# Investor Presentation

November 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 initiatives; transition to a pure-play Permian Basin company and reasons for such transition; marketing and divestiture of assets; use of proceeds from asset sales; Permian Basin development program and the Midland Basin assets reaching cash flow neutrality in 2019 while delivering strong production growth; factors impacting share repurchases; percentage of 2018 drilled wells with 10,000 foot laterals; timing and total number of wells put on production and estimated production during the quarter and year ended December 31, 2018; 2018 netback per boe; estimated LOE and Adjusted transportation expenses and percentage decreases in the total of such expenses; percentage growth in production; estimated proved reserves; estimated production split among oil, gas and NGL; well density assumptions; large upside opportunity in proven and unproven zones; ethane recovery and rejection; water recycling capacity in the Midland Basin and anticipated benefits of water infrastructure in the Permian Basin; planned benefits of centralized infrastructure; crude oil marketing strategy, including the use of physical sales contracts to secure firm takeaway capacity in the Permian Basin; estimated percentage of 2018 and 2019 marketed Permian oil production covered by term sales agreements; number, and lateral lengths of, potential future horizontal drilling locations; number of remaining risked drilling locations and refrac candidates in the Williston Basin; number and location of drilling rigs; anticipated benefits of tank-style development; maximizing production and economic recovery of oil; minimizing risk of interference and shut-in times; quarterly and annual guidance regarding production; guidance for 2018 Adjusted LOE and Adjusted transportation expense, DD&A, production and property taxes, general and administrative expense, non-cash share-based compensation expense, restructuring expense, and capital investment; and assumptions related to our guidance; and industry-leading drilling, completion and equipment costs and lease operating expense.

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; value of the U.S. dollar; actions of federal, state, local and tribal governments, foreign countries and the Organization of Petroleum Exporting Countries; timing of and actual proceeds from asset sales; actions of activist shareholders; tariffs on products QEP uses in its operations or sells; 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; transportation constraints, including gas and crude oil pipeline takeaway capacity in the Permian Basin; 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; creditworthiness of counterparties to agreements; 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 (2017 Form 10-K) and Quarterly Reports on Form 10-Q filed in 2018 (2018 Form 10-Q’s). 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. “EURs” or “estimated ultimate recoveries” refer to QEP’s internal estimates of hydrocarbon quantities that may be potentially recovered and are not proved, probable or possible reserves within the meaning of the rules of the SEC. Probable and possible reserves and EURs 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, including gas and crude oil pipeline takeaway capacity; 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 and 2018 Form 10-Q’s.

QEP refers to Adjusted transportation expense, netback 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 Initiatives Update*

**Divesture of the Company's Williston and Uinta basin assets**

- ✓ *Entered into a definitive agreement to sell Williston Basin assets for up to $1.725 billion, subject to purchase price adjustments**
- ✓ *Closed Uinta Basin divestiture for net cash proceeds of $153 million on September 6, 2018*

**Marketing of QEP's remaining non-Permian assets in the second half of 2018**

- ✓ *Continued to progress discussions with interested parties for full divestment of the Company's Haynesville/Cotton Valley assets*
- ✓ *Received net cash proceeds of $64.5 million related to the divestiture of non-core properties in 2018*
- ✓ *Reduced headcount by approximately 30% since March 1, 2018 to present, as the Company transitions to a pure-play Permian Basin company*

**Use of proceeds from asset sales to fund Permian Basin development program (1), reduce debt and return cash to shareholders through share repurchases**

- ✓ *Reduced debt outstanding by $200 million using proceeds from asset sales and excess cash-flow from operations*

**Authorized a $1.25 billion share repurchase program (2)**

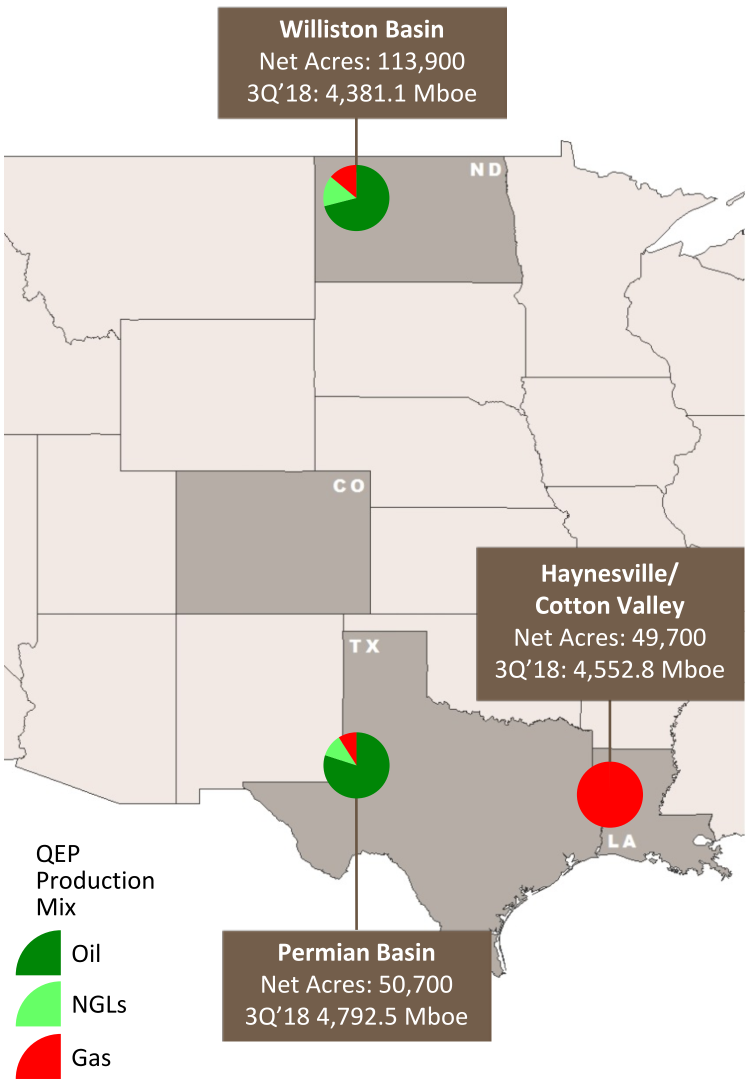
- ✓ *Repurchased a total of 6.2 million shares at a weighted average share price of $9.37 for $58.4 million*

* The purchase price is comprised of $1.65 billion in cash and contractual rights to receive up to $50 million and $25 million in the buyer's common stock if the daily volume weighted average trading price of the buyer's common stock for 10 out of 20 consecutive trading days is at or above $12 per share and $15 per share, respectively. QEP shall be entitled to the equity consideration if the share price thresholds are met at any time during the five year period following closing of the transaction.

(1) Until the program reaches operating cash-flow neutrality in 2019
(2) Subject to available liquidity, market conditions and proceeds from asset sales.

# QEP Resources – *3Q 2018 Financial & Operational Overview*

## Asset Overview(1)




## 3Q 2018 Highlights

- Total Net Equivalent Production: 14,400.0 Mboe
  - Oil Production: 6,640.5 Mbbl
  - Gas Production: 38.1 Bcf
  - NGL Production: 1,415.3 Mbbl
- Delivered record quarterly oil production of 6.6 MMbbls, including a record 3.5 MMbbls in the Permian Basin
- Decreased Permian Basin lease operating expense (LOE) to $4.42 per Boe, a 31% year-over-year decrease
- Increased 2018 oil and condensate production guidance to 24.0 MMbbl(2)
  - Reflects improved efficiencies in the Permian Basin and better than forecasted results in the Williston Basin
  - Despite the loss of 0.2 MMbbl of production associated with Uinta Basin divestiture
- Increased full year 2018 capital expenditure guidance by 4% at the midpoint:
  - Includes additional wells drilled and put on production in the Permian Basin as a result of efficiency gains
  - Includes additional refrac activity in the Williston Basin
- Secured Permian Basin flow assurance, via sales agreements with refiners and marketers, on more than 90% of current and projected gross oil volumes for the remainder of 2018 and for 2019
- Closed Uinta Basin divestiture on September 6, 2018

(1) Equivalent production excludes 67.6 Mboe from Other Northern & Other Southern regions.
(2) Midpoint of Company oil & condensate production guidance as of November 7, 2018.

# QEP Resources – *Updated 2018 Guidance*(1)

| | 2018 |
|---|---|
| Oil & Condensate Production (MMBbl) | 23.75 -24.25 |
| Gas Production (Bcf) | 136.0 - 140.0 |
| NGL Production (MMBbl) | 4.38 - 4.63 |
| Total oil equivalent production (MMBoe) | 50.8 - 52.2 |
| | |
| Adjusted lease operating and transportation expense (per Boe) | $8.00 - $9.00 |
| Depletion, depreciation and amortization (per Boe) | $16.75 - $17.75 |
| Production and property taxes (% of field-level revenue) | 8.5% |
| | |
| **(in millions)** | |
| General and administrative expense(2) | $215 - $225 |
| | |
| Capital investment (excluding property acquisitions) | |
| Drilling, Completion and Equip(3) | $1,095 - $1,145 |
| Midstream(4) | $40 |
| Corporate | $5 |
| **Total Capital Investment (excluding property acquisitions)(5)** | **$1,140 - $1,190** |

(1) As of November 7, 2018: The Company's updated guidance includes no additional adjustment for property acquisitions or divestitures, other than the Uinta Basin Divestiture which closed in September 2018, and assumes that QEP will elect to recover ethane from its produced gas for the remainder of the year in the Permian Basin where processing economics support ethane recovery. Assumes an average of four rigs and one frac crew in the Permian Basin in the fourth quarter 2018, and no additional rig activity in any of the Company's operating areas for the remainder of 2018.

(2) General and administrative expense includes approximately $35.0 million of non-cash share-based compensation expense and approximately $35.0 million of estimated restructuring expense.

(3) Approximately 70% 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. Includes capital expenditures associated with water sourcing, gathering, recycling and disposal in the Permian Basin.

(4) Includes crude oil and natural gas gathering capital expenditures in the Permian Basin and Haynesville/Cotton Valley.

(5) Increased full year 2018 capital expenditure guidance as a result of improved operational efficiencies, which the Company expects to result in 17 additional net wells being drilled and 10 additional net wells put-on-production, and an increase in the Company's working interest in acreage acquired through acquisitions and acreage swaps, in the Permian Basin during the year. The increase was partially offset by seven less net refracs put on production in the year than originally forecast.

# QEP Resources – *Permian Basin Pure-Play Strategic Rationale*

**True "black-oil" play**

- Midland Basin is a crude oil dominant province
- Current production stream from QEP wells is approximately 74% crude oil, 11% natural gas and 15% NGL (38-40 API gravity, ultra low sulfur content)

**QEP acreage is situated in the "sweet spot" of the Midland Basin**

- Supported by reservoir mapping and well performance
- Acreage selected for high original oil in place, low water cut and high percentage of crude oil in well stream
- Superior quality oil with high distillate yield

**Concentrated / contiguous acreage position**

- Compact foot print minimizes infrastructure development - oil, gas, gathering, water, roads, pads, etc.
- No material continuous drilling obligations or held-by-production requirements allows orderly development with tank-style approach

**Stacked reservoir targets**

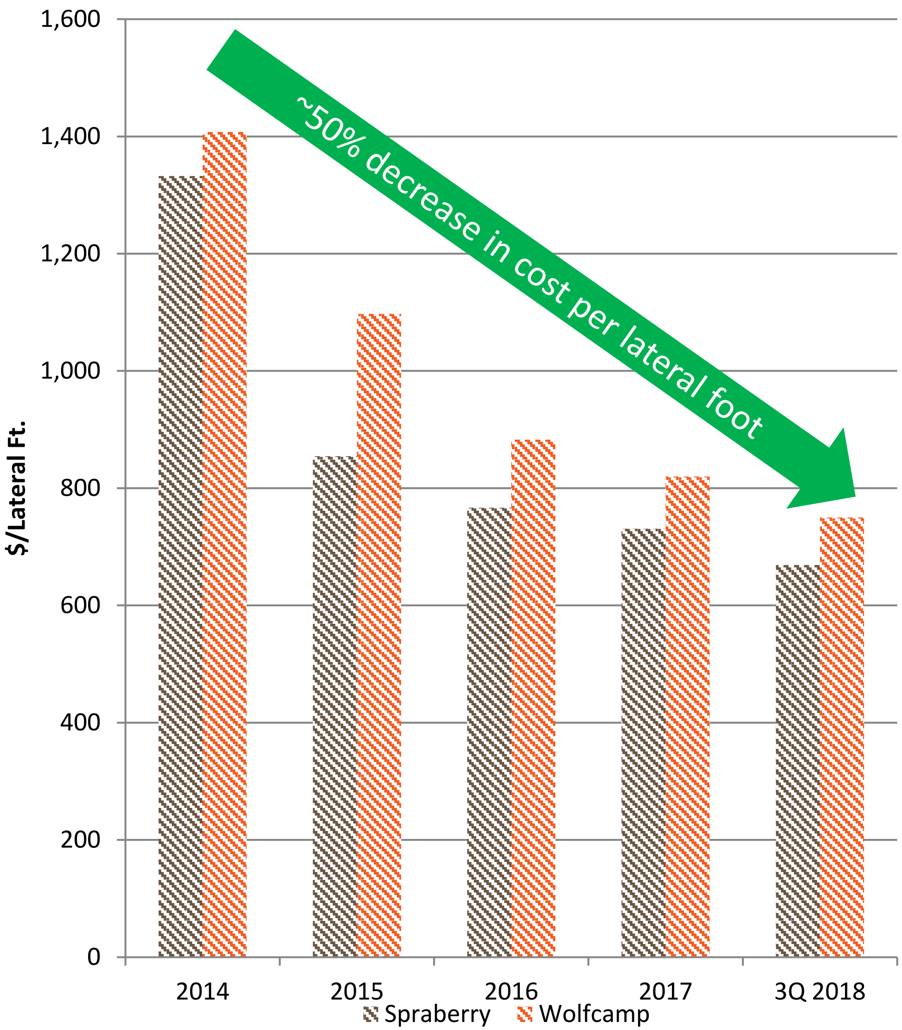
- Laterally continuous
- Well suited for 'tank-style' completion technique

**Multiple potential horizontal development targets**

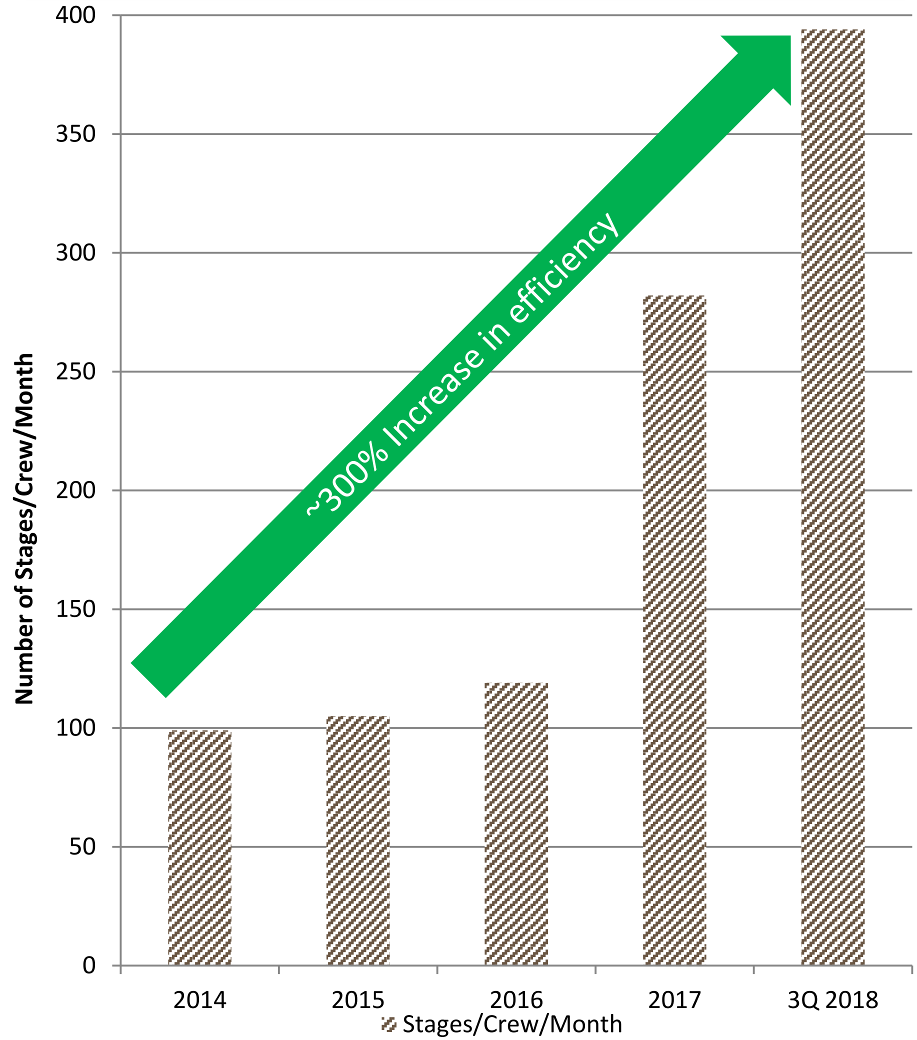
- Supports pad drilling and 'hole manufacturing'
- Significant upside to inventory of development drilling locations

# Midland Basin – *Delivering Industry-Leading Completed Well Cost*

## Driving down DC&E costs per lateral foot




## Best-in-class frac crew efficiency [1]

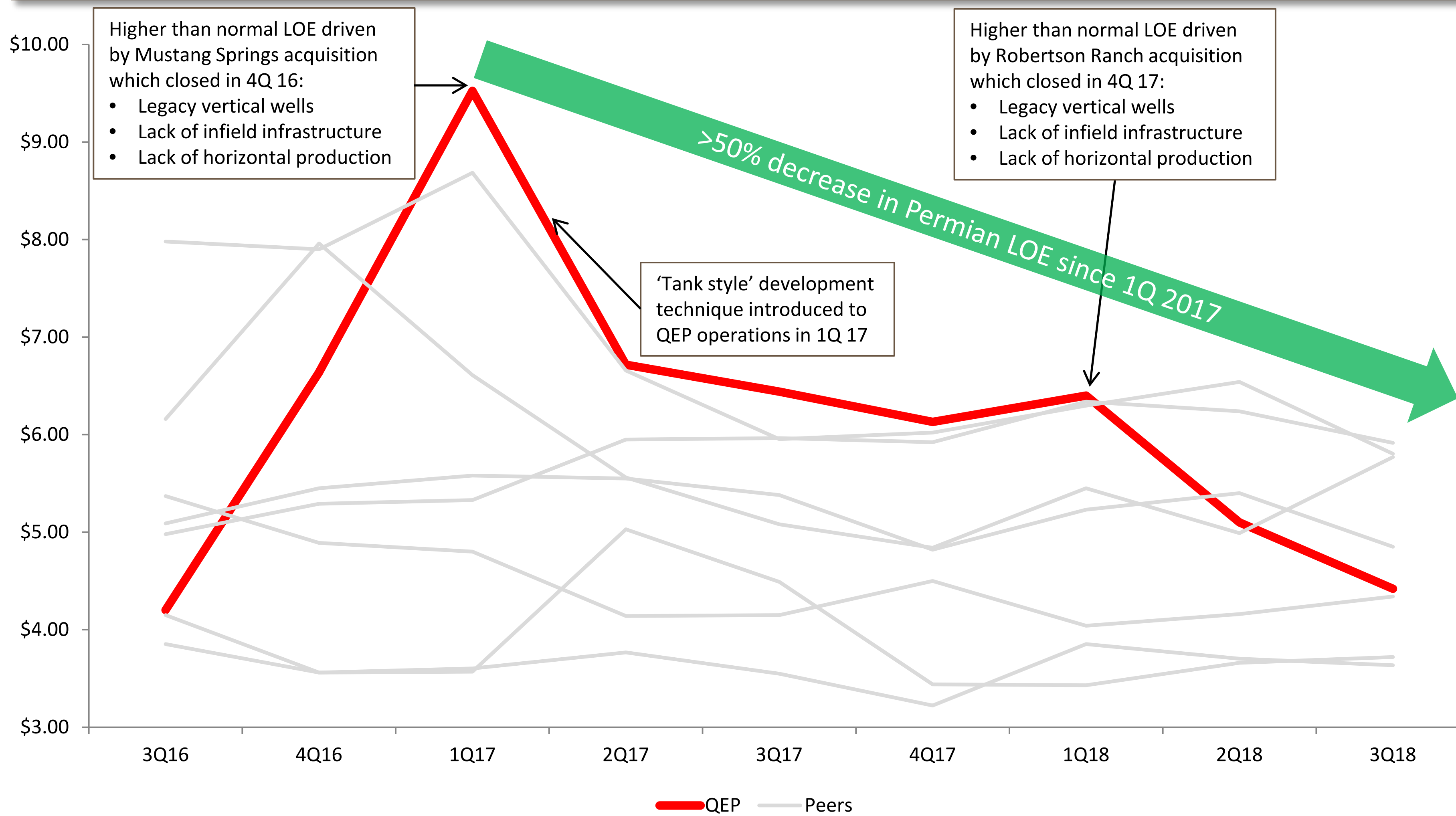



*Acreage footprint combined with some of the best geology in basin allows industry leading DC&E costs*

(1) Determined by using days crew conducting operations for QEP vs. active frac days.

# Midland Basin – *Driving Lower LOE*

## Permian LOE Trend vs. Peers[1]



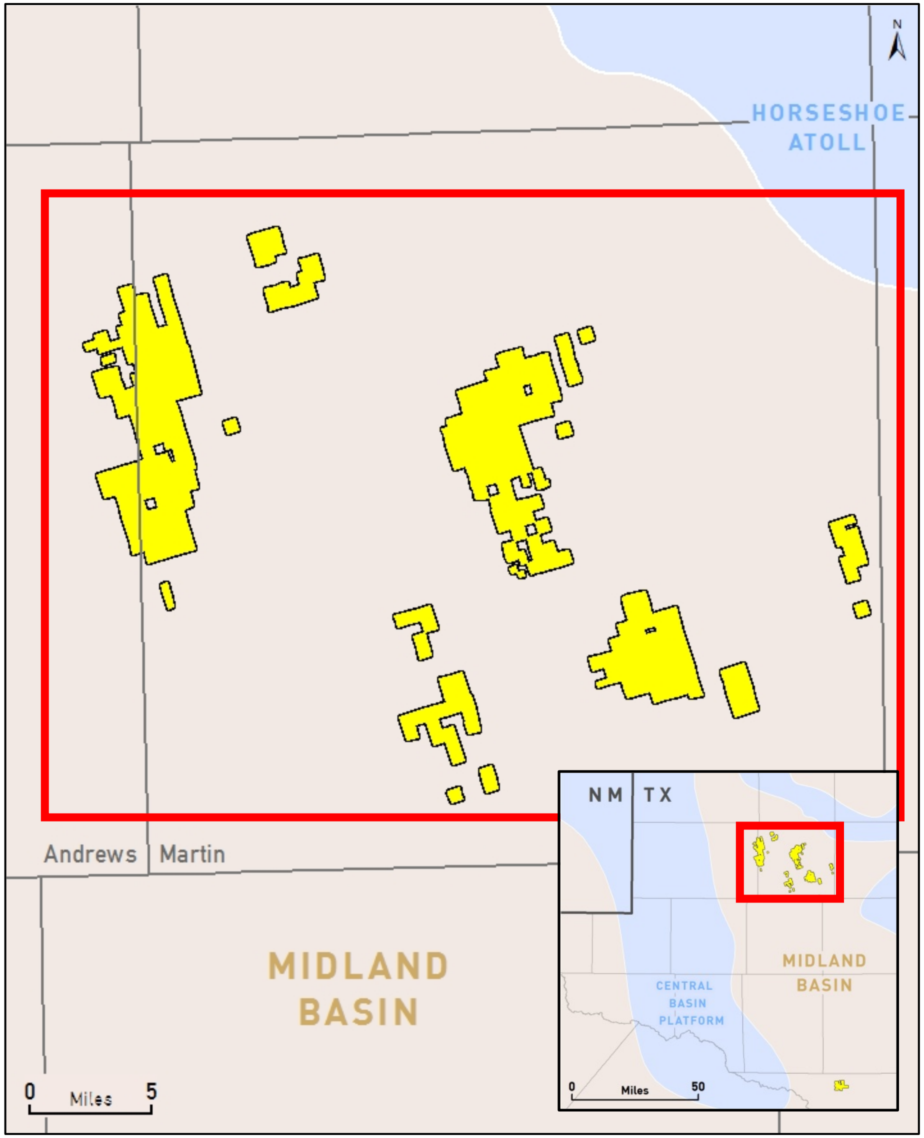

***'Tank-style' development technique and full field development is leading to lower LOE***

(1) Peers include: CPE, CXO, EGN,FANG, LPI, PE, & PXD

Source: Company filings

# Asset Overview

# Midland Basin



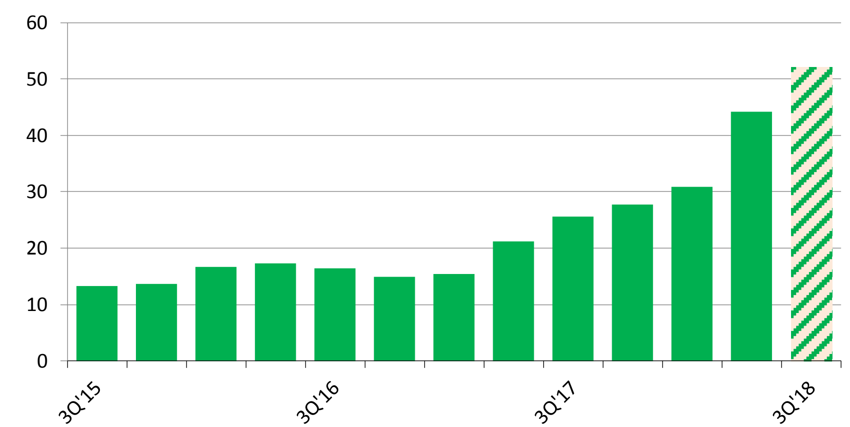

QEP Acreage as of 9/30/2018

## Profile[1]

| | |
|---|---|
| Net acres[2] | 50,700 |
| Gross operated producing wells (Vertical/Horizontal) | 476/214 |
| Average WI/average NRI | 97 / 73% |
| Proved reserves (MMboe)/% liquids[3] | 273 / 88% |
| Production Split – oil/gas/NGL | 74/11/15% |
| Rig Count | 4 |

(1) As of September 30, 2018
(2) Includes Crockett County leasehold
(3) As of December 31, 2017, SEC Pricing

## Net Production - Mboed

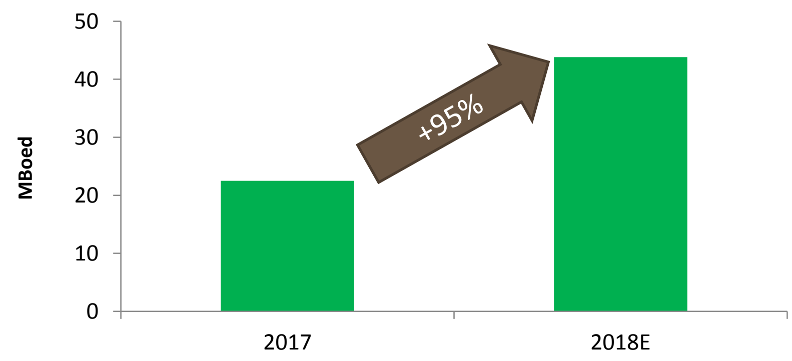


# Midland Basin – *Outlook*

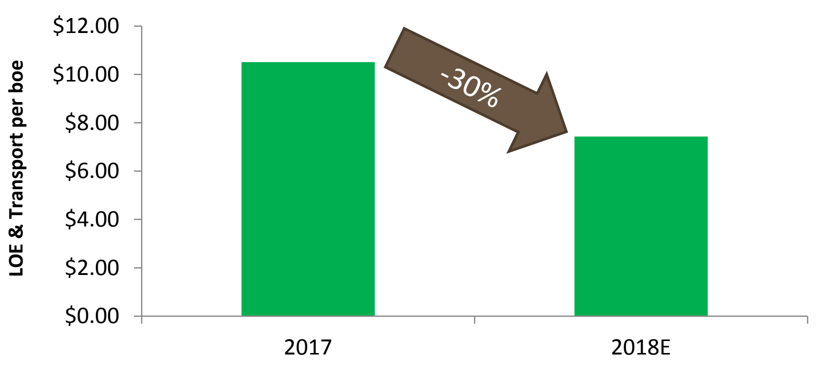
## 2018 Key Statistics

- Average of four and three-quarter operated rigs
- $800 - $820 million in drilling, completion & equip capital
- $35 million of midstream capital
- Up to 1,900 potential future horizontal drilling locations of 7,500' to 12,500' lateral length[1]
- Over 40% of wells put on production in 2018 to have 10,000'+ laterals
- ~$40 per Boe 2018 netback at current strip pricing[2]

## Production Profile




## LOE and Transportation Expense Target




## 2018 Outlook

| | 1Q18 Actual | 2Q18 Actual | 3Q18 Actual | 4Q18 Est. | 2018 Est. |
|---|---|---|---|---|---|
| **Net Production** ***(MMboe)*** | *2.8* | *4.0* | *4.8* | 4.2 – 4.6 | 15.8 – 16.2 |
| **Net Wells** ***(Put on Production)*** | *31* | *36* | *21* | 17 | 105 |
| **Capex – D, C & E *** ***($ in mm)*** | | | | | $800 - $820 |
| **Capex – Midstream** ***($ in mm)*** | | | | | $35 |

* D, C & E includes capital expenditures associated with water sourcing, gathering, recycling and disposal

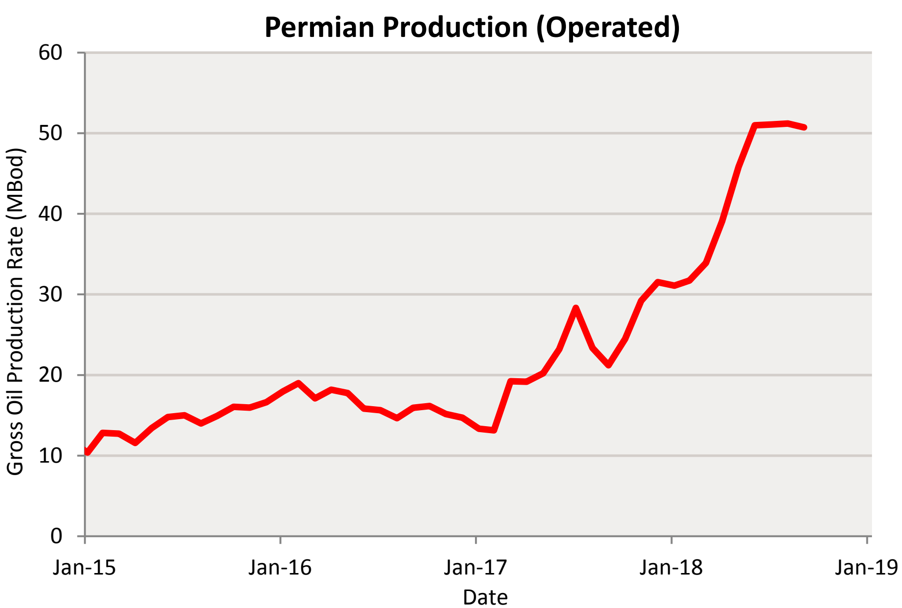
*Assuming strip pricing, we expect the Midland Basin assets to achieve operating cash flow neutrality in 2019 while delivering strong production growth*

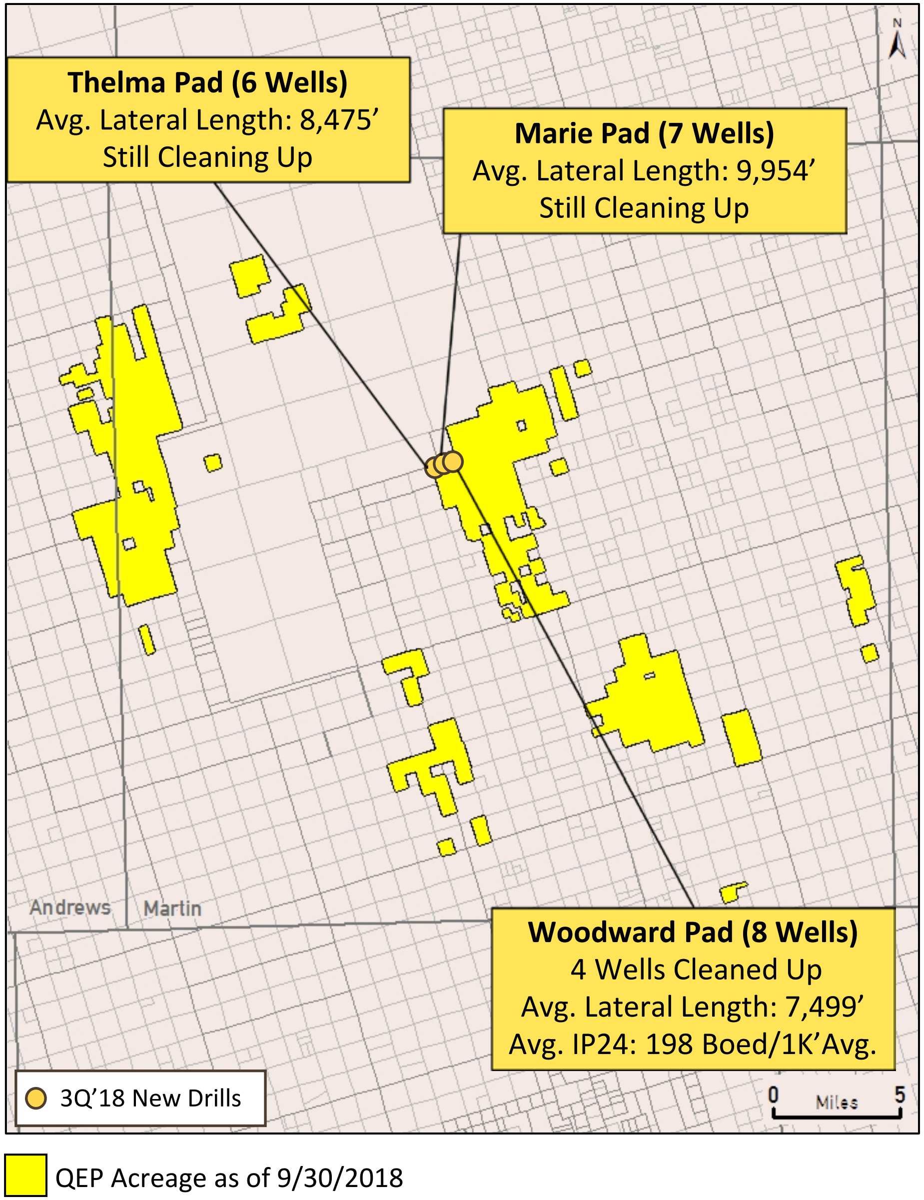
(1) As of 12/31/2017
(2) Netback (a non-GAAP measure) is calculated as oil, natural gas and NGL sales less royalties, production taxes, cash operating expenses and transportation cost and excludes the impact of hedges.

# Midland Basin – *3Q 2018 Activity*

| Well Progress (as of September 30, 2018) | Gross | Net |
|---|---|---|
| Drilling | 21 | 21.0 |
| | | |
| At total depth – under drilling rig | - | - |
| Waiting to be completed | 16 | 16.0 |
| Undergoing completion | 4 | 3.9 |
| Completed, awaiting production | 7 | 6.8 |
| Waiting on completion | 27 | 26.7 |
| | | |
| Put on production[1] | 21 | 21.0 |

[1] Total wells put on production during the quarter ended September 30, 2018.



# Midland Basin – *Crude Oil Marketing Strategy*

## Methodology

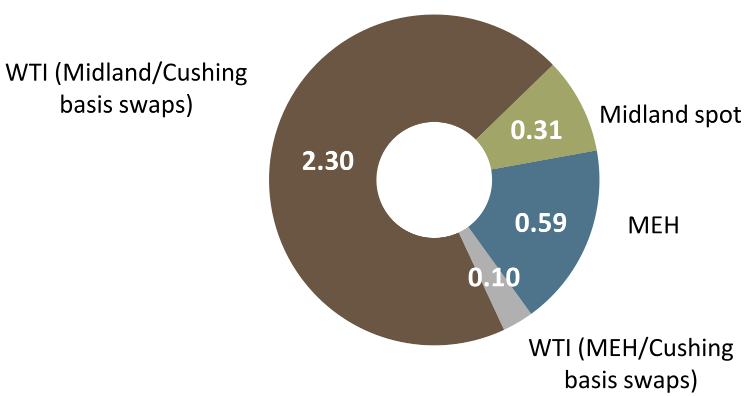
- Utilize "back-to-back" physical sales that secure takeaway without large firm pipeline commitments
  - Enter term physical sales agreements with refiners and marketers holding firm capacity on existing and new pipelines to Gulf Coast and Mid-Continent
  - Spread counterparty risk/concentration while also maximizing economics and flow assurance
  - Consider pipeline commitments if beneficial
- Controlling gathering to local trading points allows QEP to benefit from producing premium crude oil (38-40 API gravity, ultra low sulfur content "neat barrel")
- Physical sales strategy complements QEP's derivative strategy [(2)]

## Physical Sales Summary[(1)]

- More than 90% of 2018 and 2019 QEP marketed Permian oil production has dedicated/firm takeaway capacity
  - Term sales (2 years) to large counterparties who hold firm capacity on interstate/intrastate pipelines
  - WTI Midland (Argus)
  - Magellan-East Houston (MEH)
  - Evergreen deals
  - Up to 10% open to spot sales to manage production variations

## Oil Market Price Exposure (MMBbls)

**Oct – Dec 2018***




**2019**

- WTI (Midland/Cushing basis swaps)
  - 6.6 MMBbls at ($2.22)
- MEH term sales
  - 2.74 MMBbls
- MEH/Cushing basis swap
  - 0.4 MMBbls at $4.35
- Midland spot
  - Remaining volumes

* MMBbls, Oct – Dec 2018 Midland spot based off mid-point of company guidance as of November 7, 2018.

(1) QEP markets 100% of produced oil volumes for our working interest partners
(2) See derivatives table on slide 24 of this presentation

# Midland Basin – *Infrastructure Benefits*

QEP has built significant infrastructure

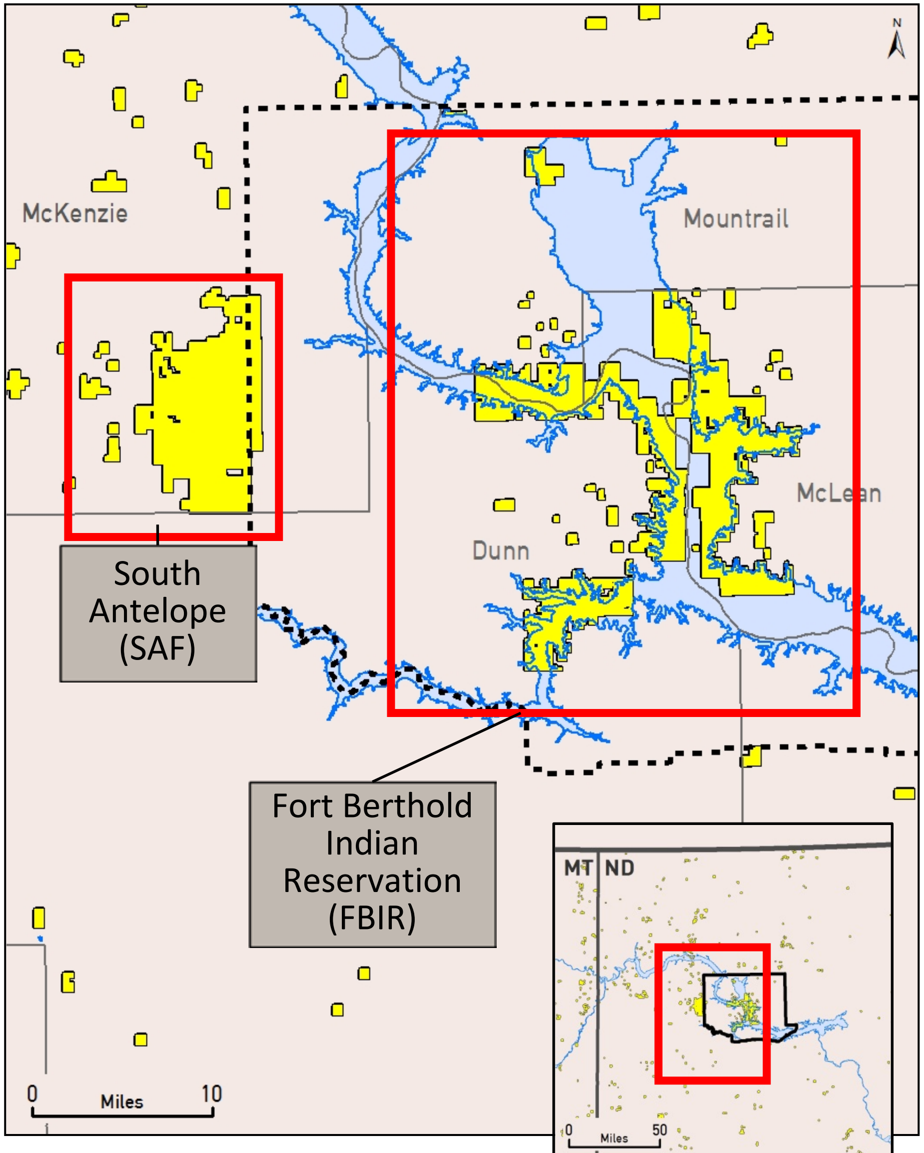
## Water Infrastructure

- Ample supply and recycled water capacity to support "tank development"
  - 100,000 bpd water recycling capacity
- Efficient delivery of water for completions
  - Large frac ponds at strategic locations
- Piped water handling reduces trucking
  - Frac supply & recycle
  - Produced water handling
- Reduced operating costs
- Deep water disposal wells
  - Drilled below deepest production

## Centralized Gathering Infrastructure

- Capital efficiencies
  - ~$170K per well savings on facilities
  - ~$200K per well savings on well site improvements
- Operating efficiencies
  - 20% decrease in gas transportation costs
  - 60% reduction in water disposal
  - 40% drop in frac water costs
  - $0.50/bbl uplift in oil price

# Williston Basin

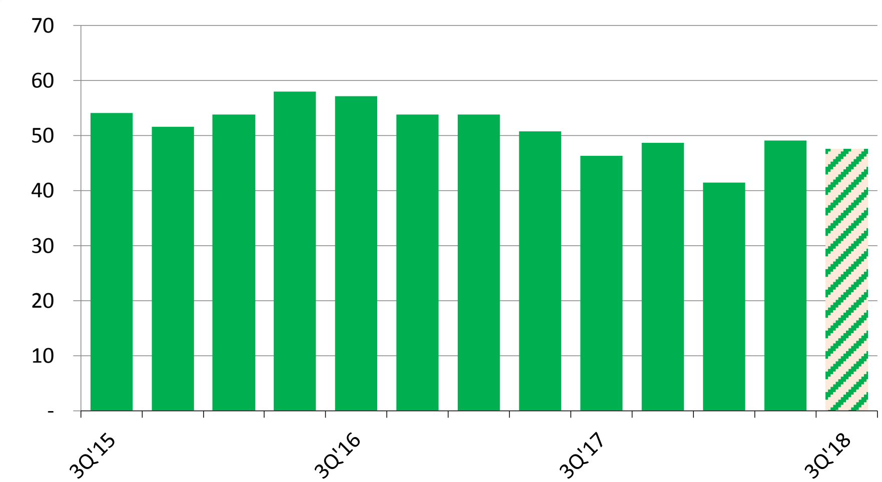



QEP Acreage as of 09/30/2018

| Profile[1] | |
|---|---|
| Net acres | 113,900 |
| Gross operated producing wells | 394 |
| Average WI/average NRI | 86/69% |
| Proved reserves (MMboe)/% liquids[2] | 147 / 88% |
| Production Split – oil/gas/NGL | 68/17/15% |

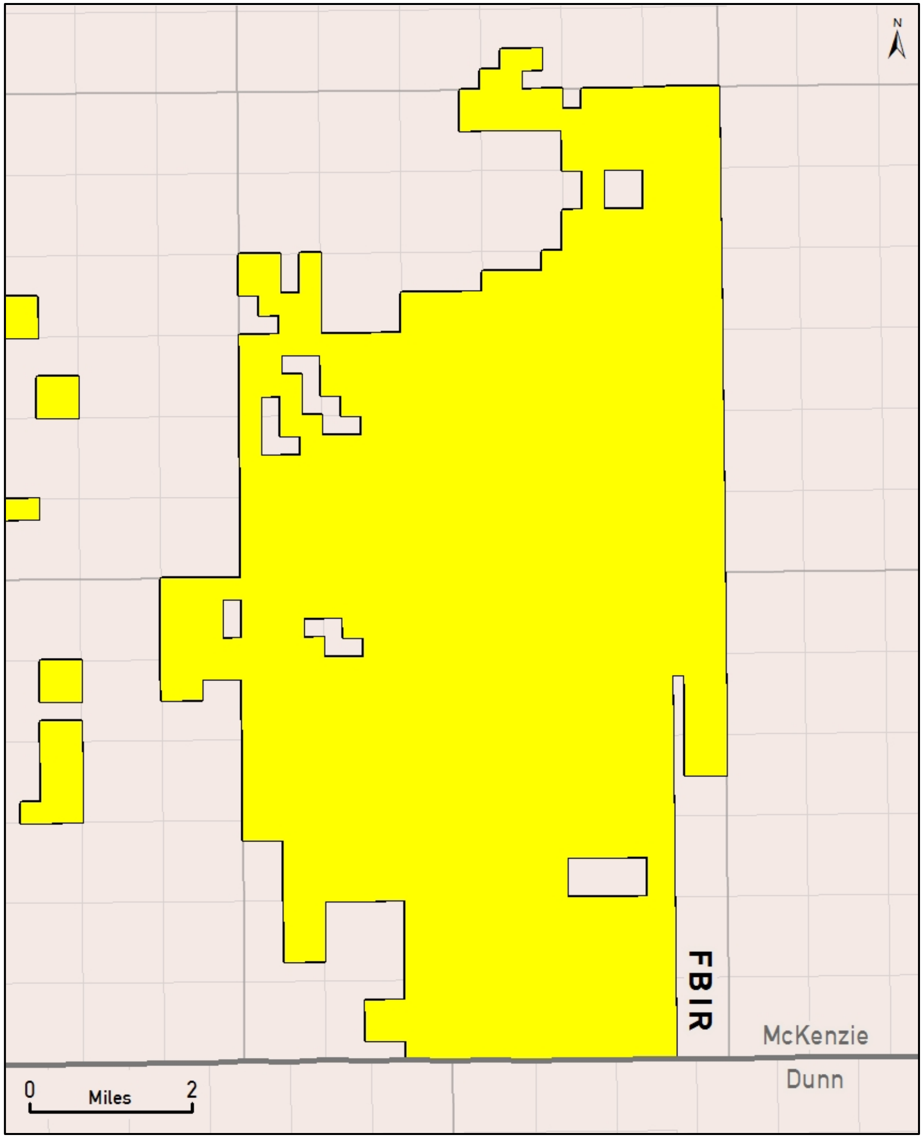
[1] As of September 30, 2018
[2] As of December 31, 2017, SEC Pricing

## Net Production - Mboed



# Williston Basin – *South Antelope 3Q 2018 Summary & Activity*

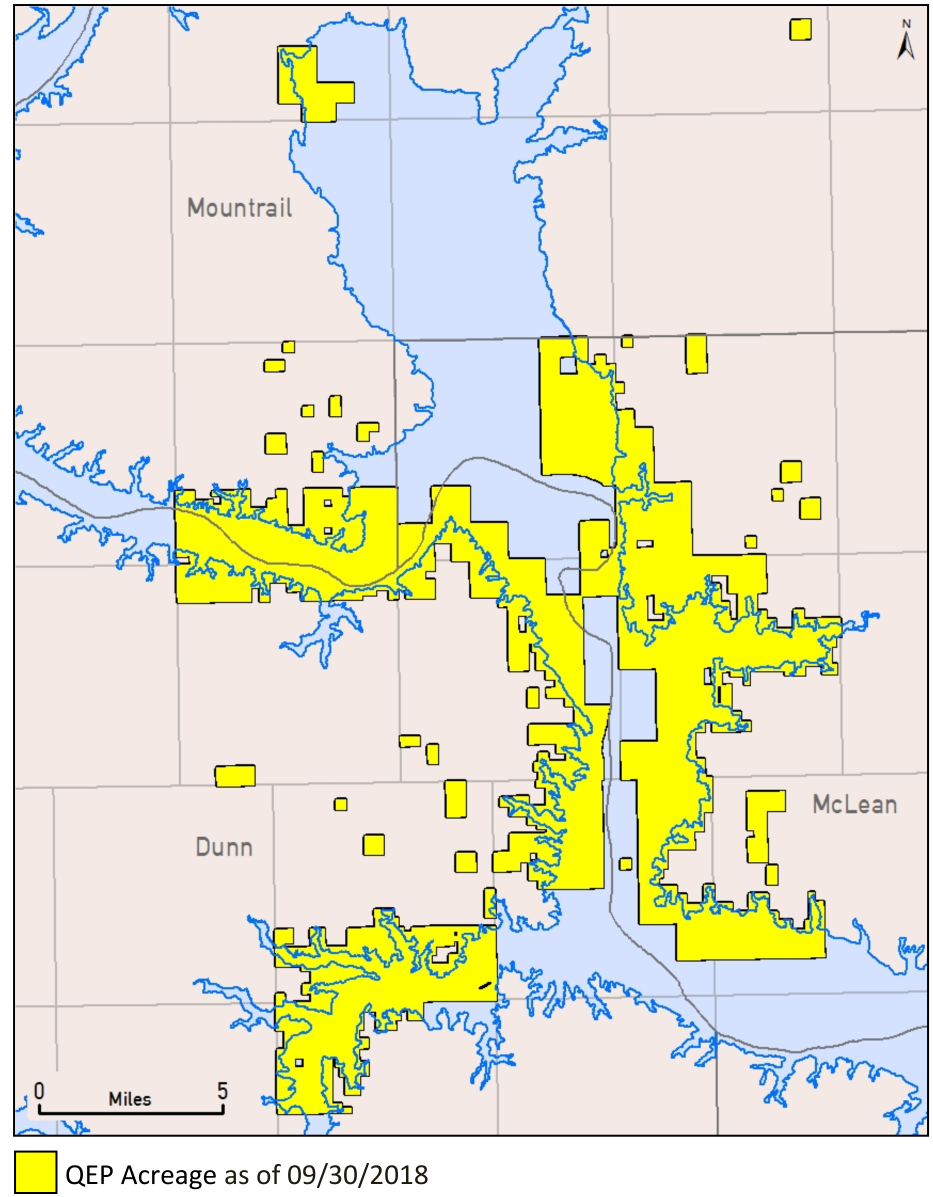
- Over 115 gross operated remaining risked drilling locations (all reserve categories)
- Over 240 gross operated remaining refrac candidates (includes modern completions)
- Approximately 268 gross operated producing wells
- Q2 2018 South Antelope refracs production update (seven wells):
  - Average 24-hour IP gross incremental production of 1,639 Boed/well (77% oil)
  - Average 30-day IP gross incremental production of 1,135 Boed/well (74% oil)
  - Average AFE $5.3 million



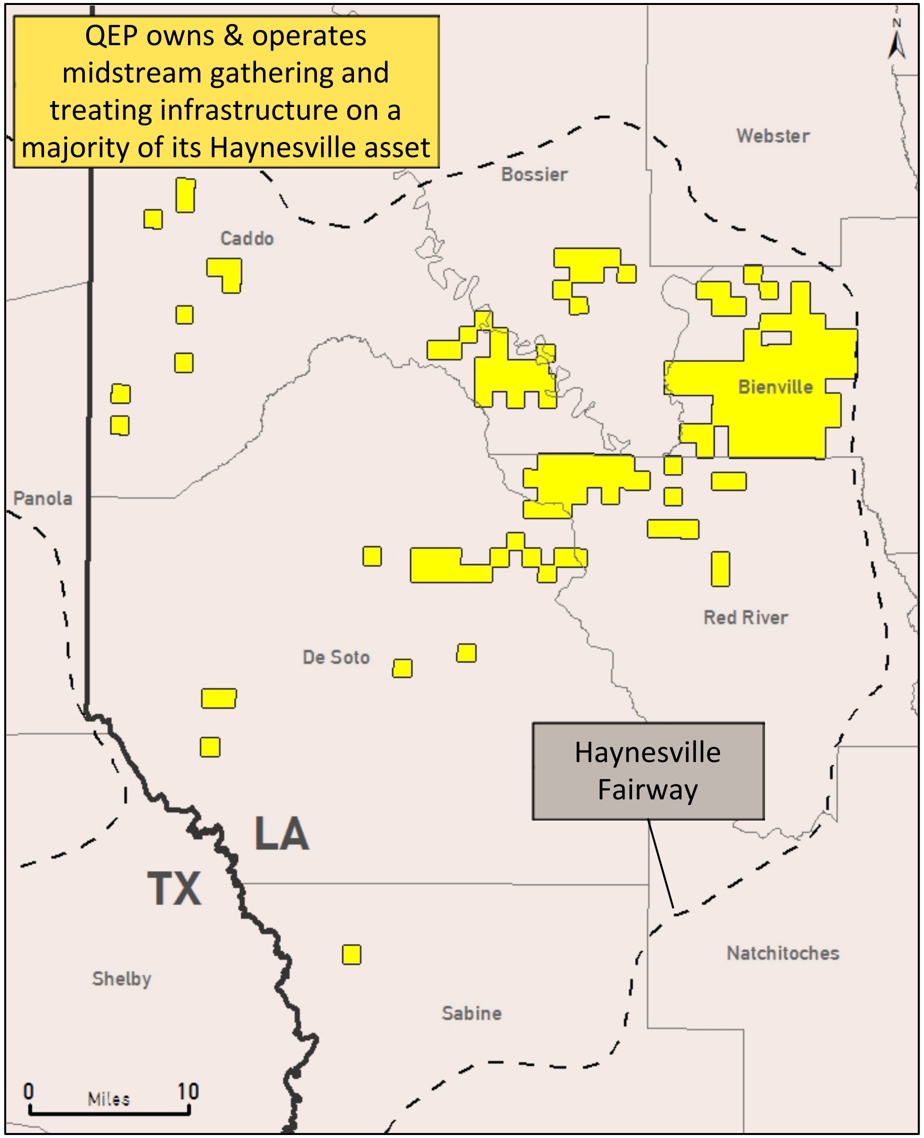

QEP Acreage as of 09/30/2018

# Williston Basin – *FBIR 3Q 2018 Summary & Activity*

- Over 240 gross operated remaining risked drilling locations (all reserve categories)
- Over 100 gross operated remaining refrac candidates (includes modern completions)
- Approximately 126 gross operated producing wells
- No activity in the quarter



# Haynesville



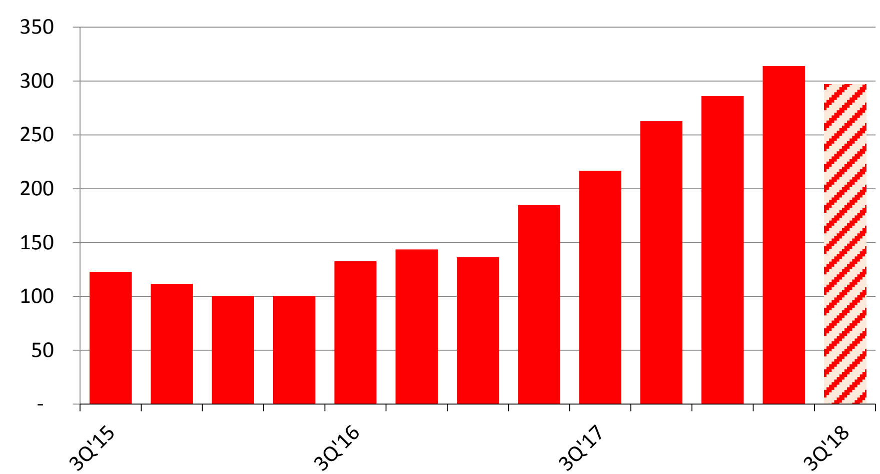

QEP Units as of 9/30/2018

## Profile[1]

| | |
|---|---|
| Net acres | 49,700 |
| Gross operated producing wells[2] | 137 |
| Average WI/average NRI[2] | 95/73% (op) |
| Proved reserves (Bcfe)/% liquids[3] | 959/ 0% |
| Production Split – oil/gas/NGL | 0/100/0% |

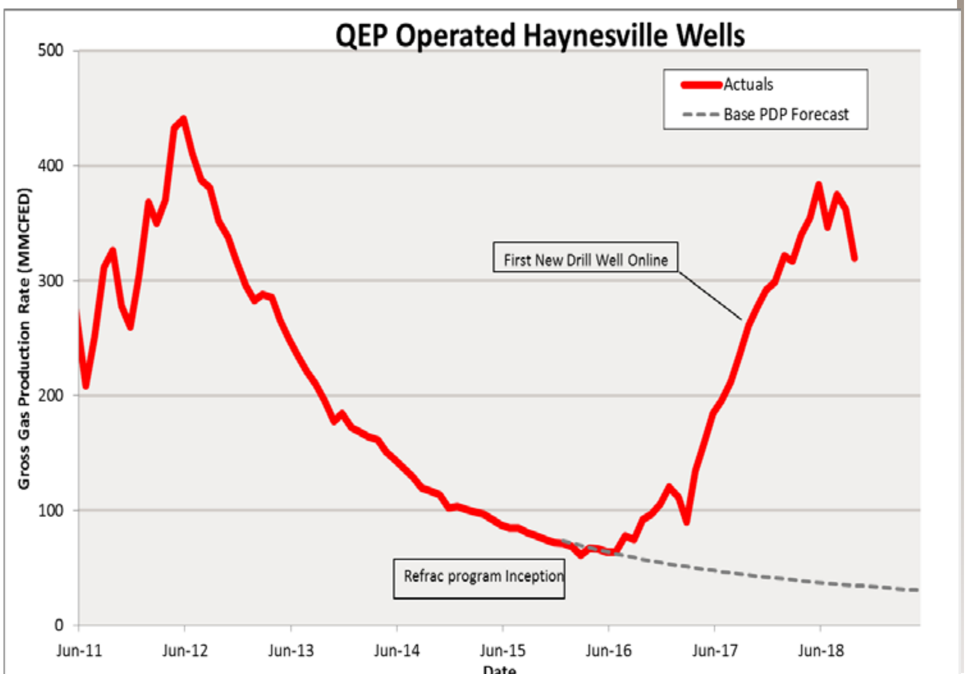
(1) As of September 30, 2018
(2) Includes only Haynesville interval wells
(3) As of December 31, 2017, SEC Pricing

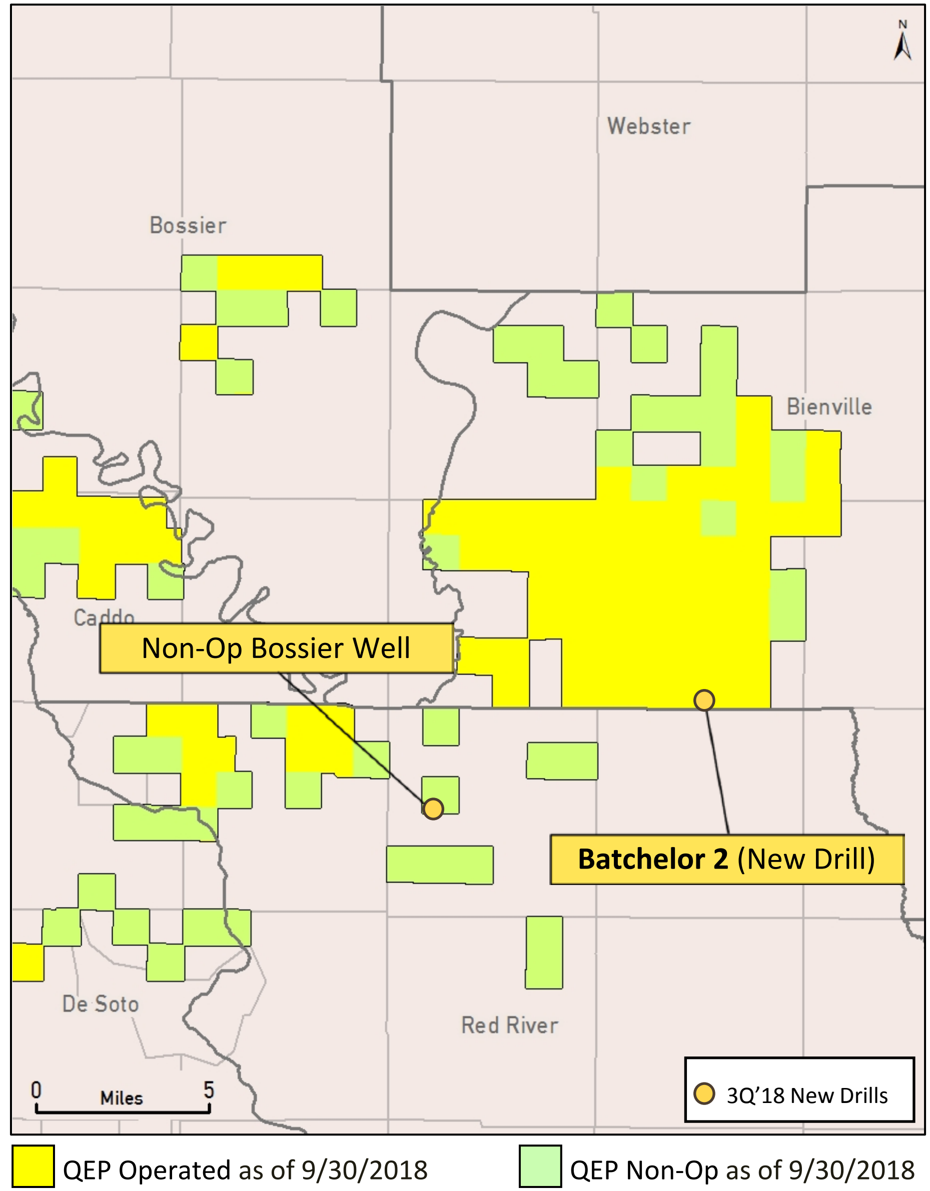
## Net Production – MMcfed



# Haynesville – *3Q 2018 Activity*

- Put on production one new 10,000' lateral well at beginning of quarter
  - Well reached peak 24-hour IP of 34.0 MMcfed
- Non-Op 5,000' lateral Bossier shale well completed
  - Max 24-hour IP of 19.0 MMcfed



# Appendix

# Permian Basin – *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 | $5.1 | $1.0 |
| | Spraberry Shale | 10,000 | $6.3 | $1.0 |
| | Wolfcamp | 7,500 | $6.4 | $1.0 |
| | Wolfcamp | 10,000 | $7.8 | $1.0 |
| | | | | |
| | | | | |
| ***Mustang Springs*** | Middle Spraberry | 7,500 | $4.9 | $1.0 |
| | Spraberry Shale | 7,500 | $4.9 | $1.0 |
| | Spraberry Shale | 10,000 | $6.1 | $1.0 |
| | Wolfcamp A | 7,500 | $5.4 | $1.0 |
| | Wolfcamp A | 10,000 | $6.8 | $1.0 |
| | Wolfcamp B | 7,500 | $5.6 | $1.0 |
| | Wolfcamp B | 10,000 | $7.0 | $1.0 |

(1) As of September 30, 2018.

# 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

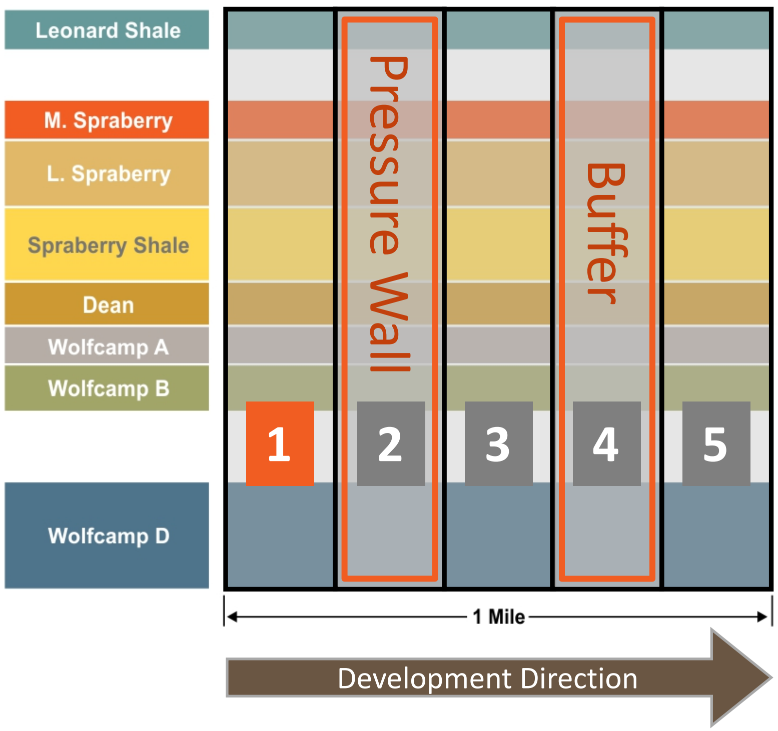
## Anticipated Benefits

Above Ground

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




LEGEND:

- 1 Producing wells
- 2 Completed wells, awaiting production ("Pressure Wall")
- 3 Wells undergoing completion
- 4 Wells waiting to be completed ("Buffer")
- 5 Wells being drilled

# 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 horizontal drilling locations of 7,500’, 10,000’, and 12,500’ laterals(1)

(1) As of 12/31/2017 - 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 October 31, 2018:

| Production Commodity Derivative Swaps | | | |
|---|---|---|---|
| **Year** | **Index** | **Total Volumes** | **Average Price per Unit** |
| **Oil Sales** | | (MMBbls) | ($/Bbl) |
| 2018 | NYMEX WTI | 2.7 | $52.45 |
| 2019 | NYMEX WTI | 11 | $54.49 |
| 2020 | NYMEX WTI | 2.9 | $62.37 |
| **Gas Sales** | | **(million MMBtu)** | **($/MMBtu)** |
| 2018 | NYMEX HH | 8.1 | $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 | NYMEX WTI | Argus WTI Midland(1) | 1.5 | ($0.99) |
| 2018 | NYMEX WTI | Argus WTI Houston(2) | 0.1 | $6.30 |
| 2019 | NYMEX WTI | Argus WTI Midland | 6.6 | ($2.22) |
| 2019 | NYMEX WTI | Argus WTI Houston | 0.4 | $4.35 |
| 2020 | NYMEX WTI | Argus WTI Midland | 1.5 | ($1.01) |
| **Gas Sales** | | | **(million MMBtu)** | **($/MMBtu)** |
| 2018 | NYMEX HH | IFNPCR | 1.2 | ($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.
(2) Argus WTI Houston is an index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.

# QEP Resources – *Debt Maturity Schedule*

**As of November 1, 2018**

| Maturity | Amount | Coupon | Duration (yrs) |
|---|---|---|---|
| 3/1/2020 | 51,753,000 | 6.800% | 1.33 |
| 3/1/2021 | 397,579,000 | 6.875% | 2.33 |
| 10/1/2022 | 500,000,000 | 5.375% | 3.92 |
| 5/1/2023 | 650,000,000 | 5.250% | 4.50 |
| 3/1/2026 | 500,000,000 | 5.625% | 7.33 |
| **5/18/2023** | **2,099,332,000** | **5.715%** | **4.55** |