QEP RESOURCES®

Investor Presentation

October 2019

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: free cash flow and return on invested capital; benefits to shareholders; an improved leverage profile; estimated production split among oil, gas and NGL; guidance for fourth quarter 2019 and fiscal 2019 production and certain underlying assumptions; guidance for 2019 Lease Operating and Adjusted Transportation & Processing Expense per Boe, DD&A per Boe, production and property taxes as a percentage of revenue, non-cash share-based compensation expense, restructuring expense, and capital investment; assumptions related to our guidance; guidance for general and administrative expense for 2019; guidance for wells put on production for fourth quarter 2019 and fiscal year 2019; reduction of G&A expense to less than $3.00 per BOE by 2020; and optimizing the Company's cost structure; estimated drill and completion costs reductions; 2020 targeted free cash flow and leverage ratio; the 2020 development program; and potential benefits of the Company's water infrastructure.

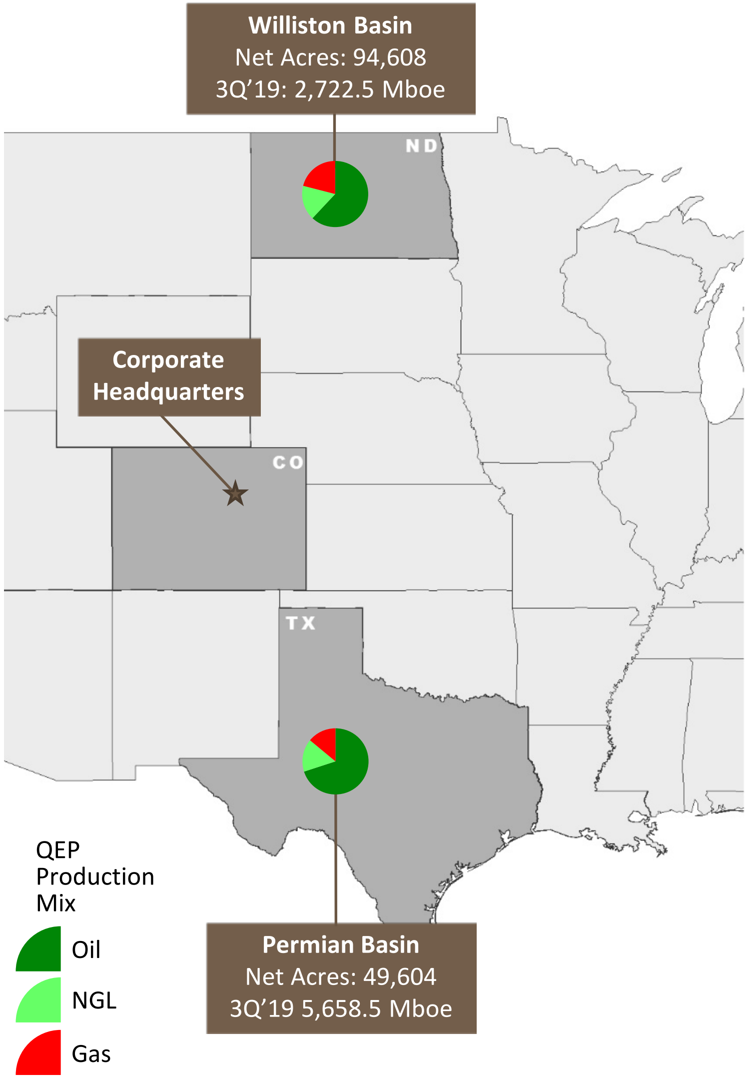
Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: the availability and cost of capital; actions of activist shareholders; results from our review of strategic alternatives; changes in local, regional, 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; tariffs on products QEP uses in its operations or sells; changes in, adoption of and compliance with laws and regulations, including those related to taxes (including decisions, policies and guidance concerning taxes), the environment, climate change, greenhouse gas or other emissions, renewable energy mandates, 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; 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, 2018 and in the Company's quarterly and current reports filed with the SEC subsequent to the Annual Report on 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. "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 Form 10-K.

QEP refers to Free Cash Flow, Adjusted Transportation & Processing Expense, Special G&A Expense 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."

Corporate Update

Asset Overview(1)



3Q 2019 Highlights

- Increased full-year production guidance for crude oil, natural gas and NGL
- Lowered mid-point of capital expenditure guidance by approximately $15 million, down $65 million year-to-date
- Reduced G&A expense to 2020 target run-rate, down approximately 40% from third quarter 2018 to third quarter 2019
- Generated Free Cash Flow (FCF)(2) of $17.5MM in the quarter
- Greater than 60% of projected 2020 oil production hedged at $58.31 per barrel
- Ended the quarter with $92.4 million of cash and cash equivalents and no borrowings under credit facility

(1) *Excludes equivalent production of 23.0 Mboe from Other Northern & Other Southern regions.*
(2) *Free Cash Flow is a Non-GAAP measure. The Company defines FCF as Adjusted EBITDA less capital expenditures and interest expense. For a detailed discussion of Adjusted EBITDA and FCF and a reconciliation to the nearest GAAP measure, see reconciliation contained in our October 23, 2019, earnings release.*

2019 Updated Guidance[1]

	4Q 2019 Guidance	2019 Updated Guidance
Oil & Condensate Production (MMBbl)	5.7 - 6.0	21.6 - 21.9 ↑
Gas Production (Bcf)	7.9 - 8.4	32.4 - 32.9 ↑
NGL Production (MMBbl)	1.3 - 1.5	5.0 - 5.2 ↑
Total oil equivalent production (MMBoe)	8.3 - 8.9	32.0 - 32.6 ↑
Lease operating expense and Adjusted Transportation & Processing Costs (per Boe)		$8.50 - $9.25 ↓
Depletion, depreciation and amortization (per Boe)		$16.75 - $17.75
Production and property taxes (% of field-level revenue)		7.5% ↑
(in millions)		
Total G&A expense[2]		$155 - $165 ↓
Less: Special G&A expense[3]		$54
Total G&A expense (excluding Special G&A)		$101 - $111 ↓
Capital investment (excluding property acquisitions)		
Drilling, Completion and Equip[4]		$515 - $530 ↓
Midstream Infrastructure[5]		$50 ↓
Corporate		$2 ↓
Total Capital Investment (excluding property acquisitions)	**$101 - $116**	**$567 - $582**
Wells put on production (net)	**3**	**65**

(1) As of October 23, 2019: The Company's fourth quarter and full year 2019 guidance assumes: (1) an oil price of $55 per barrel and a natural gas price of $2.50 per MMBtu, (2) that QEP will elect to recover ethane from its produced gas in the Permian Basin where processing economics support it, (3) no additional property acquisitions or divestitures, other than those already disclosed, (4) includes approximately 10 days of production activity in the Haynesville / Cotton Valley, and (5) the impact of lower flare volume and higher gas and NGL capture in the Permian Basin.

(2) The mid-point of G&A expense includes approximately $26.0 million of expenses related to non-cash, share-based compensation and other mark-to-market liabilities. Because these mark-to-market liabilities fluctuate with stock price changes, the amount of actual expense may vary from the forecasted amount.

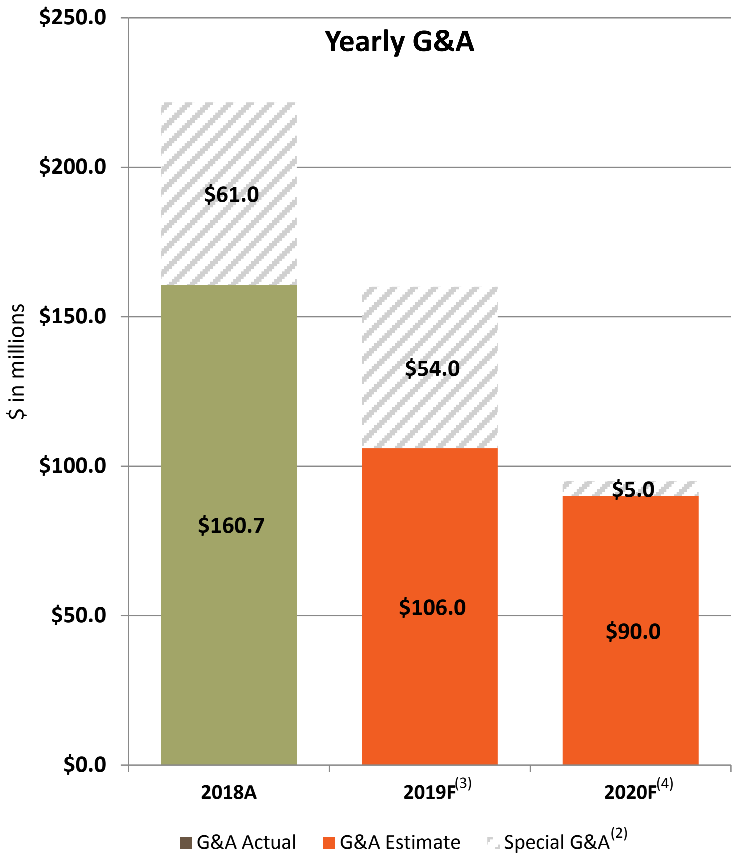
(3) Special G&A expense also includes approximately $54.0 million of estimated expenses associated with our strategic initiative process, primarily related to severance and retention programs, and includes approximately $11.0 million of accelerated shared-based compensation expense that is included in the $26.0 million of expenses related to non-cash, share-based compensation and other mark-to-market liabilities.

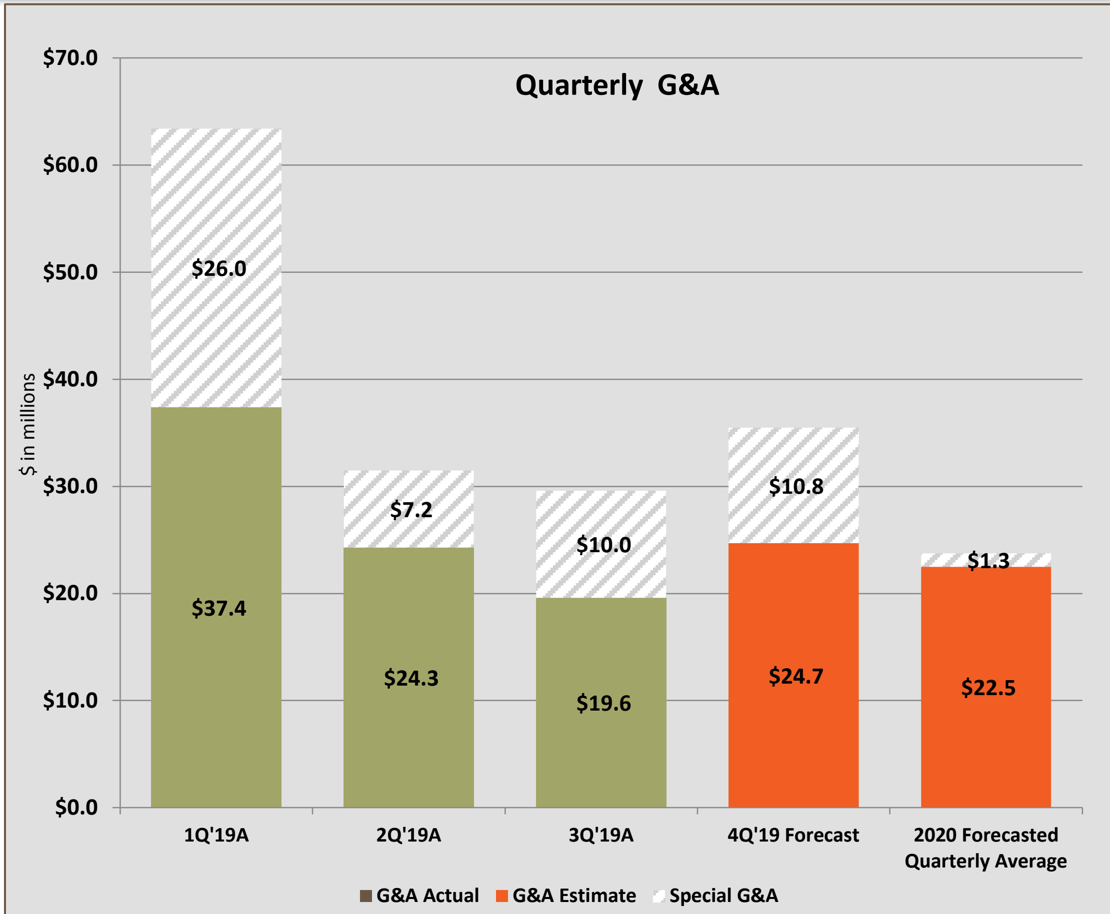
(4) Drilling, Completion and Equip includes approximately $20.0 million of non-operated well costs.

(5) Includes capital expenditures in the Permian Basin associated with (a) water sourcing, gathering, recycling and disposal and (b) crude oil and natural gas gathering systems.

Transitioning to a Low Cost Operator

QEP is Focused on Optimizing Its Cost Structure



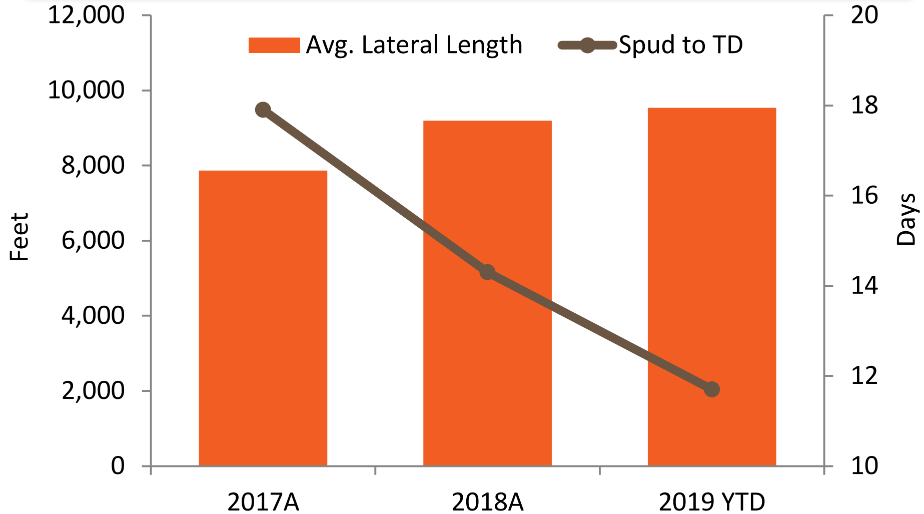


QEP Expects to Decrease G&A[1] to Less Than $3.00 per BOE by 2020

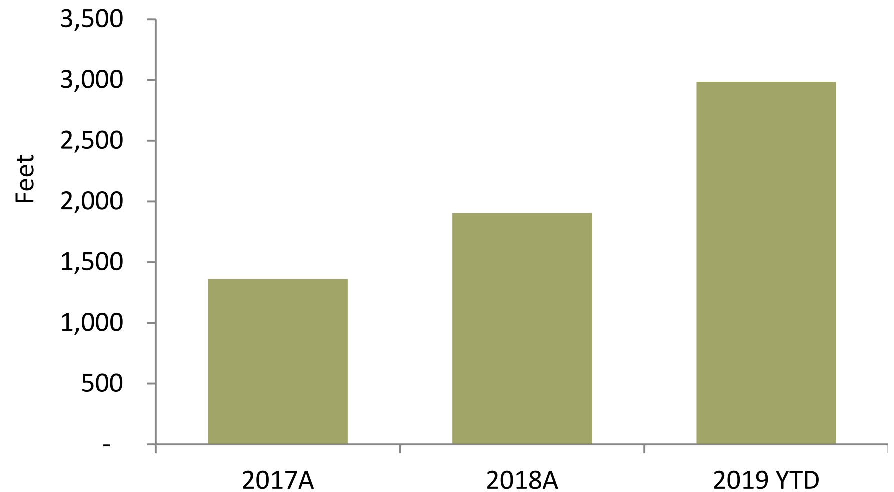
(1) G&A includes cash and non-cash share based compensation expense.
(2) Special G&A includes estimated expenses associated with our strategic initiative process, primarily related to severance and retention programs
(3) 2019F represents the midpoint of guidance as of October 23, 2019.
(4) $90 million G&A expense represents the 2020E target at less than $3.00 per BOE.

Permian Basin – Drilling and Completion Improvement

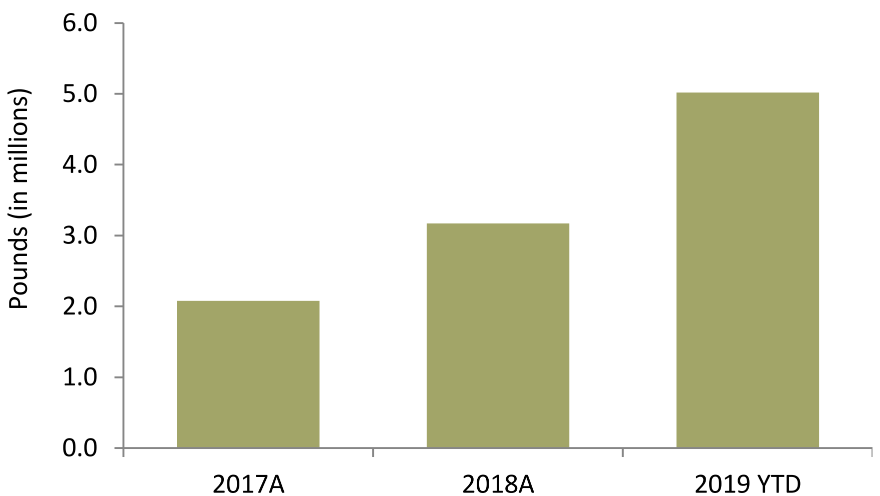
Shorter Drill Times



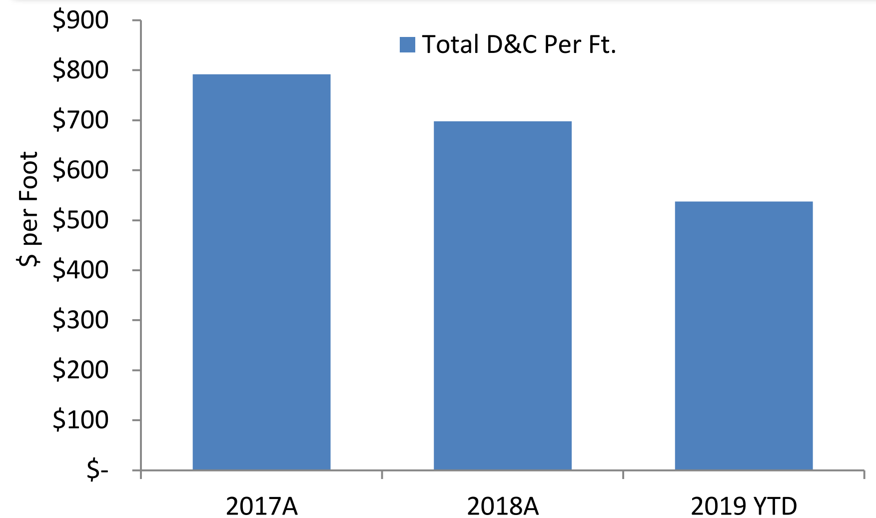
Lateral Length Completed per Day per Frac Crew



Average Proppant Placed per Day per Frac Crew

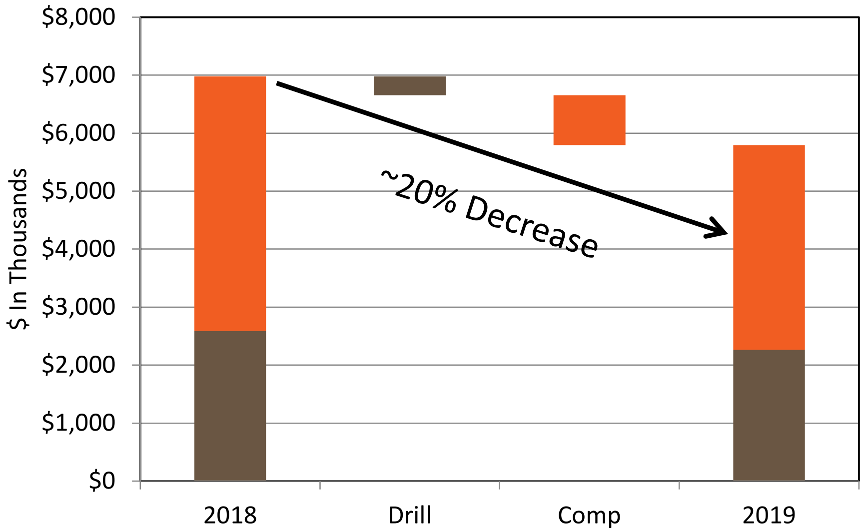


Drilling, Completion & Location Cost Improvement



Permian Basin – Drilling & Completion Cost Reductions

Greater than $1 MM per well in D&C cost reductions



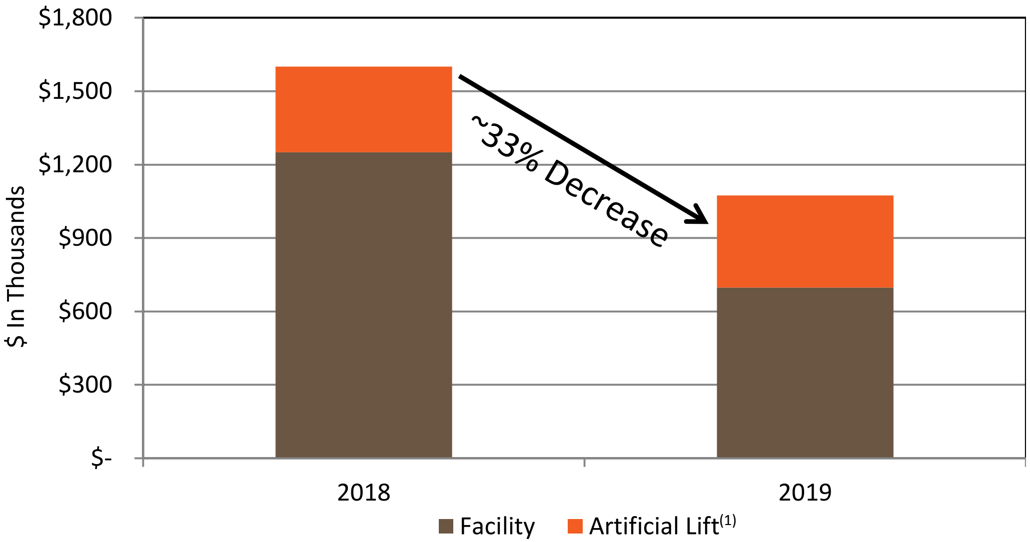
D&C Cost Reductions

- Increased pump rate down each well in simul-frac operations
- Full utilization of in-basin sand
- Increased recycled water usage
- Optimized brine and fresh water drilling mud
- Walking rig between pads

Note: Permian Basin D&C Costs Normalized to 10,000'.

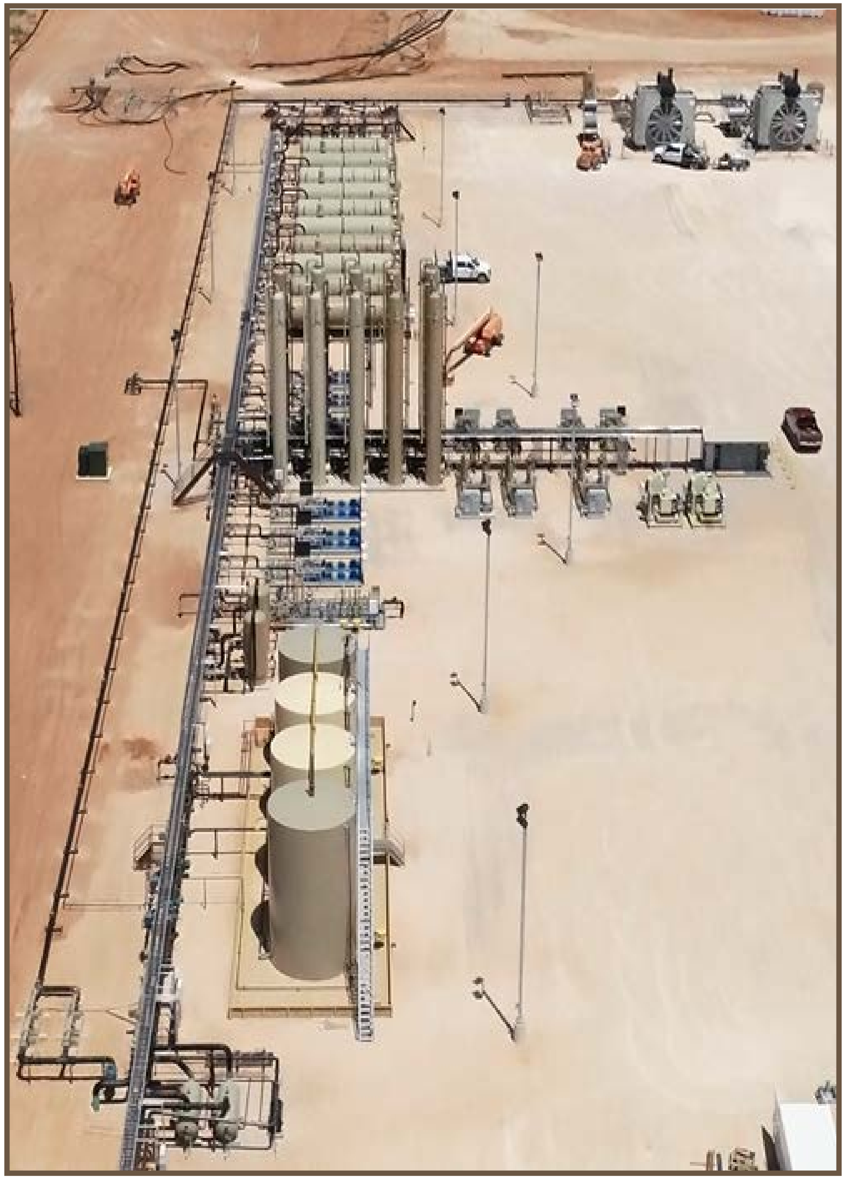
Permian Basin – Facility & Artificial Lift Cost Efficiencies

Greater than $500K Per Well Equip Cost Improvement



Economies of Scale

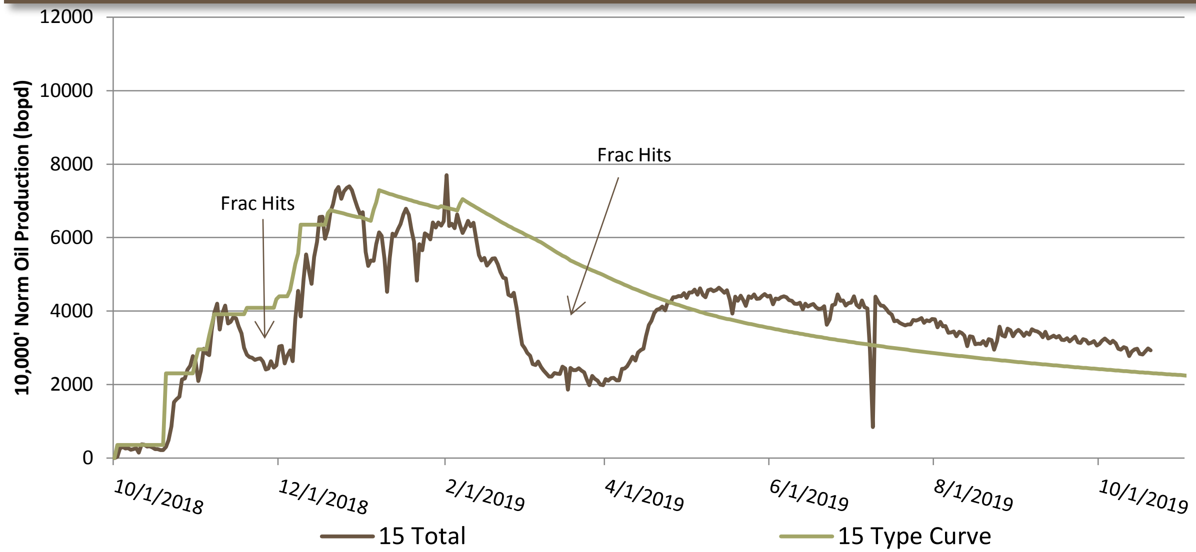
- Large shared surface facilities due to tank-style development
  - As many as 52 wells in a single facility to date
- Utilizing existing facilities to connect new wells when possible
- Modular facilities built offsite
- Skid mounted equipment allows for scaling down and moving equipment to new facility



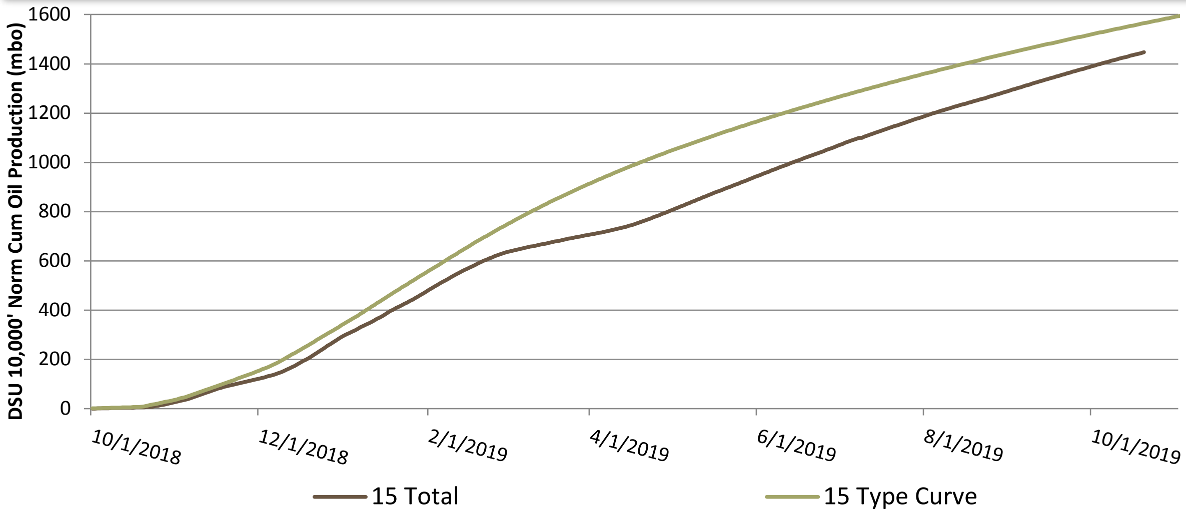
(1) For 2018, artificial Lift was a mix of gas lift and ESP initial installs. Beginning in 2019 all initial artificial lift was ESPs.

Permian Basin – Mustang Springs DSU Performance (DSU 15)

DSU 15 Production Performance

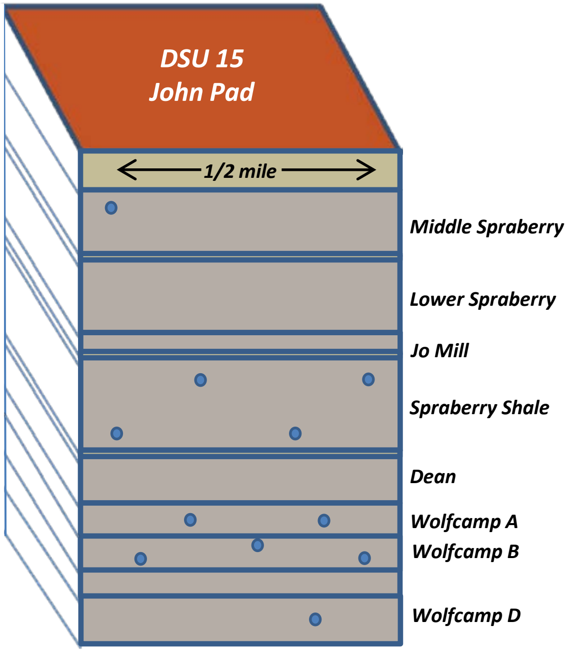


DSU 15 Cumulative Production Performance



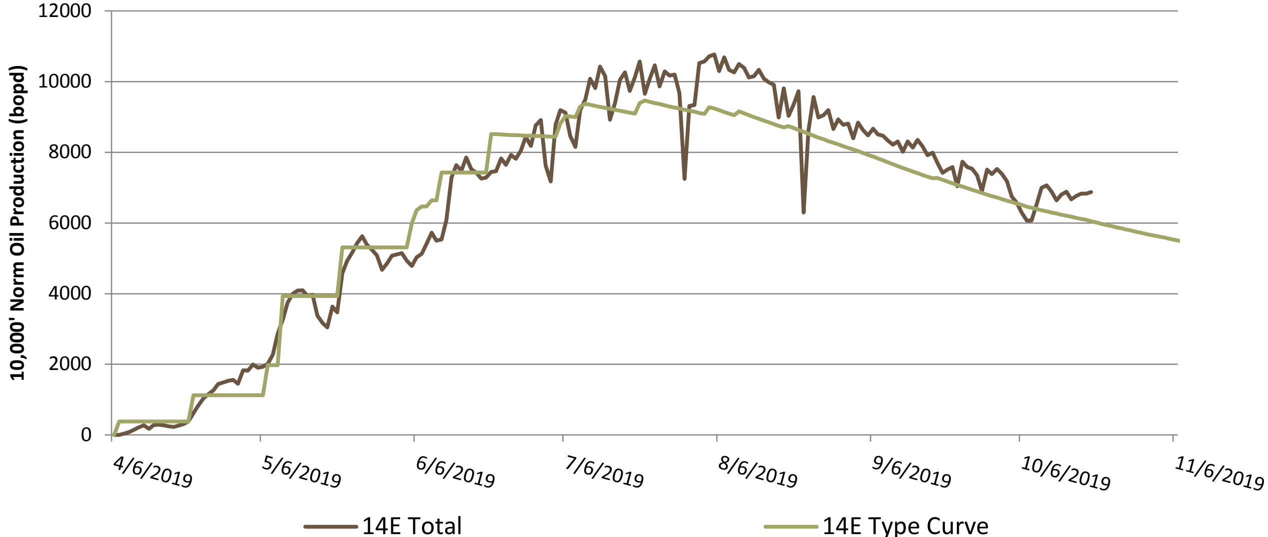
DSU 15 Results

- Early time production significantly impacted by offset frac hits
- Current rate exceeding forecast and recovering deferred production
- No changes to expected ultimate recovery

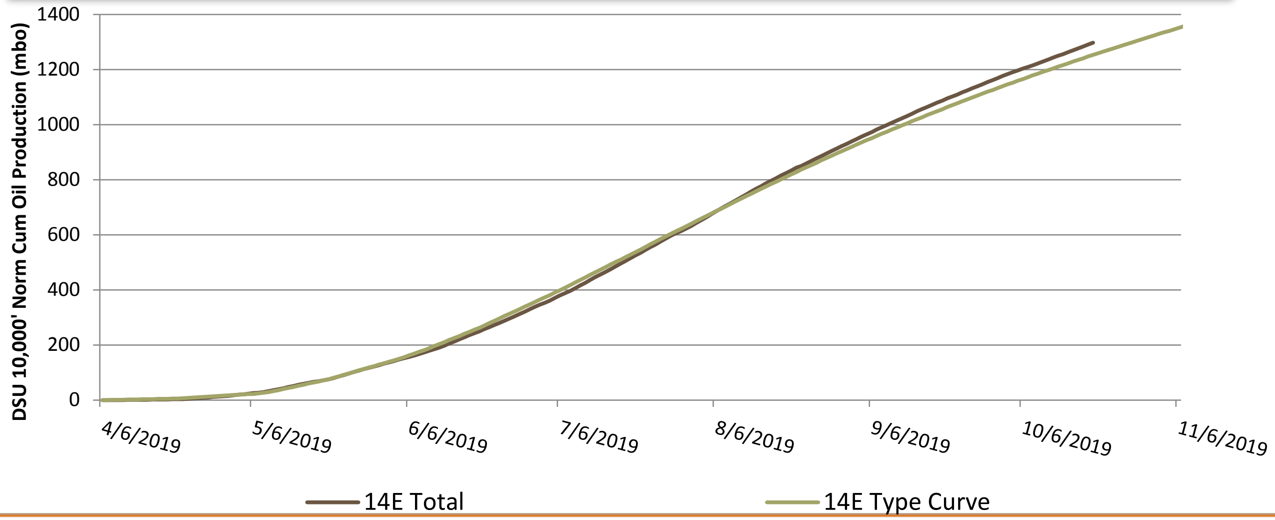


Permian Basin – Mustang Springs DSU Performance (DSU 14E)

DSU 14E Production Performance

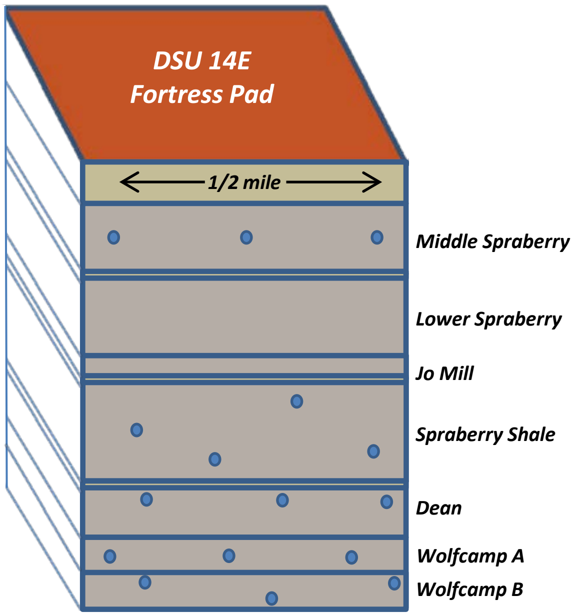


DSU 14E Cumulative Production Performance



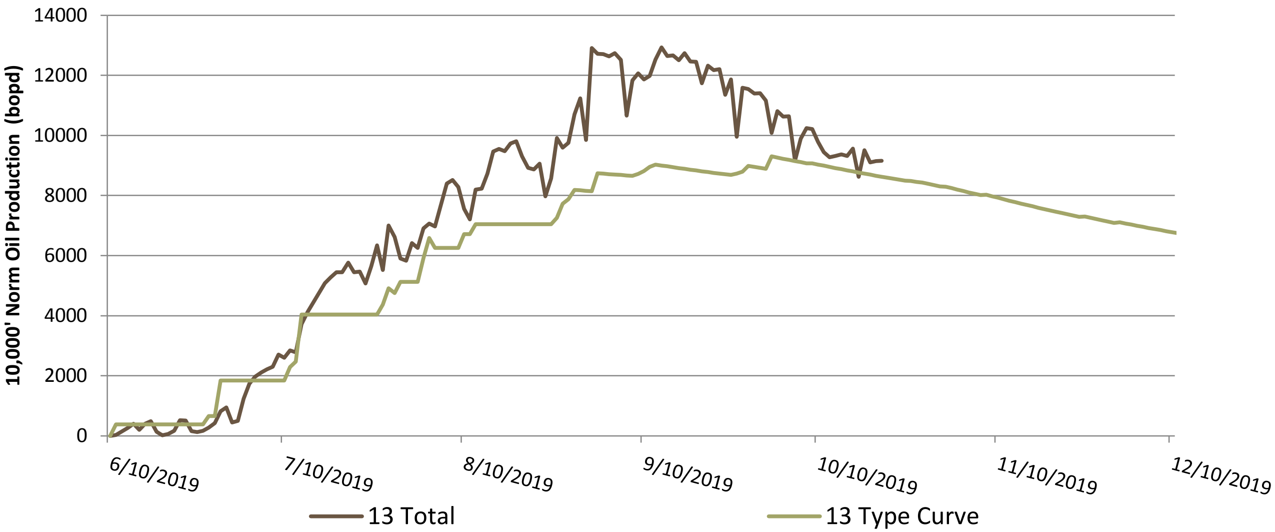
DSU 14E Results

- 180-day performance above forecast
- Incorporates updated spacing assumptions and completion design
  - More prescriptive buffer between frac crew and POP wells reducing clean-up time

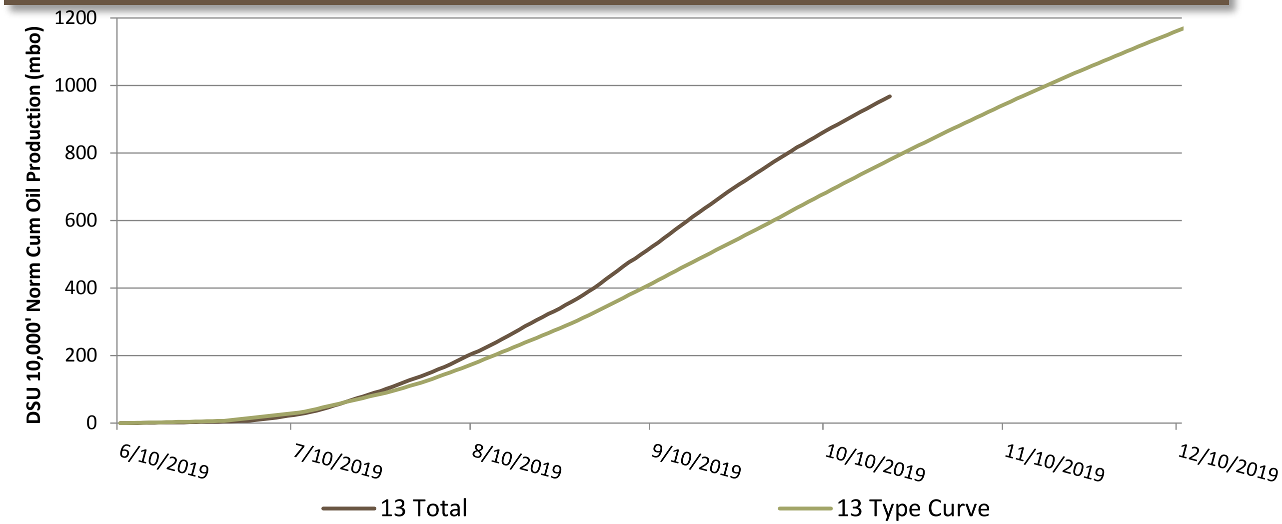


Permian Basin – *Mustang Springs DSU Performance (DSU 13)*

DSU 13 Production Performance

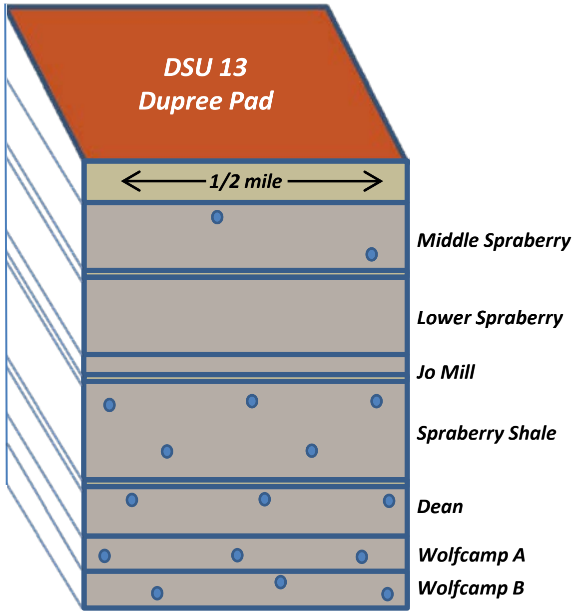


DSU 13 Cumulative Production Performance



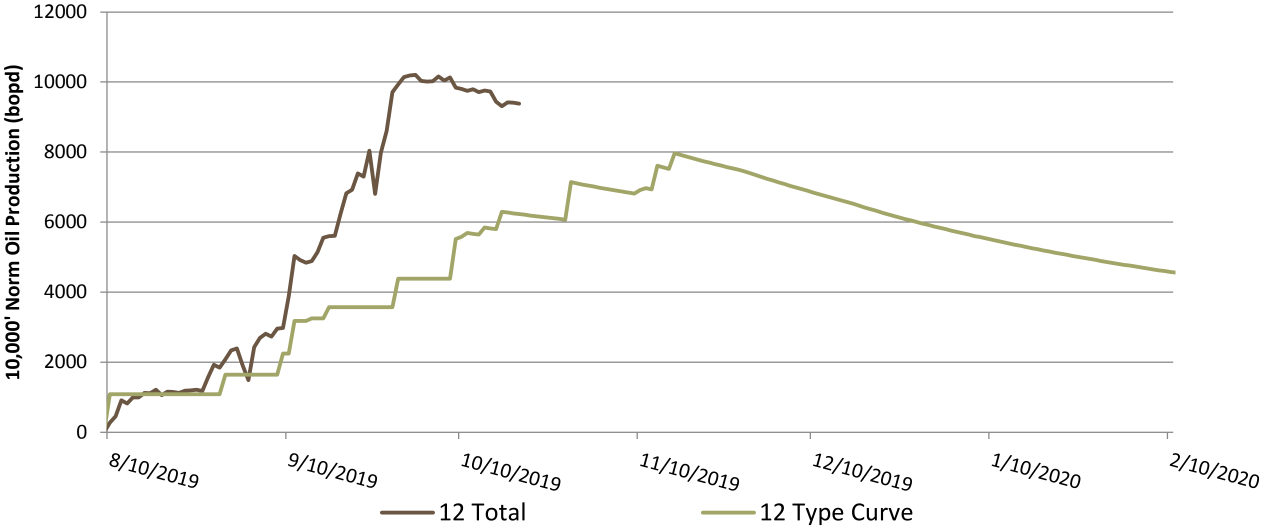
DSU 13 Results

- 120-day performance exceeding expectations
- Enhanced flowback and artificial lift strategy shorten well cleanup times and achieve peak rates sooner
- Dean and Wolfcamp A wells outperforming expectations

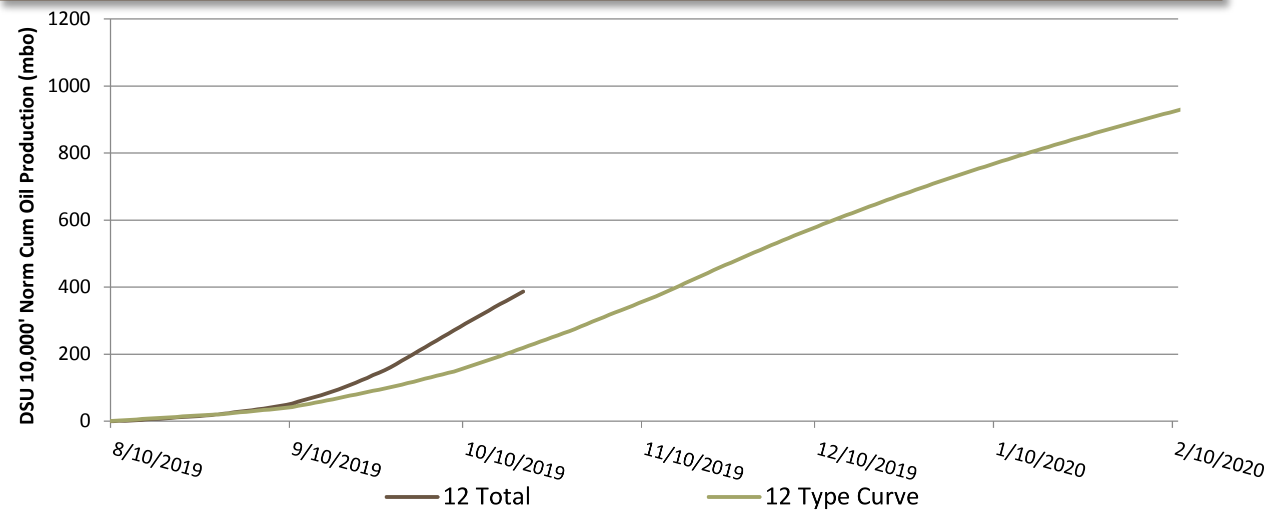


Permian Basin – *Mustang Springs DSU Performance (DSU 12)*

DSU 12 Production Performance

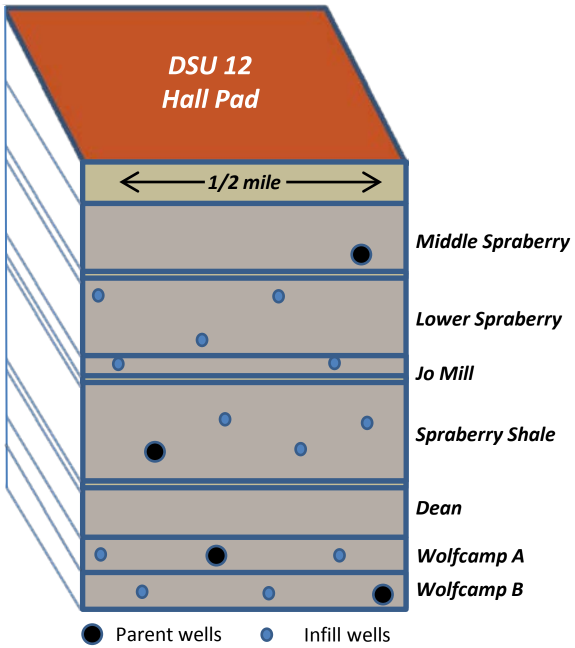


DSU 12 Cumulative Production Performance



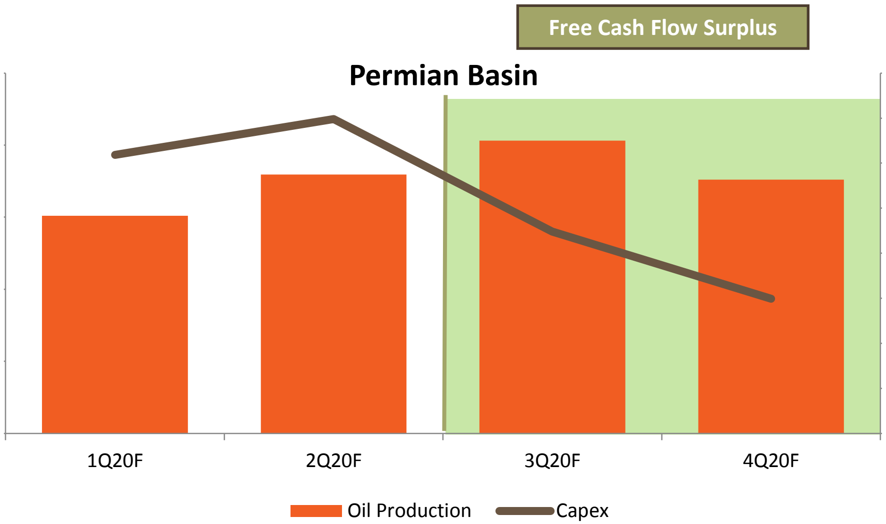
DSU 12 Results

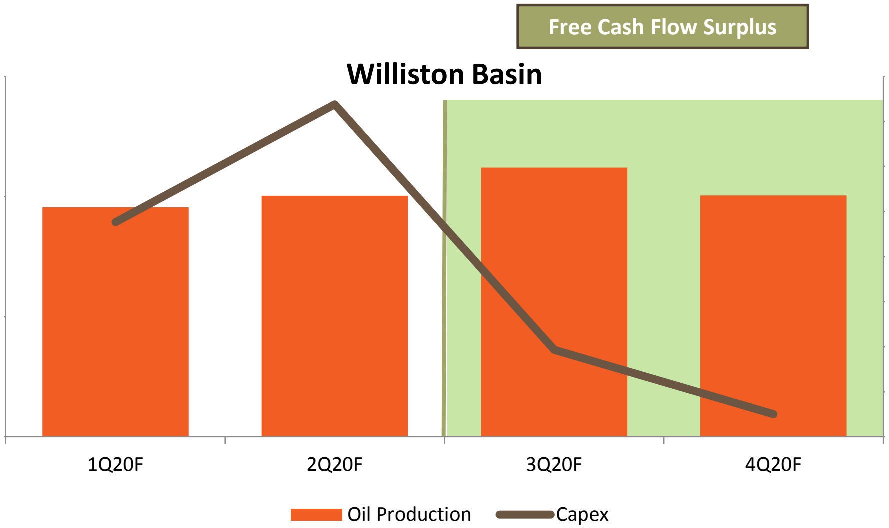
- Initial DSU performance is exceeding expectations
  - Faster cleanup profiles
- Production shown are for wells infilled around parents
- Well spacing and landing zones modified based on proximity to parent wells



Operational and Financial Seasonality

Prioritizing Balanced Growth with Free Cash Flow





Fluctuating Cash Flow

Cash flow generation will fluctuate in a predictable manner

- Jan – June
  - Majority of capital deployed
  - Modest production growth
- July – Dec (Free Cash Flow Surplus)
  - Modest capital spend
  - Production rate peaks

2020 Summary

- Targeting FCF of ~$120 million assuming a price of $55/Bbl for oil and $2.50/MMbtu for gas
  - In addition, expecting tax refund of $37 million in fourth quarter 2020

Note: Free Cash Flow is a Non-GAAP measure. For a detailed discussion of Free Cash Flow and reconciliation to the nearest GAAP measure, see reconciliation contained in our earnings release date October 23, 2019.

Permian Basin – Water Infrastructure

Water System Overview

- Benefiting from highly competitive produced water treating costs
- Capacities can be expanded for minimal capital investment
- Evaluating JVs/partnerships with third parties
- Provides a significant opportunity to generate additional cash flow

Water System Capacities

- Disposal: 215,000 – 245,000 Bwpd
- Recycle: 80,000 – 100,000 Bwpd
  (an additional 100,000 Bwpd to be added by year end '19)
- Supply: 48,000 Bwpd
- Storage: 6.0 MMBbl

QEP Priorities

- Generate organic Free Cash Flow
  - ✓ Forecasting organic FCF of ~$120MM in 2020 [(1)]
  - ✓ Continue to optimize capital expenditures and corporate overhead
- Organically reduce leverage / strengthen balance sheet
  - ✓ Through FCF generation
  - ✓ Via proceeds from water business JV or sale
  - ✓ Senior note repayment
- Return capital to shareholders
  - ✓ $0.02 per share quarterly dividend

(1) Assumes a price of $55/Bbl for oil and $2.50/Mmbtu for natural gas.

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Appendix

Derivative Positions – As of October 18, 2019

- 76% of remaining 2019* oil production covered at an average price of $56.83/Bbl
- 62% of 2020 forecasted oil production at an average price of $58.31/Bbl

Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Swap Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2019	NYMEX WTI	3.6	$55.44
2019	ICE Brent	0.5	$66.73
2019	Argus WTI Midland	0.2	$54.60
2019	Argus WTI Houston	0.1	$65.70
2020	NYMEX WTI	11.3	$58.29
2020	Argus WTI Midland	1.5	$57.30
2020 (January - June)	Argus WTI Houston	1.0	$60.06

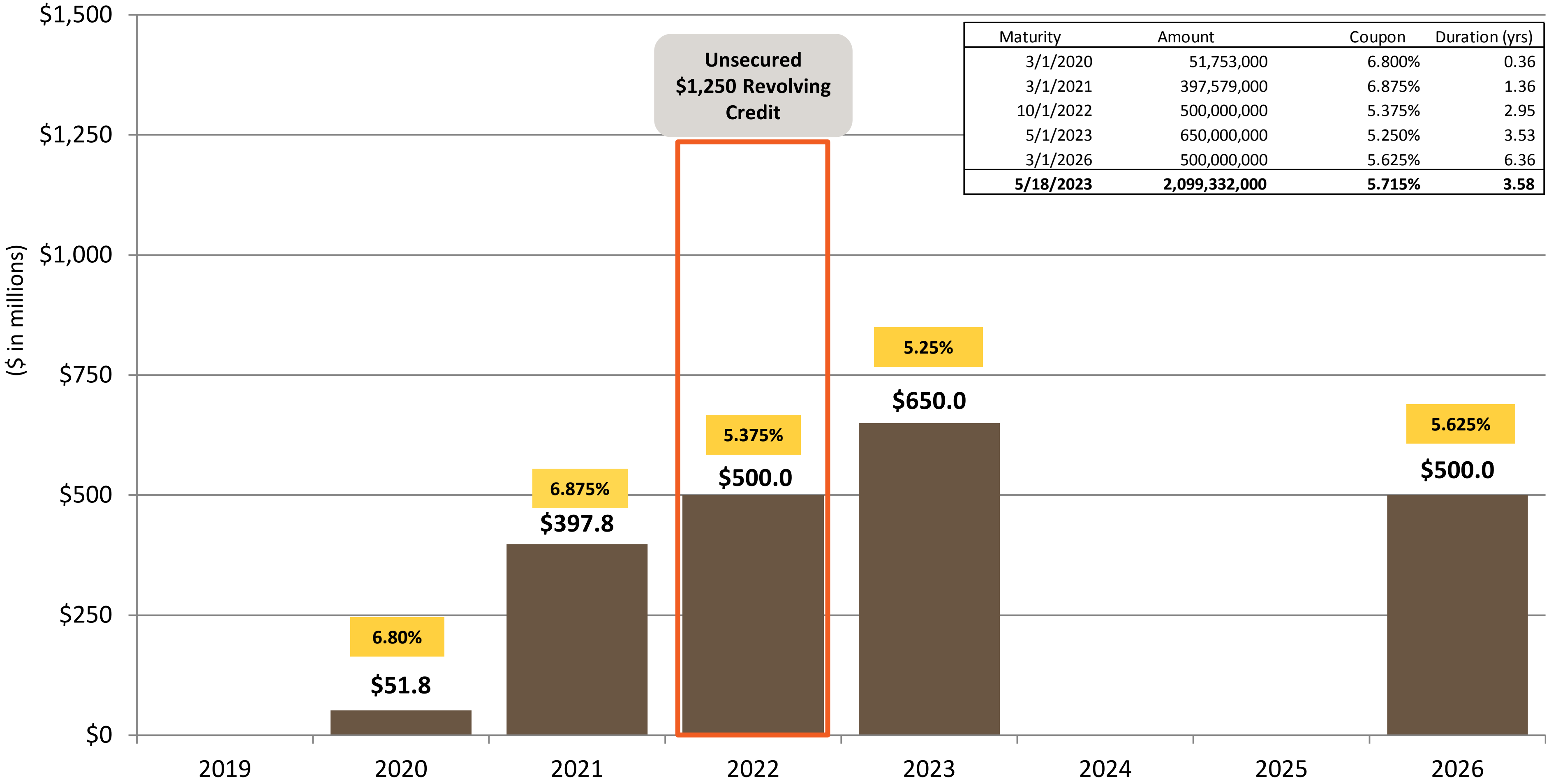
Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			(MMBbls)	($/Bbl)
2019	NYMEX WTI	Argus WTI Midland	1.7	($2.22)
2019	NYMEX WTI	Argus WTI Houston	0.5	$3.69
2020	NYMEX WTI	Argus WTI Midland	6.6	$0.17
2020 (January - June)	NYMEX WTI	Argus WTI Houston	0.4	$3.75

(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.

** Midpoint of 4Q 2019 guidance as of October 23, 2019.*

Debt Maturity Schedule

As of October 21, 2019

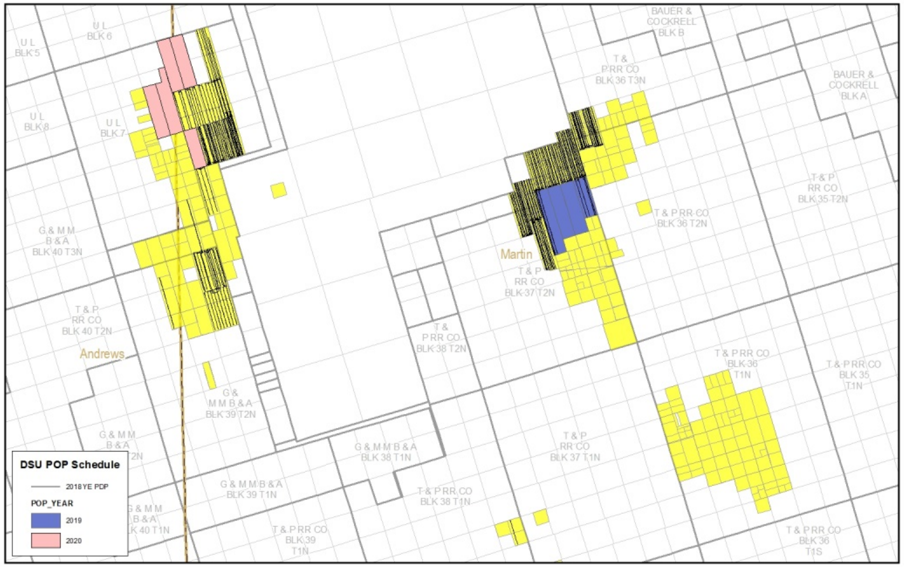


Maturity	Amount	Coupon	Duration (yrs)
3/1/2020	51,753,000	6.800%	0.36
3/1/2021	397,579,000	6.875%	1.36
10/1/2022	500,000,000	5.375%	2.95
5/1/2023	650,000,000	5.250%	3.53
3/1/2026	500,000,000	5.625%	6.36
5/18/2023	**2,099,332,000**	**5.715%**	**3.58**

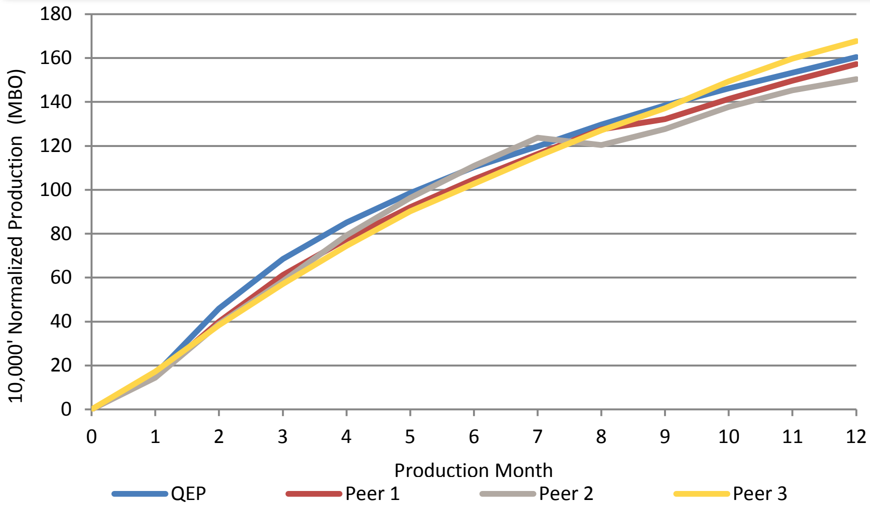
Permian Basin – 2020 Development Program

2020 Plan Overview

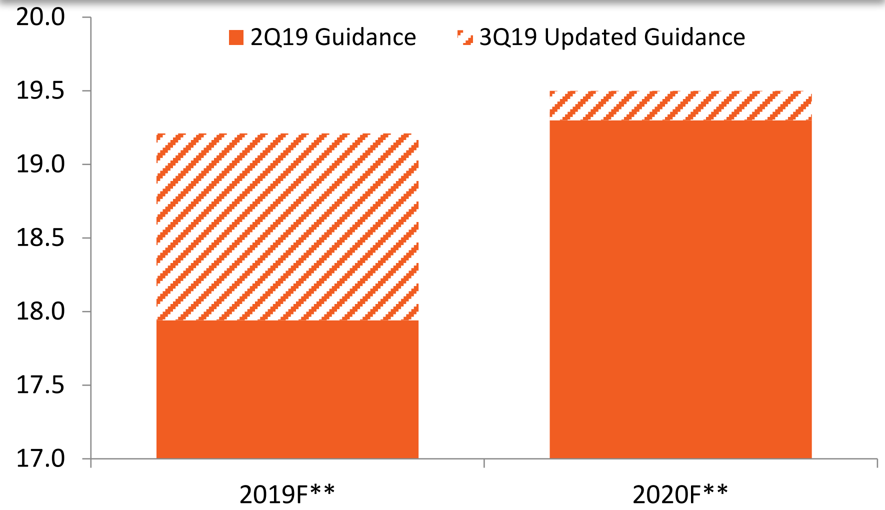
- Two rig program
- 100% on County Line acreage
  - ~60% of program in proven Spraberry Shale formation
- ~60 net wells put on production
  - Develops ~6% of remaining inventory
- Capital program is ~$45 million lower than 2019
- Modest production growth over improved full year 2019 guidance



Spraberry Shale Performance* (*12 -20* wells/mi)



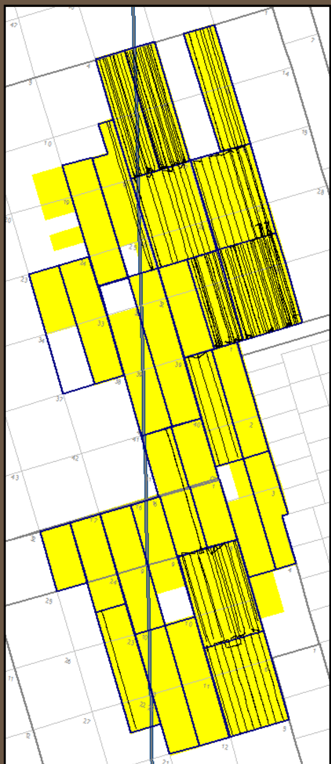
2020 Permian Basin Equivalent Volumes (Mboe)



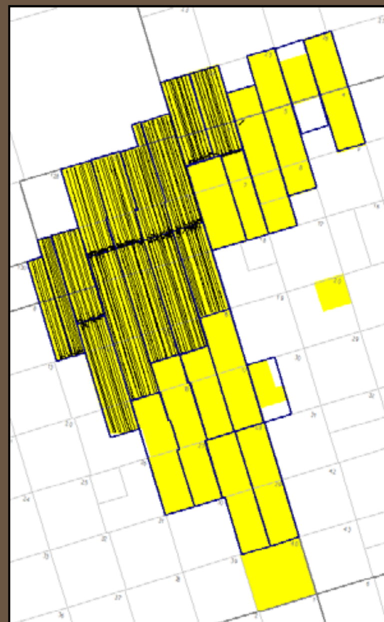
Note: QEP data consists of all wells in the Middle Spraberry (5/mi), Spraberry Shale (16/mi), and Wolfcamp A (3/mi) at the planned development densities
** IHS public data in Western Martin County since 1/2016. Peer group consists of PXD, ECA, and CXO. ** Represents midpoint of guidance as of October 23, 2019.*

Over 15 Years of Inventory in the Permian Basin[1]

County Line[2]



Mustang Springs



Robertson Ranch

Forecasted Average Density (wells/mi)		
Area	**CL**	**MS/RR**
Middle Spraberry	5-6	2-4
Lower Spraberry	4-5	4-5
Jo Mill	-	4-5
Spraberry Shale	15-16	8
Dean	-	6-7
Wolfcamp A	4-6	7-8
Wolfcamp B	-	7-8
Wolfcamp D	-	-
Total	28-33	38-45

- ~1,000 remaining locations based on $50/BBL oil price
- Density varies by area due to geologic variation
  - Increased density and additional zones achieved through price improvement, cost improvement, frac optimization and better targeting

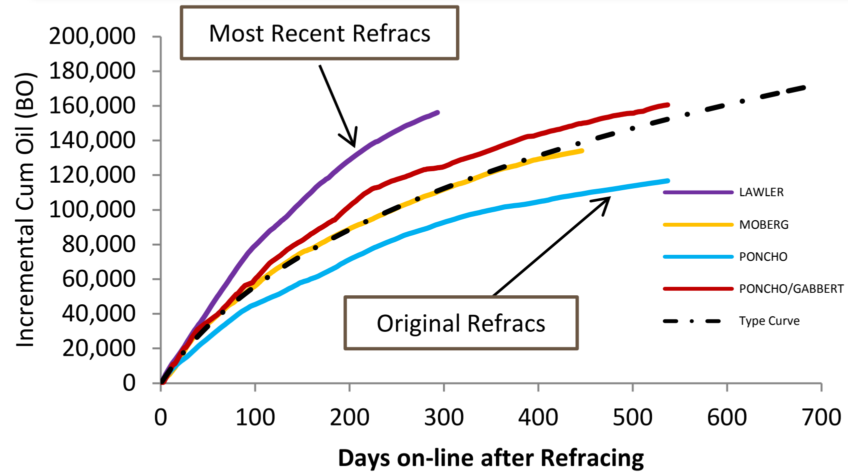
(1) At current two rig program.
(2) Most of southern County Line DSU's only developed in single zone.

Williston Basin – 2020 Development Program

2020 Plan Overview

- Development plan is based on a selective drilling and refrac program
- Capital program of ~$130 - $150 million
- Maintain relatively flat production profile
- Generates significant cash flow at the field level

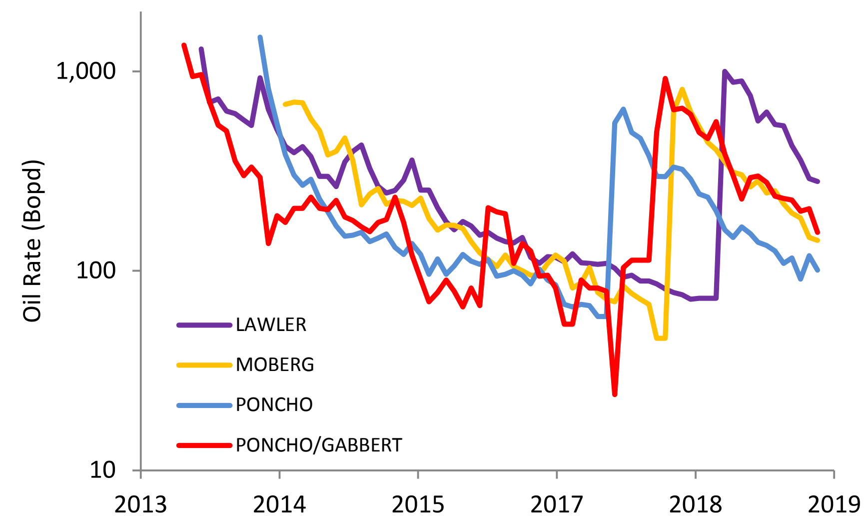
South Antelope Refrac Performance



Inventory Update

- 100+ "high-quality" refrac candidates(1)
  - Most recent refracs had an F&D cost of $8-$10/Boe
  - Avoid the parent-child interference associated with infill development
- 100+ new drill wells (non-infill) locations(1)
- 100+ additional well inventory with higher commodity price environment

South Antelope Refrac Uplift



(1) *Only includes locations identified as those making acceptable returns at $50 per barrel of crude oil.*