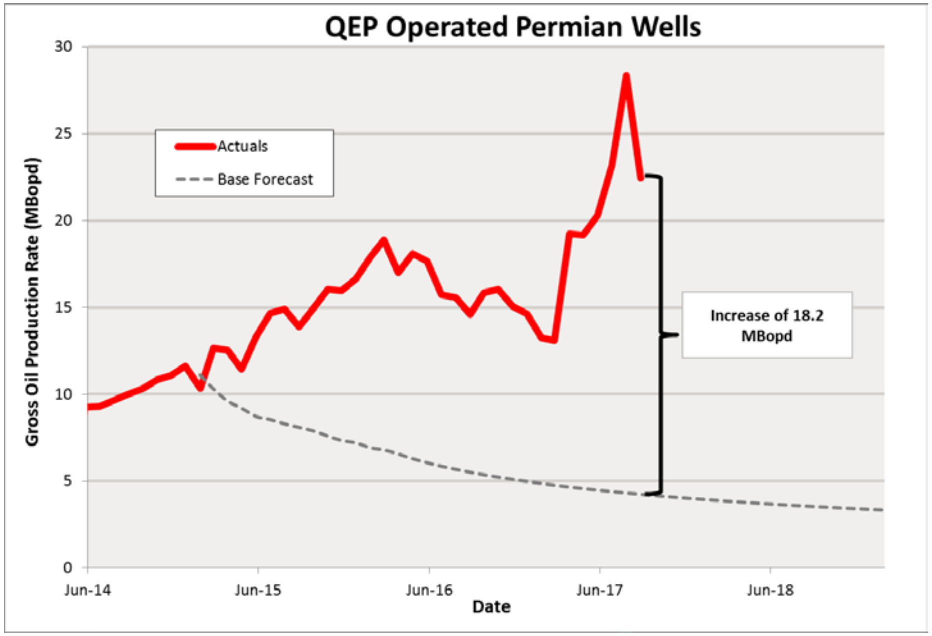


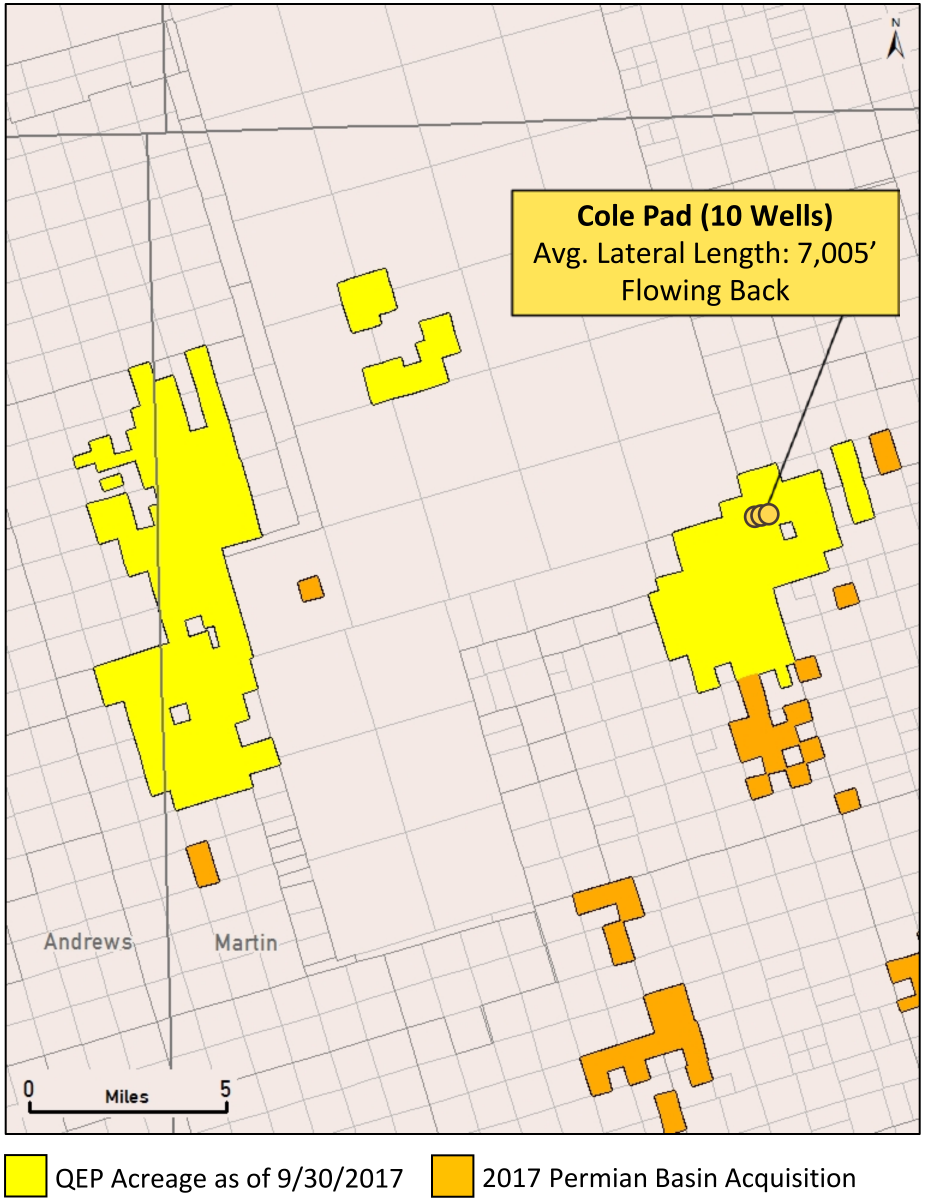
- Well density tests utilizing tank-style development show similar performance to non tank-style development

Midland Basin – *3Q 2017 Activity*

- **Completions:** 10
  - Spraberry Shale (6)
  - Middle Spraberry (4)
- **Waiting on Completion / Drilling Summary** (1)

Activity	Spraberry Shale	Middle Spraberry	Wolfcamp A	Wolfcamp B
Waiting on Completion	11	7	4	6
Drilling (2)	9	7	7	11





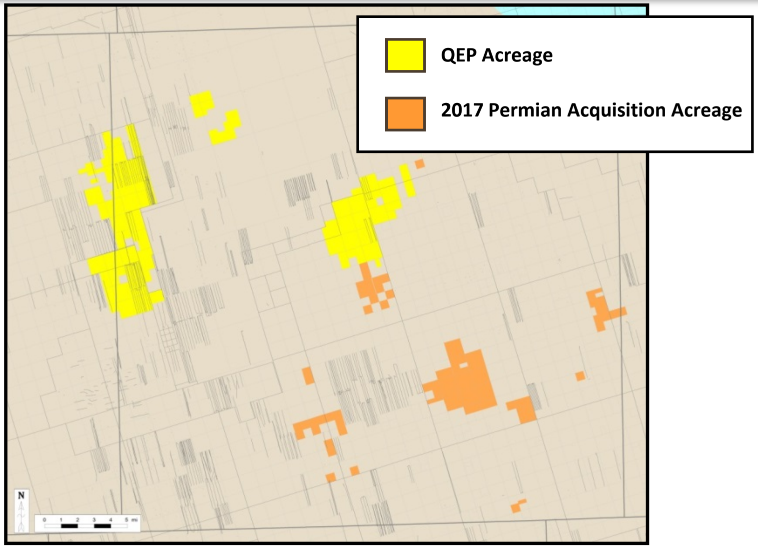
(1) Excludes activity in unproven zones. Drilling: Lower Spraberry (1), Dean (2) and Jo Mill (1); Waiting on Completion: Lower Spraberry (1).
(2) Includes 21 wells for which surface casing has been set but did not have a rig drilling as of September 30, 2017.

Midland Basin – *Acquisition Summary*

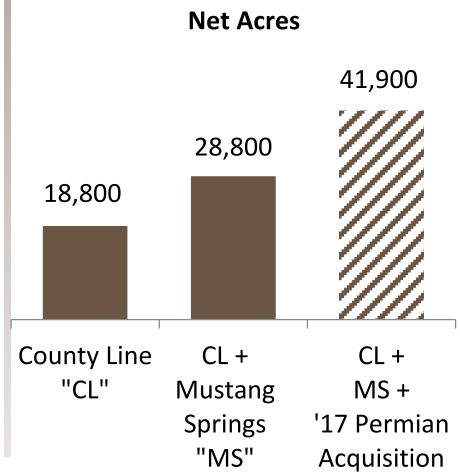
Acquisition Overview

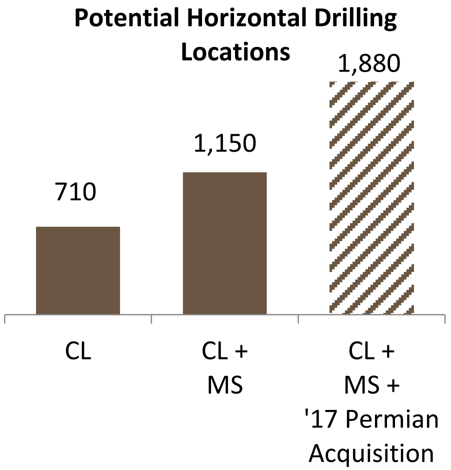
- Acquired crude oil and natural gas properties in in Martin County, TX for ~$683.5 million
  - ~ 13,000 net acres[1]
  - Over 730 potential horizontal drilling locations in four horizons – Middle Spraberry, Spraberry Shale, Wolfcamp A and Wolfcamp B
  - Additional potential horizontal drilling locations in emerging prospective horizons
  - Nearly all of the acreage is held by production to the Wolfcamp Formation or deeper
  - Average 84% working interest, subject to a 25% royalty burden
  - Current net production of ~550 Boed (71% oil) from 89 vertical wells
- Acquisition structured as a like-kind-exchange and was funded utilizing proceeds from the Pinedale Divestiture, which closed on September 20, 2017
- Acquisition closed on October 24, 2017

Pro Forma Leasehold



Pro Forma Statistics[2]

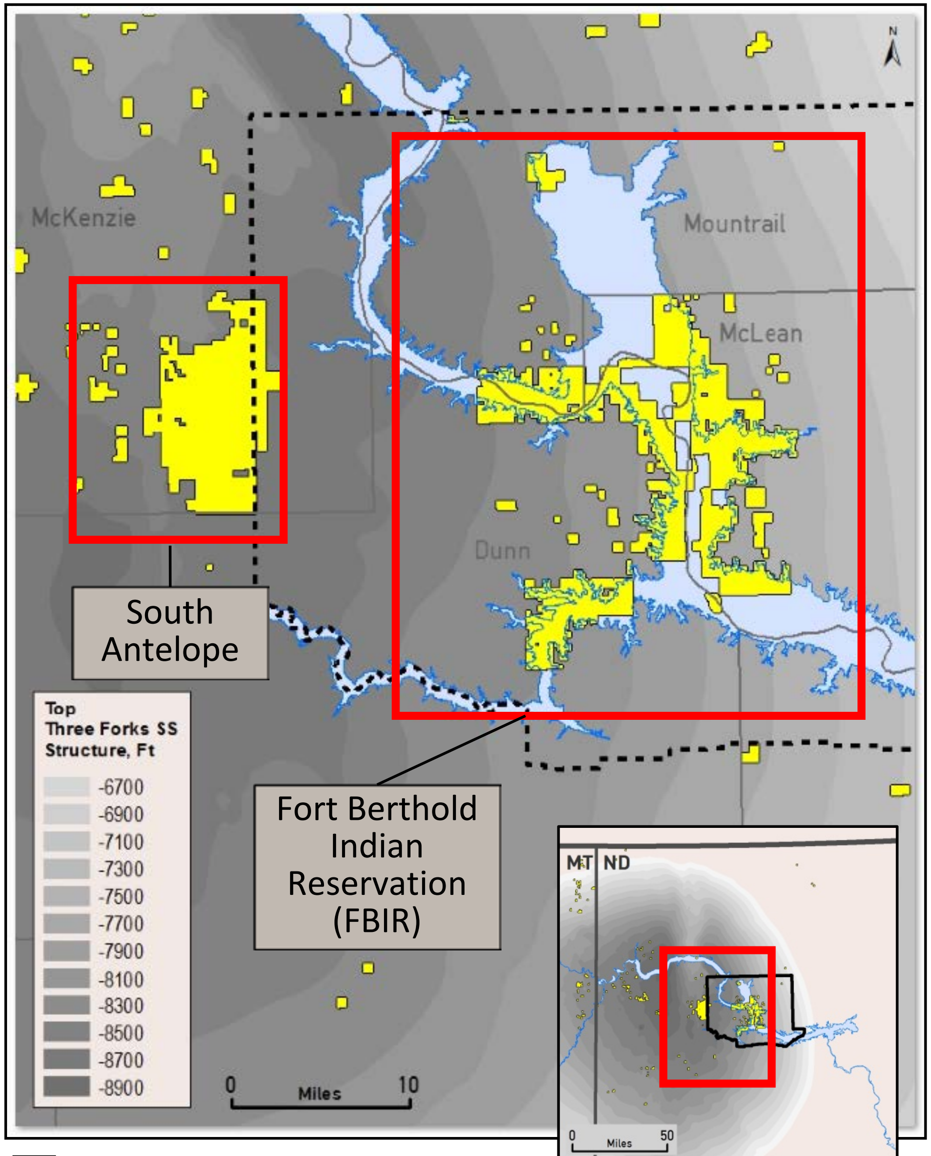




(1) Approximately 700 additional acres contracted for in the transaction were not included in the closing , but are expected to be acquired by the Company within the next 30 days for an aggregate purchase price not to exceed $38 million.

(2) County Line and Mustang Springs acreage as of September 30, 2017; excludes acreage in the southern Midland Basin and on the Central Basin Platform.

Williston Basin



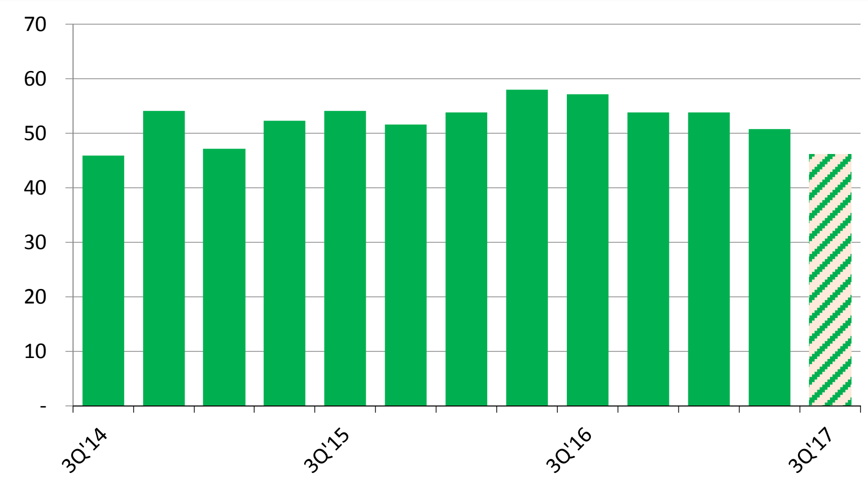
QEP Acreage as of 9/30/2017

Profile[1]

Net acres	115,500
Gross operated producing wells	384
Average WI/average NRI	85/68%
Proved reserves (MMboe)/% liquids[2]	160 / 86%
Production Split – oil/gas/NGL	66/14/20%
Rig Count	1

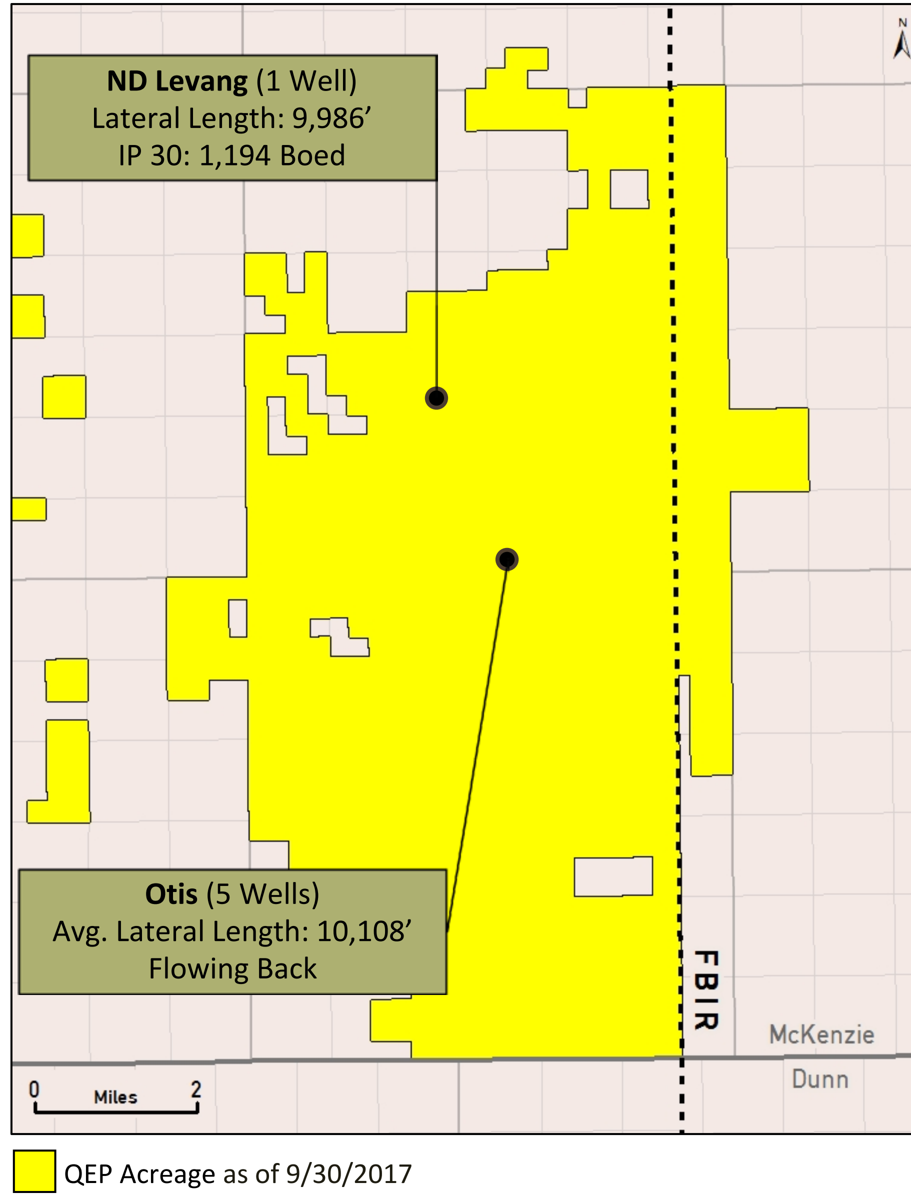
[1] As of September 30, 2017 except for reserve estimates
[2] As of December 31, 2016, SEC Pricing

Net Production - Mboed



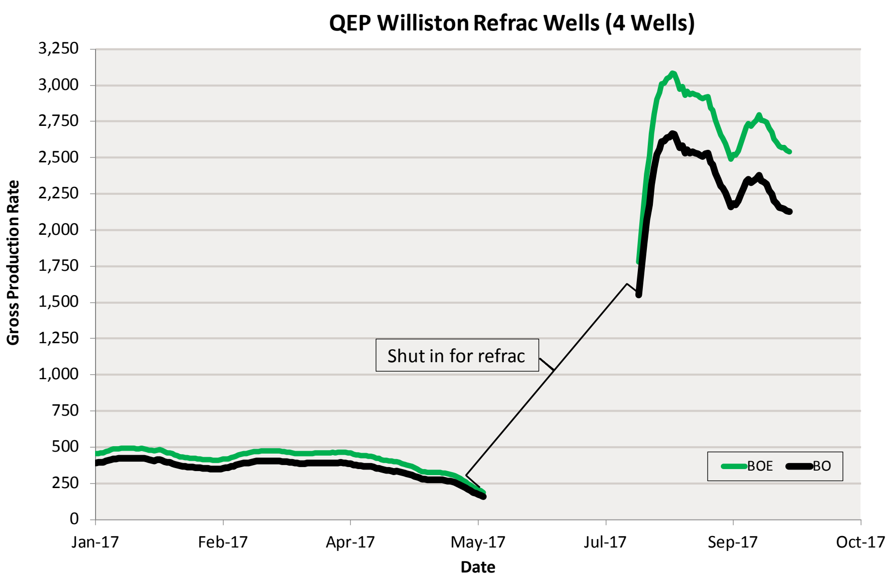
Williston Basin – *South Antelope 3Q 2017 Activity*

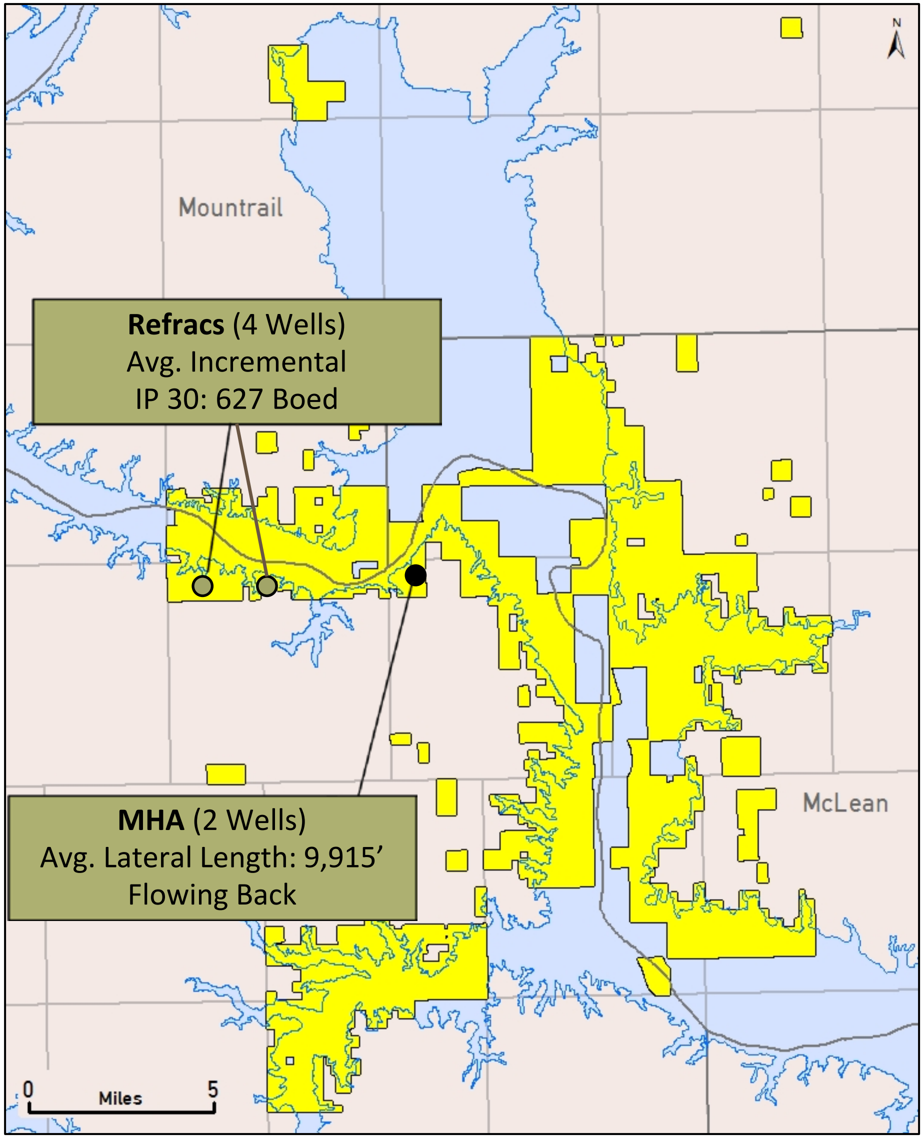
- **Net Acres:** ~30,900
- **Rig Count:** 0
- **Completions:** 6
  - Bakken (4)
  - Three Forks 2 (2)
- **Waiting on Completion:** 0



Williston Basin – *FBIR 3Q 2017 Activity*

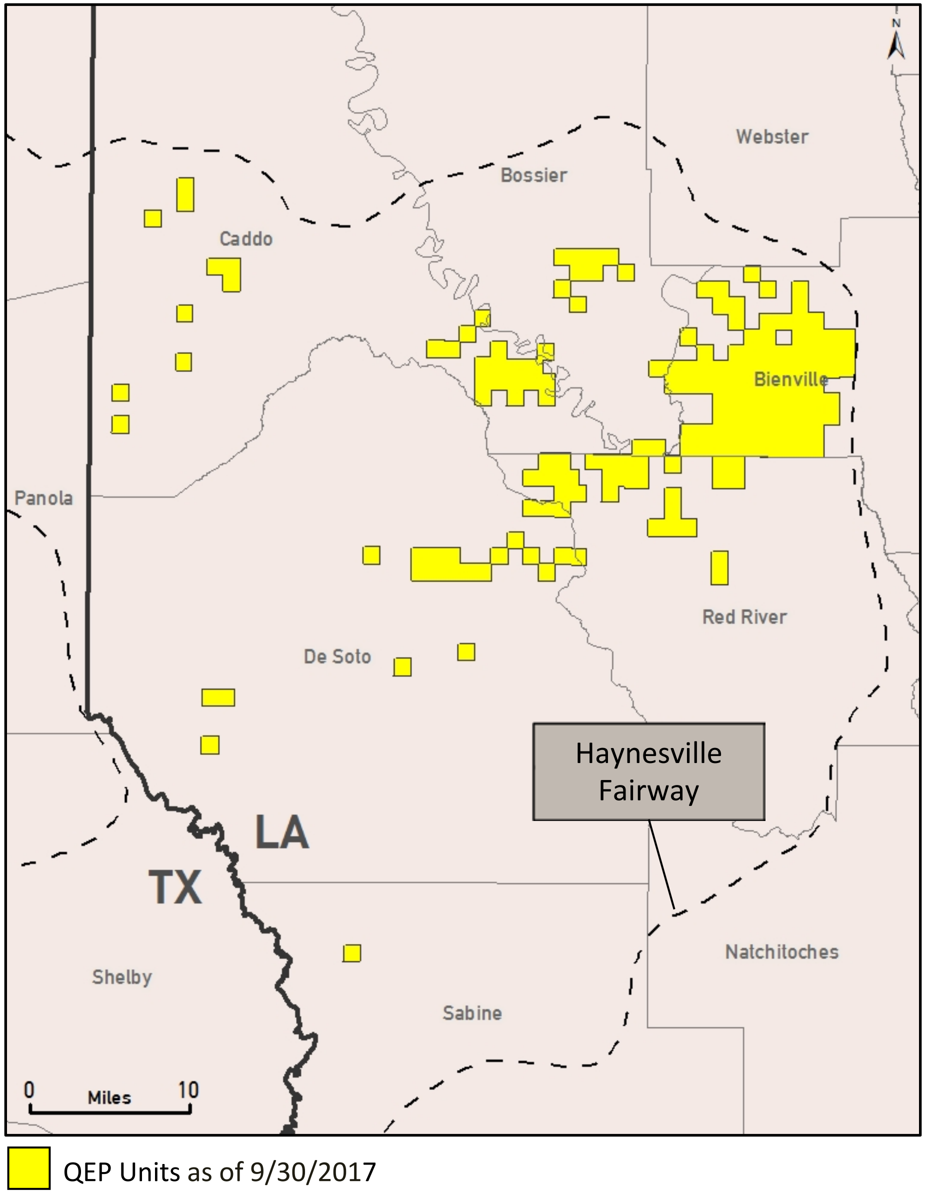
- **Net Acres:** ~66,500
- **Rig Count:** 1
- **Completions:** 2
  - Bakken (1)
  - Three Forks (1)
- **Refracs:** 4
- **Waiting on Completion**: 1
  - Bakken (1)
- **Drilling:** 1
  - Three Forks (1)





QEP Acreage as of 9/30/2017

Haynesville

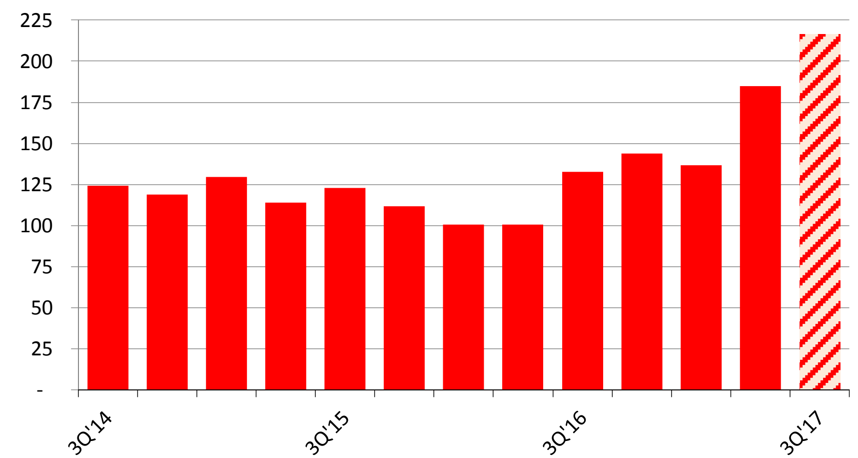


Profile[1]

Net acres	48,900
Gross operated producing wells[2]	130
Average WI/average NRI	89/68% (op)
Proved reserves (Bcfe)/% liquids[3]	866 / 0%
Production Split – oil/gas/NGL	0/100/0%
Rig Count	1

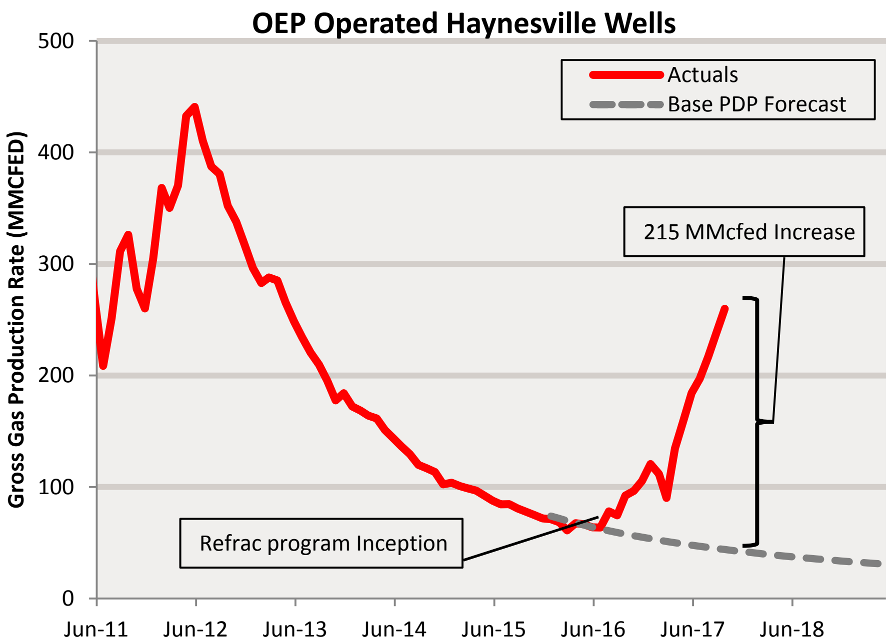
[1] As of September 30, 2017, except for reserve estimates
[2] Includes only Haynesville interval wells
[3] As of December 31, 2016, SEC Pricing

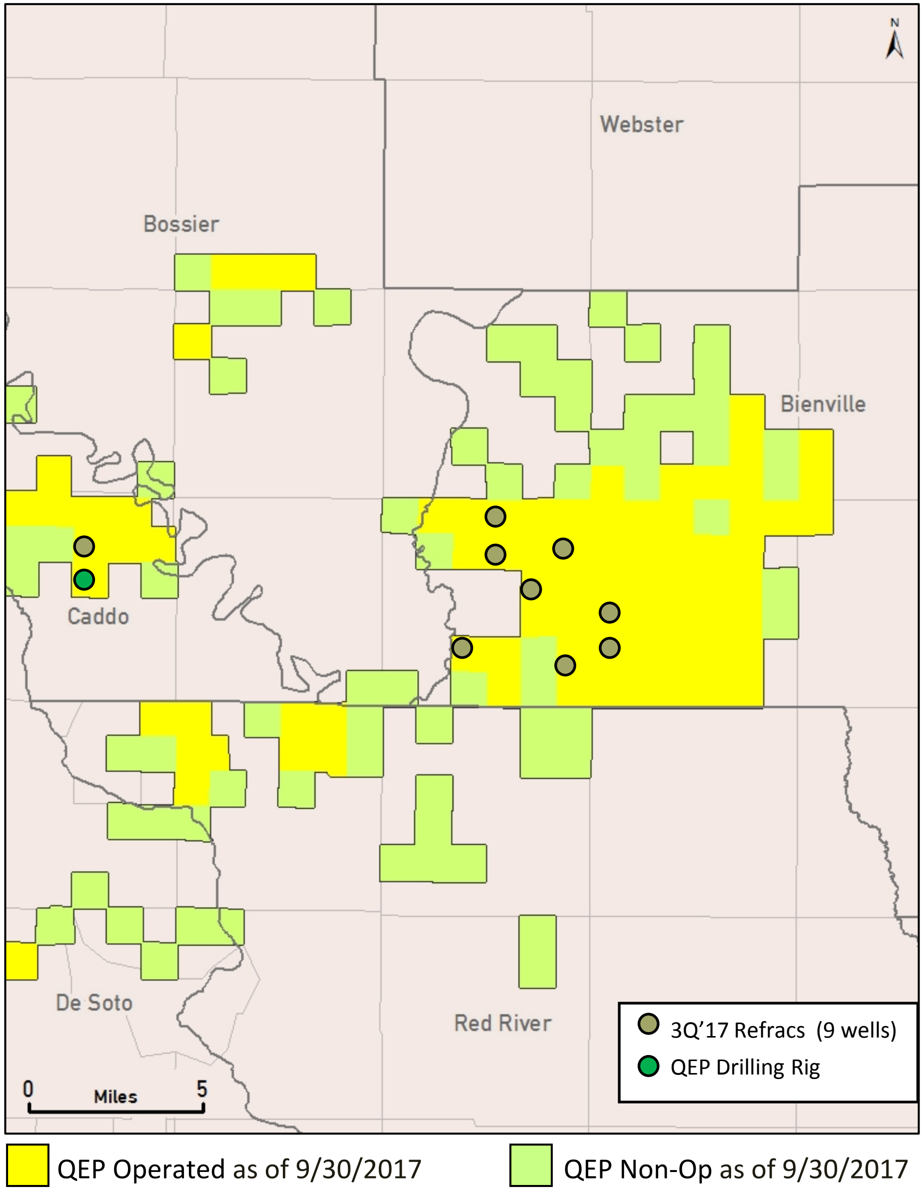
Net Production – MMcfed



Haynesville – *3Q 2017 Activity*

- Completed nine refracs
- Refrac program has increased Haynesville gross production by ~215 MMcfed since inception
- Added drilling rig in September 2017
  - Drilling one 5,000' lateral before beginning 10,000' well program





Appendix

Midland & 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	$5.2	$0.8
	Spraberry Shale	10,000	$6.4	$0.8
Mustang Springs	Middle Spraberry	7,500	$5.1	$0.8
	Spraberry Shale	7,500	$5.1	$0.8
	Wolfcamp A	7,500	$6.2	$0.8
	Wolfcamp B	7,500	$6.4	$0.8

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	$1.4

Midland Basin – *Well Density Assumptions*

	County Line	Mustang Springs	2017 Permian Acquisition
Leonard Shale	0-6 wells/mile	Upside Potential	Upside Potential
M. Spraberry	5-9 wells/mile	5-8 wells/mile	5-8 wells/mile
L. Spraberry	Upside Potential	Upside Potential	Upside Potential
Spraberry Shale	8-16 wells/mile	8-14 wells/mile	8-14 wells/mile
Dean	Upside Potential	Upside Potential	Upside Potential
Wolfcamp A	0-4 wells/mile	4-8 wells/mile	4-8 wells/mile
Wolfcamp B	0-8 wells/mile	6-14 wells/mile	6-14 wells/mile
Wolfcamp D	0-8 wells/mile	Upside Potential	Upside Potential

- Stacked pay opportunity across core Permian acreage position
- Large upside opportunity in both proven and unproven zones
- Nearly 1,900 potential future locations of 7,500’ and 10,000’ laterals[1]

(1) excludes zones labeled as upside potential

Midland 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

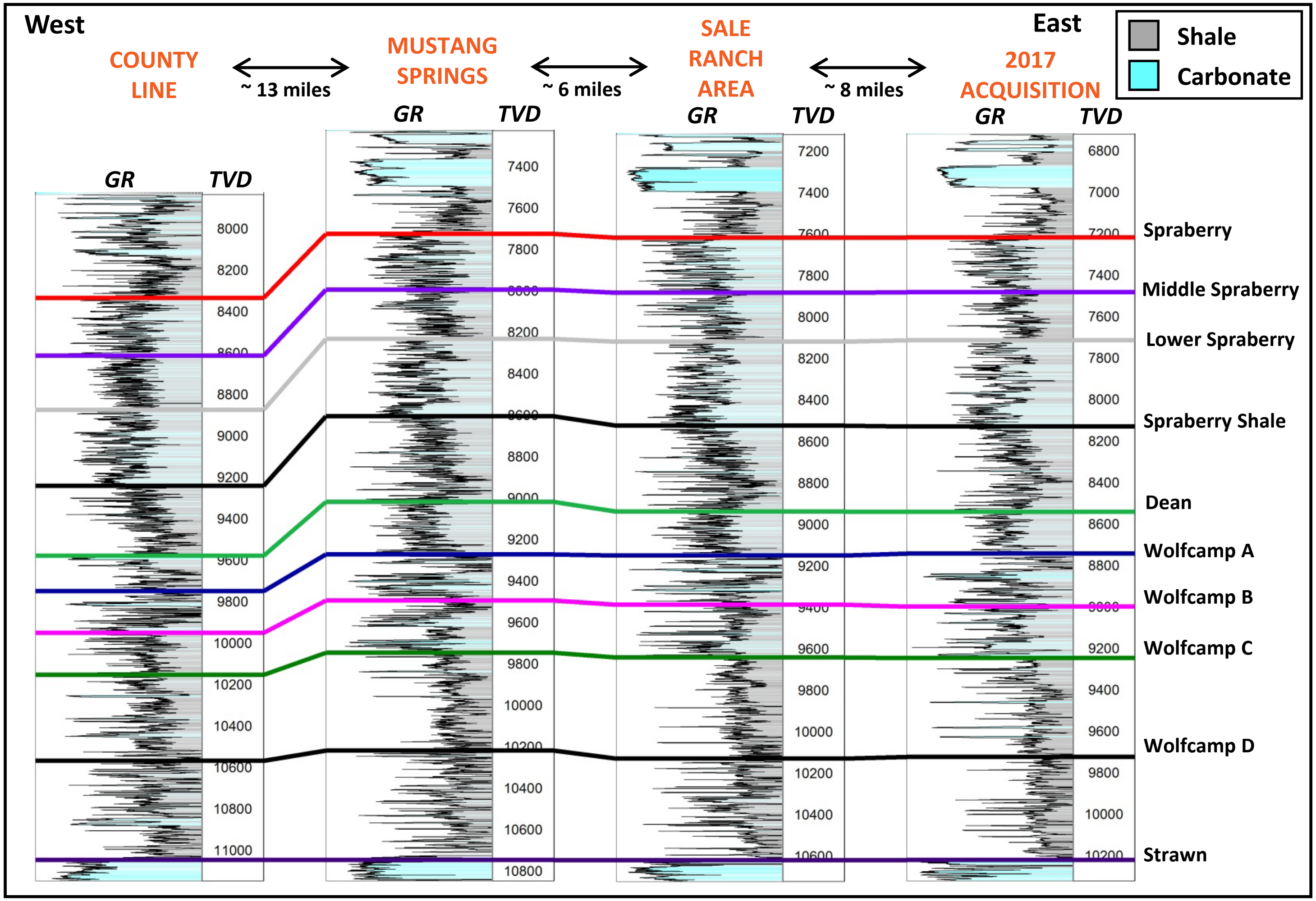
Development Optimization Plans

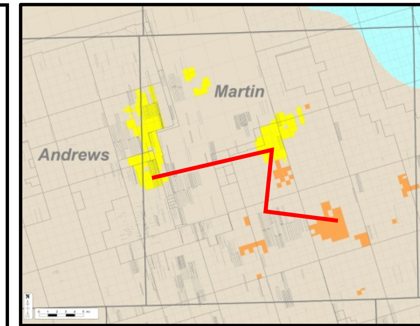
- Parent well tests
  - Provide baseline well performance in four zones MS, SS, WA and WB
- Density tests
  - Drive ultimate spacing of each reservoir and sequencing of development
  - Establish optimum drilling and completion program to maximize production and minimize well interference

Density Pilot Tests

- Two pilot tests in progress
  - Evaluate a continuum of wells across all four target horizons
- West Pilot – *completed September 2017*
  - Evaluate higher well density in MS & SS and lower density in WA and WB
- East Pilot – *estimated completion November 2017*
  - Evaluate higher well density in WA & WB and lower density in MS and SS

Midland Basin – *Predictable Geology Across Acreage*





County Line, Mustang Springs, Sale Ranch Area and 2017 Acquisition 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 production derivative positions (excluding storage derivatives) as of October 20, 2017:

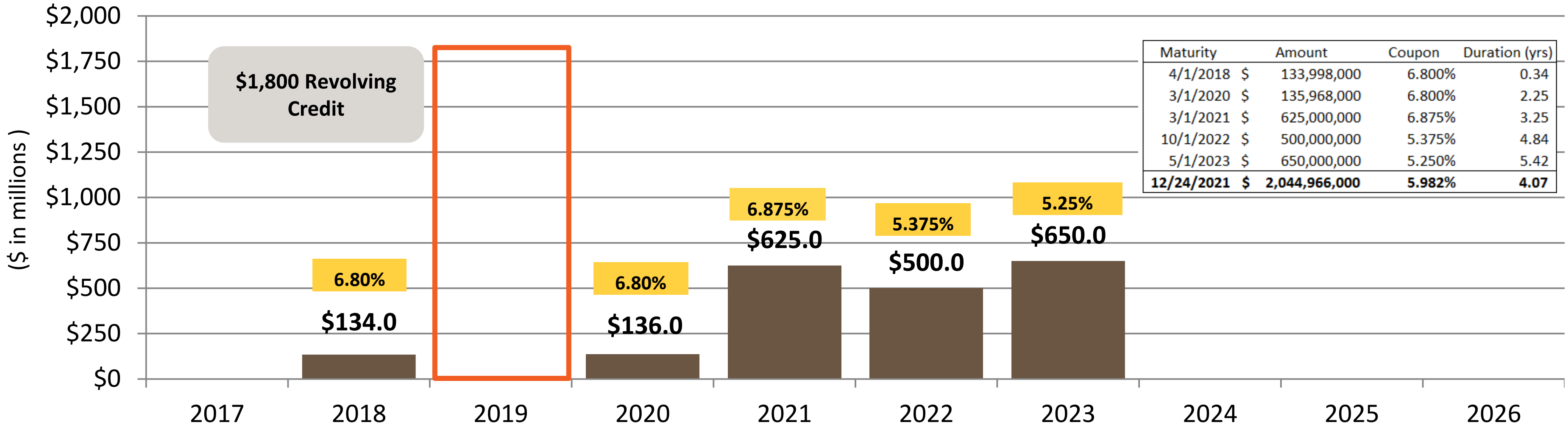
Production Commodity Derivative Swap Positions			
Year	**Index**	**Total Volumes**	**Average Price per Unit**
Oil Sales		**(MMBbls)**	**($/Bbl)**
2017	NYMEX WTI	3.6	$51.51
2018	NYMEX WTI	15.7	$52.37
2019	NYMEX WTI	4.4	$50.37
Gas Sales		**(million MMBtu)**	**($/MMBtu)**
2017	NYMEX HH	16.5	$2.87
2017	IFNPCR	4.3	$2.49
2018	NYMEX HH	109.5	$2.99
2019	NYMEX HH	25.6	$2.87

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]	1.1	($0.67)
2018 (Full Year)	NYMEX WTI	Argus WTI Midland[1]	7.3	($1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland[1]	0.7	($0.75)
2019	NYMEX WTI	Argus WTI Midland[1]	3.3	($0.90)
Gas Sales			**(million MMBtu)**	**($/MMBtu)**
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

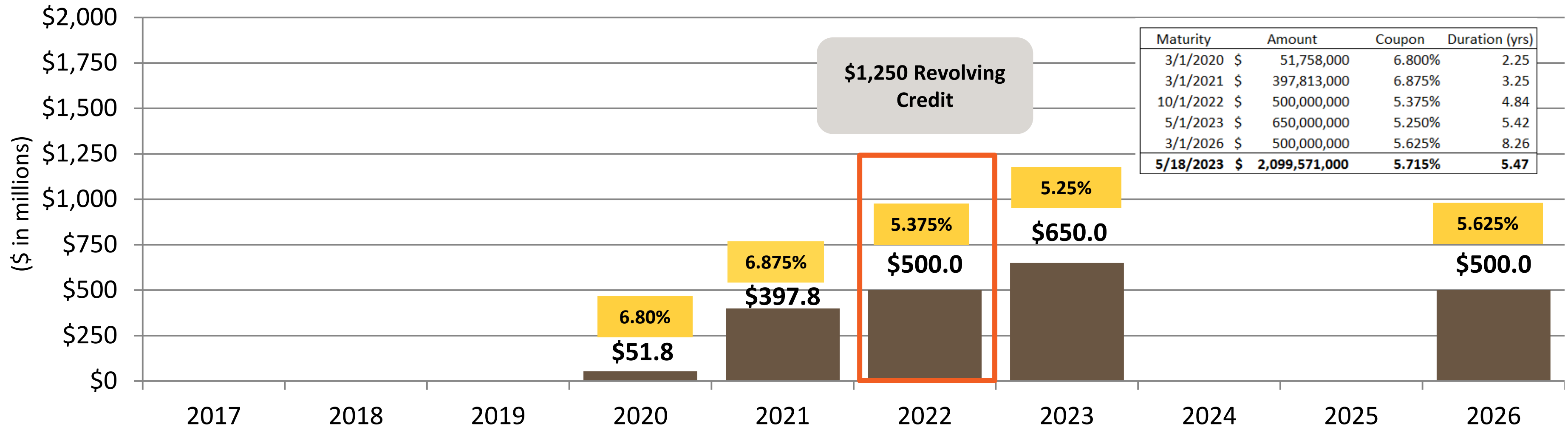
QEP Resources – *Debt Maturity Schedule*

As of October 25, 2017



Maturity		Amount	Coupon	Duration (yrs)
4/1/2018	$	133,998,000	6.800%	0.34
3/1/2020	$	135,968,000	6.800%	2.25
3/1/2021	$	625,000,000	6.875%	3.25
10/1/2022	$	500,000,000	5.375%	4.84
5/1/2023	$	650,000,000	5.250%	5.42
12/24/2021	**$**	**2,044,966,000**	**5.982%**	**4.07**

Pro Forma for Notes Offering, Redemption, Tender Offer and Revised Revolving Credit Facility



Maturity		Amount	Coupon	Duration (yrs)
3/1/2020	$	51,758,000	6.800%	2.25
3/1/2021	$	397,813,000	6.875%	3.25
10/1/2022	$	500,000,000	5.375%	4.84
5/1/2023	$	650,000,000	5.250%	5.42
3/1/2026	$	500,000,000	5.625%	8.26
5/18/2023	**$**	**2,099,571,000**	**5.715%**	**5.47**

Note: Redemption and Tender Offer settled and closed on December 6, 2017

QEP Resources – 2017 Annual Incentive Plan

2017 Goals	2017 Target
Operational Performance - 25% Weighting	
•Total Equivalent Production (MMBoe)	55.40
•EBITDA per Boe[1]	$14.29
•Health, Safety and Environment	
•Hazard Identification and Reporting Rate (HIRR)	200
•Total Recordable Incident Rate (TRIR)	1.00
•Severity rate (spills)	30.00
Financial Performance - 25% Weighting	
•Balance Sheet Discipline - gross debt/EBITDA ratio	2.50
•Capital Efficiency - drilling rate of return[2]	35.0%
Reserve Growth - 25% Weighting	
•Validate estimated reserves on acquisitions	100%
•Reserves replacement ratio[3]	150%
Strategic Initiatives - 25% Weighting	Assessed by Board
•Technical innovation	
•Portfolio optimization	
•Long-term financial planning and risk management	
•Other	

[1] Adjusted EBITDA normalized for price ($55 oil and $3 gas) divided by total equivalent production.
[2] Before tax rate of return calculated at the individual well level based on price-normalized ($55 oil and $3 gas) future cash flows for wells drilled Q416 through Q317. Target reflects full-cycle costs.
[3] Reserve adds excluding acquisitions/divestitures and price-related revisions.