DIAMONDBACK Energy

Investor Presentation

August 2021

Forward Looking Statement and Non-GAAP Financial Measures

Forward-Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Diamondback Energy, Inc. (“we”, the “Company” or “Diamondback”) expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “believe,” “expect,” “may,” “estimates,” “will,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could,” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company’s acquisitions, dispositions, drilling programs, production, hedging activities, capital expenditure levels, environmental targets, and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced in the Company’s filings with the Securities and Exchange Commission (“SEC”), including its Forms 10-K, 10-Q and 8-K and any amendments thereto, relating to financial performance and results, the volatility of realized oil and natural gas prices, the threat, occurrence, potential duration or other implications of epidemic or pandemic diseases, including the ongoing coronavirus (“COVID-19”) pandemic, or any government response to such threat, occurrence or pandemic; conditions of U.S. oil and natural gas industry and the effect of U.S. energy, monetary and trade policies, U.S. and global economic conditions and political and economic developments, including the impact of the recent U.S. presidential and congressional elections on energy and environmental policies and regulations, any other potential regulatory actions (including those that may impose production limits in the Permian Basin), current macroeconomic conditions, demand for oil and natural gas, impact of impairment charges, effects of hedging arrangements, availability of drilling equipment and personnel, levels of production; severe weather conditions (including the impact of the recent severe winter storms on production volume), impact of reduced drilling activity, availability of sufficient capital to execute the Company’s business plan, successful results from the Company’s identified drilling locations, the Company’s ability to replace reserves and efficiently develop and exploit its current reserves, the Company’s ESG goals and initiatives, the Company’s ability to successfully identify, complete and integrate acquisitions of properties or businesses, including the recently completed merger with QEP Resources, Inc. (“QEP”) and acquisition of certain assets from Guidon Operating LLC (“Guidon”), the Company’s ability to complete its pending divestiture discussed in this presentation, and other important factors that could cause actual results to differ materially from those projected.

Any forward-looking statement speaks only as of the date on which such statement is made, and Diamondback undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Readers are cautioned not to place undue reliance on these forward-looking statements that speak only as of the date hereof.

The presentation also contains the Company’s updated capital expenditure and production guidance, and certain forward-looking information, with respect to 2021. The actual levels of production, the Company’s ability to complete the newly-announced divestiture of assets, capital expenditures, expenses and other estimates may be higher or lower than these estimates due to, among other things, uncertainty in drilling schedules, changes in market demand and unanticipated delays in production. These estimates are based on numerous assumptions, including assumptions related to number of wells drilled, average spud to release times, rig count, and production rates for wells placed on production. All or any of these assumptions may not prove to be accurate, which could result in actual results differing materially from estimates. If any of the rigs currently being utilized or intended to be utilized becomes unavailable for any reason, and the Company is not able to secure a replacement on a timely basis, we may not be able to drill, complete and place on production the expected number of wells. Similarly, average spud to release times may not be maintained in 2021. No assurance can be made that new wells will produce in line with historic performance, or that existing wells will continue to produce in line with expectations. Our ability to fund our 2021 and future capital budgets is subject to numerous risks and uncertainties, including volatility in commodity prices and the potential for unanticipated increases in costs associated with drilling, production and transportation. In addition, our production estimate assumes there will not be any new federal, state or local regulation of portions of the energy industry in which we operate, or an interpretation of existing regulation, that will be materially adverse to our business. For additional discussion of the factors that may cause us not to achieve our production estimates, see the Company’s filings with the SEC, including its forms 10-K, 10-Q and 8-K and any amendments thereto. We do not undertake any obligation to release publicly the results of any future revisions we may make to this prospective data or to update this prospective data to reflect events or circumstances after the date of this presentation. Therefore, you are cautioned not to place undue reliance on this information.

Non-GAAP Financial Measures

Consolidated Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines Adjusted EBITDA as net income (loss) attributable to Diamondback Energy, Inc., plus net income (loss) attributable to non-controlling interest ("net income (loss)") before non-cash (gain) loss on derivative instruments, net, interest expense, net, depreciation, depletion, amortization and accretion, depreciation and interest expense related to equity method investments, impairment and abandonments related to equity method investments, (gain) loss on sale of equity method investments, loss on extinguishment of debt, impairment of oil and natural gas properties, non-cash equity-based compensation expense, capitalized equity-based compensation expense, merger and integration expense, other non-cash transactions and provision for (benefit from) income taxes, if any. Consolidated Adjusted EBITDA is not a measure of net income as determined by United States’ generally accepted accounting principles ("GAAP"). Management believes Consolidated Adjusted EBITDA is useful because the measure allows it to more effectively evaluate the Company’s operating performance and compare the results of its operations from period to period without regard to its financing methods or capital structure. The Company adds the items listed above to net income (loss) in arriving at Consolidated Adjusted EBITDA because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Consolidated Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of the Company’s operating performance or liquidity. Certain items excluded from Consolidated Adjusted EBITDA are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure, as well as the historic costs of depreciable assets. The Company’s computation of Consolidated Adjusted EBITDA may not be comparable to other similarly titled measures of other companies or to such measure in our credit facility or any of our other contracts. For a reconciliation of Consolidated Adjusted EBITDA to net income (loss), and other non-GAAP financial measures, please refer to our earnings release furnished to, and other filings we make with the SEC.

Free Cash Flow, which is a non-GAAP financial measure, is cash flow from operating activities before changes in working capital in excess of cash capital expenditures. The Company believes that Free Cash Flow is useful to investors as it provides a measure to compare both cash flow from operating activities and additions to oil and natural gas properties across periods on a consistent basis. These measures should not be considered as an alternative to, or more meaningful than, net cash provided by operating activities as an indicator of operating performance. The Company's computation of operating cash flow before working capital changes and Free Cash Flow may not be comparable to other similarly titled measures of other companies. The Company uses Free Cash Flow to reduce debt, and increase the return of capital to stockholders above the base dividend. For a reconciliation of net cash provided by operating activities to operating cash flow before working capital changes and to Free Cash Flow, please refer to our earnings release furnished to, and other filings we make with, the SEC.

Net Debt is outstanding long-term debt, comprised of bonds, borrowings under our credit facility and other interest-bearing long-term debt, excluding any issuance premiums or discounts, less cash on hand.

Oil and Gas Reserves

The SEC generally permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, and certain probable and possible reserves that meet the SEC’s definitions for such terms. The Company discloses only estimated proved reserves in its filings with the SEC. The Company’s estimated proved reserves (including those of its consolidated subsidiaries) as of December 31, 2020 referenced in this presentation were prepared by Ryder Scott Company, L.P., an independent engineering firm, and comply with definitions promulgated by the SEC. Additional information on the Company’s estimated proved reserves is contained in the Company’s filings with the SEC. This presentation also contains the Company’s internal estimates of its potential drilling locations, which may prove to be incorrect in a number of material ways. Actual number of locations that may be drilled may differ substantially.

Diamondback Energy: Leading Pure-play Permian Operator

Large Cap Permian pure-play E&P:

- ~414,000 net Midland and Delaware basin acres[1]
- >11,100 gross (>7,600 net horizontal locations)[1]

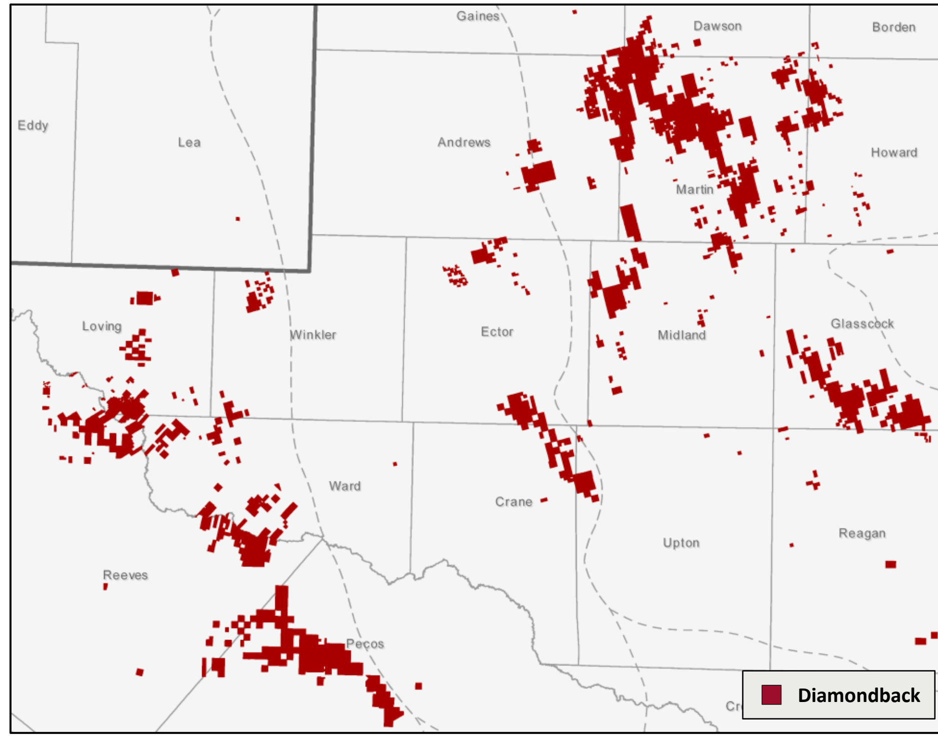
Significant Free Cash Flow and Low Cost Structure:

- Generated $578 million of Free Cash Flow ("FCF") in Q2 2021; $909 million of FCF generated in the first half of 2021
- $1.80 per share annual dividend, up ~13% from $1.60 per share previously[2]
- Anticipate maintaining Q4 2021 Permian Basin oil production in 2022 for 10% - 15% more capital than current 2021 capital budget; implied breakeven WTI oil price of ~$32 / Bbl[3]
- Pre-dividend FCF in 2022 expected to be split equally between return of capital to stockholders and additional debt reduction[2]

Strong Balance Sheet with Substantial Liquidity:

- Fully redeemed $191 million aggregate principal amount of remaining 4.625% Energen bonds
- Announced full redemption of $432 million remaining aggregate principal amount of 5.375% bonds due 2025
- >$1.8 billion of standalone liquidity as of June 30, 2021[4]
- Pending divestiture of Williston Basin asset acquired in QEP transaction expected to close in late Q3 2021
- Plan to redeem $650 million 2023 bonds with a combination of cash on hand and proceeds from the pending Williston Basin divestiture

Diamondback Acreage Map[1]



Diamondback Market Snapshot

NASDAQ Symbol: FANG

Market Cap: $13,965 million

Net Debt: $7,076 million[5]

Enterprise Value: $22,005 million

Share Count: 181 million

Annual Dividend: $1.80 (2.3% current yield)[2]

Source: Company data, public filings, and Bloomberg. Financial data as of 6/30/2021. Market data as of 7/30/2021.

(1) Excludes non-Permian assets. Net acreage excludes exploratory and conventional acreage.

(2) Future dividends subject to the discretion and approval of the Board of Directors. Yield based on 7/30/2021 closing price.

(3) Cash flow breakeven defined as estimated cash CAPEX required to maintain implied Q4 2021 Permian oil production through 2022; assumes $2.50/Mcf Henry Hub gas prices and $18/Bbl NGL prices. Please see slide 10 for additional detail.

(4) Excludes Viper and Rattler.

(5) Long-term debt less cash.

Diamondback: Investment Highlights

Q2 2021 Highlights	◆ Generated $578 million of FCF ($3.18 / share)(1) ◆ Oil production of 242.5 Mbo/d (401.5 Mboe/d) ◆ Increasing annual dividend by ~13% to $1.80 / share; declared Q2 2021 cash dividend of $0.45 / share payable August 19, 2021 ◆ Closed non-core Permian divestitures for net proceeds of $82 million ◆ Fully redeemed $191 million aggregate principal amount of remaining 4.625% EGN bonds
2021 Guidance	◆ Increased production guidance to 219 – 222 Mbo/d (363 – 370 Mboe/d) ◆ Lowered Cash CAPEX guidance to $1.525 – $1.625 billion, down 6% versus prior guidance ◆ Expect to drill 210 – 220 gross wells and complete 265 – 275 gross horizontal wells with an average lateral of ~10,300 feet (75% Midland Basin / 25% Delaware Basin)
Q3 2021 Guidance	◆ Production guidance of 233 – 239 Mbo/d (388 – 398 Mboe/d)(2) ◆ Permian production guidance of 218 – 222 Mbo/d (363 – 370 Mboe/d) ◆ Cash CAPEX guidance of $430 – $480 million
Investment Framework	◆ Expect to generate substantial pre-dividend Free Cash Flow through 2021, with a reinvestment rate of <50%, assuming current commodity prices(1) ◆ FCF and asset sale proceeds to reduce callable debt by up to $1.2 billion by YE21 ◆ Company expects it can maintain Q4 2021 Permian oil production through 2022 spending 10% - 15% more capital than 2021 plan; cash flow breakeven WTI oil price of ~$32 / Bbl(3) ◆ 50% of 2022 FCF expected to be returned to stockholders
ESG Initiatives	◆ Committed to reducing Scope 1 GHG intensity by at least 50% from 2019 levels by 2024 ◆ Committed to reducing methane intensity by at least 70% from 2019 levels by 2024 ◆ "Net Zero Now": As of January 1, 2021, every hydrocarbon molecule produced by Diamondback is anticipated to be produced with zero net Scope 1 emissions

Source: Company data and filings. Financial data as of 6/30/2021 unless otherwise noted.

(1) FCF defined as operating cash flow before changes in working capital less cash CAPEX. Reinvestment rate defined as cash CAPEX divided by pre-dividend cash flow from operations before changes in working capital.

(2) Assumes full third quarter 2021 Williston Basin production contribution of 15-17 MBO/d (25-29 MBOE/d). Third quarter volumes will be reduced proportionally dependent upon close date of Williston Basin Sale.

(3) Cash flow breakeven defined as estimated cash CAPEX required to maintain implied Q4 2021 Permian oil production through 2022; assumes $2.50/Mcf Henry Hub gas prices and $18/Bbl NGL prices. Please see slide 10 for additional detail.

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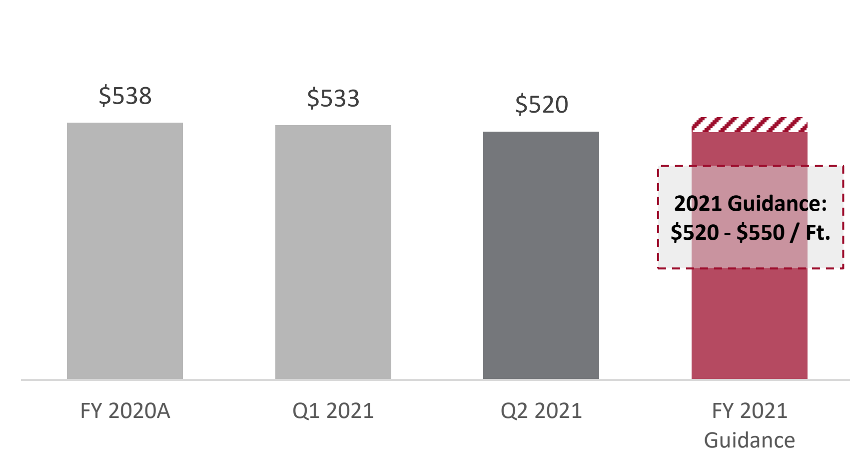
Second Quarter 2021 Execution

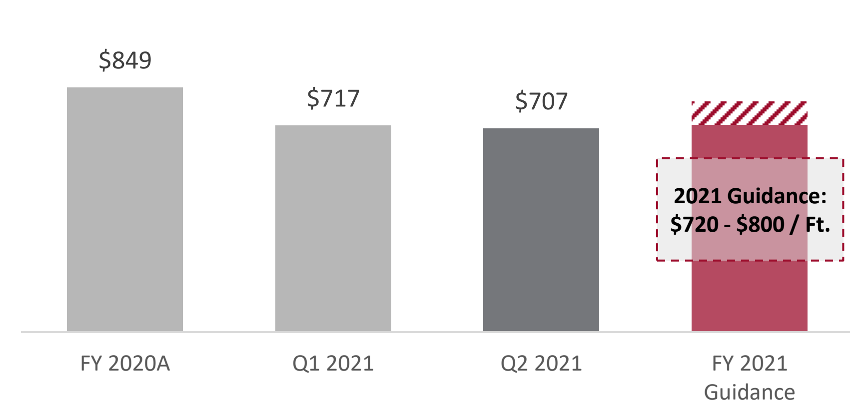
Q2 2021 Execution

	Q1 2021	Change	Q2 2021
Oil Production *Net Mbo/d*	184	+32%	242
Net Lateral Feet *TIL Net Ft. (1,000's)*	620	+7%	662
Cash Margin *% of Unhedged Realized Price[1]*	76%	~Flat	76%
Reinvestment Rate *Cash CAPEX / Cash Flow (%)*	47%	-18%	39%
Free Cash Flow *$ / Share[2]*	$2.01	+58%	$3.18
Quarterly Dividend *$ / Share[3]*	$0.40	+13%	$0.45

Gross Midland Basin D,C&E Well Costs ($ / Ft.)[4]



Gross Delaware Basin D,C&E Well Costs ($ / Ft.)[4]



Source: Company data, filings and estimates.

(1) Unhedged cash margins calculated as the sum of unhedged realized price per boe less cash operating costs including interest divided by unhedged realized price per boe.

(2) Free cash flow calculated as operating cash flow before changes in working capital and dividends, less cash CAPEX for D,C&E, non-operated properties and workovers, midstream, infrastructure and environmental; excludes long-haul pipeline investments.

(3) Future dividends subject to the discretion and approval of the Board of Directors.

(4) Well costs assume gross Rattler costs.

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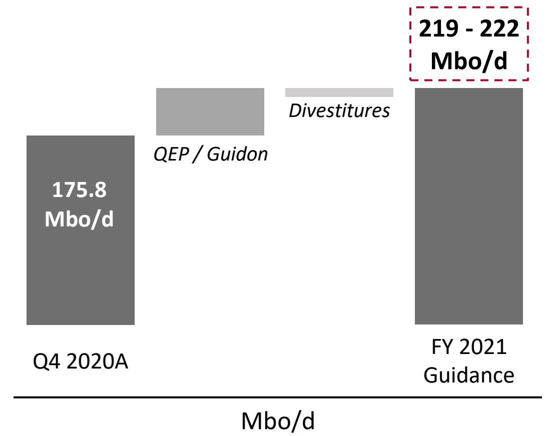
Overview of 2021 Guidance and Capital Budget

2021 Activity and Guidance Midpoints vs 2020

	2020A	Prior 2021 Guidance	2021 Guidance	Change
Oil Production *Net Mbo/d*	181	214	221	+22%
TIL Lateral Feet *Net Ft. (1,000's)*	1,668	2,621	2,585	+55%
Drilled Lateral Feet *Net Ft. (1,000's)*	1,968	1,906	2,034	+3%
Capital Budget *$MM(1)*	$1,859	$1,675	$1,575	-15%
Annual Dividend *$ / Share*	$1.50	$1.60	$1.80	+20%
Reinvestment Rate *$55 / Bbl WTI(2)*	92%	55%	50%	-46%

2021 Production and Activity Outlook

2021 plan focused on maintaining pro forma Q4 2020 Permian oil production



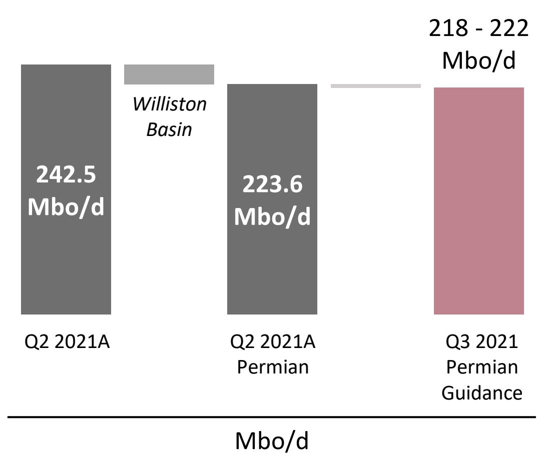
FY 2021 Activity

210 – 220
Gross operated wells drilled

265 – 275
Gross operated wells TIL

75%
Midland Basin net lateral ft.

Q3 2021 Production and Capital Guidance



Q3 2021 Guidance

233 – 239
Oil Production (Mbo/d)

218 – 222
Permian Oil (Mbo/d)

$430 – $480
Cash CAPEX ($MM)

Source: Company data, filings and estimates.

(1) Capital budget includes spending for operated drill, complete and equip ("D,C&E"), non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.

(2) Reinvestment rate calculated as cash CAPEX (defined below) divided by pre-dividend cash flow from operations before changes in working capital.

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2021 Free Cash Flow Sensitivity

- Diamondback believes it can maintain Q4 2020 oil production (pro forma for Guidon and QEP acquisitions) with estimated cash CAPEX of $1.525 - $1.625 billion in 2021; implies 15% decrease relative to standalone CAPEX for 2020
- At current commodity prices, Diamondback expects to generate substantial pre-dividend Free Cash Flow in 2021
- Prioritizing growing the base dividend while maintaining pro forma Q4 2020 oil volumes; expect additional free cash flow to continue to accelerate debt reduction this year

Illustrative 2021E Consolidated Free Cash Flow at Various WTI Oil Prices ($MM)[1]

FY 2021 Assumptions

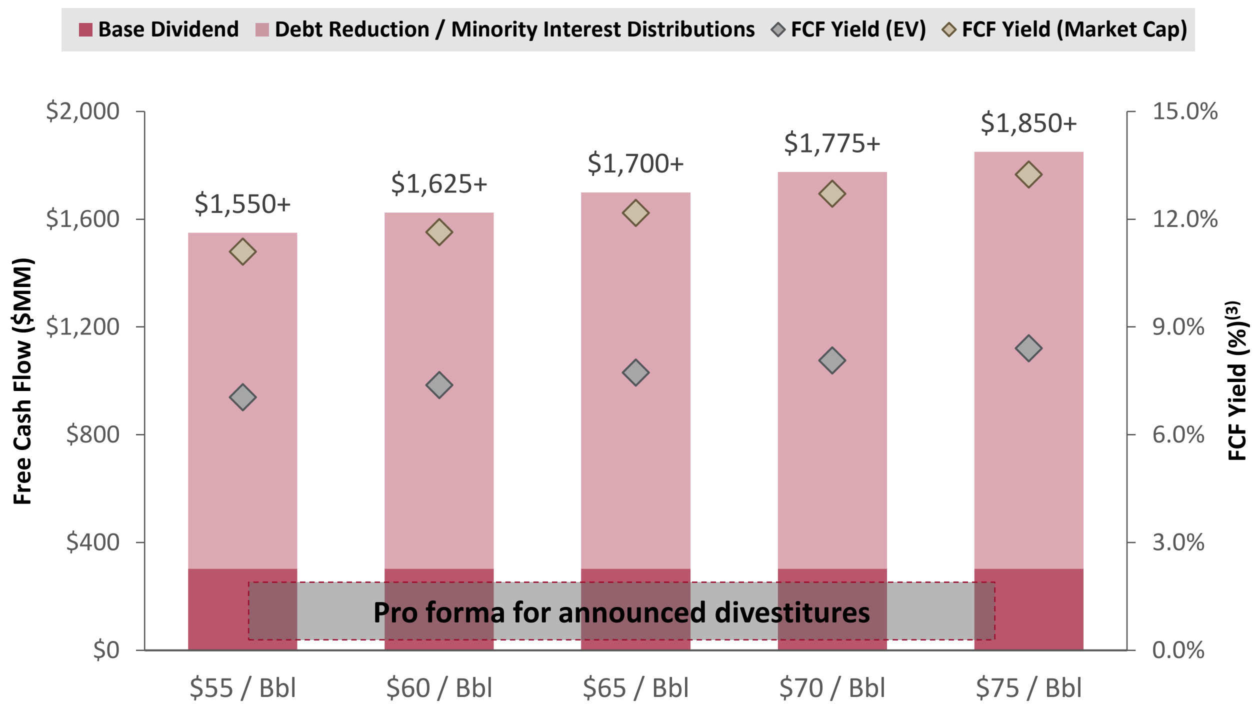
219 - 222 Mbo/d
Oil Production

$1.525 - $1.625 billion
Cash CAPEX[2]

~95%
% of WTI Realized ($/Bbl)

$18/Bbl / $2.50/Mcf
Unhedged NGL / Gas Prices

$1.75 / Share
Annual Shareholder Dividend[4]



Source: Company data, filings and estimates. Note: All 2021E scenarios incorporate identical activity levels, capital spending, production, respectively; assumes current cash operating costs, well costs and incorporate current hedges.
(1) Free cash flow calculated as operating cash flow before changes in working capital and dividends, less cash CAPEX (defined below). Based on the same assumptions, illustrative 2021E consolidated operating cash flow would be over $3,125MM at $55/Bbl, over $3,200MM at $60/Bbl, over $3,275MM at $65/Bbl, over $3,350MM at $70/Bbl, and over $3,425MM at $75/Bbl. We are unable to present a quantitative reconciliation because we cannot reliably predict certain of the necessary components of operating cash flow, such as changes in working capital.
(2) Defined as capital spending for operated D,C&E, non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.
(3) Free cash flow yield calculated as free cash flow divided by FANG's enterprise value ("EV") and FANG's market capitalization ("Market Cap") as of 7/30/2021, respectively.
(4) Based on actual Q1 2021 dividend of $0.40 per share and the Q2 2021 run-rate of $0.45 per share. Future dividends subject to the discretion and approval of the Board of Directors.

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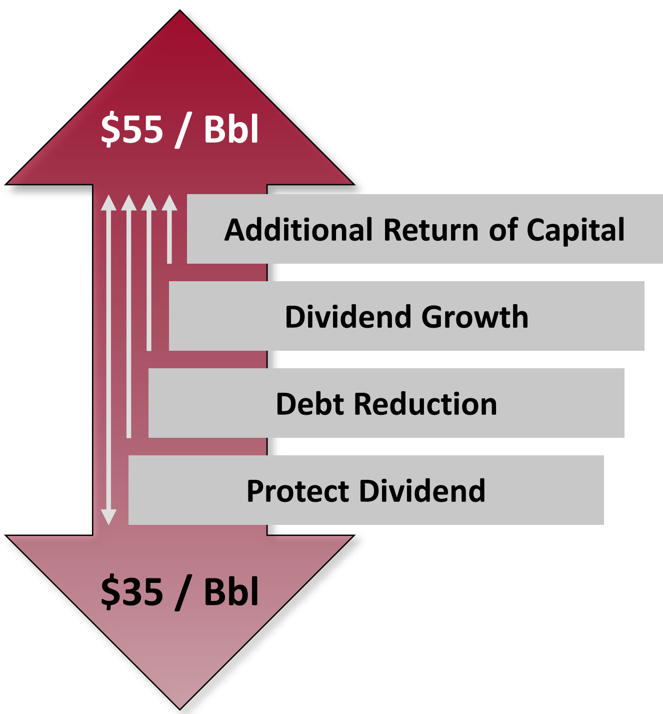
Diamondback Investment Framework

- Diamondback has proven it has the size, scale, balance sheet, asset quality and cost structure to weather a prolonged downturn and can now thrive in the upcycle
- Diamondback's investment framework and capital allocation philosophy remains very simple: protect and consistently grow our base dividend, spend maintenance capital to hold oil production flat, and use excess Free Cash Flow and asset sale proceeds in the second half of 2021 to pay down debt
- Committed to accelerating return of capital in 2022, with 50% of 2022 FCF expected to be returned to stockholders

Investment Framework



YTD Execution on Investment Framework[1]

1

>$900 million of Free Cash Flow generated in 1H 2021[1]

Dividend protected down to ~$35 / Bbl WTI oil in 2022

2

$623 million of bonds redeemed since closing QEP[2]

Expect to redeem up to $1.2 billion in callable debt by YE21

3

Increased quarterly dividend by 20%

4

50% of 2022 Free Cash Flow expected to be allocated to return of capital to stockholders

Source: Company data, filings and estimates. Note: All 2021E scenarios incorporate identical activity levels, capital spending, production, respectively; assumes current cash operating costs, well costs and incorporate current hedges.

(1) Free cash flow calculated as operating cash flow before changes in working capital and dividends, less cash CAPEX for D,C&E, non-operated properties and workovers, midstream, infrastructure and environmental; excludes long-haul pipeline investments.

(2) Pro forma for the announced redemption of $432 million remaining aggregate principal amount of 5.375% bonds due 2025.

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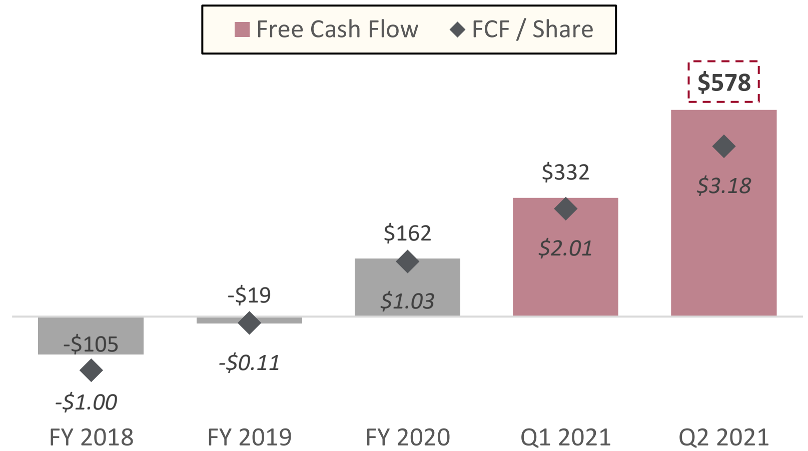
Year to Date Execution on Investment Framework

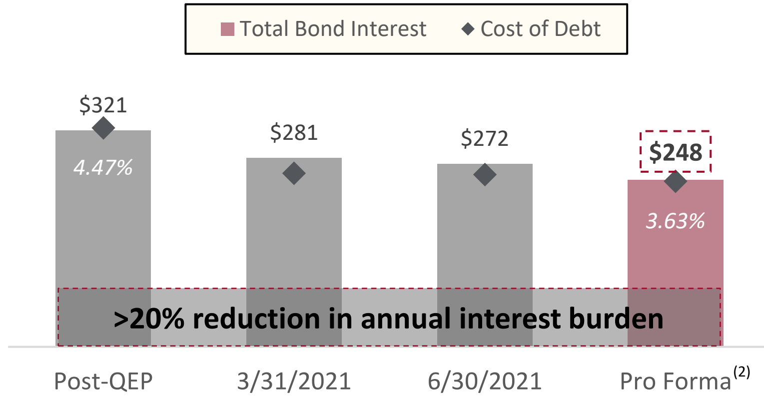
YTD Execution on Investment Framework:

- >$900 million of Free Cash Flow generated in 1H 2021[1]
- $1.80 per share annual dividend, up 20% year to date
- >$620 million of bonds redeemed year to date; annualized pro forma interest burden down 23% prior to refinancing QEP debt in Q1 2021[2]
- Plan to redeem 2023 notes in Q4 2021 after closing previously announced divestiture of Williston Basin asset
- Current dividend protected down to ~$35 / Bbl WTI oil prices in 2022

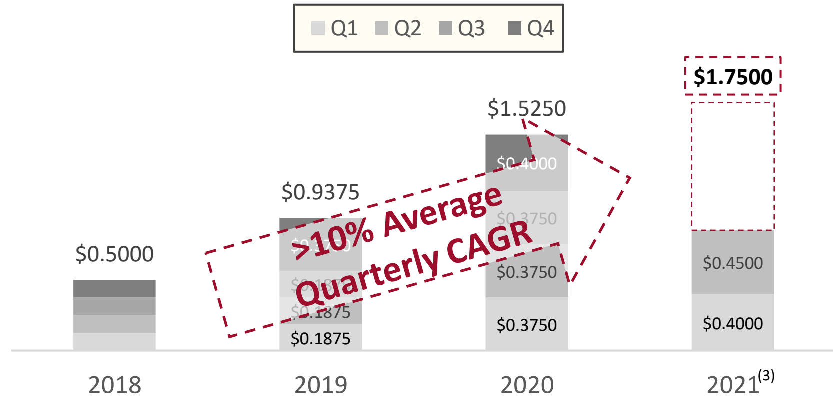
Consolidated Free Cash Flow Generation[1]



Consolidated Interest Burden and Cost of Borrowing



Cash Dividends Over Time ($ / Share)



Diamondback generated over $900 million of Free Cash Flow in the first half of 2021[1], which the Company used to reduce gross debt and increase its dividend

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 3/31/2021, pro forma for announced non-core Permian divestures.

(1) Free cash flow calculated as operating cash flow before changes in working capital and dividends, less cash CAPEX for D,C&E, non-operated properties and workovers, midstream, infrastructure and environmental; excludes long-haul pipeline investments.

(2) Pro forma for the announced redemption of $432 million remaining aggregate principal amount of 5.375% bonds due 2025.

(3) Based on actual Q1 2021 dividend of $0.40 per share and the Q2 2021 run-rate of $0.45 per share. Future dividends subject to the discretion and approval of the Board of Directors.

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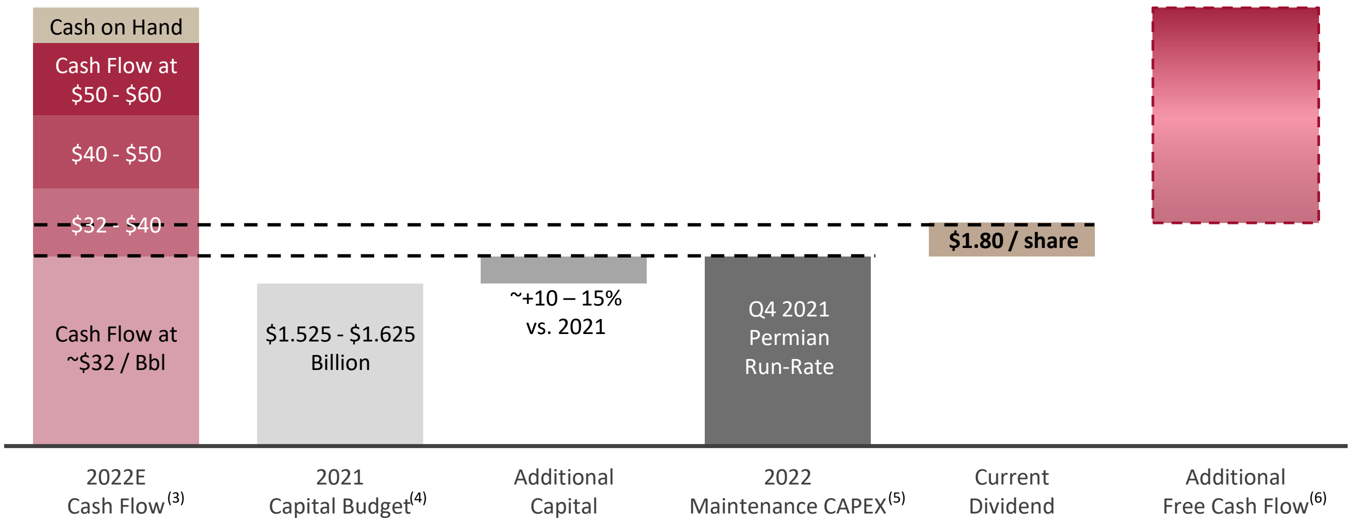
Increasing Return of Capital to Stockholders in 2022

- Diamondback believes the global oil market remains artificially undersupplied and therefore does not warrant shale production growth
- Company expects it can maintain expected Q4 2021 Permian oil production throughout 2022 while generating substantial Free Cash Flow at current commodity prices (~$32/Bbl breakeven WTI oil price)(1)(2)
- While we expect to use a large portion of FCF and asset sale proceeds to reduce debt in 2H 2021, the Company plans to return 50% of its 2022 FCF to stockholders, including current $1.80 / share annual dividend

Illustrative 2022E Consolidated Sources and Uses of Cash Flow at Various WTI Oil Prices



2022 FCF Allocation Plan:

- ~50% Return to Stockholders
- ~50% Debt Reduction

2022 Maintenance Plan:

- 218 – 222 Permian Oil Production (Mbo/d)
- +10 – 15% Additional CAPEX vs. 2021
- ~$32 / Bbl Breakeven WTI Oil Price ($/Bbl)(1)

Diamondback plans to return 50% of 2022 Free Cash Flow to stockholders

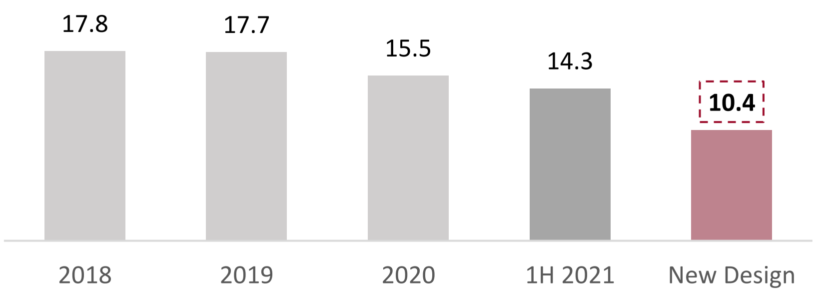
Source: Company data, filings and estimates. Note: All 2022E scenarios incorporate identical activity levels, capital spending, production, respectively; assumes current cash operating costs and well costs.

(1) Breakeven WTI oil price calculated as the per barrel price for oil needed to generate cash flow equivalent with the amount of capital required to keep its estimated Q4 2021 oil production flat in 2022.
(2) Free cash flow calculated as operating cash flow before changes in working capital and dividends, less cash CAPEX (defined below).
(3) Assumes +$3.00/Bbl premium for Brent crude oil, $2.50/Mcf Henry Hub gas prices and $18/Bbl NGL prices; excludes the impact of current commodity hedges.
(4) Defined as capital spending for operated D,C&E, non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.
(5) Maintenance CAPEX defined as estimated capital required to keep estimated Q4 2021 Permian oil production flat throughout the full year 2022.
(6) Additional Free Cash Flow calculated as 2022E free cash flow (defined above) less capital required to fund to FANG's current dividend of $1.80 / share.

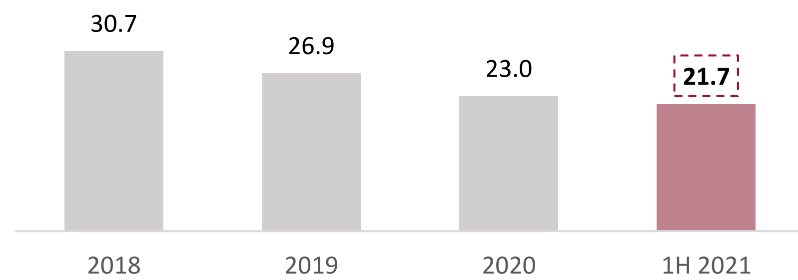
Continued Best-in-Class Operational Performance

- Step-change in drilling efficiencies due to QEP integration and synergies; drilling times down >30% in Midland Basin using latest design
- Step-change in completion efficiency due to full incorporation of Simul-Frac technology; expected to be used on majority of future completions

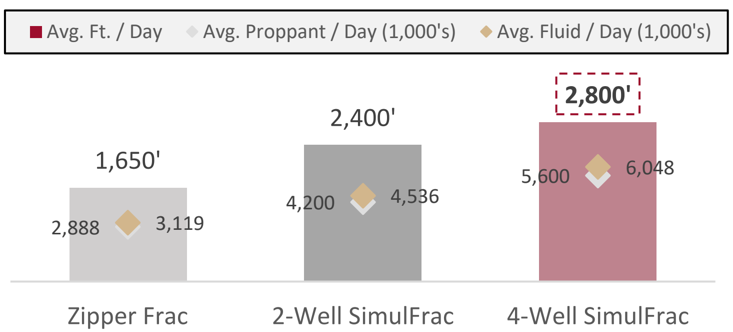
Midland Basin Drilling Days (Days to Total Depth)



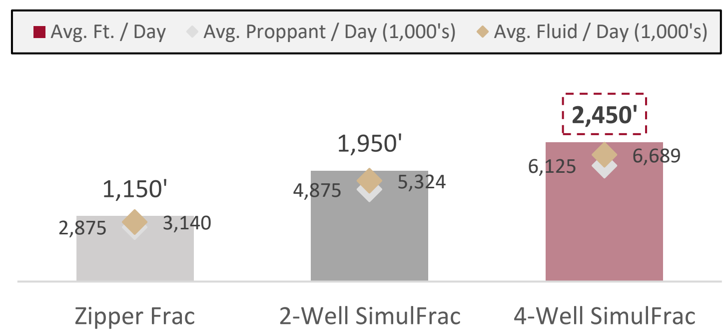
Delaware Basin Drilling Days (Days to Total Depth)



Midland Basin Completion Efficiency



Delaware Basin Completion Efficiency



Diamondback continues to push the limit on operational efficiencies and has quickly optimized drilling and completion best practices from the integration of QEP

Source: Company data and estimates as of 6/30/2021.

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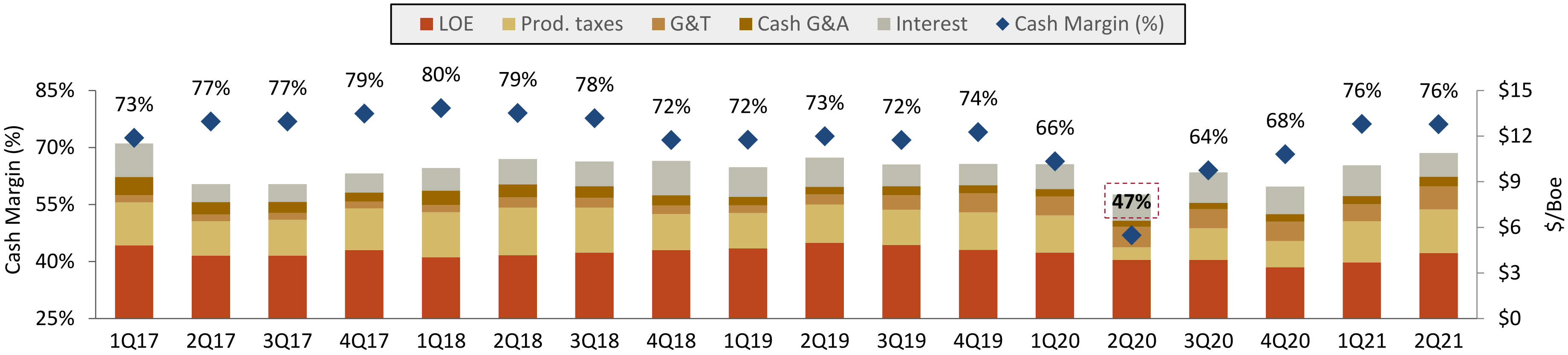
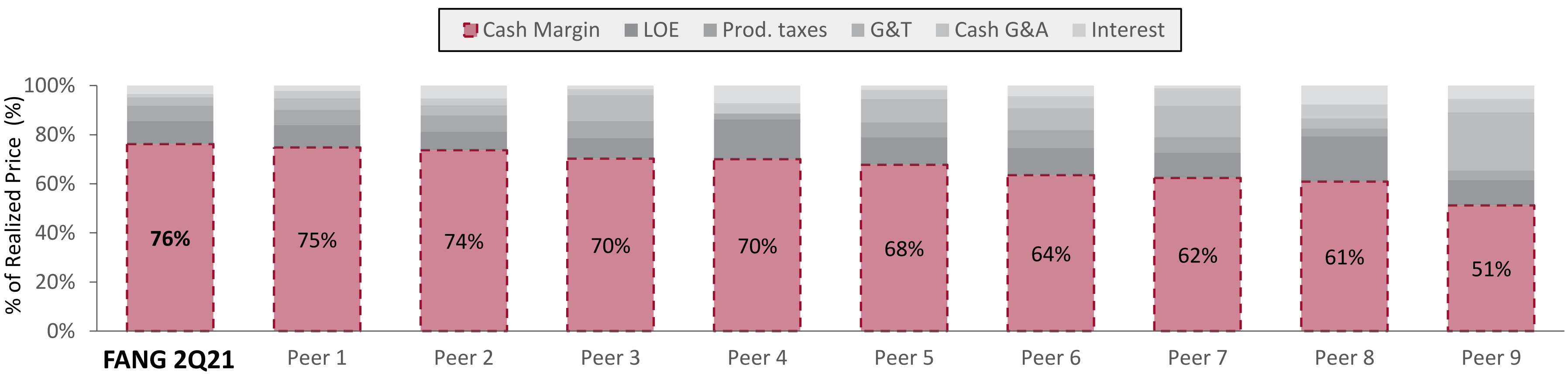
Peer-Leading Cash Margins and Operating Costs

Diamondback Cash Margins and Operating Costs Including Interest Over Time(1)(2)



Cash Margins and Operating Costs versus Extended Peer Group (% of Unhedged Realized Price)(1)(2)



Peer leading cash operating costs and a low interest burden allow Diamondback to maintain high cash margins in almost any commodity price environment

Source: Company data and latest peer filings as of 7/30/2021. Extended peers include PXD, CLR, EOG, HES, XEC, DVN, MRO, APA and OVV.

(1) Cash operating costs including interest calculated as the sum of LOE, G&T, production taxes, cash G&A expense and interest expense per boe.

(2) Unhedged cash margins calculated as the sum of unhedged realized price per boe less cash operating costs including interest divided by unhedged realized price per boe.

DIAMONDBACK Energy

Capital Structure and Liquidity

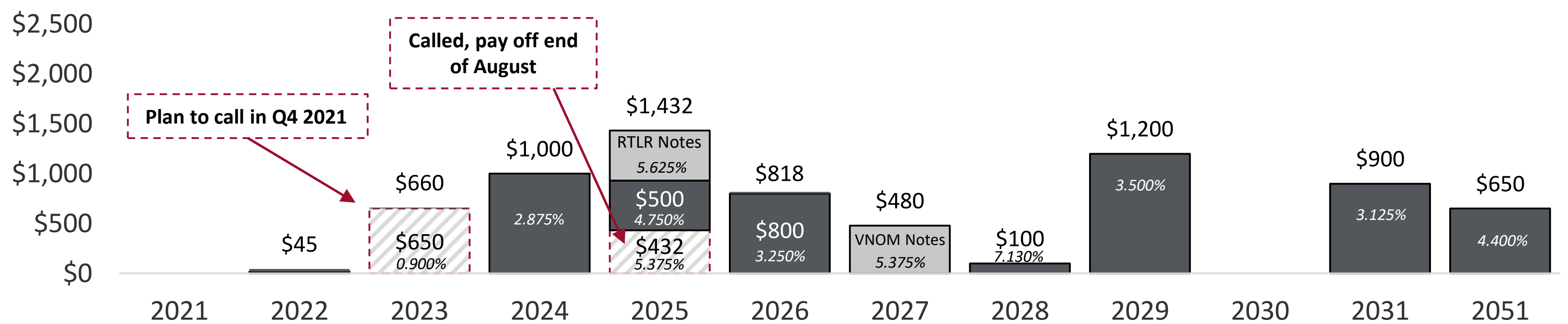
- Standalone liquidity of >$1.8 billion as of June 30, 2021[1]
- Consolidated total liquidity of $3.0 billion
- Consolidated net debt of ~$7.1 billion, down >$500 million quarter over quarter
- Fully redeemed $191 million aggregate principal amount of remaining 4.625% Energen bonds in June 2021
- Announced full redemption of $432 million remaining aggregate principal amount of 5.375% 2025 notes
- Pro forma annual interest burden of ~$248 million; down ~11% (~$32 million) from $281 million previously[2]
- Plan to call $650 million of 0.900% 2023 notes in Q4 2021 after Williston Basin sale closes

FANG's Liquidity and Capitalization ($MM)

FANG's Consolidated Capitalization	6/30/2021
Cash and cash equivalents	$344
FANG's Revolving Credit Facility	$0
VNOM's Revolving Credit Facility	62
RTLR's Revolving Credit Facility	5
Senior Notes	7,285
DrillCo Agreement	68
Total Debt	***$7,420***
Net Debt	***$7,076***

FANG's Standalone Liquidity	6/30/2021
Cash[1]	$284
Elected commitment amount	1,600
Liquidity	***$1,884***

FANG's Debt Maturity Profile ($MM)



Source: Company Filings, Management data and Estimates.
(1) Excludes Viper and Rattler.
(2) Pro forma for the announced redemption of $432 million remaining aggregate principal amount of 5.375% bonds due 2025.

DIAMONDBACK Energy

2021 Guidance Update

- Full year 2021 oil production guidance of 219.0 – 222.0 Mbo/d; 2021 plan aimed at maintaining pro forma Q4 production levels net of asset sales
- Full year 2021 CAPEX budget of $1.525 - $1.625 billion; implies 15% reduction compared to 2020 CAPEX
- Expect to complete 265 – 275 gross horizontal wells with an average lateral length of ~10,300 feet

Q3 2021 Guidance

- Q3 2021 oil production guidance of 233.0 – 239.0 Mbo/d (388.0 – 398.0 Mboe/d)(1)
- Q3 2021 cash CAPEX guidance of $430 – $480 million

Diamondback 2021 Capital Activity Guidance

Gross (net) horizontal wells drilled	210 – 220 (193 – 202)
Gross (net) horizontal wells completed	265 – 275 (246 – 256)
Average lateral length (ft.)	~10,300’
Midland Basin well costs per lateral foot(2)	$520 – $550
Delaware Basin well costs per lateral foot(2)	$720 – $800
Midland Basin net lateral feet (%)	~75%
Delaware Basin net lateral feet (%)	~25%

	Diamondback	Viper
Net Production – Mboe/d	363.0 – 370.0	26.25 – 27.00
Oil Production – Mbo/d	219.0 – 222.0	15.75 – 16.25
Unit Costs ($/boe)		
Lease Operating Expenses	$3.90 – $4.30	
Gathering & Transportation	$1.25 – $1.35	
Cash G&A	$0.45 – $0.55	$0.60 – $0.80
Non-Cash Equity Based Compensation	$0.30 – $0.40	$0.10 – $0.25
D,D&A	$8.75 – $10.75	$9.50 – $10.50
Interest Expense (net)	$1.50 – $1.70	$3.00 – $3.25
Production and Ad Valorem Taxes (% of Revenue)(3)	7%	7%
Corporate Tax Rate (% of Pre-tax Income)	23%	

Diamondback Capex Budget ($MM)	
Operated D,C&E	$1,215 – $1,265
Non-Operated Properties / Capital Workovers	$160 – $180
Midstream (ex. long-haul pipeline investments)(4)	$50 – $70
Infrastructure and Environmental	$100 – $110
Total 2021 Capital Budget	**$1,525 – $1,625**

Source: Company filings, management data and estimates.
(1) Assumes full third quarter 2021 Williston Basin production contribution of 15-17 MBO/d (25-29 MBOE/d). Third quarter volumes will be reduced proportionally dependent upon final close date of Williston Basin Sale
(2) Well costs assume gross Rattler costs.
(3) Includes production taxes of 4.6% for crude oil and 7.5% for natural gas and NGLs and ad valorem taxes.
(4) Includes $20 million of spend related to midstream assets currently owned directly by Diamondback.

DIAMONDBACK Energy




ESG Update

Environmental Strategy Update

- Diamondback recently announced significant changes to environmental, social and governance ("ESG") performance and disclosure, including Scope 1 and methane emissions intensity reduction targets as well as a commitment to Scope 1 carbon emission neutrality, or "Net Zero Now"
- Carbon emissions are seen as a “cost” at Diamondback, and we expect to become the low-cost carbon operator while maintaining our best-in-class cost structure

Environmental Strategy Highlights	
Greenhouse Gas (“GHG”) Emissions Reduction Targets	◆ **Reduce Scope 1 GHG intensity by at least 50% from 2019 levels by 2024** ◆ **Reduce methane intensity by at least 70% from 2019 levels by 2024**
“Net Zero Now”	◆ **As of January 1, 2021, every hydrocarbon produced by Diamondback is anticipated to be produced with zero net Scope 1 emissions** ◊ Recognizing the Company will still have a carbon footprint, Diamondback has purchased carbon offset credits to offset remaining emissions ◊ Intend to eventually invest in income-generating projects that will more directly offset remaining Scope 1 emissions
Short-term Incentive Compensation (“STI”)	◆ **Increased ESG component weighting to 20% from 15% previously** ◊ Component determined by meeting or exceeding the same key environmental and safety metrics as 2020: flaring intensity, GHG intensity, recycled water percentage, fluid spill control and TRIR (safety)

Source: Company data and filings.

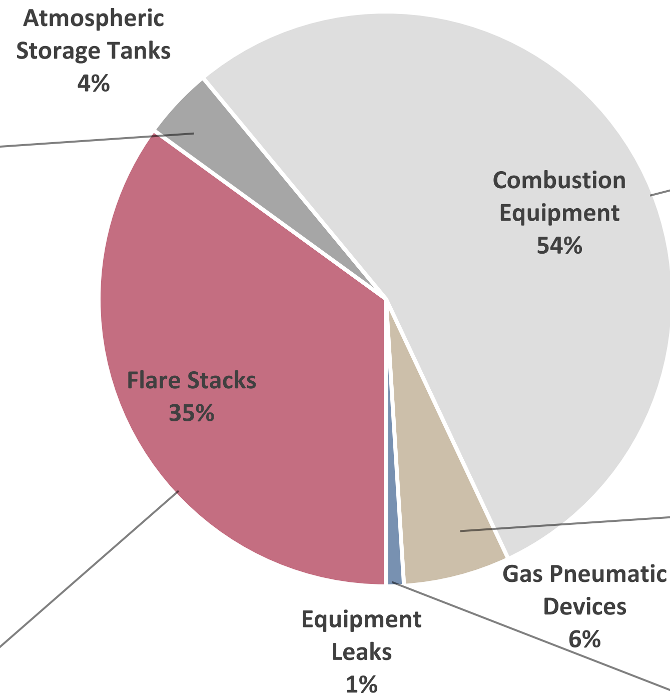
CO2e Emissions Breakdown and Strategic Reduction Initiatives

Diamondback 2020 CO2e Emissions Detail and Current Strategic Initiatives:

Atmospheric Storage Tanks:
~4% of CO2e emissions

Drivers: encompasses tanks at all batteries; primarily dependent on volume moving through facilities

Initiatives: first tankless facility design to be installed Q4 2021; limited tank design proven successful via two pilot projects; plan is to extend this pilot to another five assets in 2021 and 15 in 2022



Flare Stacks:
~35% of CO2E emissions

Drivers: flaring at the wellhead primarily due to takeaway / third party issues

Initiatives: : Minimize flaring; currently at ~0.9% of gross gas produced(1); down >80% from ~5.6% in 2019; continue work and negotiations with third party gatherers to ensure optimized uptime; continue evaluation of FANG-owned gathering to further increase runtime

Combustion Equipment:
~54% of CO2e emissions

Drivers: encompasses all drilling rigs, completion crews, workover rigs, generators and gas engine driven compressors

Initiatives: Remove / replace >200 electrical generation and natural gas driven compression units by 2023; continue electrical substation construction efforts; work to electrify drilling operations

Gas Pneumatic Devices:
~6% of CO2e emissions

Drivers: >1000 tank batteries; legacy batteries run off gas pneumatic systems; currently, 40% of our current horizontal batteries have air compression

Initiatives: Air pneumatics installed on new batteries; plan to spend ~$60 million over next four years to retrofit most batteries with air pneumatics

Equipment Leaks:
~1% CO2e emissions

Initiatives: Aerial monitoring and FLIR cameras; now conducting quarterly flyovers of all batteries and continuing to increase number of FLIR cameras, while implementing best practices to monitor methane leaks; will have four continuous emissions monitoring pilot projects in the field by Q3 2021

2020 Scope 1 GHG Emissions:
~1.2 million mt of CO2e
Intensity: 10.8 mt / net mboe produced
AXPC Intensity: 9.5 mt / gross mboe

Diamondback is committed to reducing its Scope 1 GHG intensity by at least 50% from 2019 levels by 2024

Source: Company data, filings and estimates.
(1) Represents flaring metric for YTD 2021 as of 6/30/2021; excludes QEP.

DIAMONDBACK Energy

Methane Emissions and Strategic Reduction Initiatives

Diamondback 2020 Methane Emissions Detail and Current Strategic Initiatives:

Gas Pneumatic Devices:
~57% of methane emissions

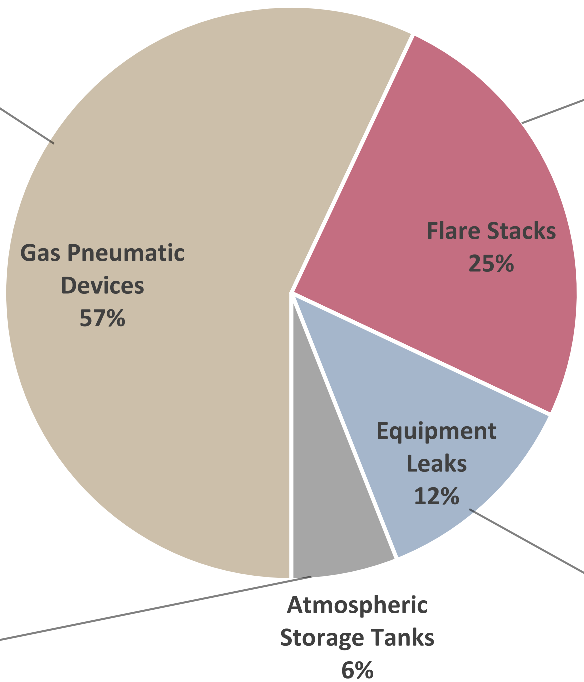
Drivers: >1000 tank batteries; legacy batteries run off gas pneumatic systems; currently, 40% of our current horizontal batteries have air compression

Initiatives: Air pneumatics installed on new batteries; plan to spend ~$60 million over next four years to retrofit most batteries with air pneumatics

Flare Stacks:
~25% of methane emissions

Drivers: flaring at the wellhead primarily due to takeaway / third party issues

Initiatives: Minimize flaring; currently at ~0.9% of gross gas produced[1]; down >80% from ~5.6% in 2019; continue work and negotiations with third party gatherers to ensure optimized uptime; continue evaluation of FANG-owned gathering to further increase runtime



Atmospheric Storage Tanks:
~6% of methane emissions

Drivers: encompasses tanks at all batteries; primarily dependent on volume moving through facilities

Initiatives: first tankless facility design to be installed Q4 2021; limited tank design proven successful via two pilot projects; plan is to extend this pilot to another five assets in 2021 and fifteen in 2022

Equipment Leaks:
~12% of methane emissions

Initiatives: Aerial monitoring and FLIR cameras; now conducting quarterly flyovers of all batteries and continuing to increase number of FLIR cameras, while implementing best practices to monitor methane leaks; will have four continuous emissions monitoring pilot projects in the field by Q3 2021

2020 Methane Emissions:
5,079 tons of methane
Methane Intensity: 0.15%[2]
AXPC Methane Intensity: 0.04[3]

Diamondback is committed to reducing its methane intensity by at least 70% from 2019 levels by 2024

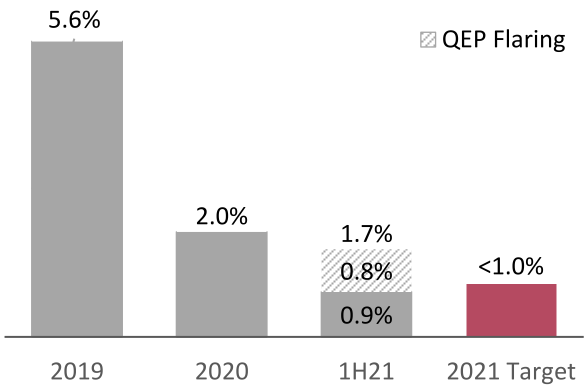
Source: Company data, filings and estimates.
(1) Represents flaring metric for YTD 2021 as of 6/30/2021; excludes QEP.
*(2) Methane Intensity % is calculated as (metric tons of CH4) / ((gross gas produced) * (average mole fraction of methane in produced gas) * (methane density of .0292 kg/scf)).*
(3) AXPC defines Methane Intensity as metric tons of CH4 divided by gross annual production (mboe).

DIAMONDBACK Energy

Environmental, Social and Governance ("ESG")

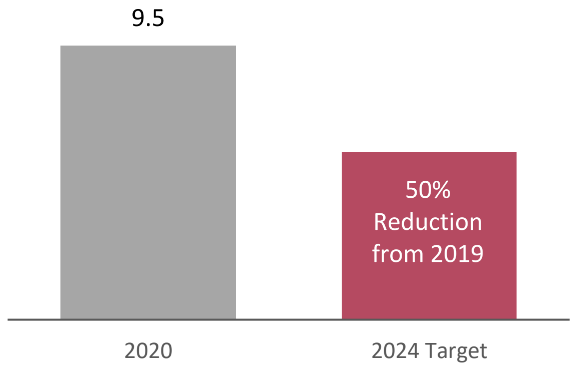
Flaring (% of Gross Gas Production)

2021 Goal: Flare <1.0% of Gross Gas



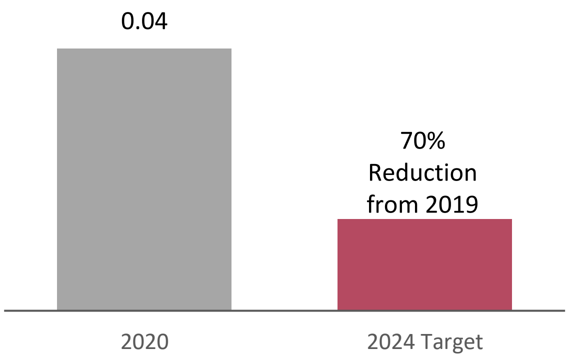
GHG Intensity (mt / mboe Produced)(1)

Goal: Reduce 2019 intensity by 50% by 2024



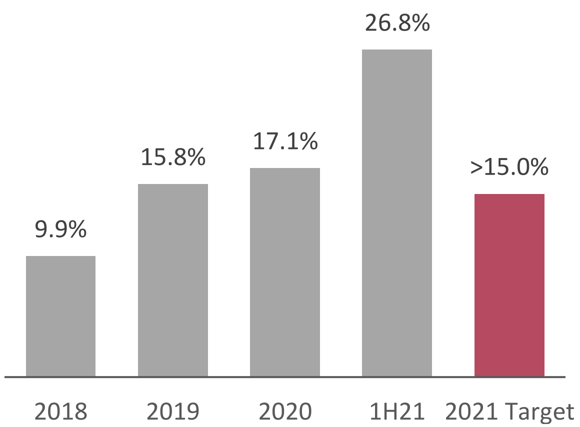
Methane Intensity (mt / mboe Produced)(1)

Goal: Reduce 2019 intensity by 70% by 2024



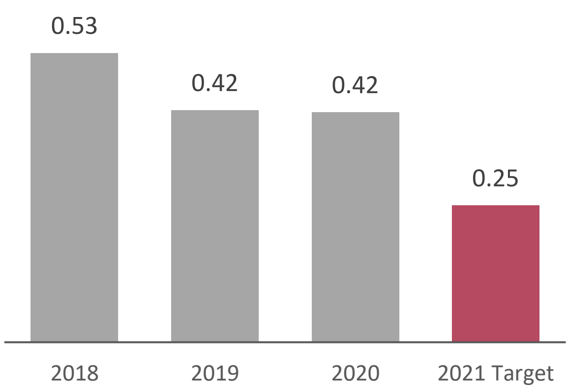
Water Recycling (% of Consumed)(1)

2021 Goal: >15% Water Recycling



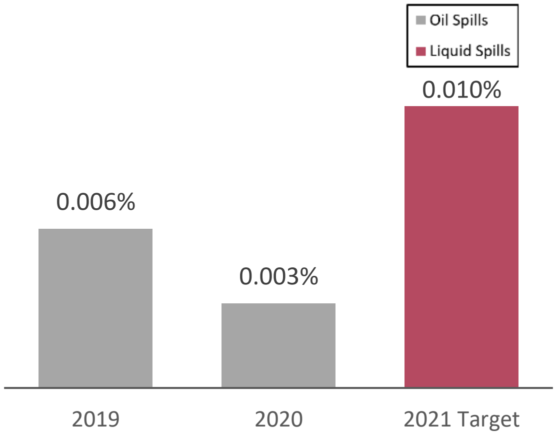
Employee Safety (TRIR)

2021 Goal: TRIR at or below 0.25



Liquids Spill Rate (%)(1)

2021 Goal: <0.01% of produced liquids



Source: Company data, filings and estimates.
(1) Updated to reflect AXPC guidance definition

DIAMONDBACK Energy

Differential Per Share Metrics and Cost Structure

Return On and Return Of Capital

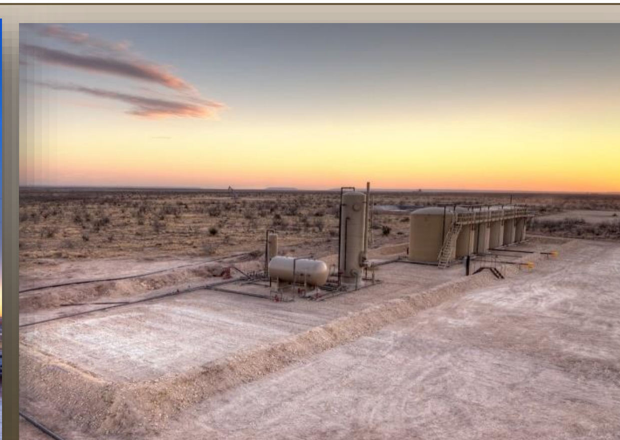
Significant Resource Potential

Conservative Financial Management

Strategic Acquisitions and Execution

Efficient Conversion of Resource to Cash Flow

DIAMONDBACK Energy



APPENDIX

Midland Basin Inventory and Development Strategy

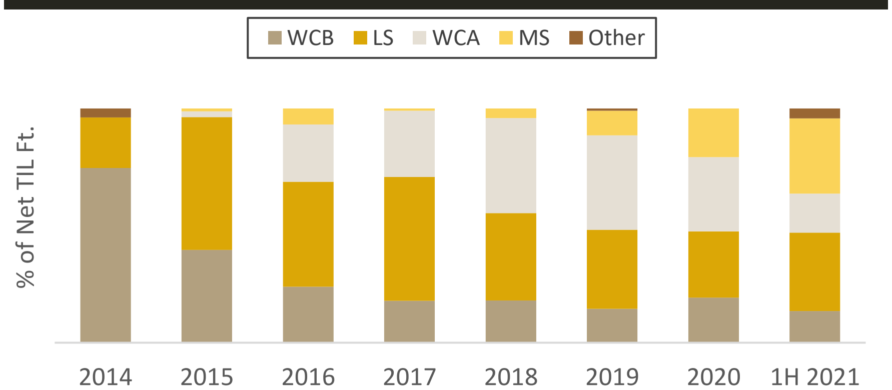
Diamondback Midland Basin Inventory:

- 6,900 gross (5,134 net) horizontal locations with an average lateral length of ~8,700 feet
- Primary zones: ~3,500 net locations (MS, LS, WCA and WCB); total net lateral footage up 10% from YE 2019[(1)]
- Diamondback has executed a co-development strategy over the past few years, with inter-lateral and vertical spacing varying between zones in each development area
- Diamondback has widened average inter-lateral spacing to 5-7 wells per section in all but the highest returning zone by operating area; tightest Midland Basin spacing still ~660’

Midland Basin Economic Locations at Various Oil Prices[(2)]

Oil Price	Gross Economic Locations
$40 / Bbl	6,021
$45 / Bbl	6,674
$50 / Bbl	6,839
$55 / Bbl	6,872
$60 / Bbl	6,908

Midland Basin Development by Zone (% of Net Lateral Ft.)



Gross (Net) Midland Basin Locations by Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
MS	236 (115)	341 (252)	769 (634)	**1,346 (1,001)**	*8,800'*
LS	191 (78)	352 (264)	644 (512)	**1,187 (855)**	*8,700'*
WCA	205 (89)	291 (226)	565 (456)	**1,061 (771)**	*8,600'*
WCB	213 (95)	343 (257)	637 (511)	**1,193 (862)**	*8,700'*
Other[(3)]	355 (160)	489 (387)	1,324 (1,097)	**2,168 (1,644)**	*8,800'*
Total	**1,200 (537)**	**1,816 (1,386)**	**3,939 (3,210)**	**6,955 (5,134)**	***8,700'***

Diamondback has consistently maintained conservative spacing assumptions, preferring a higher rate of return to higher net present value

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 3/31/2021, pro forma for announced non-core Permian divestures.
(1) Primary zones include Jo Mill / Middle Spraberry (“MS”), Lower Spraberry (“LS”), Wolfcamp A (“WCA”) and Wolfcamp B (“WCB”).
(2) Defined as gross locations that can generate at least a 10% rate of return. Assumes current well costs, 30% of WTI NGL pricing and $2.00/Mcf gas prices.
(3) Other zones comprised of Wolfcamp D, Wolfcamp C, Dean, Clearfork and Barnett intervals.

DIAMONDBACK Energy

Delaware Basin Inventory and Development Strategy

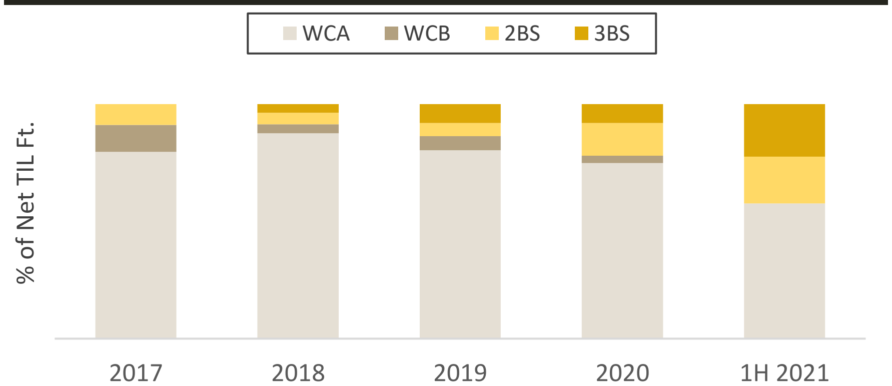
Diamondback Delaware Basin Inventory:

- 4,200 gross (2,501 net) horizontal locations with an average lateral length of ~7,700 feet
- Primary zones: >2,200 net locations (2BS, 3BS, WCA and WCB)(1)
- No Federal Land exposure
- Inter-lateral and vertical spacing between zones varies by major development area
- Diamondback has widened average inter-lateral spacing to 4-5 wells per section in all but the highest returning zone by operating area; tightest Delaware Basin spacing still ~880'

Delaware Basin Economic Locations at Various Oil Prices(2)

Oil Price	Gross Economic Locations
$40 / Bbl	2,745
$45 / Bbl	3,348
$50 / Bbl	3,872
$55 / Bbl	4,034
$60 / Bbl	4,090

Delaware Basin Development by Zone (% of Net Lateral Ft.)



Gross (Net) Delaware Basin Locations by Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
2BS	268 (167)	170 (107)	384 (257)	**822 (531)**	*7,900'*
3BS	503 (297)	277 (172)	525 (320)	**1,305 (789)**	*7,600'*
WCA	268 (149)	220 (132)	293 (185)	**781 (467)**	*7,700'*
WCB	252 (129)	175 (104)	335 (217)	**762 (451)**	*7,900'*
Other(3)	245 (109)	134 (52)	181 (102)	**560 (263)**	*7,200'*
Total	**1,536 (851)**	**976 (568)**	**1,718 (1,081)**	**4,230 (2,501)**	***7,700'***

Diamondback has consistently maintained conservative spacing assumptions, preferring a higher rate of return to higher net present value

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 3/31/2021, pro forma for announced non-core Permian divestures.
(1) Primary zones include Second Bone Spring ("2BS"), Third Bone Spring ("3BS"), Wolfcamp A ("WCA") and Wolfcamp B ("WCB")
(2) Defined as gross locations that can generate at least a 10% rate of return. Assumes current well costs, 30% of WTI NGL pricing and $2.00/Mcf gas prices.
(3) Other zones primarily comprised of the 1st Bone Spring, Avalon, Wolfcamp C and Wolfcamp XY intervals.

DIAMONDBACK Energy

Oil Takeaway Solutions

Oil Purchase Contracts:

- Diamondback's oil production is purchased under long term purchase agreements with four large, well-funded counterparties
- Every major operating area has a long-term oil purchase agreement and is dedicated to a long haul pipeline
- Long-term agreements and associated physical pipeline space provide insurance in times of uncertainty

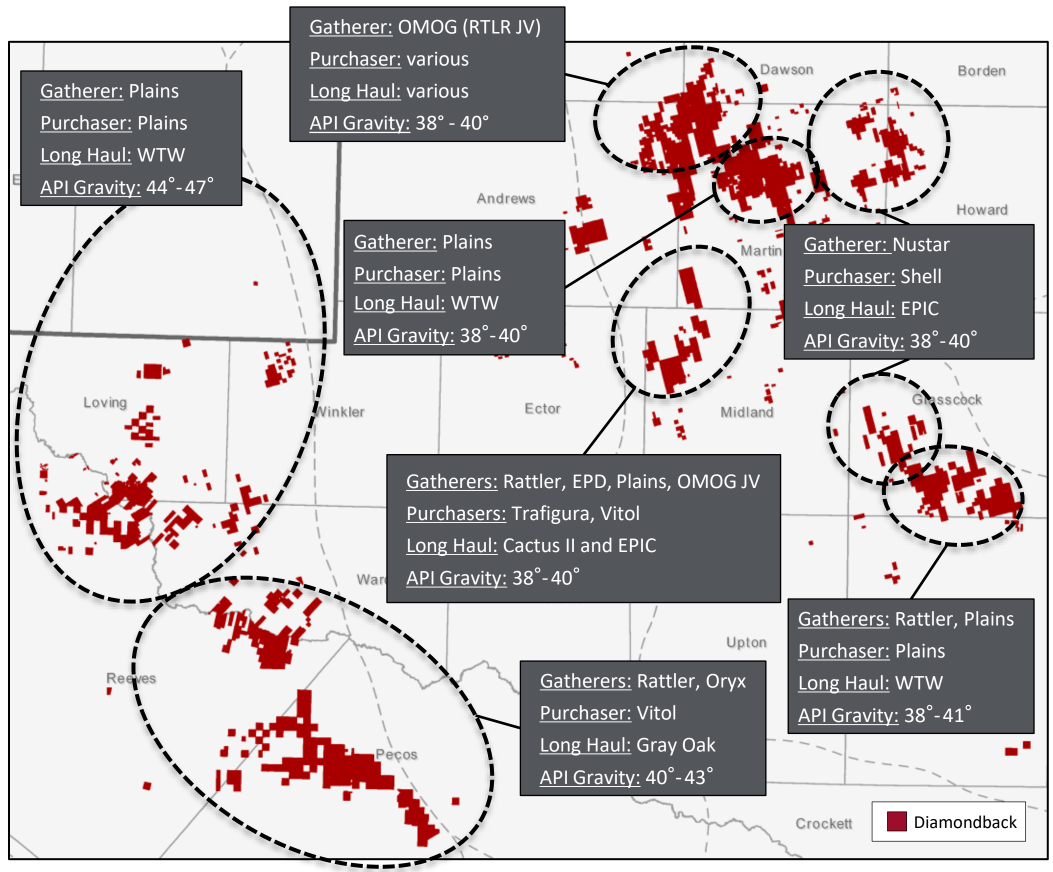
Obligations and Pricing Exposure:

- Take or pay obligations to pipelines and firm sales in 2020 cover 125,000 gross bo/d
  - Increases to 175,000 gross bo/d with the in-service date of the Wink to Webster pipeline

Oil Exposure and Expected Differentials

Exposure (Benchmark)	Estimated Deduct ($ / Bbl)	2021E Production (%)
Brent	$5.00 - $6.00	~60%
MEH	$4.00 - $5.00	~15%
WTI Midland	$1.00 - $2.00	~25%

Oil Takeaway Solutions



Diamondback's oil marketing agreements provide long-term flow assurance to the most liquid markets as well as minimize local basis exposure

Source: Company filings, management data and estimates.

DIAMONDBACK Energy

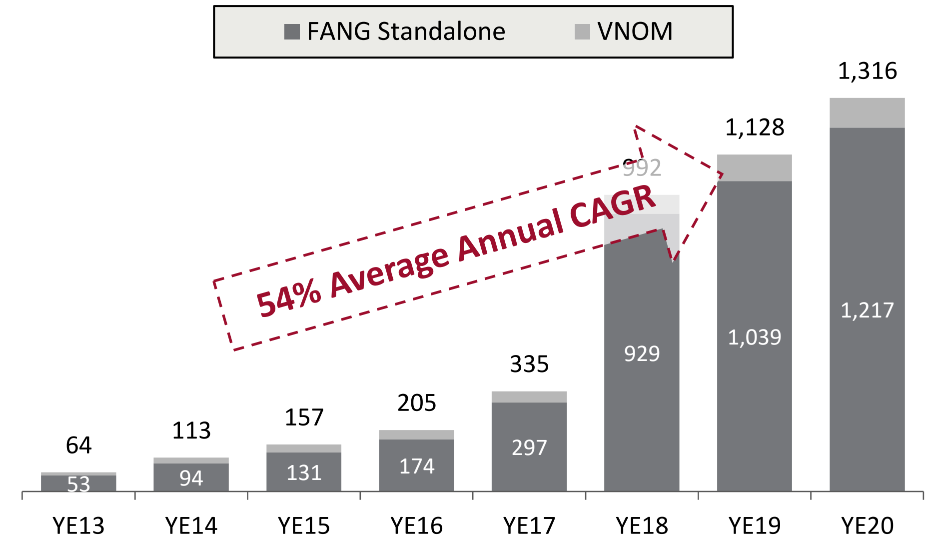
2020 Reserves

- YE20 proved reserves increased 17% y/y to 1,316 MMBoe (759 MMBo, 62% PDP)
- PDP reserves of 817 MMBoe; PDP oil reserves of 443 MMBo
- Oil comprised 58% of total proved reserves on 3-stream basis; ~64% of total on 2-stream basis
- Consolidated proved developed F&D for 2020 was $9.65/boe with drill bit F&D of $5.00

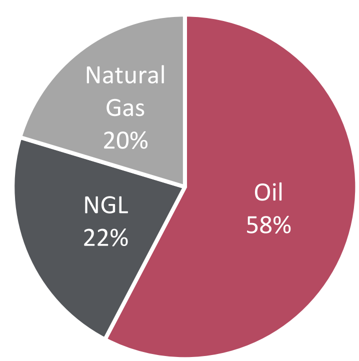
F&D Costs

($/Boe)	2017	2018	2019	2020
Proved Developed F&D[1]	$9.09	$10.44	$10.87	$9.65
Drill Bit F&D[2]	$7.22	$7.28	$11.11	$5.00
Reserve Replacement[3]	549%	1,479%	231%	272%
Organic Reserve Replacement[4]	443%	457%	250%	269%

Total Reserve Growth (MMBoe)

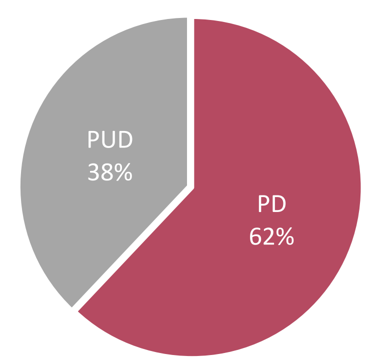


1P Reserves – By Commodity



1,316 MMBOE

1P Reserves – By Category



1,316 MMBOE

Source: Company Filings, Management Data and Estimates.

(1) PD F&D costs defined as exploration and development costs divided by the sum of reserves associated with transfers from proved undeveloped reserves at YE2019 including any associated revisions in 2020 and extensions and discoveries placed on production during 2020.

(2) Drill bit F&D costs defined as the exploration and development costs divided by the sum of extensions, discoveries and recoveries.

(3) Defined as the sum of extensions, discoveries, revisions, and purchases, divided by annual production.

(4) Defined as the sum of extensions, discoveries, and revisions, divided by annual production.

DIAMONDBACK Energy

Current Hedge Summary: Oil

Consolidated Crude Oil Hedges (Bbl/day, $/Bbl)						
Crude Oil Hedges	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**
Swaps - WTI	**38,348**	**30,674**	**1,000**	**1,000**	**–**	**–**
	$42.82	$42.36	$45.00	$45.00	–	–
Swaps - MEH	**5,000**	**5,000**	**–**	**–**	**–**	**–**
	$37.78	$37.78	–	–	–	–
Swaps - Brent[(1)]	**5,000**	**5,000**	**–**	**–**	**–**	**–**
	$41.62	$41.62	–	–	–	–
Total Oil Swaps	**48,348**	**40,674**	**1,000**	**1,000**	**--**	**--**
Costless Collars - WTI	**17,685**	**29,663**	**19,500**	**11,000**	**–**	**–**
Floor / Ceiling	$35.27 / $46.50	$39.83 / $56.45	$46.28 / $72.67	$47.27 / $74.07	–	–
Costless Collars - MEH	**5,000**	**5,000**	**22,000**	**22,000**	**6,000**	**–**
Floor / Ceiling	$45.00 / $57.90	$45.00 / $78.75	$45.91 / $70.95	$46.36 / $72.20	$50.00 / $77.12	–
Costless Collars - Brent	**67,000**	**59,000**	**55,000**	**32,000**	**9,000**	**5,000**
Floor / Ceiling	$40.39 / $49.28	$40.95 / $50.93	$45.55 / $71.08	$46.25 / $76.81	$47.22 / $78.34	$45.00 / $75.56
Total Costless Collars	**89,685**	**93,663**	**96,500**	**65,000**	**15,000**	**5,000**
Long Puts - WTI[(2)]	**–**	**–**	**7,500**	**–**	**–**	**–**
	–	–	$47.51	–	–	–
Long Puts - Brent[(3)]	**–**	**–**	**4,000**	**4,000**	**–**	**–**
	–	–	$50.00	$50.00	–	–
Total Long Puts	**--**	**--**	**11,500**	**4,000**	**--**	**--**
Total Crude Oil Hedges	**138,033**	**134,337**	**109,000**	**70,000**	**15,000**	**5,000**
Basis Swaps - WTI	**34,000**	**34,000**	**10,000**	**10,000**	**10,000**	**10,000**
	$0.91	$0.91	$0.84	$0.84	$0.84	$0.84
Total Basis Swaps	**34,000**	**34,000**	**10,000**	**10,000**	**10,000**	**10,000**
Roll Swaps - WTI	**57,261**	**64,000**	**20,000**	**20,000**	**20,000**	**20,000**
	$0.50	$0.56	$0.54	$0.54	$0.54	$0.54
Total Roll Swaps	**57,261**	**64,000**	**20,000**	**20,000**	**20,000**	**20,000**

Source: Company data as of 7/30/2021.

(1) Includes 13,900 BO/d of swaps in the first half of 2021, and 8,250 BO/d for second half of 2022, whereby the counterparty has the right to exercise the hedge at a weighted-average price of $67.54/Bbl in the first half of 2022 and $68.62/Bbl in the second half of 2022.

(2) Excludes a deferred premium at the weighted-average price of $1.66/Bbl.

(3) Excludes a deferred premium at the weighted-average price of $1.60/Bbl.

Current Hedge Summary: Natural Gas and Natural Gas Liquids

Consolidated Natural Gas Hedges (Mmbtu/day, $/Mmbtu)

Natural Gas Hedges	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Swaps - Henry Hub	**245,000**	**245,000**	–	–	–	–
	$2.65	$2.65	–	–	–	–
Swaps - Waha *Fixed Price*	**50,000**	**50,000**	–	–	–	–
	$1.92	$1.92	–	–	–	–
Total Gas Swaps	**295,000**	**295,000**	–	–	–	–
Costless Collars - Henry Hub	–	–	**250,000**	**190,000**	**80,000**	**80,000**
Floor / Ceiling	–	–	$2.64 / $4.44	$2.53 / $4.01	$2.50 / $4.45	$2.50 / $4.45
Total Costless Collars	–	–	**250,000**	**190,000**	**80,000**	**80,000**
Total Natural Gas Hedges	**295,000**	**295,000**	**250,000**	**190,000**	**80,000**	**80,000**
Basis Swaps - Waha	**250,000**	**250,000**	**210,000**	**210,000**	**210,000**	**210,000**
	($0.66)	($0.66)	($0.34)	($0.34)	($0.34)	($0.34)
Total Basis Swaps	**250,000**	**250,000**	**210,000**	**210,000**	**210,000**	**210,000**

Consolidated Natural Gas Liquids Hedges (Bbl/day, $/Bbl)

Natural Gas Liquids Hedges	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Swaps - Mont Belvieu Propane	**2,000**	**2,000**	–	–	–	–
	$29.40	$29.40	–	–	–	–
Total NGL Swaps	**2,000**	**2,000**	–	–	–	–

Source: Company data as of 7/30/2021.

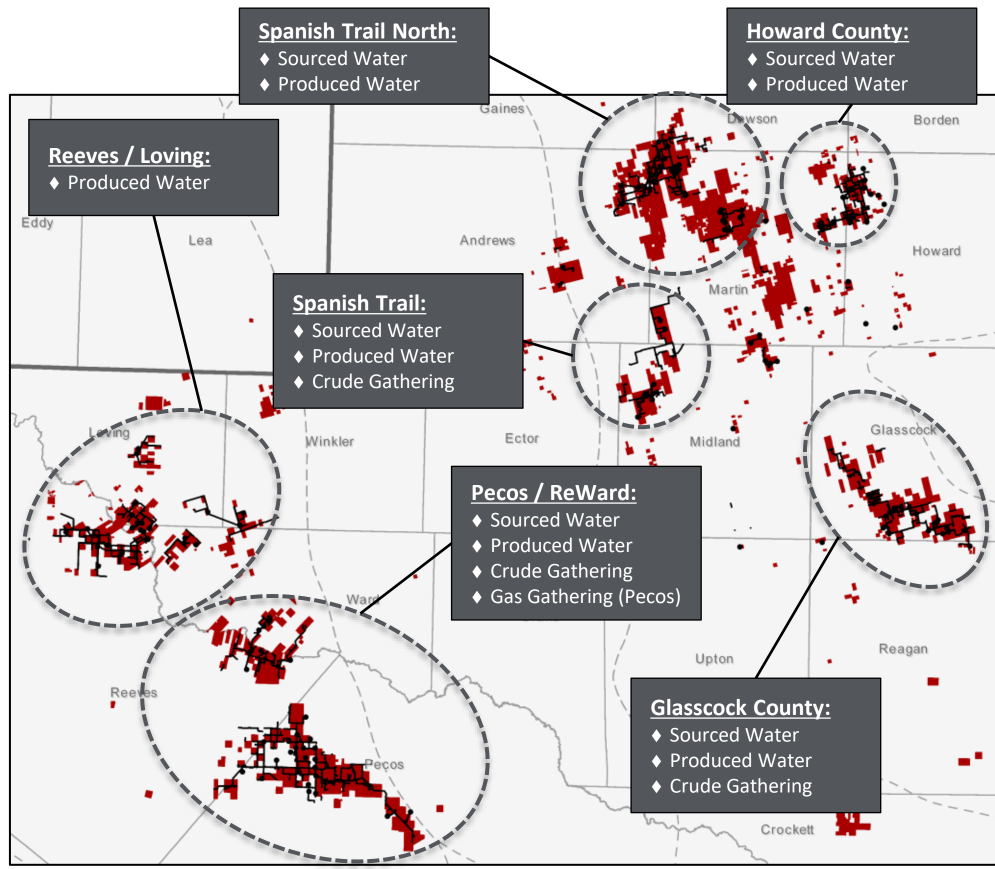
Build-out of Midstream Assets Through Rattler Midstream

Rattler Midstream:

- Publicly-traded midstream subsidiary (NASDAQ: RTLR) created by Diamondback
- Interests fully aligned with upstream operations:
  - Assets located in all core operating areas
  - Midstream services key to Diamondback's low-cost operations
  - Close coordination and development visibility allows efficient and timely midstream build-out
  - Vehicle for participation in non-upstream investment opportunities such as long-haul pipelines
- <u>Annual Distribution:</u> $0.80 / unit (7.7% yield)[1]

Rattler Capacity Overview		
Fee Stream	Midland	Delaware
Produced Water – Bbl/d	1,785,000	1,330,000
Sourced Water – Bbl/d	455,000	120,000
Crude Oil – Bbl/d	65,000	225,000
Natural Gas – Mcf/d	--	180,000[2]
Total	**~2,300,000**	**~1,850,000**

Rattler Midstream Asset Map



Rattler secures FANG's access to vital midstream services and supports FANG's low-cost operations via improving realizations and lower LOE

Source: Company filings, management data and estimates.
(1) Based on Rattler's most recent quarterly distribution announced on 5/4/2021. Yield based on RTLR's closing price as of 7/30/2021.
(2) 151,000 Mcf/d compression capacity.

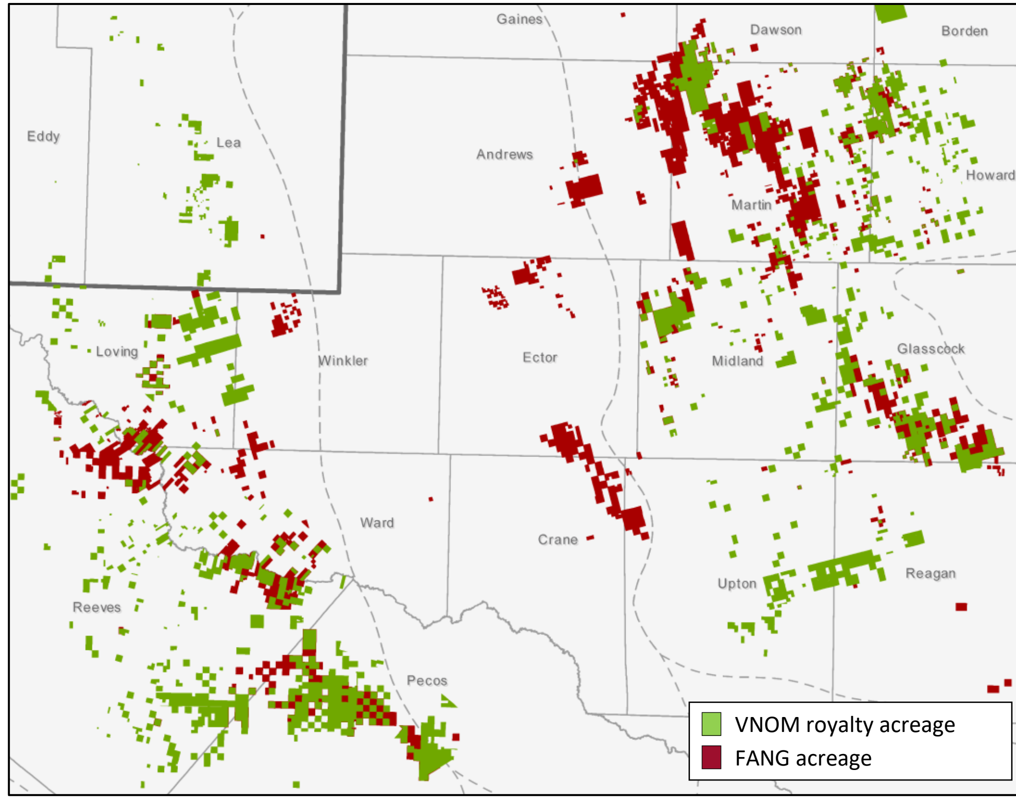
DIAMONDBACK Energy

Viper Overview

Viper Energy Partners:

- Publicly-traded mineral and royalty subsidiary (NASDAQ: VNOM) created by Diamondback
  - Focused on owning and acquiring minerals and royalty interests in the Permian Basin, with a primary focus on Diamondback-operated acreage
- 24,341 net royalty acres, ~52% of which are operated by Diamondback
- Diamondback incentivized to focus development on Viper's acreage when possible due to improved consolidated returns
  - 24 of Diamondback's 65 Q2 2021 completions on Viper's acreage, in which Viper owned a 10.8% average NRI
- Q2 2021 average oil production of 16.5 Mbo/d; generated $0.47 / unit in distributable cash flow
- Outside of Diamondback operating almost 60% of Viper's current oil production, Viper has diversified exposure to other competent operators within the Permian Basin and Eagle Ford Shale

Viper Mineral and Royalty Assets



Viper's Mineral and Royalty Interests Provide Perpetual Ownership Exposure to High Margin, Largely Undeveloped Assets and Lower Diamondback's Consolidated Breakevens

Source: Partnership data and filings. Data as of 6/30/2021.

DIAMONDBACK Energy

Diamondback Energy Corporate Headquarters
500 West Texas Ave., Suite 1200
Midland, TX 79701
www.diamondbackenergy.com

Adam Lawlis, Vice President, Investor Relations
(432) 221-7400
ir@diamondbackenergy.com