QEP RESOURCES

Investor Presentation

February 2018

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: planned strategic and financial initiatives; transition to a pure-play Permian Basin company; concentration on core Permian asset and benefits of such concentration; marketing and divestiture of assets; use of proceeds from asset sales; reaching cash flow neutrality in 2019; factors impacting share repurchases; delivering strong production growth; reducing drilling and completion cost, operating cost and F&D cost per boe; expanding operating margins and returns on invested capital; advancing simultaneous development; percentage of 2018 drilled wells with 10,000 foot laterals; 2018 netback per boe; estimated LOE and transportation expenses and decreases in the total of such expenses; growth in production; estimated number of net wells put on production each quarter and for the year ended 2018; estimated proved reserves; estimated production split among oil, gas and NGL; large upside opportunity in proven and unproven zones; capital costs and pros and cons of ESP and gas lift installation; benefits of centralized infrastructure; stacked pay opportunity across core Permian acreage position; amount and allocation of capital investment; number, and lateral lengths of, potential future horizontal drilling locations; number and location of drilling rigs; benefits of tank-style development; maximizing economic recovery of oil and capital efficiency; minimizing risk of interference and shut-in times; quarterly and annual guidance regarding production and net wells; guidance for 2018 LOE and transportation expense, DD&A, production and property taxes, general and administrative expense, non-cash share-based compensation expense, retention program 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; market conditions; actual proceeds from asset sales; actions of activist shareholders; changes in, adoption of and compliance with laws and regulations, including decisions, policies and guidance concerning taxes, 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; 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 section of QEP's Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 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; 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; actions of lessors and surface owners; 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 2017 Form 10-K.

QEP refers to Adjusted EBITDA, Adjusted Net Income (Loss), F&D Costs per Boe 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, as applicable, see the recent earnings press release and SEC filings at the Company's website at www.qepres.com under "Investor Relations."

QEP Resources – *2018 Strategic & Financial Initiatives*

QEP's Board of Directors has unanimously approved several strategic and financial initiatives to transition to a pure-play Permian Basin company

Strategic Initiatives

- Engaged financial advisors to assist with the divestiture of the Company's Williston and Uinta basin assets, with data rooms expected to be opened in late March or early April
- Market remaining non-Permian assets, including the Haynesville/Cotton Valley, in the second half of 2018

Financial Initiatives

- Use proceeds from asset sales to fund Permian Basin development program, until the program reaches operating cash flow neutrality in 2019, reduce debt and return cash to shareholders through share repurchases
- Authorized a $1.25 billion share repurchase program[(1)]
- Approved 2018 capital investment plan of approximately $1.075 billion, of which approximately 65% will be directed toward the Permian Basin

Today our Permian assets consist of approximately 44,000 net acres in the core of the northern Midland Basin, which delivered 8.2 MMBoe of net production in 2017 with estimated total proved year-end 2017 reserves of 272.7 MMboe

(1) Subject to available liquidity, market conditions and proceeds from asset sales .

QEP Resources – *Pure-Play Permian Basin Company*

- **Concentrating our efforts on our core Permian assets**
  - Contiguous 44,000 net acres in the core of the northern Midland Basin
    - *Avg. WI 95%/ NRI 72%*
  - Oil production growth of over 70% at the midpoint in 2018
  - Anticipated benefits:
    - Achieves operating cash flow neutrality in 2019(1) while delivering strong production growth
    - Reduces drilling & completion cost, operating cost and F&D cost per Boe(2)
    - Expands operating margins and returns on invested capital
- **Advancing the simultaneous development of our stacked pay utilizing "tank-style" completions, which we believe**
  - Maximizes the economic recovery of oil
  - Maximizes capital efficiency through shared surface facilities and service logistics
  - Minimizes risk of interference and shut-in times of offset producing wells

Pure-Play Permian Company Delivering Strong Returns for Our Shareholders

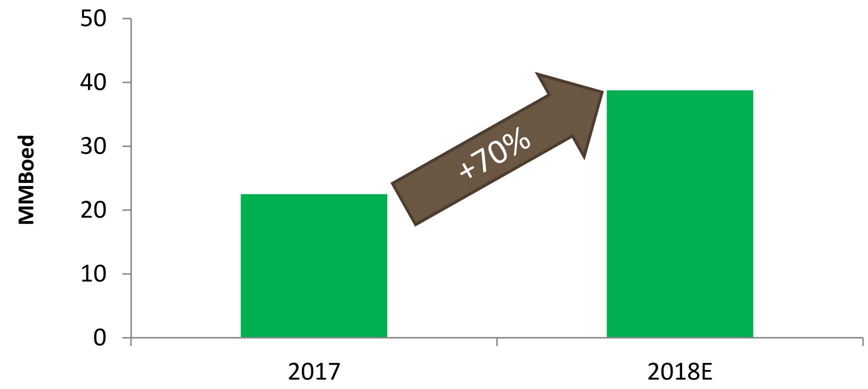
(1) Defined as capital expenditures being approximately equal to operating cash flows.
(2) Management defines F&D Cost (a non-GAAP measure) as total costs incurred (an unaudited GAAP measure) divided by the sum of revisions of previous reserve estimates, extensions and discoveries and purchases of reserves in place.

Midland Basin – *Outlook*

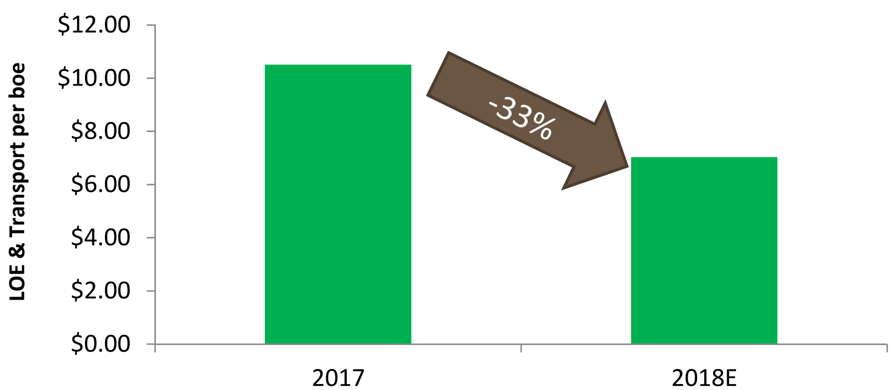
2018 Key Statistics

- Five operated rigs
- \$650 - \$700 million in drilling and completion capital
- \$35 - \$45 million of infrastructure capital
- Up to 1,900 potential future horizontal drilling locations of 7,500' to 12,500' lateral length
- Over 35% of wells put on production in 2018 to have 10,000'+ laterals
- ~\$35 per Boe 2018 netback at current strip pricing(1)

Production Profile



LOE and Transportation Expense Target



2018 Outlook

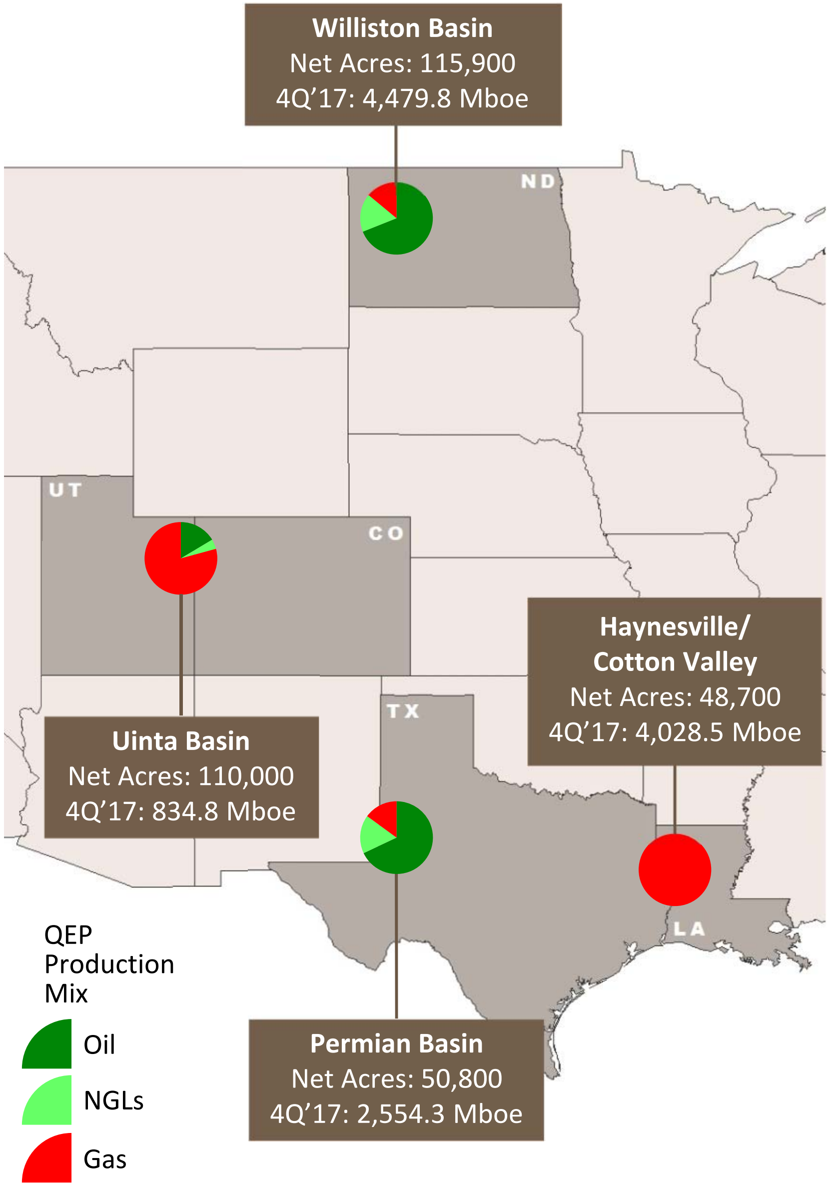
	1Q18	2Q18	3Q18	4Q18	2018
Net Production ***(MMboe)***	2.6 – 2.8	3.3 – 3.5	3.6 – 4.0	4.1 – 4.4	13.6 – 14.7
Net Wells ***(Put on Production)***	18	34	23	20	95
Capex – D&C ***(\$ in mm)***					\$650 - \$700
Capex – Infrastructure ***(\$ in mm)***					\$35 - \$45

Assuming \$55 / bbl and \$3 / MMbtu, we expect the Midland Basin assets to achieve operating cash flow neutrality in 2019 while delivering strong production growth

(1) Netback (a non-GAAP measure) is calculated as oil, natural gas and NGL sales less royalties, production taxes, cash operating expenses and transportation cost and excludes the impact of hedges.

QEP Resources – *4Q 2017 Financial & Operational Overview*

Asset Overview[(1)]



4Q 2017 Highlights

- Total Net Equivalent Production: 12,069.9 Mboe
  - Oil Production: 5,240.6 Mbbl
  - Gas Production: 34.1 Bcf
  - NGL Production: 1,140.9 Mbbl
- Increased net equivalent production in the Permian Basin to a record 27.8 Mboed, a 87% year-over-year increase
- Completed five refracs on South Antelope in the Williston Basin with a nine fold increase in average 30-day incremental oil production
- Increased net equivalent production in the Haynesville/Cotton Valley to 262.7 MMcfed, a 83% year-over-year increase
- Completed the acquisition of approximately 15,100 net acres in the Permian Basin for an aggregate purchase price of $720.7 million, subject to post-closing purchase price adjustments

(1) Equivalent production excludes 283.2 Mboe from Other Northern & Other Southern regions.

QEP Resources – *2018 Guidance*[1]

	2018
Oil Production (MMBbl)	21.0 - 22.5
Gas Production (Bcf)	132.0 - 143.0
NGL Production (MMBbl)	4.7 - 5.2
Total oil equivalent production (MMBoe)	47.7 - 51.5
Lease operating and transportation expense (per Boe)	$9.00 - $10.00
Depletion, depreciation and amortization (per Boe)	$17.50 - $18.50
Production and property taxes (% of field-level revenue)	8.5%
(in millions)	
General and administrative expense[2]	$185 - $205
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip[3]	$965 - $1065
Infrastructure	$50
Corporate	$10
Total Capital Investment (excluding property acquisitions)	**$1,025 - $1,125**

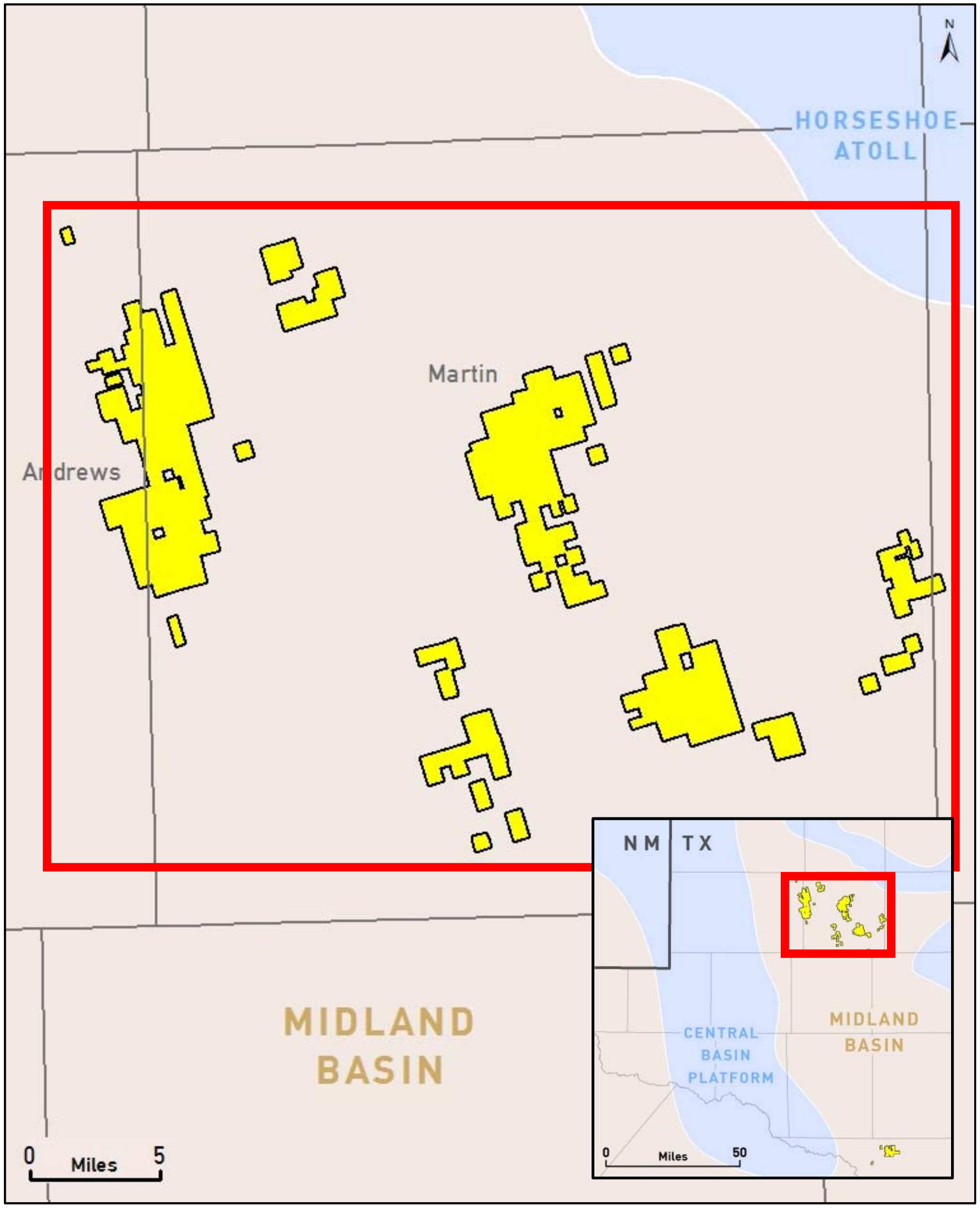
(1) As of February 28, 2018: The Company's guidance assumes no additional property acquisitions or divestitures and assumes that QEP will elect to reject ethane from its produced gas for the entire year where QEP has the right to make such an election. Assumes an average of six rigs for 2018, with an average of five rigs in the Permian Basin and an average of one-half rig operating in each of the Williston Basin and the Haynesville.

(2) General and administrative expense includes approximately $25.0 million of non-cash share-based compensation expense and approximately $20.0 million of estimated retention and severance program expense.

(3) Approximately 65% of the planned capital investment is focused on projects in the Permian Basin. Drilling, Completion and Equip includes approximately $20.0 million of non-operated well completion costs.

Asset Overview

Midland Basin



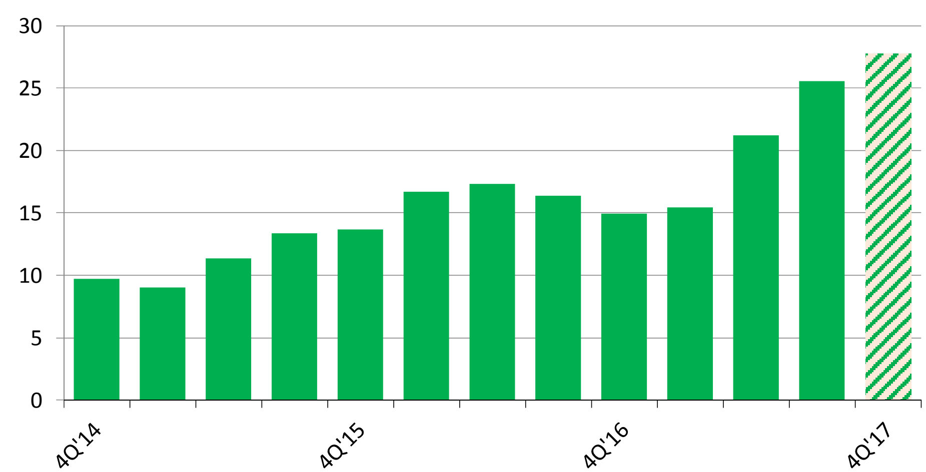
QEP Acreage as of 12/31/2017

Profile(1)

Net acres(2)	50,800
Gross operated producing wells (Vertical/Horizontal)	496/124
Average WI/average NRI	95 / 72%
Proved reserves (MMboe)/% liquids(3)	273 / 88%
Production Split – oil/gas/NGL	75/11/14%
Rig Count	6

(1) As of December 31, 2017
(2) Includes Crockett County leasehold
(3) As of December 31, 2017, SEC Pricing

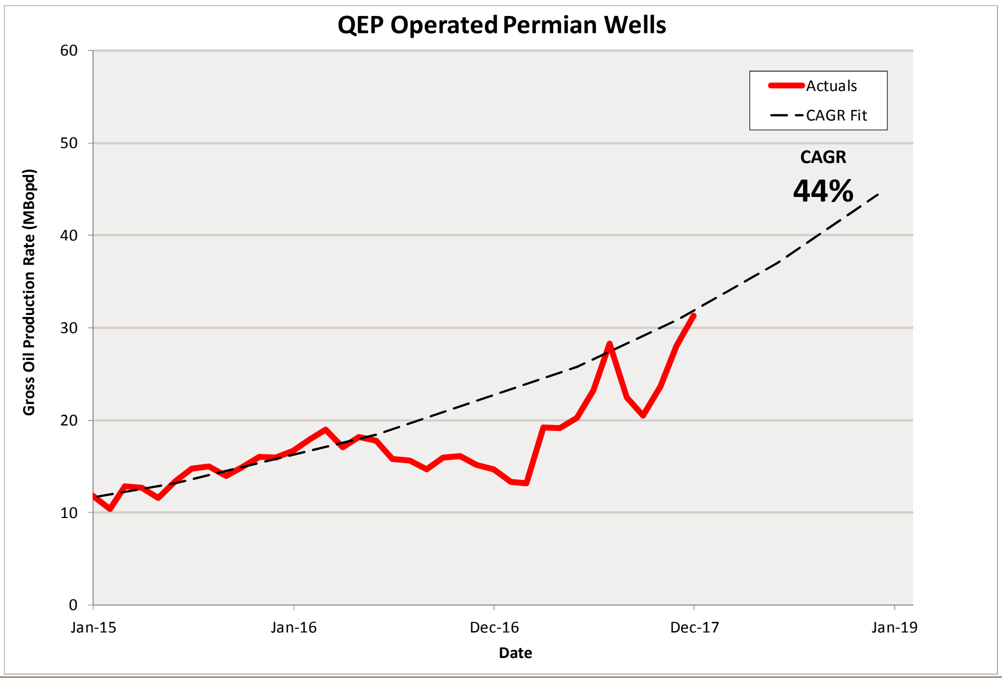
Net Production - Mboed

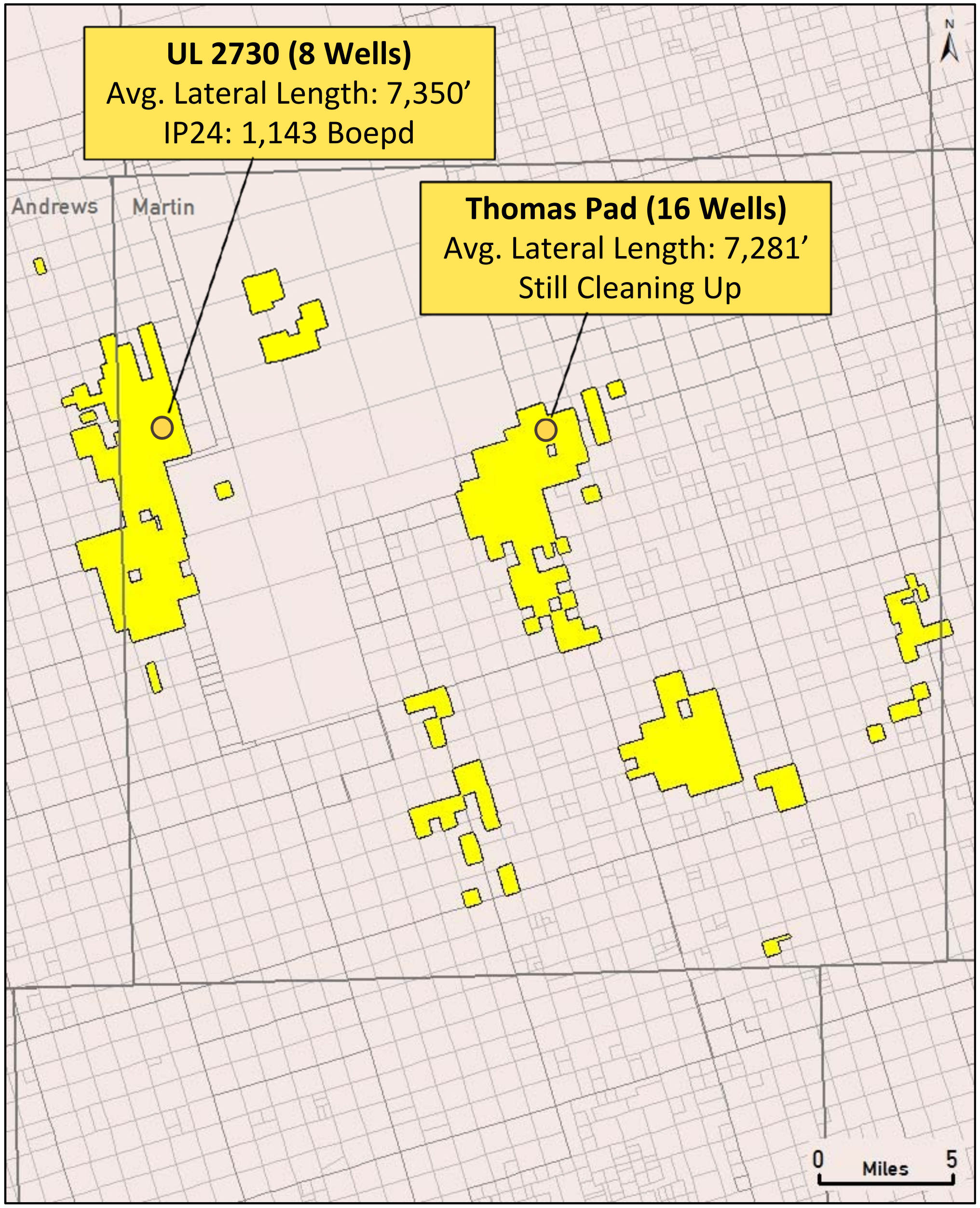


Midland Basin – *4Q 2017 Activity*

- **Completions:** 24
  - Middle Spraberry (6)
  - Spraberry Shale (9)
  - Wolfcamp A (3)
  - Wolfcamp B (5)
  - Lower Spraberry (1)
- **Waiting on Completion / Drilling Summary**

Activity	Middle Spraberry	Spraberry Shale	Wolfcamp A	Wolfcamp B
Waiting on Completion(1)	4	13	5	11
Drilling(2)	2	16	5	6





QEP Acreage as of 12/31/2017

(1) Excludes activity in unproven zones.
(2) Includes 18 wells for which surface casing has been set as of December 31, 2017.

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

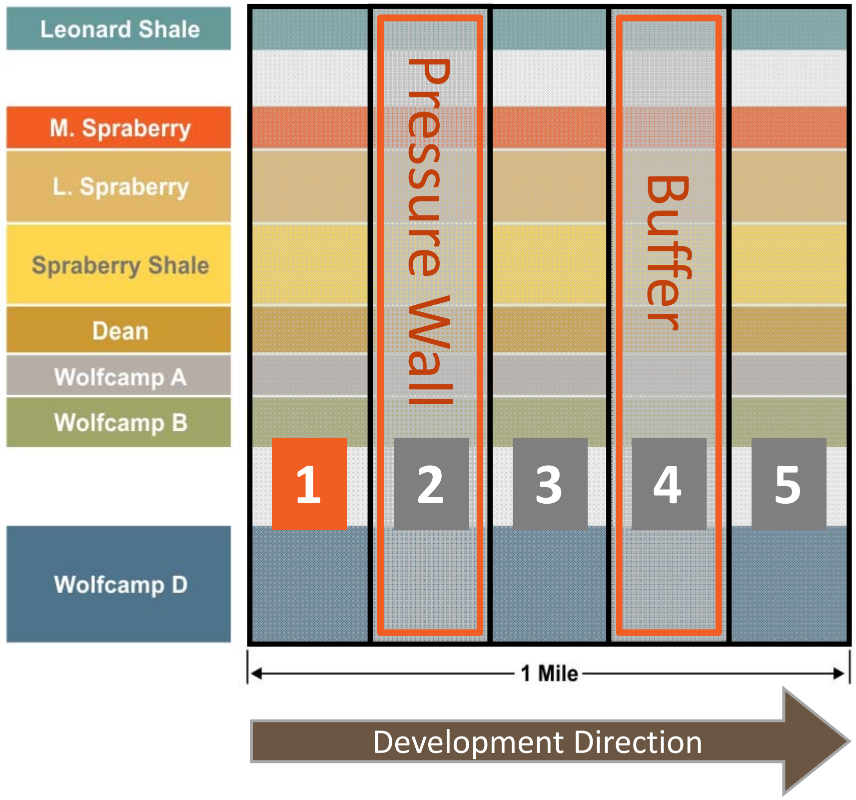
Benefits

Above Ground

- Maximizes 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

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

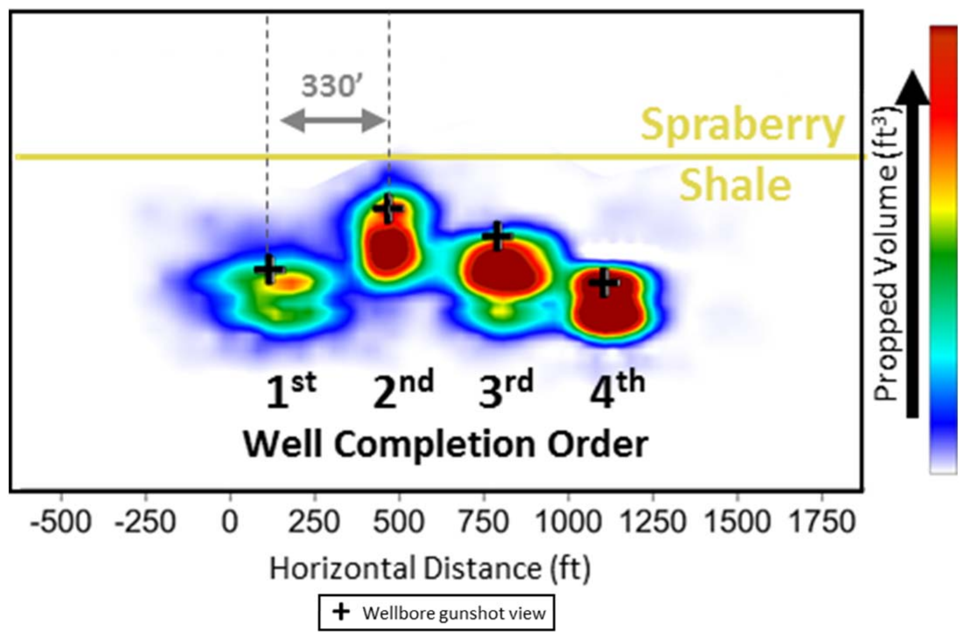


LEGEND:

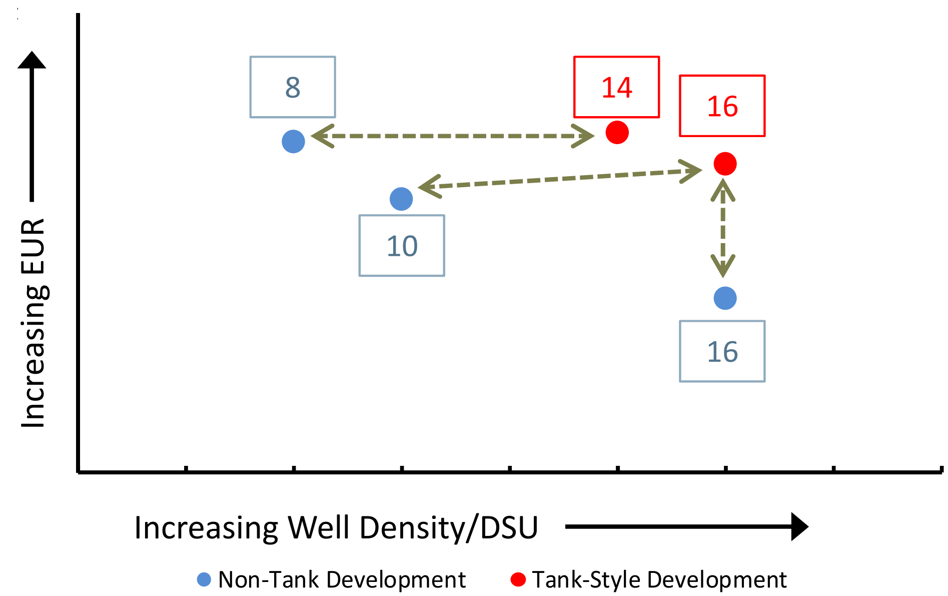
1 Producing wells
2 Completed wells waiting to be turned-to-sales ("Pressure Wall")
3 Wells being completed
4 Wells waiting-on-completion ("Buffer")
5 Wells being drilled

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

Microseismic Study



Tank-Style Proof of Concept



Microseismic Observations

- Increased fracture complexity for wells later in tank-style development sequence
- Evidence of increased stimulated rock volume

Maximization of oil recovery

Tank Style Development Observations

- Increased density impacts are minimized
- Outperforming non-tank development wells
- Extracting more oil per square mile

Development focus on Tank-Style completions

Midland Basin – *Optimization & Pilot Test Results*

	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 →

Optimization & Pilot Test Findings

- Higher initial flowing pressure in tank developed vs. non-tank developed wells
  - *Increased initial pressures realized in all four zones and all densities tested*
- Tank-Style development adds more frac complexity allowing drilling at higher densities
  - *Beyond day 120, oil rates in high-density Spraberry units (8 & 14 wells per mile) exceed that of parent wells*
- Wolfcamp zones show potential for higher densities than initially anticipated
  - *All Wolfcamp A densities tested have outperformed pre-drill expectations*
  - *Early results in Wolfcamp A and B show minimal production impact as a result of increasing well density, as high as 14 wells/mile tested*
- Spraberry Shale and Wolfcamp B zones seeing additional benefit from wine rack targeting within the formation

Midland Basin – *Gas Lift Drives Significant Cost Savings*

QEP Has Shifted to Gas Lift in the Midland Basin

ESP Installation

- *Pros*
  - Potentially higher IP rates
  - No fuel gas required
- *Cons*
  - High capital and operating costs
  - More downtime
  - Later installation
- *Capital Cost(1)*
  - Typical ESP "life-cycle" cost: $800K

Gas Lift Installation

- *Pros*
  - Lower capital and operating costs
  - Less downtime
  - Earlier installation
- *Cons*
  - Must have a gas supply
  - Must have adequate compression
  - Require more engineering up front
- *Capital Cost(1)*
  - Typical gas lift "life-cycle" cost: $500K

Utilization of Gas Lift Significantly Reduces Well Operating Costs

~$300K per well in "life-cycle" savings
~$80K per well of LOE savings in first two years

(1) Estimated.

Midland Basin – *Centralized Infrastructure Benefits*

QEP Operated Centralized Infrastructure Drives Capital & Operating Cost Efficiencies

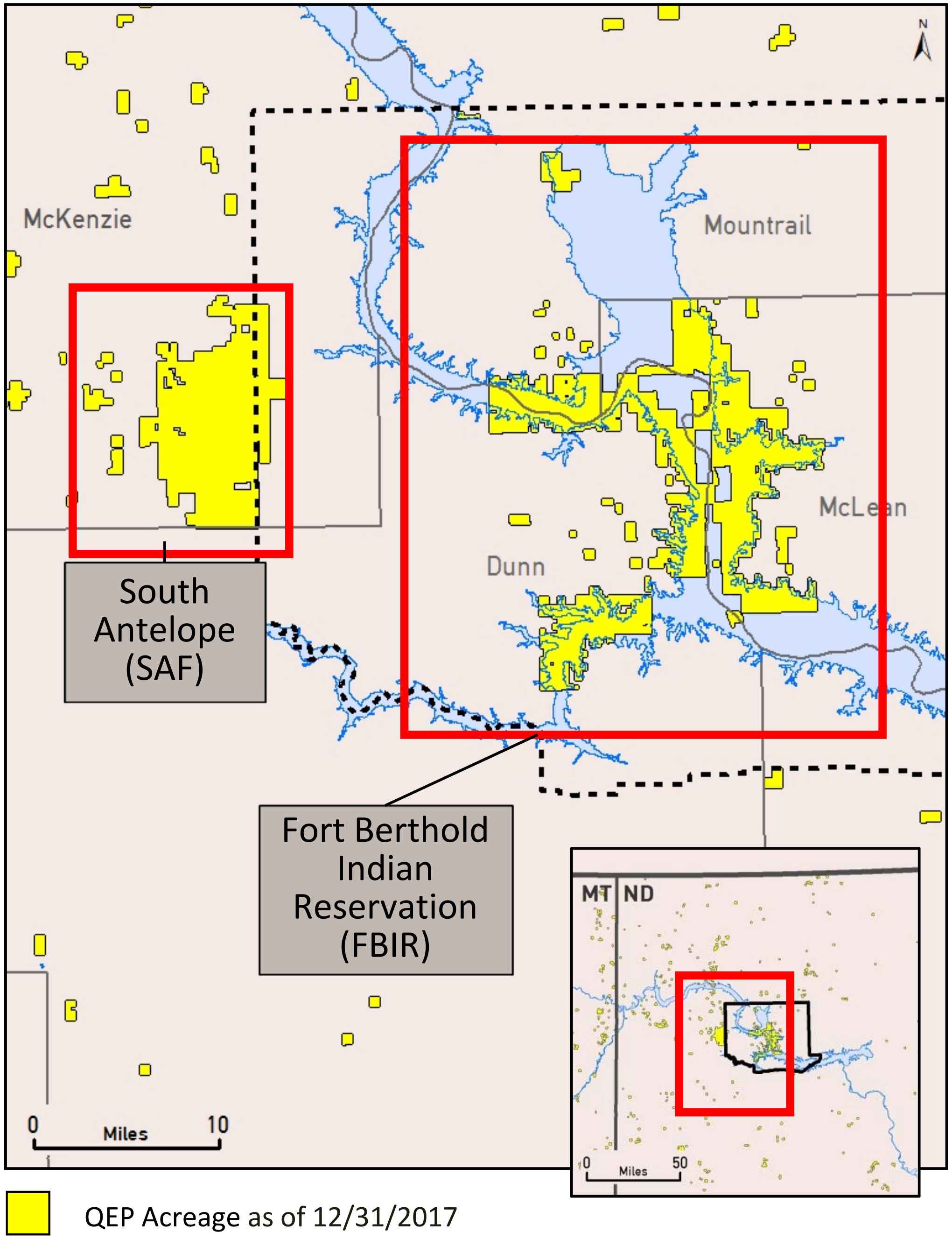
Capital Efficiencies

- $170K per well savings on facilities
- $200K per well savings on well site improvements

Operating Efficiencies

- 20% decease in gas transportation
- 60% reduction in water disposal
- 40% drop in frac water costs
- $0.50/bbl uplift in oil price

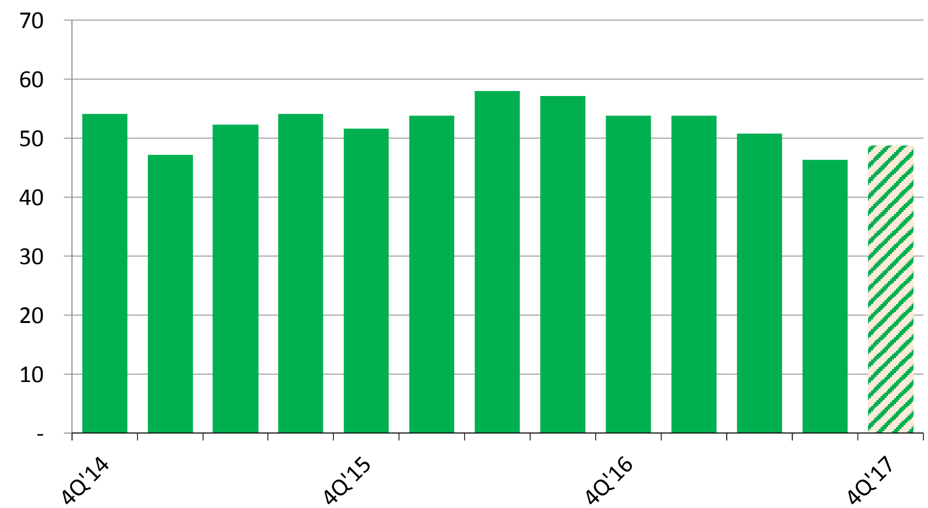
Williston Basin



Profile[1]	
Net acres	115,900
Gross operated producing wells	387
Average WI/average NRI	86/69%
Proved reserves (MMboe)/% liquids[2]	147 / 88%
Production Split – oil/gas/NGL	70/14/16%
Rig Count	1

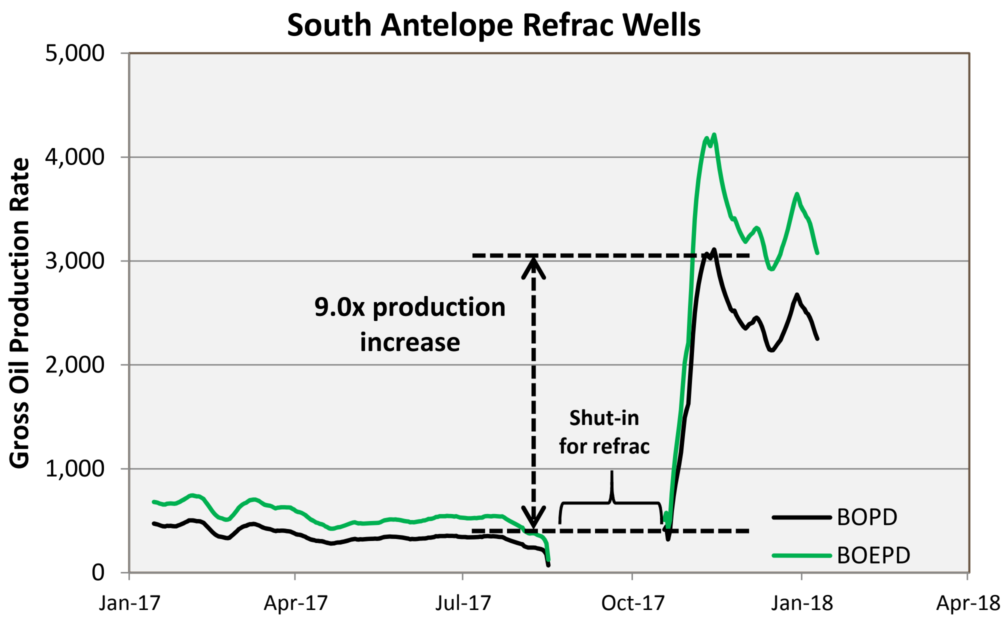
[1] As of December 31, 2017
[2] As of December 31, 2017, SEC Pricing

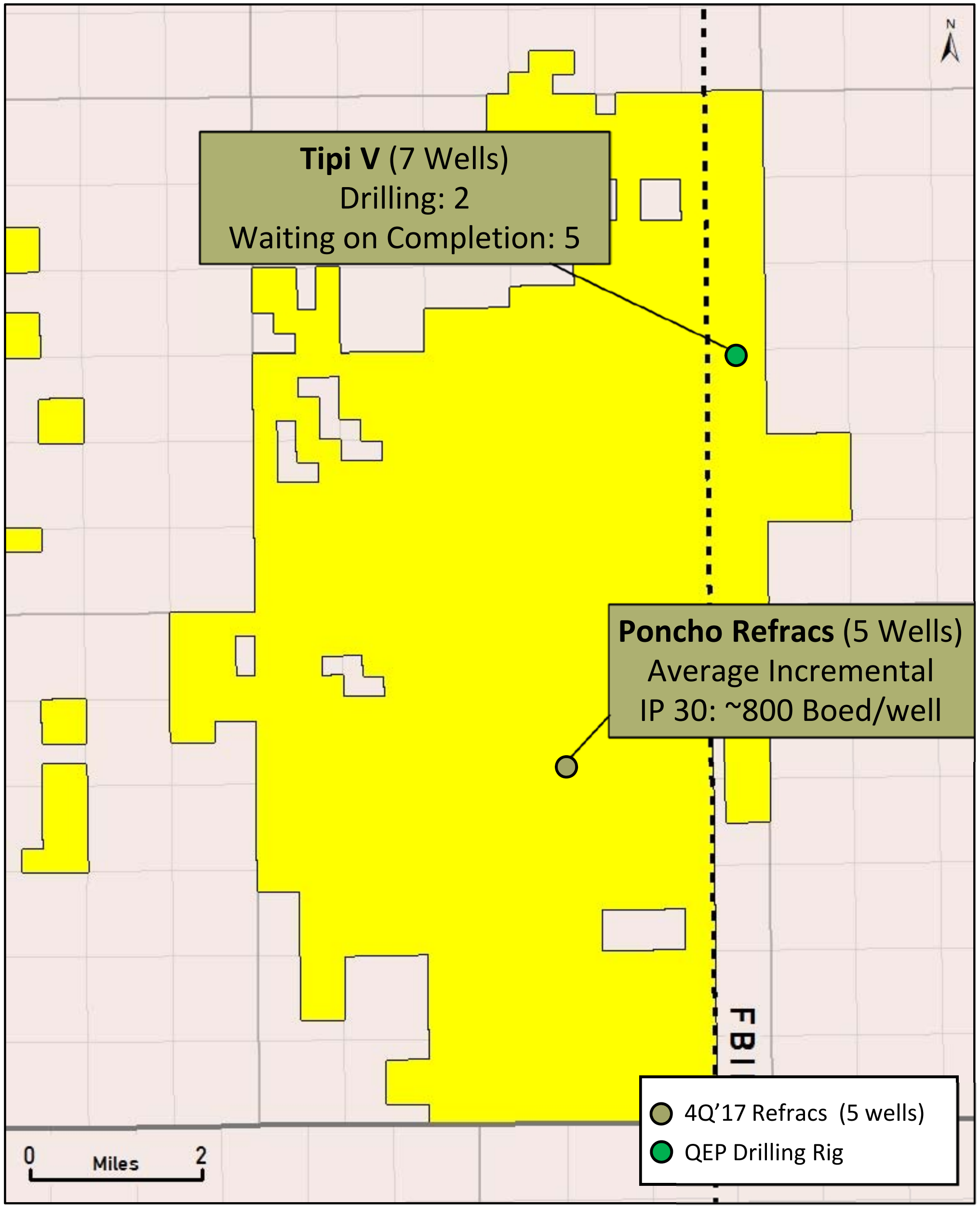
Net Production - Mboed



Williston Basin – *South Antelope 4Q 2017 Activity*

- **Net Acres:** ~ 30,800
- **Rig Count:** 1
- **Completions:** 0
- **Refracs:** 5
- **Waiting on Completion:** 5
  - Bakken (3); Three Forks (2)
- **Drilling:** 2
  - Bakken (1); Three Forks (1)



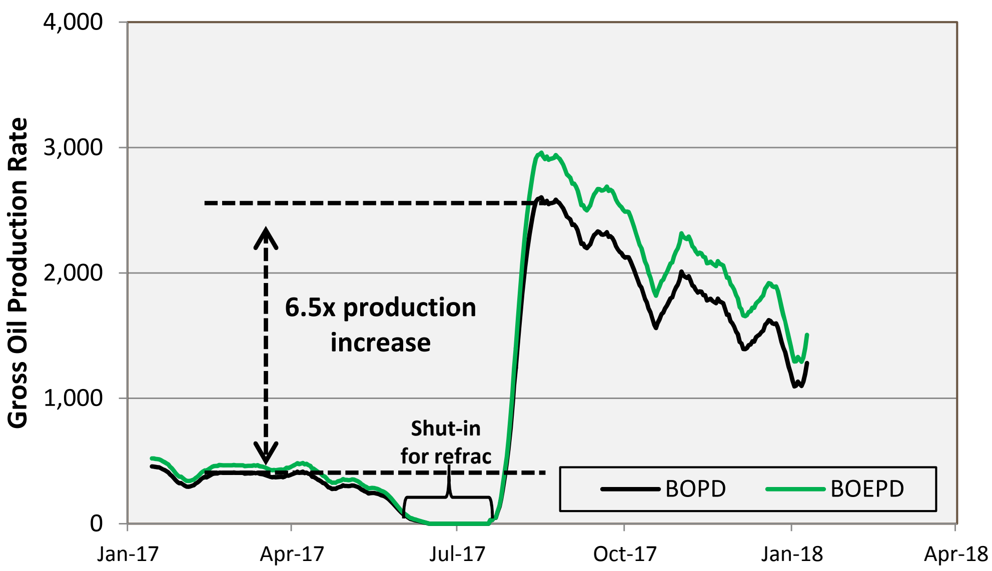


QEP Acreage as of 12/31/2017

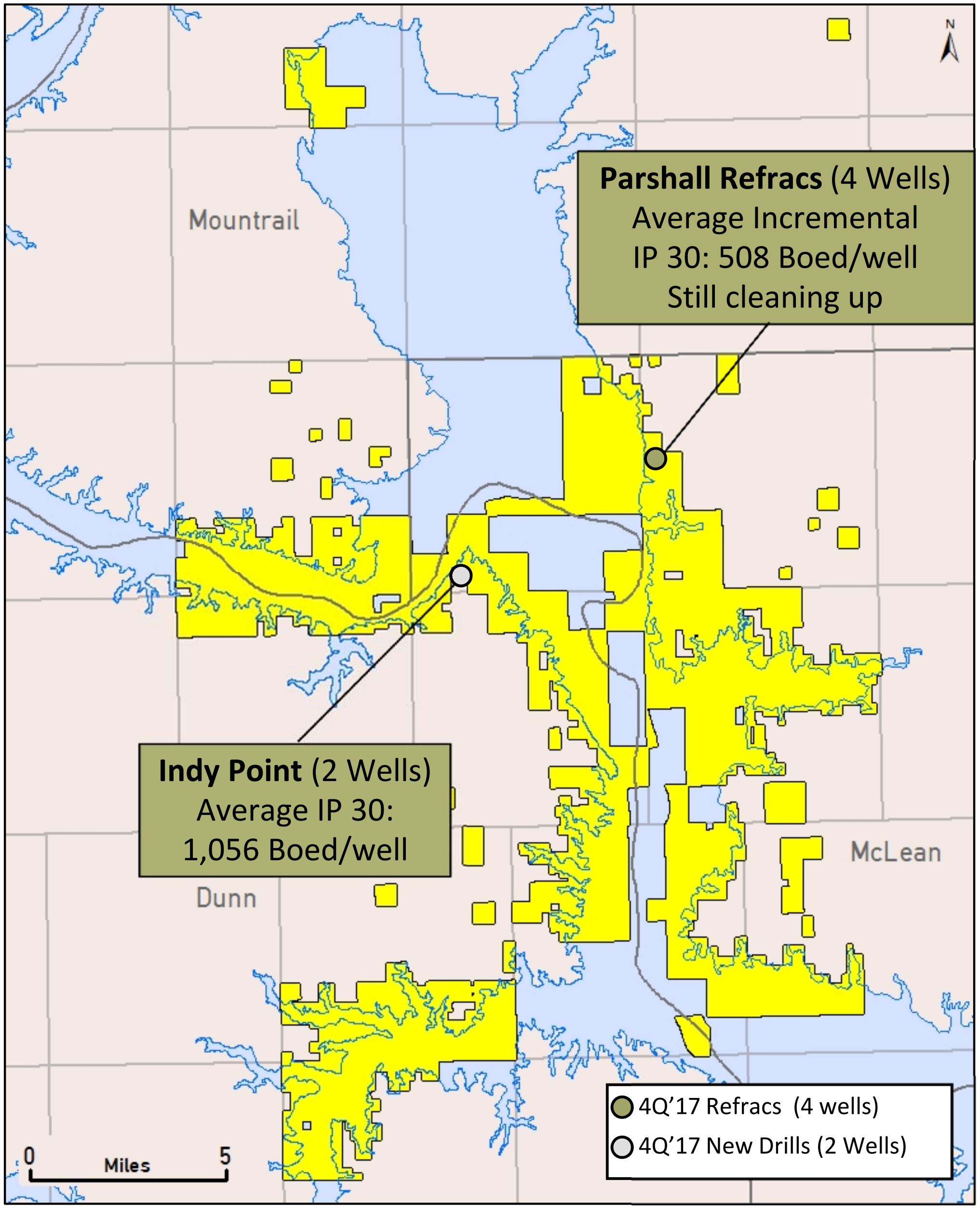
Williston Basin – *FBIR 4Q 2017 Activity*

- **Net Acres:** ~ 66,500
- **Rig Count:** 0
- **Completions:** 2
  - Bakken (1)
  - Three Forks (1)
- **Refracs:** 4
- **Waiting on Completion**: 0
- **Drilling:** 0

Fort Berthold Refrac Wells [1]

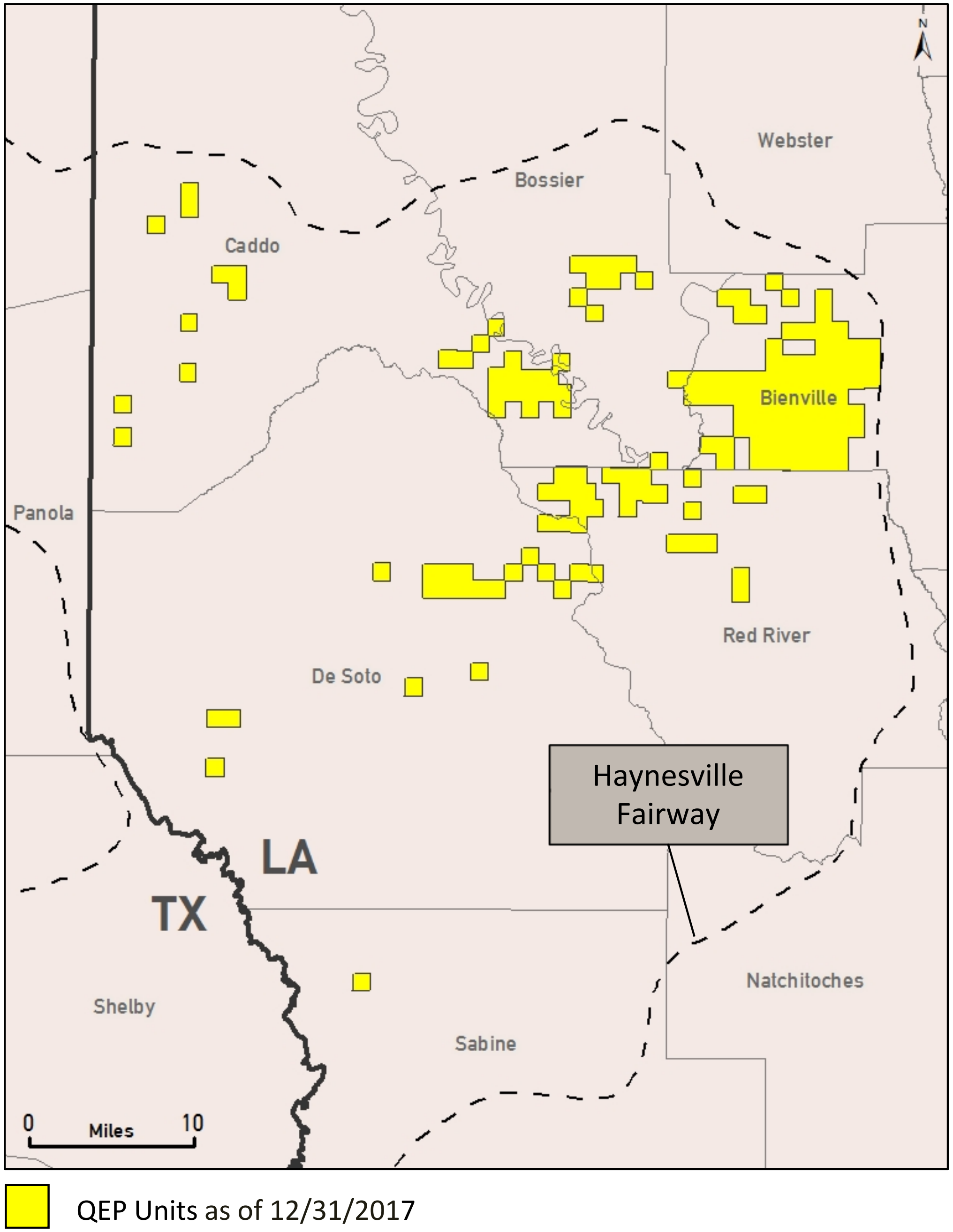


[1] Includes only Late Q3 refracs, Q4 refracs still cleaning up



QEP Acreage as of 12/31/2017

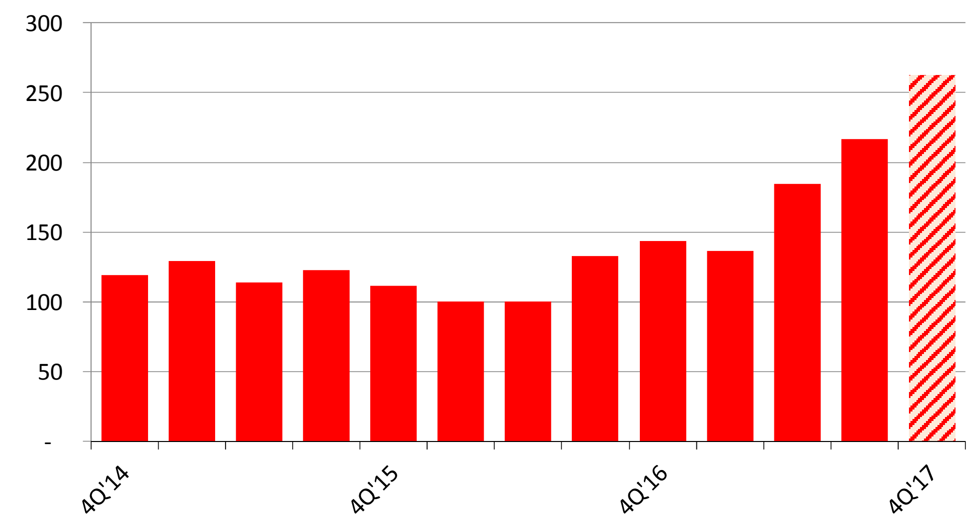
Haynesville



Profile(1)	
Net acres	50,300
Gross operated producing wells(2)	133
Average WI/average NRI(2)	94/72%
Proved reserves (Bcfe)/% liquids(3)	959/ 0%
Production Split – oil/gas/NGL	0/100/0%

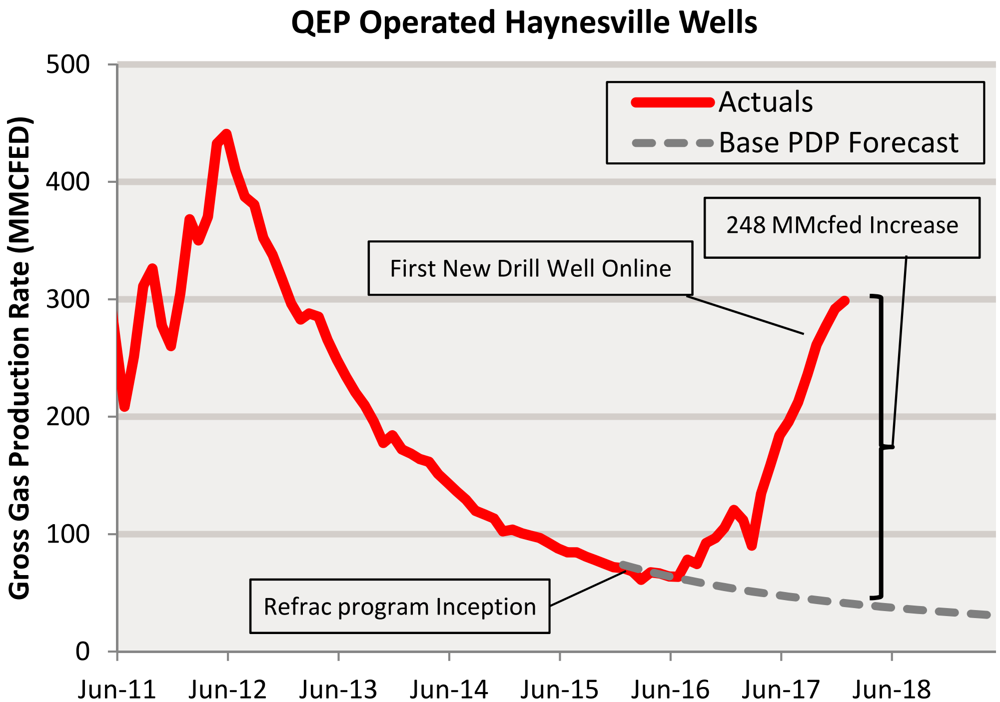
(1) As of December 31, 2017
(2) Includes only Haynesville interval wells
(3) As of December 31, 2017, SEC Pricing

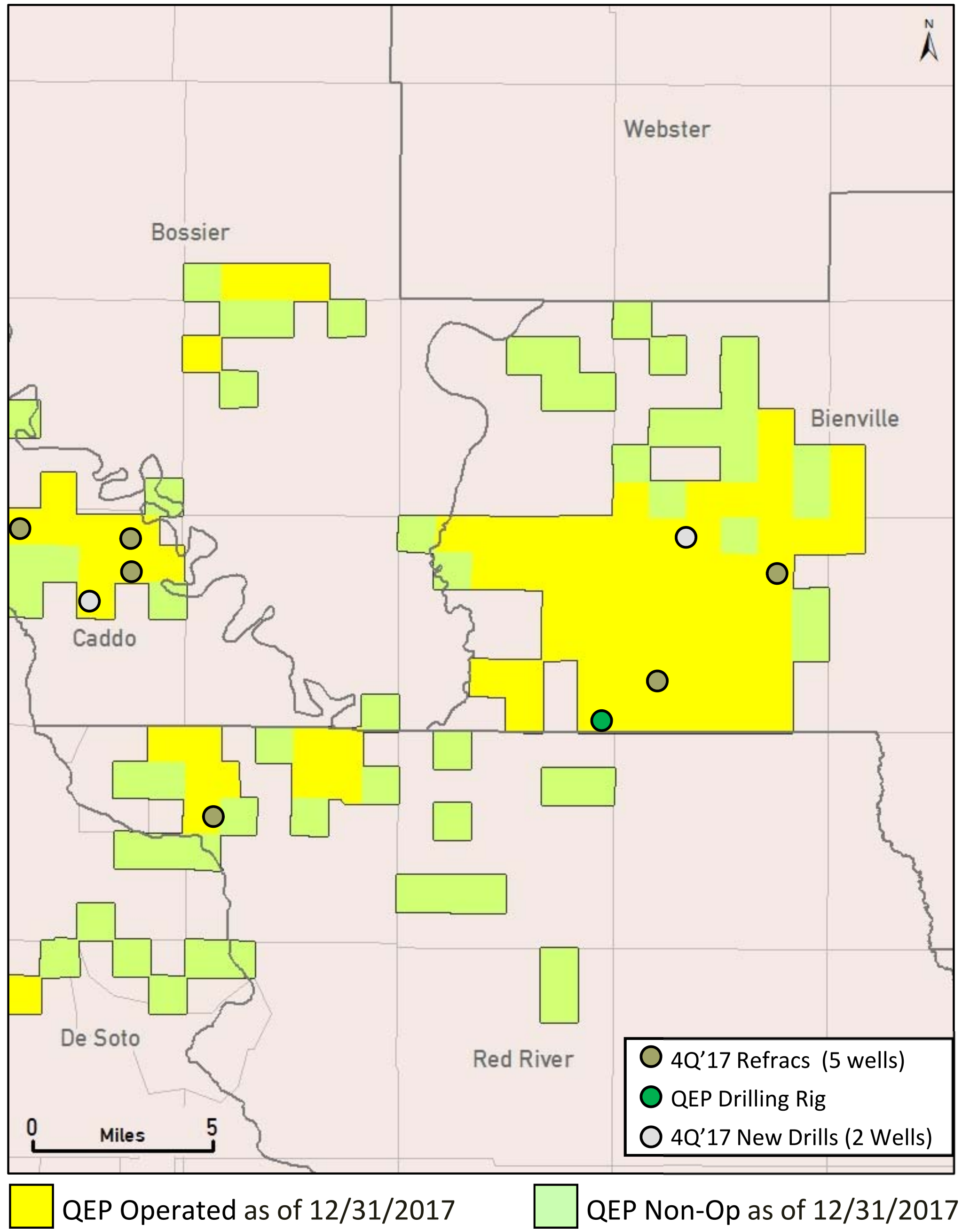
Net Production – MMcfed



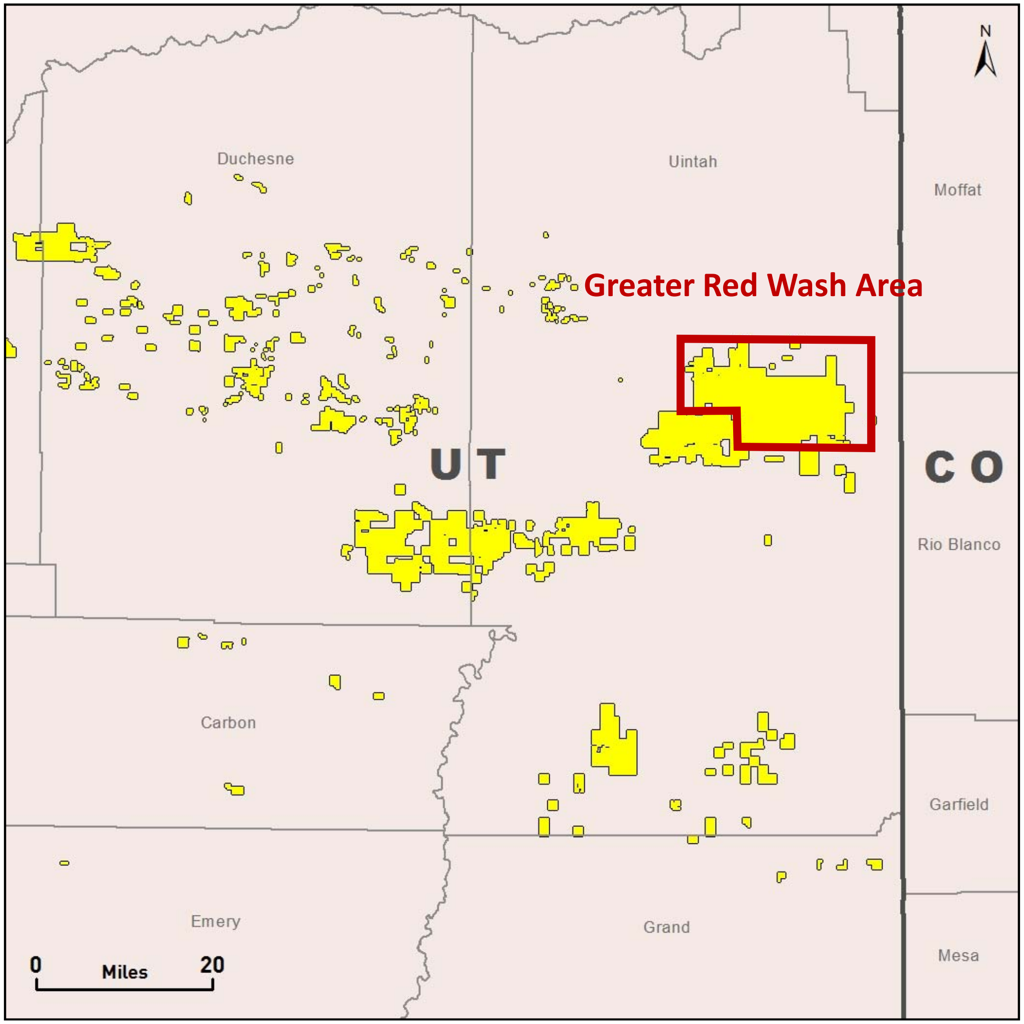
Haynesville – *4Q 2017 Activity*

- Drilled and completed two new wells in 4Q 2017
  - 5,000' new well $IP_{24\ hr}$ of 21.1 MMcfd
  - 10,000' new well cleaning up at quarter end
- Completed five refracs in 4Q 2017 with average refrac incremental 24hr IP of 17.4 MMcfd/well
- Haynesville gross production has increased ~248 MMcfd since activity resumed 2Q 2016





Uinta Basin



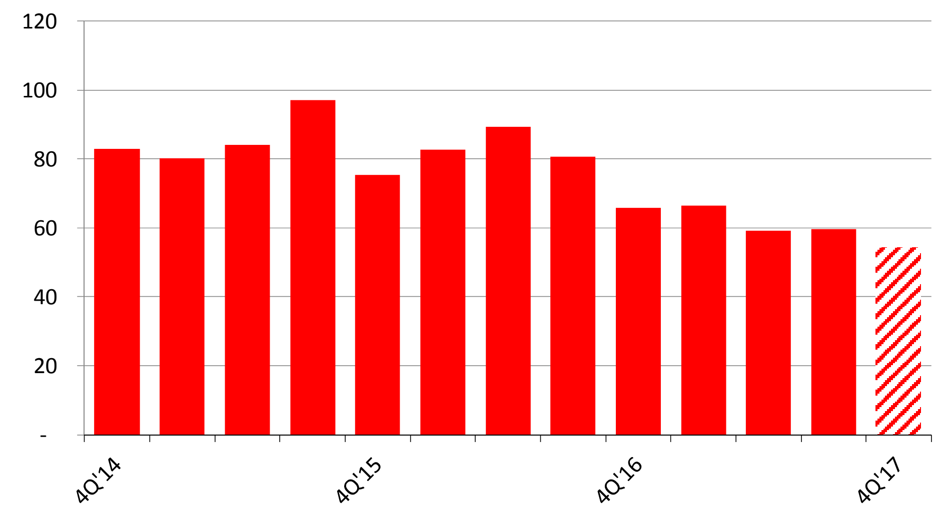
QEP Acreage as of 12/31/2017

Profile(1)

Net acres	230,050(2) 109,986(3)
Gross operated producing wells	754(2), 103(3)
Average WI – Current Producing Wells	84%(2), 98%(3)
Average WI/NRI – Remaining Locations(3)	94/81%
Proved reserves (Bcfe)/% liquids(4)	505/10%
Production Split – oil/gas/NGL(3)	4/91/5%

(1) As of December 31, 2017
(2) Total Uinta Basin
(3) Greater Red Wash Mesaverde Fairway (KJ, Red Wash & South Red Wash)
(4) As of December 31, 2017, SEC pricing Greater Red Wash Mesaverde play only

Net Production - MMcfed



Appendix

Midland & Williston Basins – *Detailed Well Cost Summary*[1]

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	$1.0
	Spraberry Shale	10,000	$6.4	$1.0
	Wolfcamp	7,500	$6.4	$1.0
	Wolfcamp	10,000	$7.8	$1.0
Mustang Springs	Middle Spraberry	7,500	$5.1	$1.0
	Spraberry Shale	7,500	$5.1	$1.0
	Wolfcamp A	7,500	$5.8	$1.0
	Wolfcamp B	7,500	$5.9	$1.0

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	$1.0
FBIR	Middle Bakken / Three Forks	10,000	$6.2	$1.5

(1) As of December 31, 2017

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
- Up to 1,900 potential future drilling locations of 7,500', 10,000', and 12,500' laterals[1]

(1) Excludes zones labeled as upside potential.

QEP Resources – *Derivative Positions*

The following tables present QEP's volumes and average prices for its open production derivative positions as of February 23, 2018:

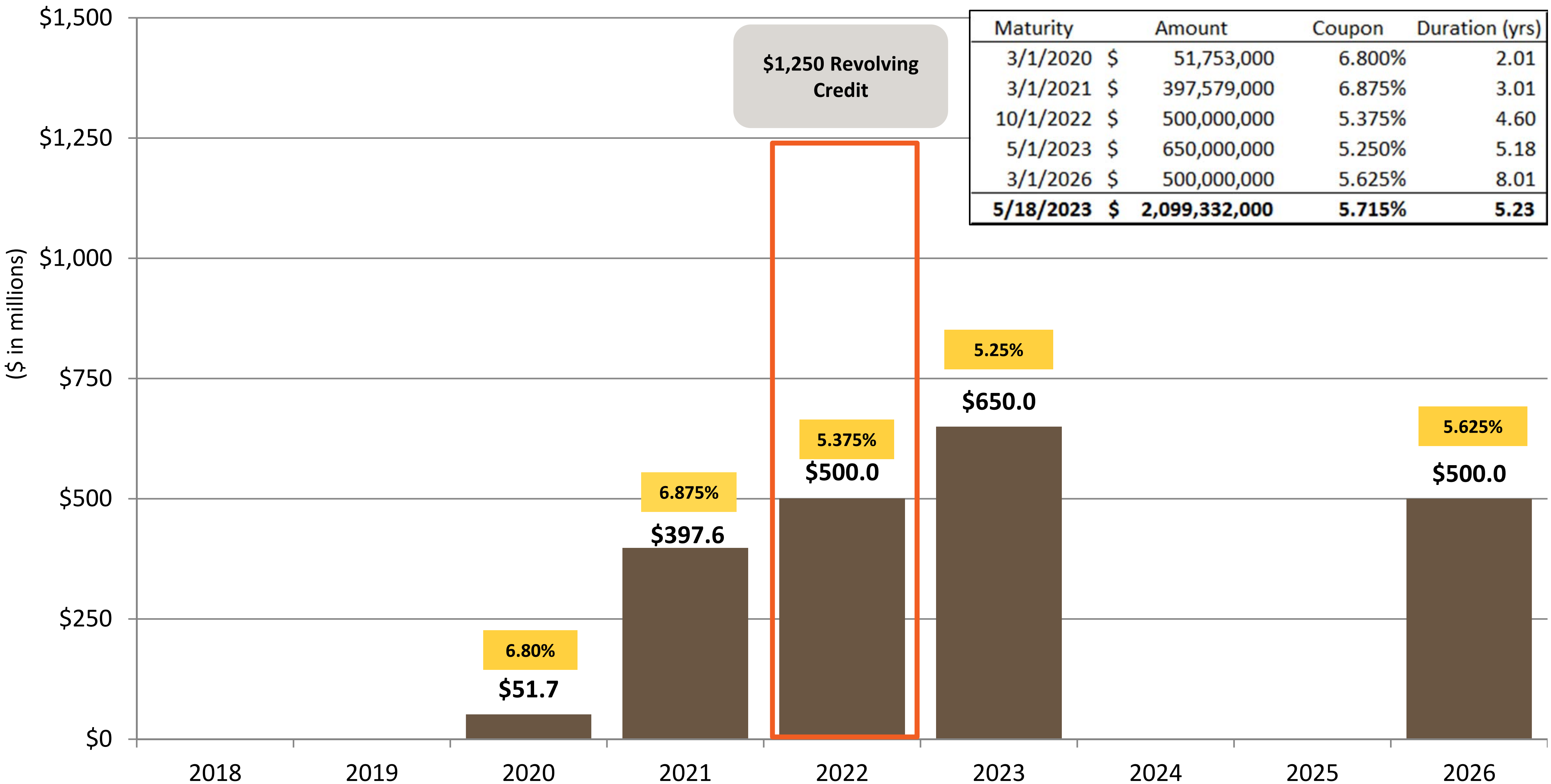
Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2018	NYMEX WTI	15.4	$52.48
2019	NYMEX WTI	9.1	$52.45
Gas Sales		**(million MMBtu)**	**($/MMBtu)**
2018 (Full Year)	NYMEX HH	91.8	$2.99
2018 (July through December)	NYMEX HH	1.8	$3.01
2019	NYMEX HH	43.8	$2.86

Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			**(MMBbls)**	**($/Bbl)**
2018 (Full Year)	NYMEX WTI	Argus WTI Midland[(1)]	6.7	($1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland[(1)]	0.9	($0.71)
2019	NYMEX WTI	Argus WTI Midland[(1)]	4.7	($0.77)
Gas Sales			**(million MMBtu)**	**($/MMBtu)**
2018	NYMEX HH	IFNPCR	6.1	($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 February 26, 2018



Maturity	Amount	Coupon	Duration (yrs)
3/1/2020	$ 51,753,000	6.800%	2.01
3/1/2021	$ 397,579,000	6.875%	3.01
10/1/2022	$ 500,000,000	5.375%	4.60
5/1/2023	$ 650,000,000	5.250%	5.18
3/1/2026	$ 500,000,000	5.625%	8.01
5/18/2023	**$ 2,099,332,000**	**5.715%**	**5.23**