Investor Presentation

February 2020

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 first quarter 2020 and fiscal year 2020 production and certain underlying assumptions; guidance for 2020 Lease Operating Expense per Boe, Transportation & Processing Costs per Boe, DD&A per Boe, production and property taxes as a percentage of revenue, general and administrative expense, non-cash share-based compensation expense, and capital investment; expected drilling and completion cost per lateral foot and frac efficiency for fiscal year 2020; assumptions related to our guidance; guidance for wells and refracs put on production for first quarter 2020 and fiscal year 2020; and optimizing the Company’s cost structure; estimated drill and completion costs reductions; 2020 targeted free cash flow and leverage ratio; potential benefits of the Company’s water infrastructure; and estimated capital expenditure and production through 2021.

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; 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, 2019 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.

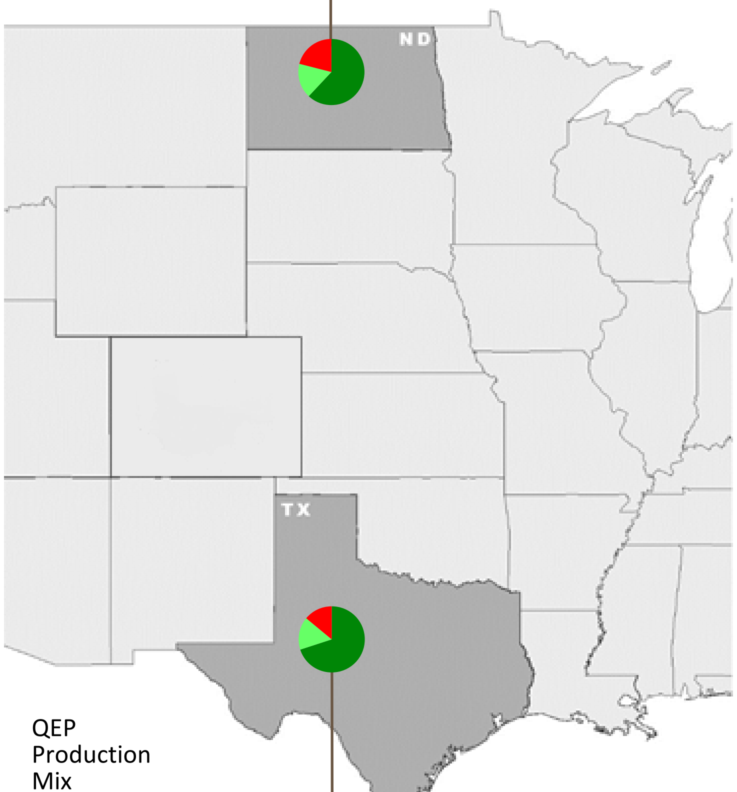
The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or through reliable technology to be economically and legally producible at specific prices and existing economic and operating conditions. The SEC permits 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]

Williston Basin
Net Acres: 94,608
4Q'19: 3,341.9 Mboe



QEP Production Mix
- Oil
- NGL
- Gas

Permian Basin
Net Acres: 49,165
4Q'19 5,113.4 Mboe

4Q & Full Year 2019 Highlights

- Generated Free Cash Flow (FCF)[2] of $56.2 million in the quarter
- Achieved D&C costs of $536 per lateral foot in the Permian Basin
- Completed 3,000 lateral feet per day with a single frac crew in the Permian Basin
- Reduced 4Q'19 G&A expense approximately 45% compared with 4Q'18 and achieved target 2020 G&A run rate
- Hedged 76% of projected 2020 oil production at ~$58 per barrel
- Organically delevered balance sheet, retiring $66.9 million of debt
  - Redeemed 6.8% Senior Notes Due 2020 - $51.7 million
  - Open market purchase of 6.875% Senior Notes Due 2021 - $15.2 million
- Ended the quarter with $166.3 million of cash and cash equivalents and no borrowings under credit facility

(1) Excludes equivalent production of 10.0 Mboe from Other Northern & Other Southern regions.
(2) Free Cash Flow is a Non-GAAP measure. The Company defines FCF as Adjusted EBITDA plus non-cash share-based compensation less interest expense, excluding amortization of deferred finance costs, and accrued property, plant and equipment capital expenditures. For a detailed discussion of Adjusted EBITDA and FCF and a reconciliation to the nearest GAAP measure, see reconciliation contained in our February 26, 2020 earnings release.

2019 Guidance Lookback[1]

	Original 2019 Guidance Midpoint	2019 Actual
Oil & Condensate Production (MMBbl)	21.0	21.6
Gas Production (Bcf)	24.0	33.1
NGL Production (MMBbl)	3.95	5.1
Total oil equivalent production (MMBoe)	29.0	32.2
Lease operating expense and Adjusted Transportation & Processing Costs (per Boe)	$9.50	$8.90
Depletion, depreciation and amortization (per Boe)	$17.25	$16.77
Production and property taxes (% of field-level revenue)	7.0%	7.5%
(in millions)		
Total G&A expense	$175	$156
Less: Special G&A expense[2]	$54	$50
Total G&A expense (excluding Special G&A)	$121	$106
Capital investment (excluding property acquisitions)		
Drilling, Completion and Equip[3]	$565	$527.7
Midstream Infrastructure[4]	$70	$41.8
Corporate	$5	$2.0
Total Capital Investment (excluding property acquisitions)	**$640**	**$571.50**
Wells put on production (net)	**53**	**65**

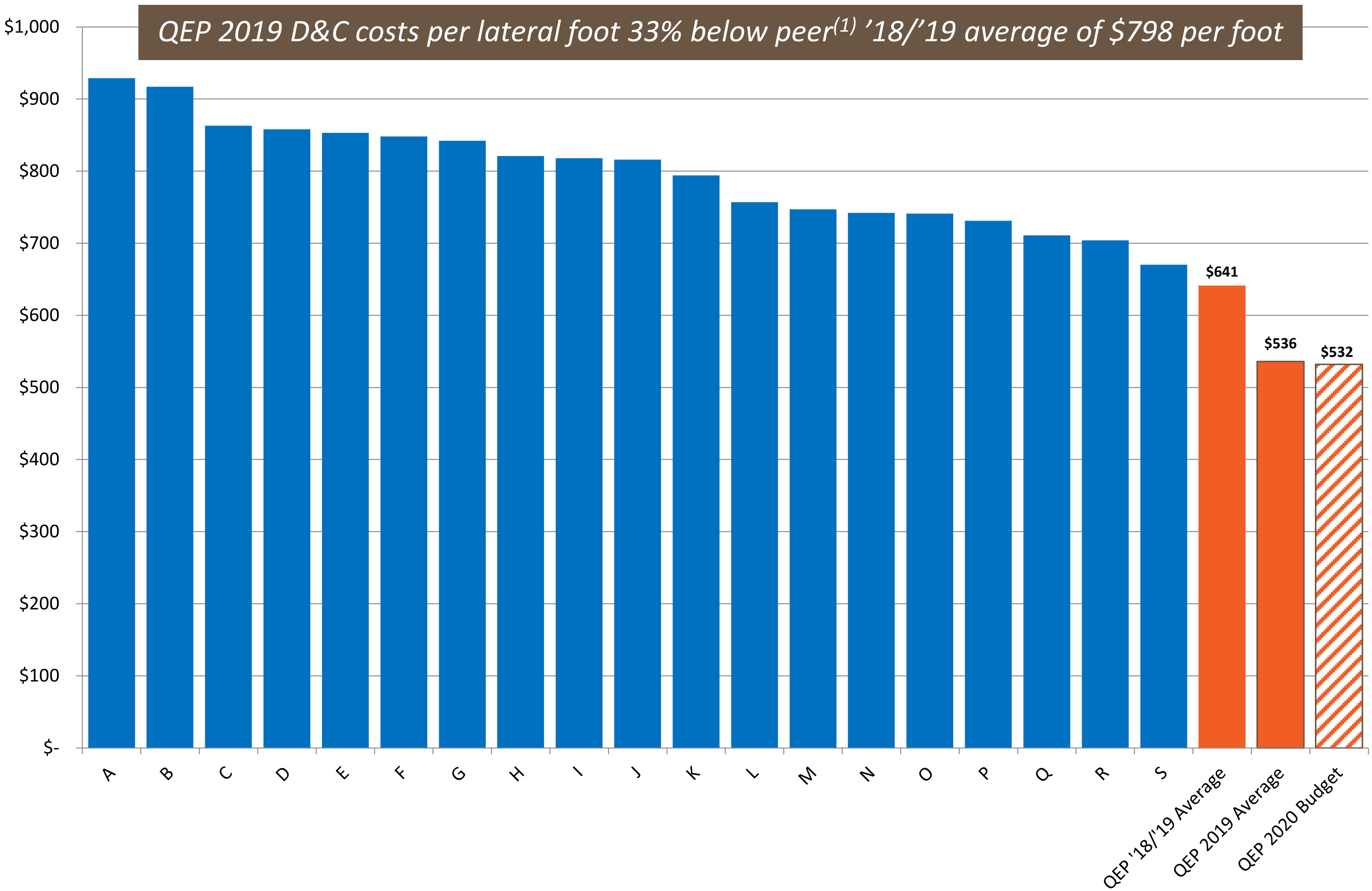
(1) As of February 20, 2019: The Company's full year 2019 guidance assumed an oil price of $55 per barrel and a natural gas price of $2.75 per MMBtu, assumed that QEP will elect to recover ethane from its produced gas in the Permian Basin where processing economics support ethane recovery, and assumed no property acquisitions or divestitures.
(2) Special G&A expense also included approximately $54 million of estimated expenses associated with our strategic initiative process, primarily related to severance and retention programs, and included approximately $11.0 million of accelerated shared-based compensation expense that is included in the $26 million of expenses related to non-cash, share-based compensation and other mark-to-market liabilities.
(3) Drilling, Completion and Equip includes approximately $20.0 million of non-operated well costs.
(4) 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.

2020 Guidance[1]

	1Q'20 Guidance	2020 Guidance
Oil & Condensate Production (MMBbl)	5.0 - 5.1	21.35 - 22.45
Gas Production (Bcf)	8.2 - 8.5	31.0 - 34.0
NGL Production (MMBbl)	1.3 - 1.4	5.0 - 5.6
Total oil equivalent production (MMBoe)	7.6 - 7.9	31.5- 33.7
Lease operating expense (per Boe)		\$5.20 - \$5.80
Adjusted Transportation and Processing Costs (per Boe) (2)		\$3.30 -\$3.60
Depletion, depreciation and amortization (per Boe)		\$17.75 - \$18.75
Production and property taxes (% of field-level revenue)		7.5%
(in millions)		
G&A expense (3)		\$85.0 -\$95.0
Capital investment (excluding property acquisitions)		
Drilling, Completion and Equip (4)		\$520.0 - \$565.0
Midstream Infrastructure (5)		\$20.0 - \$25.0
Corporate		\$5
Total Capital Investment (excluding property acquisitions)	\$180.0 - \$195.0	\$545.0 - \$595.0
Wells put on production (net)	21	69
Refracs put on production (net)	0	8

(1) As of February 26, 2020. QEP's first quarter and full year 2020 guidance assumes: (i) a WTI NYMEX oil price of \$55 per barrel, and a natural gas price of \$2.50 per MMBtu at Henry Hub, adjusted for applicable commodity and location differentials, (ii) that QEP will elect to recover ethane from its produced gas in the Permian Basin where processing economics support it, (iii) no property acquisitions or divestitures, and (iv) no impacts from a potential monetization of the Permian Basin water asset.
(2) Adjusted Transportation and Processing Costs (per Boe) is a non-GAAP measure. Refer to the definitions and reconciliations of Non-GAAP Measures in our press release dated February 26, 2020..
(3) The mid-point of G&A expense includes approximately \$13 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.
(4) Drilling, Completion and Equip includes approximately \$35 million of non-operated well costs.
(5) Includes capital expenditures in the Permian Basin associated with (i) water sourcing, gathering, recycling and disposal and (ii) crude oil and natural gas gathering system.

Permian Basin – Peer Leading D&C Cost Per Lateral Foot

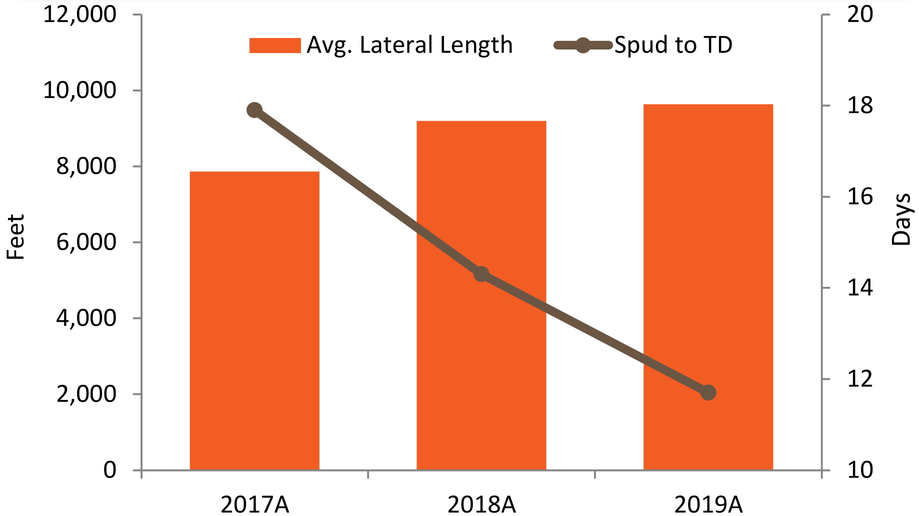


Source: Rystad Energy ShaleWellCube

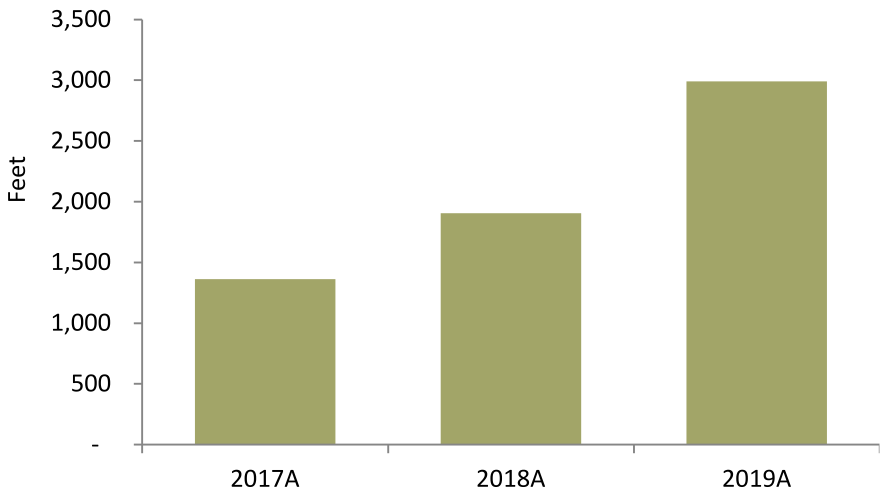
(1) '18/'19 average of following peers: Apache, Callon, Chevron, Concho, CrownQuest, Diamondback, Doublepoint, Endeavor, Exxon Mobil, Guidon, Hunt, Laredo, Lario, Ovintiv, Parsley, Pioneer, Sable, SM Energy, and Surge

Permian Basin – Historical Drilling and Completion Improvement

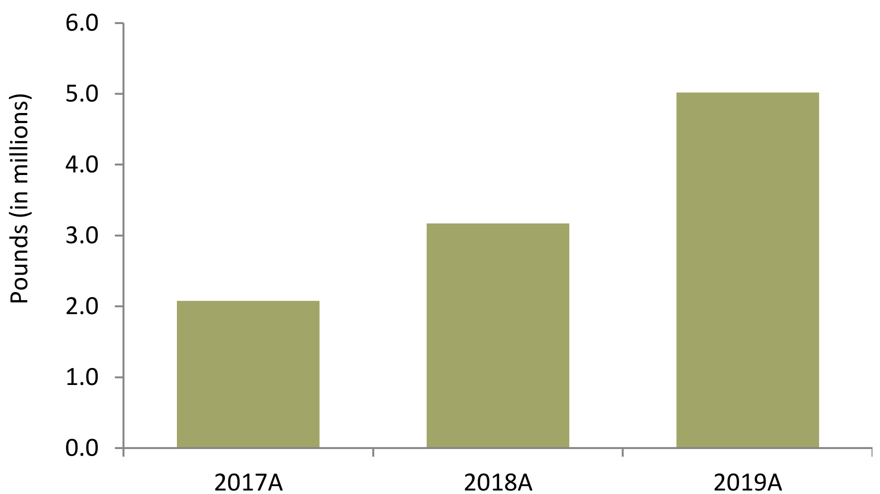
Shorter Drill Times



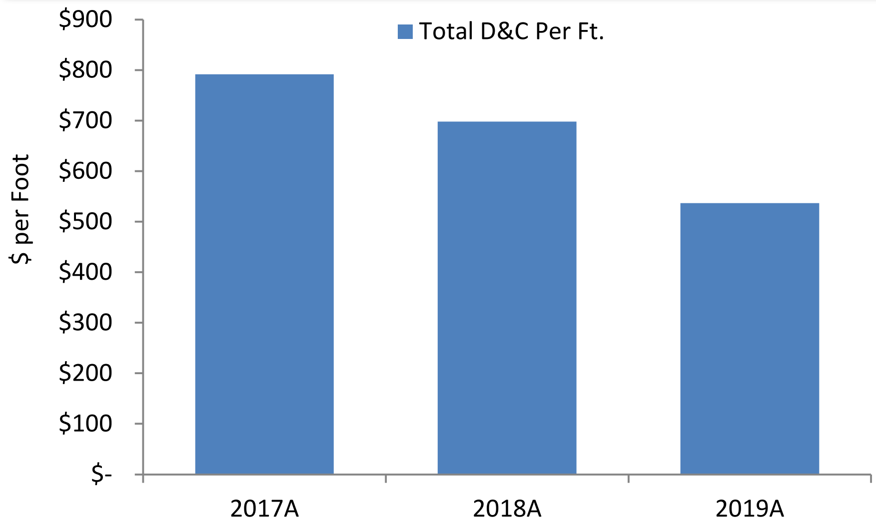
Lateral Length Completed per Day per Frac Crew



Average Proppant Placed per Day per Frac Crew

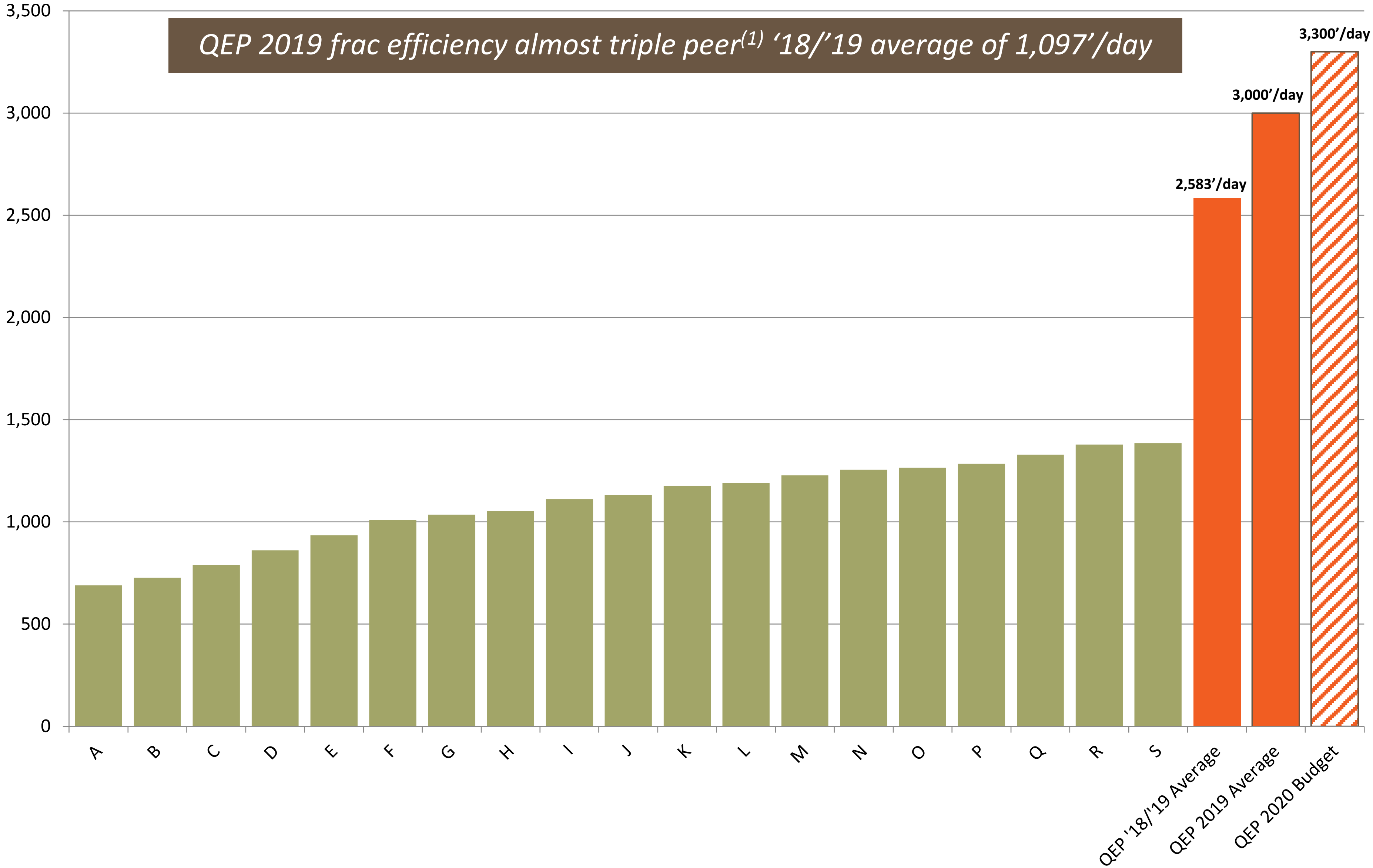


Drilling, Completion & Location Cost Improvement



Note: Spud to TD days include time to drill surface holes

Permian Basin – Peer Leading Frac Efficiency

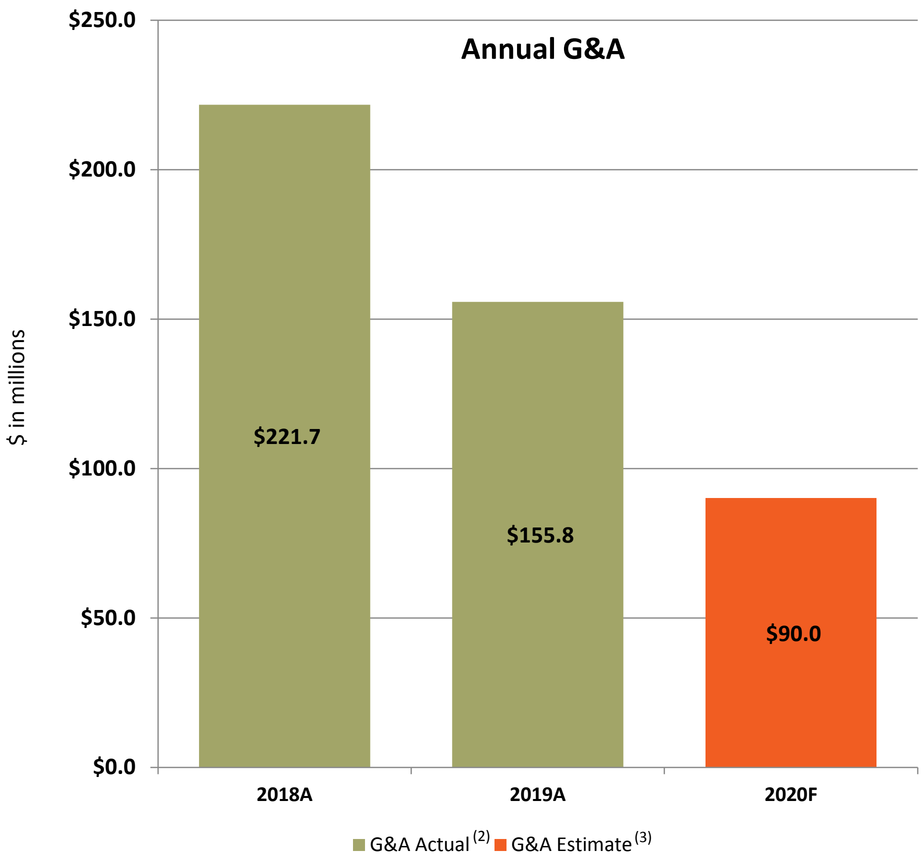


Source: Rystad Energy ShaleWellCube

(1) '18/'19 average of following peers: Apache, Callon, Chevron, Concho, CrownQuest, Diamondback, Doublepoint, Endeavor, Exxon Mobil, Guidon, Hunt, Laredo, Lario, Ovintiv, Parsley, Pioneer, Sable, SM Energy, and Surge

Transitioning to a Low Cost Operator

QEP is Focused on Optimizing Its Cost Structure



- G&A employee-related reductions
  - Lowered non-officer headcount by 60% since 2018
  - Decreased officer headcount by 54% in 2019
  - Retained core technical, operating and business expertise
- Reduced non-employee expense by 45% in 2019
  - Reduced corporate office footprint
  - 23% reduction in IT related costs
- Plan to deliver an additional 40% reduction to G&A[1] in 2020 compared with 2019

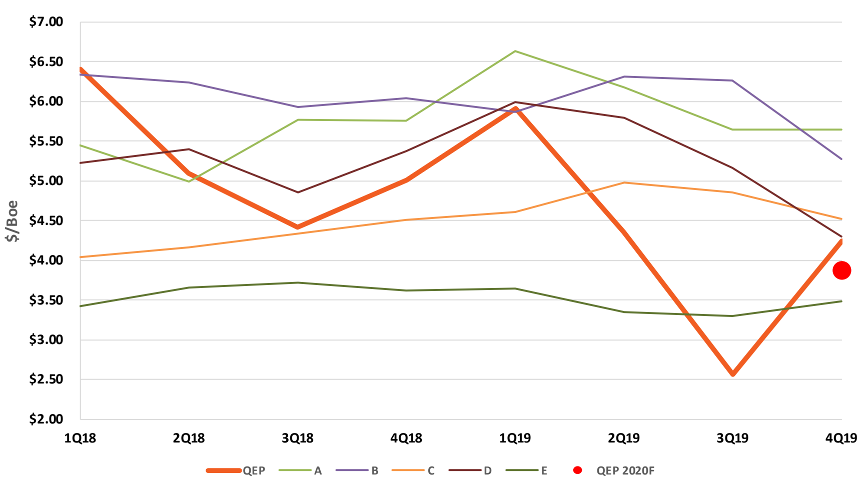
QEP Has Decreased G&A to Less Than $2.80 per BOE in 2020

(1) G&A includes cash and non-cash share based compensation expense. Based on February 26, 2020 guidance.
(2) G&A includes estimated expenses associated with our strategic initiative process, primarily related to severance and retention programs of $61 million in 2018 an $50.1 million in 2019.
(3) $90 million G&A expense represents the midpoint of 2020 G&A guidance.

Permian Basin – LOE Versus Peers

- Trending towards top-tier LOE performance
- 2019 reductions attributable to better management of maintenance and repair, rebidding of all services, and reduction of pumper routes
- 2020 focus will remain on planned maintenance activities and effective use of contracted services

LOE Trend vs Selected Peers[1]

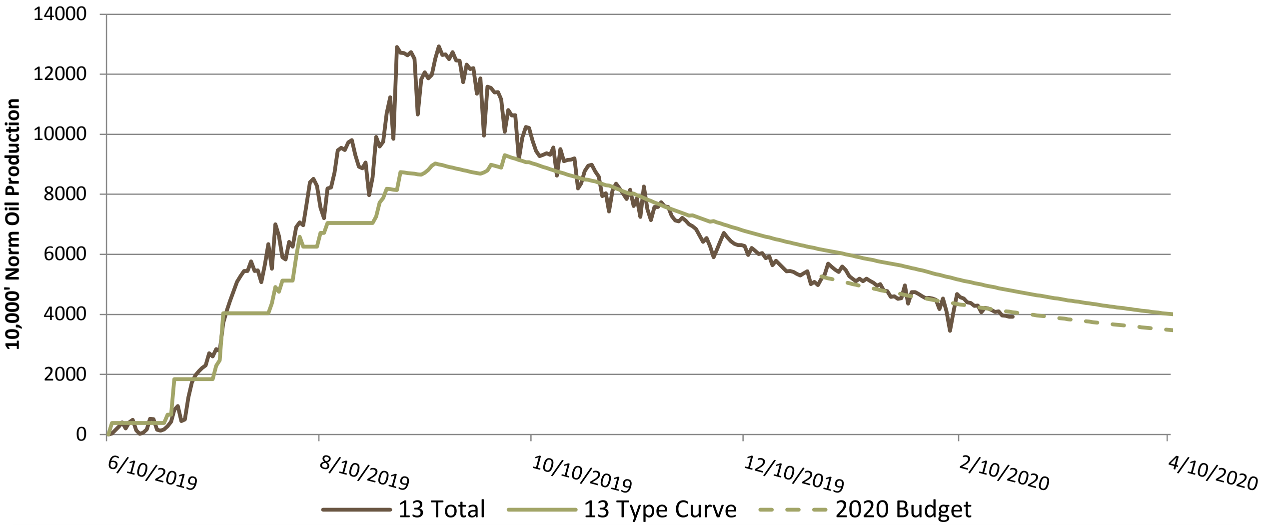


LOE Trend

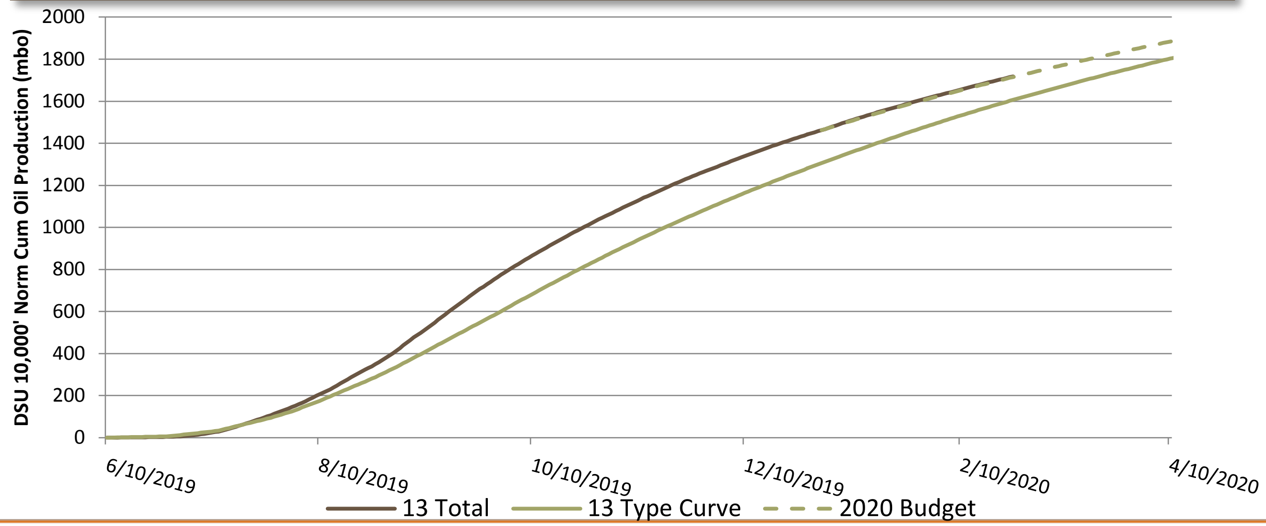
(1) Peers: CPE, CXO, FANG, PXD, PE. LOE includes workover expense.

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

DSU 13 Production Performance

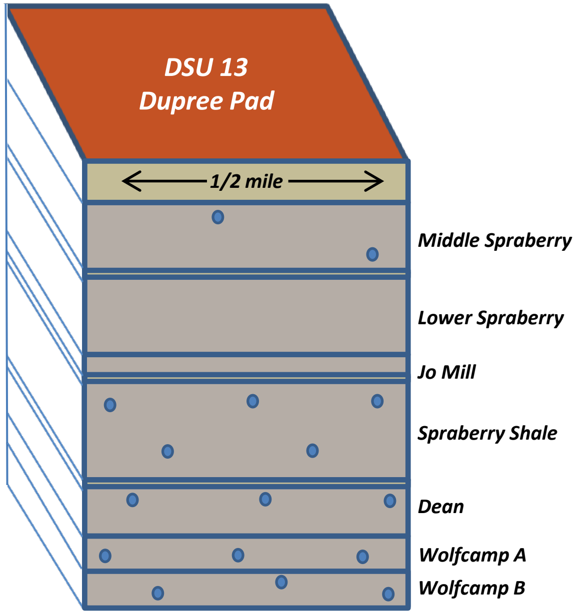


DSU 13 Cumulative Production Performance



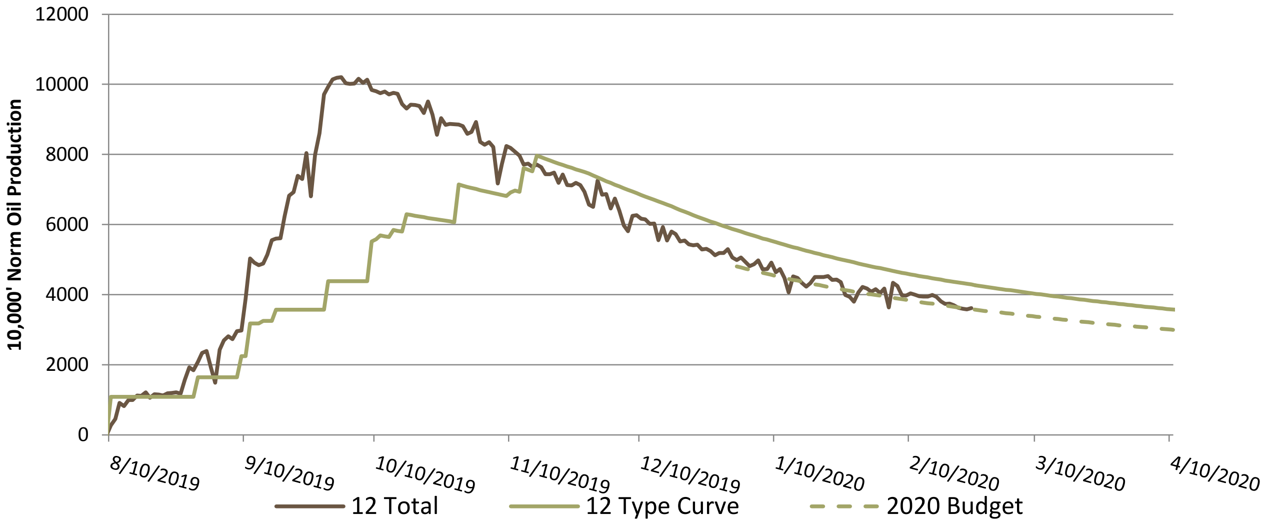
DSU 13 Results

- Enhanced flowback and artificial lift strategy shorten well cleanup times and achieve peak rates sooner
- Acceleration of oil recovery creates additional value to QEP
- No changes to expected ultimate recovery

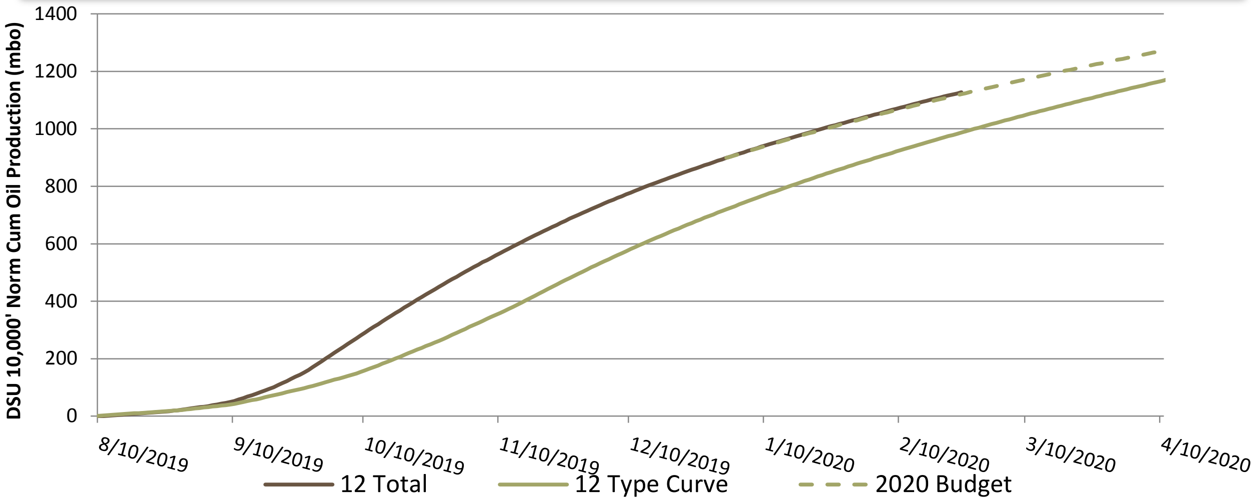


Permian Basin – *Mustang Springs DSU Performance (DSU 12)*

DSU 12 Production Performance

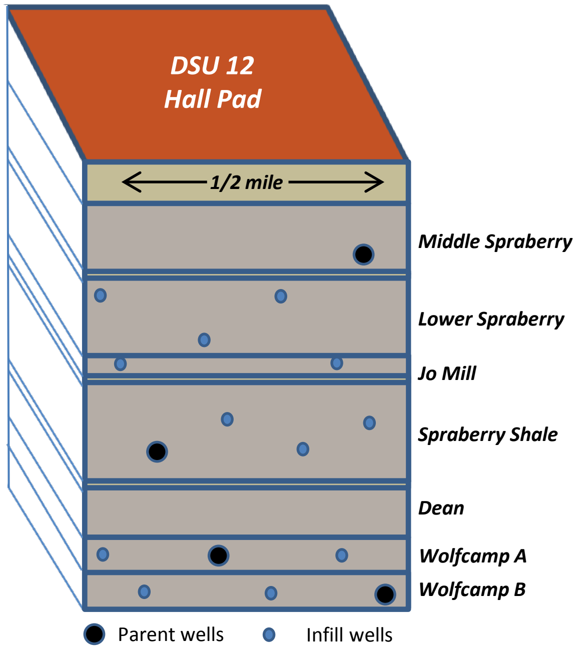


DSU 12 Cumulative Production Performance



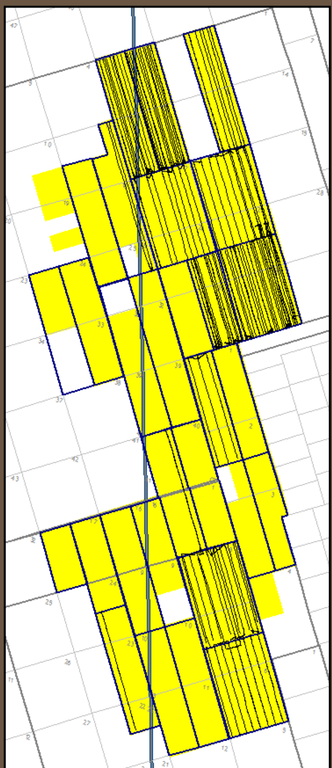
DSU 12 Results

- Parent-child interactions delivered within expectations
- Enhanced flowback and artificial lift methods improved early time performance
- No change to expected ultimate recovery

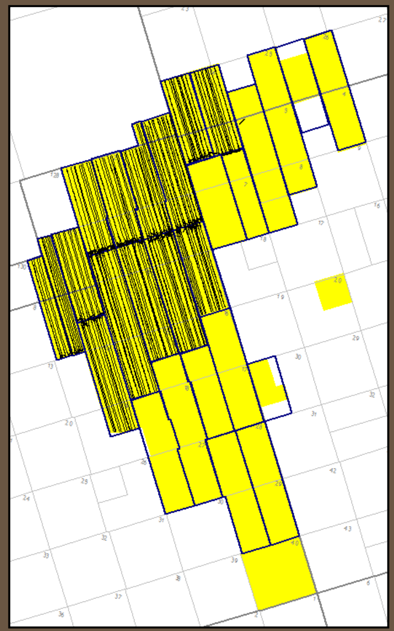


Over 15 Years of Inventory in the Permian Basin[1]

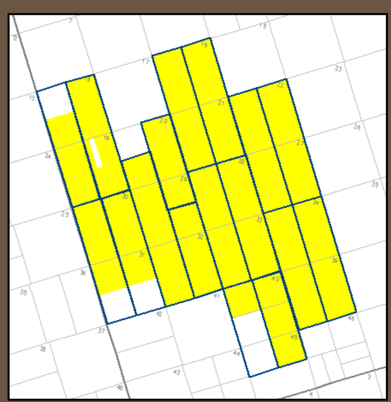
County Line[2]



Mustang Springs



Robertson Ranch



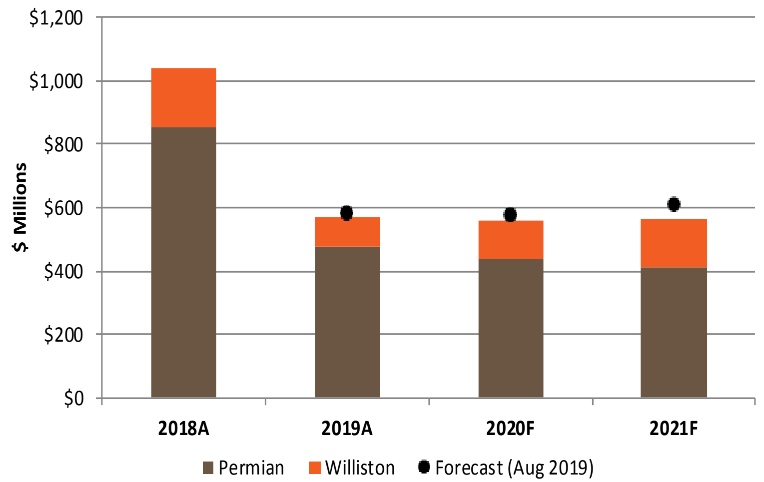
Forecasted Average Density (wells/mi)		
Area	**CL**	**MS/RR**
Middle Spraberry	5-6	2-4
Lower Spraberry	4-5	4-5
Jo Mill	-	4-5
Spraberry Shale	15-16	8
Dean	-	6-7
Wolfcamp A	4-6	7-8
Wolfcamp B	-	7-8
Wolfcamp D	-	-
Total	28-33	38-45

- ~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

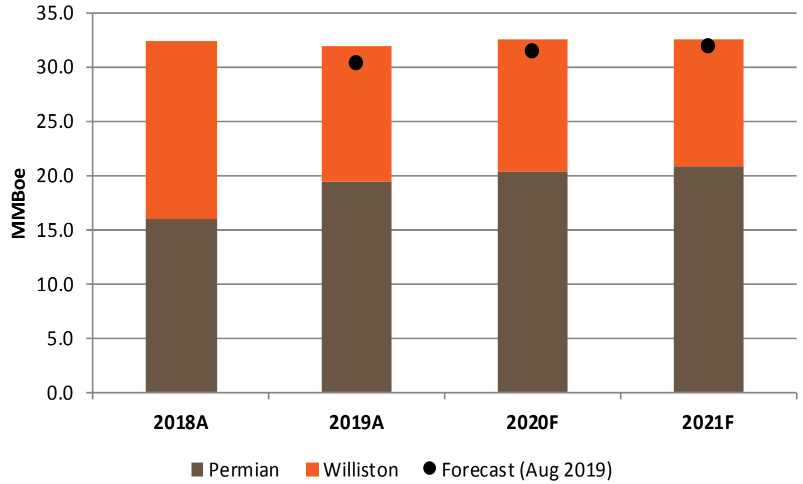
(1) *At current two rig program.*
(2) *Most of southern County Line DSU's only developed in single zone.*

QEP Resources 2018 – 2021 Overview

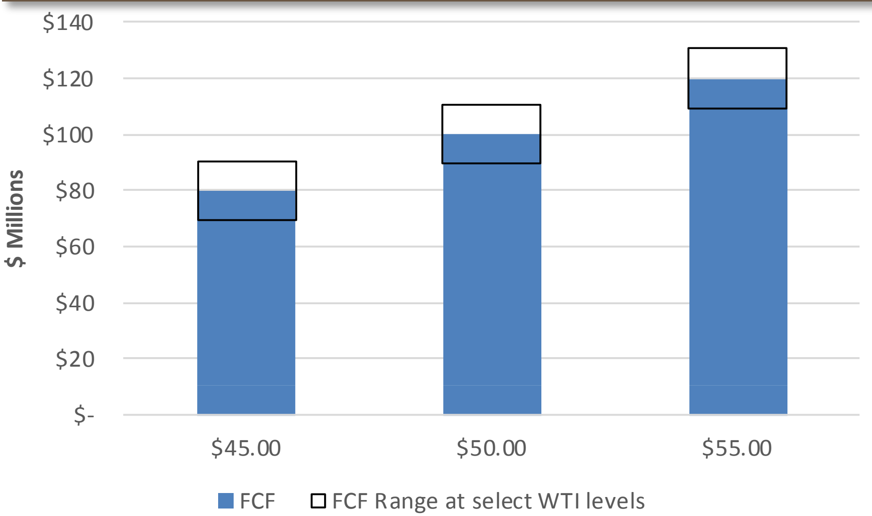
Capital Expenditures



Production (MMboe)

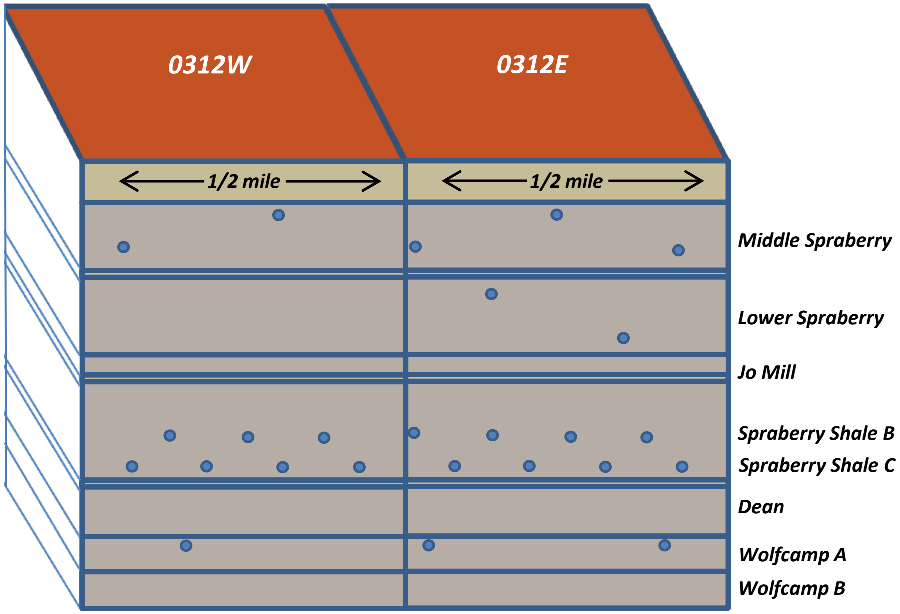


2020 Free Cash Flow



- Capital
  - Capital spend to be held flat at ~$570 million through 2021, down from August 2019 forecast
- Production
  - Permian – Expect to deliver a 3-yr CAGR of 9.0% (2021/2018), increased from August 2019 forecast
  - Williston – Expect to remain flat at ~12 MMboe through 2021
- Free Cash Flow
  - Expect to deliver ~$100 million at $50 WTI in 2020

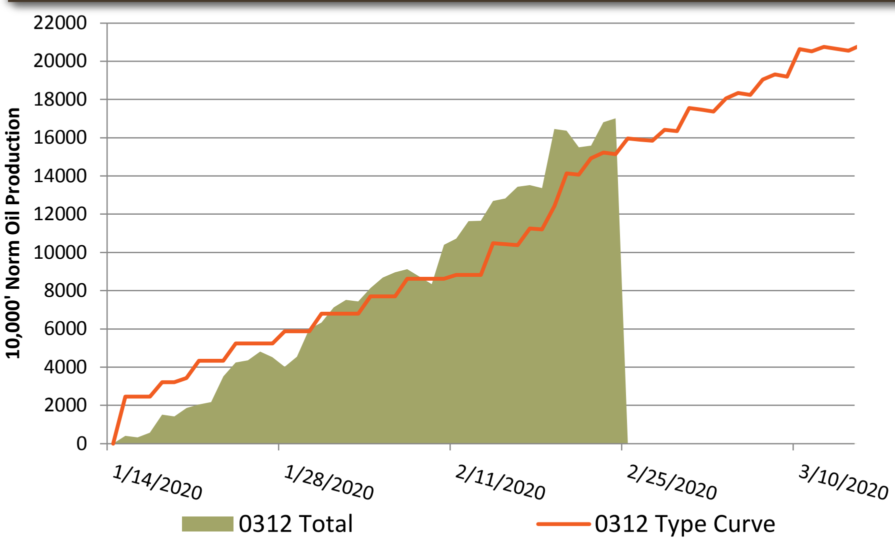
Permian Basin – *County Line University 0312E/W*



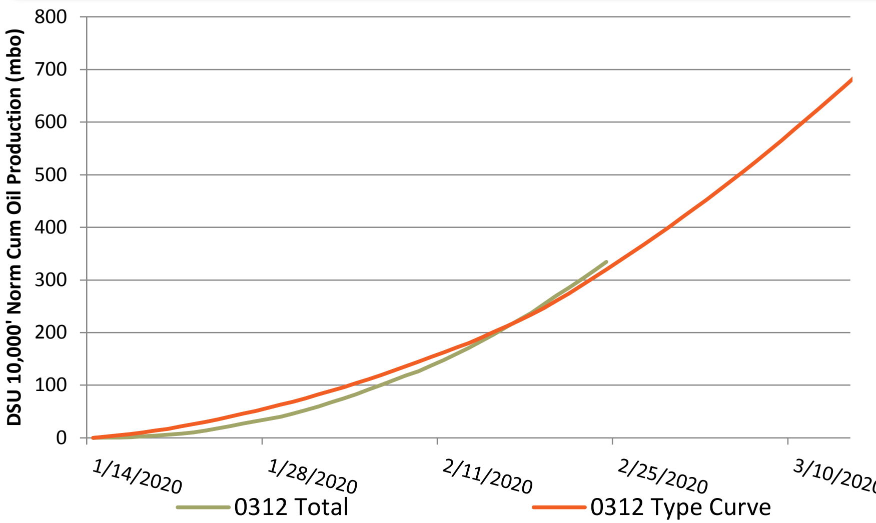
Early Time Observations

- Wolfcamp A and Spraberry Shale C-bench are outperforming expectations
- Spraberry Shale B-bench performing as expected
- Consistent with tank-style development, shallower targets continue to produce significant water volume as reservoir pressure is drawn down
  - Oil volumes expected to increase as wells reach pre-frac reservoir pressure

UL 0312 Production Performance



UL 0312 Cumulative Production Performance



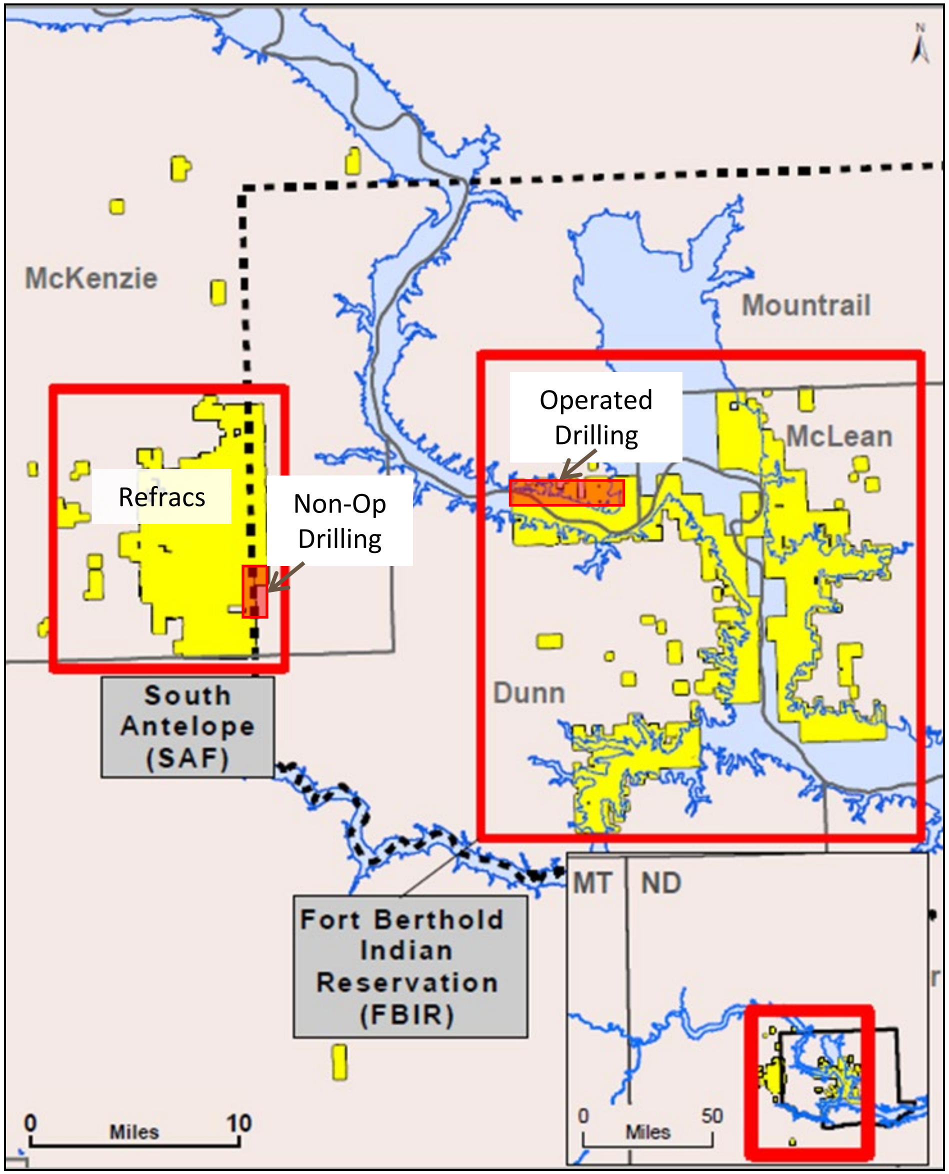
Williston Basin – 2020 Development Program

2020 Plan Overview

- Development plan is based on a selective drilling and refrac program
- Capital program of $120 million
  - Includes ~$35 million non-op drilling
- Maintains relatively flat production profile of 12 MMboe
- Generates meaningful cash flow

Inventory Update

- 100+ refrac candidates
- 100+ new drill wells (non-infill) locations at $50 WTI
- 100+ additional well inventory with higher commodity price environment



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: 280,000 Bwpd
- Recycle: 200,000 Bwpd
- Supply: 62,000 Bwpd
- Storage: 6.0 MMBbl

QEP Priorities

- Generate Free Cash Flow
  - ✓ Forecasting ~$100 million in 2020
  - ✓ Continue to optimize capital expenditures, LOE and corporate overhead
- Organically reduce leverage / strengthen balance sheet
  - ✓ Through FCF generation
  - ✓ Via proceeds from potential asset sales, including Permian water asset
  - ✓ Senior note repayment
- Return capital to shareholders
  - ✓ $0.02 per share quarterly dividend

Appendix

Derivative Positions – As of February 14, 2020

- 76% of 2020 forecasted oil production covered at an average price of $58/Bbl

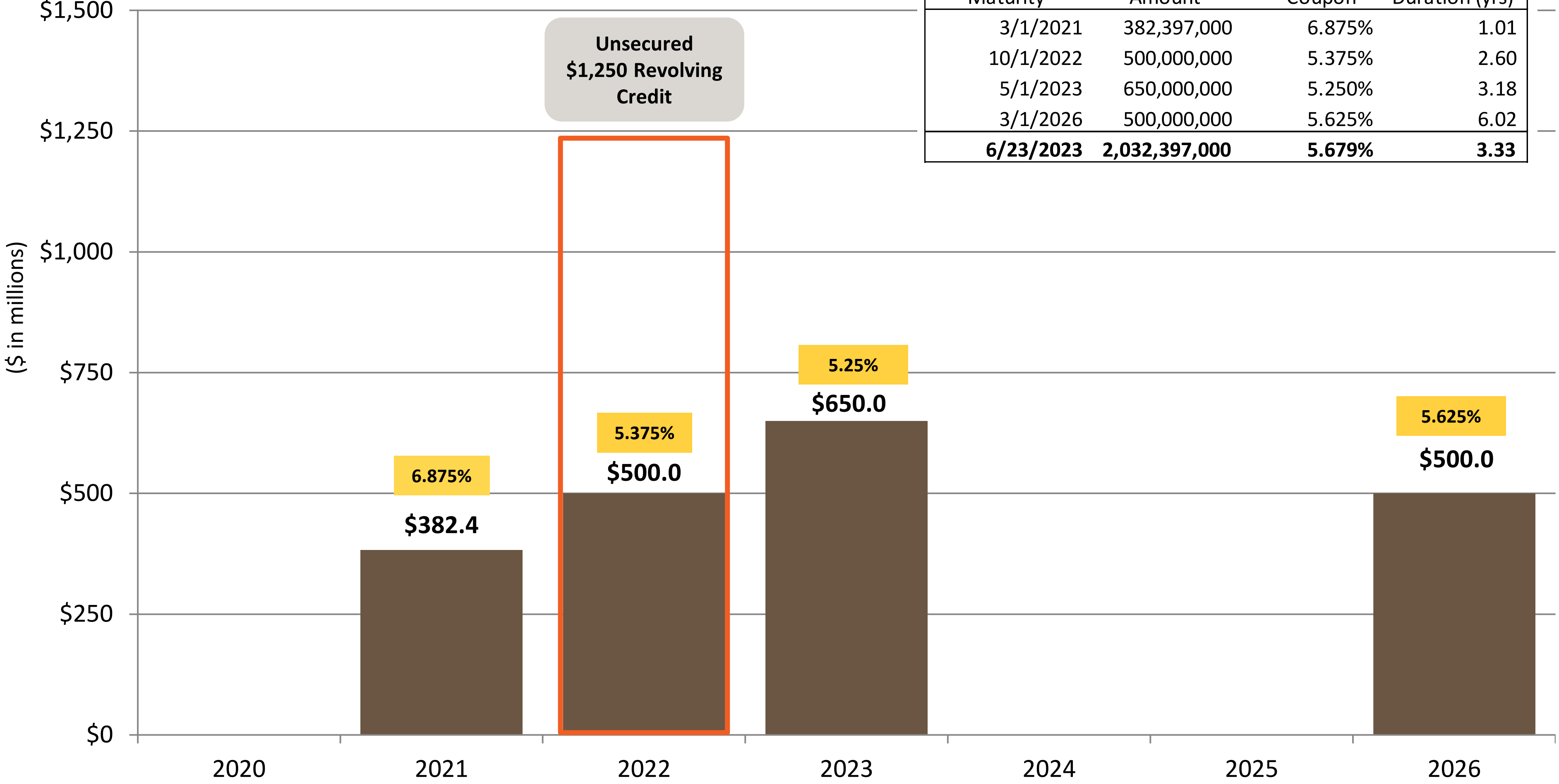
Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Swap Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2020	NYMEX WTI	13.0	$57.81
2020	Argus WTI Midland	1.3	$57.30
2020	Argus WTI Houston	0.8	$60.06
2021	NYMEX WTI	1.6	$55.04

Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			(MMBbls)	($/Bbl)
2020	NYMEX WTI	Argus WTI Midland	6.2	$0.19
2020	NYMEX WTI	Argus WTI Houston	0.3	$3.75
2021	NYMEX WTI	Argus WTI Midland	4.4	$0.99

(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.

Debt Maturity Schedule

As of February 25, 2020



Senior Notes Summary

Maturity	Amount	Coupon	Duration (yrs)
3/1/2021	382,397,000	6.875%	1.01
10/1/2022	500,000,000	5.375%	2.60
5/1/2023	650,000,000	5.250%	3.18
3/1/2026	500,000,000	5.625%	6.02
6/23/2023	**2,032,397,000**	**5.679%**	**3.33**