DIAMONDBACK Energy

Investor Presentation

June 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, Free Cash Flow and Net Debt are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Consolidated Adjusted EBITDA as net income (loss) plus non-cash (gain) loss on derivative instruments, net, interest expense, net, depreciation, depletion and amortization expense, impairment of oil and natural gas properties, non-cash equity based compensation expense, capitalized equity-based compensation expense, asset retirement obligation accretion expense, loss from equity method investments, loss on damaged assets, gain (loss) on revaluation of investment, loss on extinguishment of debt and income tax (benefit) adjusted for non-controlling interest in net income (loss). Consolidated Adjusted EBITDA is not a measure of net income (loss) as determined by United States generally accepted accounting principles, or GAAP. Management believes Consolidated Adjusted EBITDA is useful because the measure allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We add 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 our 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 (loss) as determined in accordance with GAAP or as an indicator of our 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. Our computation of Consolidated Adjusted EBITDA may not be comparable to other similarly titled measures of other companies or to such measures in our revolving credit facility and the indenture governing our senior notes. 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 is cash flow from operating activities before changes in working capital in excess of cash capital expenditures. Management 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. Our 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. 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:

- ~418,000 net Midland and Delaware basin acres[1]
- >11,100 gross (>7,600 net horizontal locations)[1]
- Includes over 80,000 net acres and ~850 gross (~750 net) horizontal locations in the Midland Basin from the recently completed Guidon and QEP acquisitions

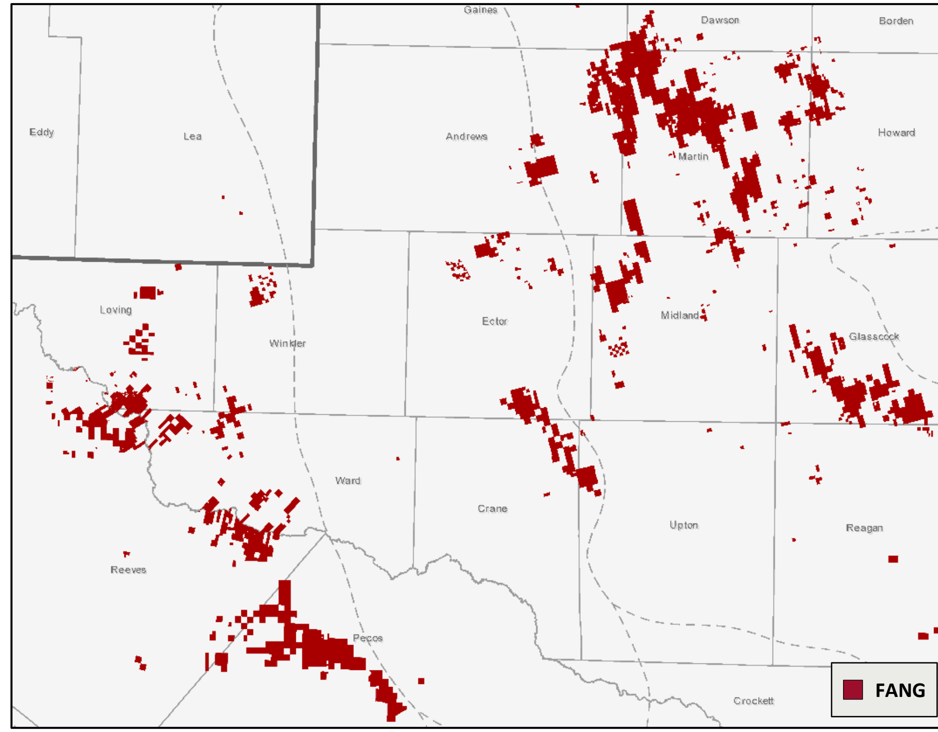
Significant Free Cash Flow and Low Cost Structure:

- Generated $331 million of Free Cash Flow ("FCF") in Q1 2021, with cash operating costs of $8.06 per boe[2]
- Expect to generate substantial consolidated pre-dividend FCF in 2021 at current commodity prices[2]
- Anticipate maintaining pro forma Q4 2020 Permian oil production in 2021 with 10% less capital than standalone 2020

Strong Balance Sheet with Substantial Liquidity:

- Refinanced >$1.9 billion of FANG's 2025 notes and QEP bonds in March 2021; $40 million of annual interest savings
- ~$2.0 billion of standalone liquidity as of March 31, 2021[3]
- Pending divestiture of Williston asset acquired in QEP transaction expected to close in Q3 2021 and divestiture of non-core Permian assets closed in Q2 2021, with total consideration of $832 million[4]
- Future FCF in excess of dividend, as well as proceeds from the announced non-core asset sales, expected to be used to reduce callable debt by up to $1.2 billion by YE21

Diamondback Pro Forma Acreage Map[1]



Diamondback Market Snapshot

NASDAQ Symbol: FANG

Market Cap: $14,793 million

Net Debt: $7,594 million[5]

Enterprise Value: $23,366 million

Share Count: 181 million

2021 Annual Dividend: $1.60 (2.0% current yield)[6]

Source: Company data, public filings, and Bloomberg. Financial data as of 3/31/2021. Market data as of 4/30/2021.

(1) Pro forma for announced divestitures. Net acreage excludes exploratory and conventional acreage.

(2) FCF defined as operating cash flow before changes in working capital less cash CAPEX. Reinvestment rate calculated as cash CAPEX divided by pre-dividend operating cash flow before changes in working capital. See slides 8-9 for more detail.

(3) Excludes Viper and Rattler.

(4) Subject to closing adjustments.

(5) Long-term debt less cash.

(6) Yield based on 4/30/2021 closing price. Future dividends subject to the discretion and approval of the Board of Directors.

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Diamondback: Investment Highlights

Q1 2021 Highlights	◆ Generated $331 million of FCF[(1)] ◆ Oil production of 184.2 Mbo/d (307.4 Mboe/d) ◆ Cash operating costs of $8.06 per boe; including cash G&A of $0.54 per boe ◆ Dividend of $0.40 / share; payable May 20, 2021 ◆ Signed definitive agreements to divest Williston Basin asset acquired in QEP transaction and non-core Permian assets for $832 million (~16 Mbo/d of FY 2021E production)
2021 Guidance	◆ Production guidance of 212 – 216 Mbo/d (350 – 360 Mboe/d) ◆ Cash CAPEX guidance of $1.60 – $1.75 billion ◆ Expect to drill 200 – 215 gross wells and complete 275 – 285 gross horizontal wells with an average lateral of ~10,300 feet (75% Midland Basin / 25% Delaware Basin)
Q2 2021 Guidance	◆ Production guidance of 232 – 236 Mbo/d (387 – 394 Mboe/d) ◆ Cash CAPEX guidance of $350 – $400 million
2021 Investment Framework	◆ Anticipate maintaining pro forma Q4 2020 Permian oil production through 2021 spending 10% less capital than standalone 2020 plan ◆ Expect to generate substantial pre-dividend Free Cash Flow in 2021, with a reinvestment rate of <55%, assuming current commodity prices[(1)] ◆ Free Cash Flow in excess of dividend expected to be used to accelerate debt paydown
ESG Initiatives and Q1 2021 Performance	◆ 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 ◆ Flared 0.75% of gross gas production in Q1 2021 (1.0% with QEP), down >85% from 2019

Source: Company data and filings. Financial data as of 3/31/2021 unless otherwise noted.

(1) Free Cash Flow ("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. See slides 8-9 for more detail.

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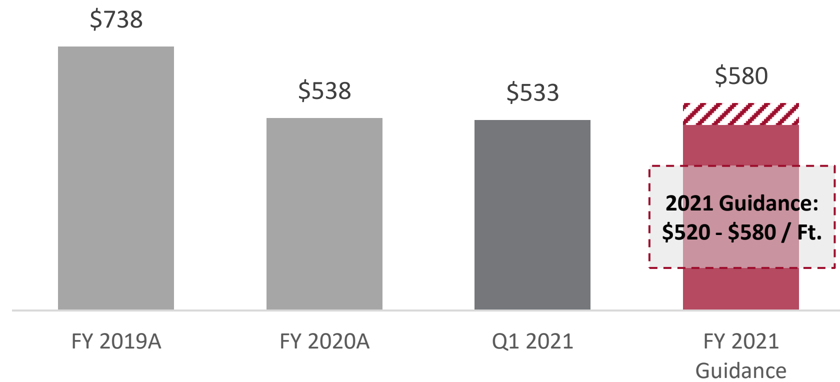
First Quarter 2021 Execution

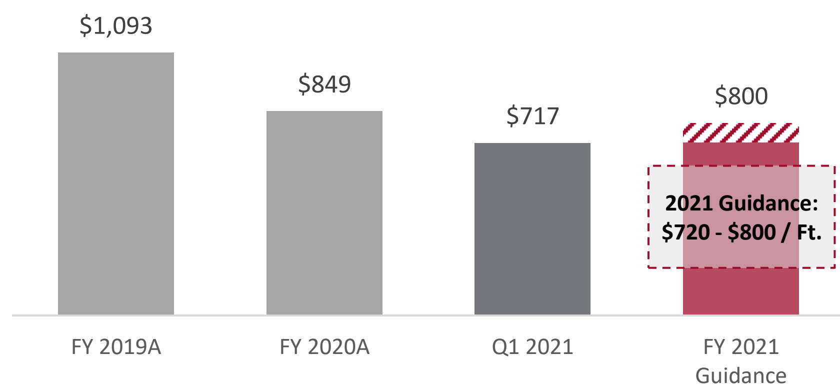
Q1 2021 Execution

	Q4 2020	Change	Q1 2021
Oil Production *Net Mbo/d*	176	+5%	184
Net Lateral Feet *TIL Net Ft. (1,000's)*	421	+48%	623
Cash Margin *% of Unhedged Realized Price[1]*	68%	+12%	76%
Cash CAPEX *$MM*	$226	+31%	$296
Reinvestment Rate *Cash CAPEX / Cash Flow (%)*	48%	-2%	47%
Free Cash Flow *$ / Share[2]*	$1.53	+31%	$2.01

Gross Midland Basin D,C&E Well Costs ($ / Ft.)[3]



Gross Delaware Basin D,C&E Well Costs ($ / Ft.)[3]



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) Well costs assume gross Rattler costs.

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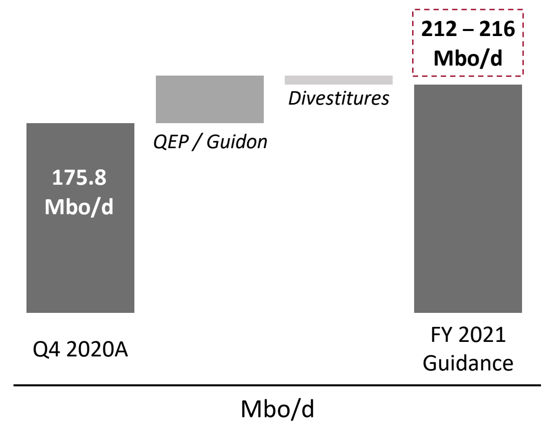
Overview of 2021 Guidance and Capital Budget

2021 Activity and Guidance Midpoints vs 2020

	2020A Standalone	Change	2021 Guidance
Oil Production *Net Mbo/d*	181	+18%	214
TIL Lateral Feet *Net Ft. (1,000's)*	1,668	+57%	2,621
Drilled Lateral Feet *Net Ft. (1,000's)*	1,968	-3%	1,906
Capital Budget *$MM(1)*	$1,859	-10%	$1,675
Annual Dividend *$ / Share*	$1.50	+7%	$1.60
Reinvestment Rate *$55 / Bbl WTI(2)*	92%	-40%	~55%

2021 Production and Activity Outlook

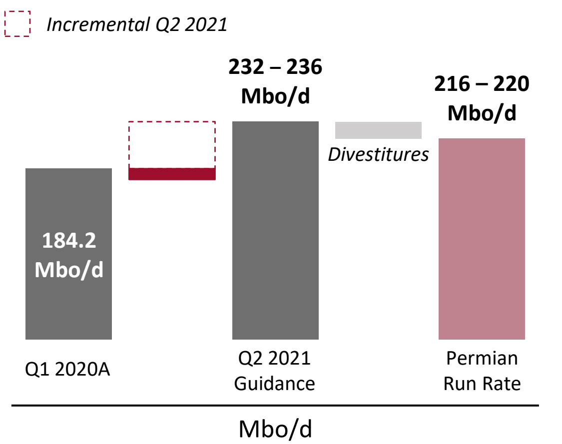
2021 plan focused on maintaining pro forma Q4 2020 Permian oil production



FY 2021 Activity

- **200 – 215** Gross operated wells drilled
- **275 – 285** Gross operated wells TIL
- **75%** Midland Basin net lateral ft.

Q2 2021 Production and Capital Guidance



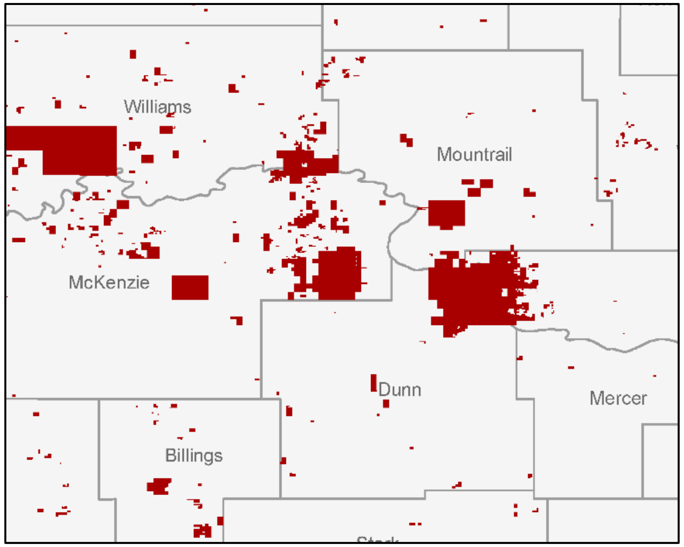
Q2 2021 Guidance

- **232 – 236** Oil Production (Mbo/d)
- **216 – 220** Permian Oil (Mbo/d)
- **$350 – $400** Cash CAPEX ($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. See slide 9 for additional detail.

Overview of Pending Williston Basin & Non-Core Permian Divestitures

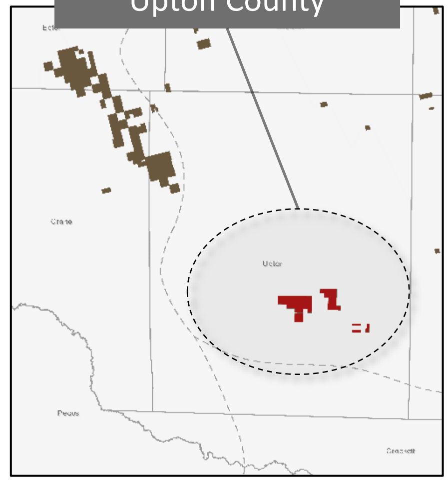
Williston Basin Asset Divestiture



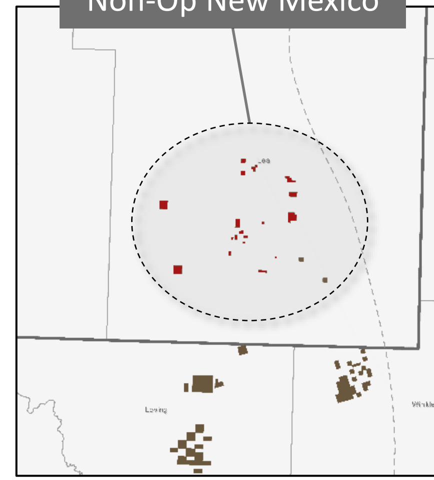
Williston Basin Divestiture Overview	
Gross Proceeds	$745 million
Net Acres	~95,000
2021E Production (Bo/d)	~15,000
2021E Production (Boe/d)	~25,000
Estimated Close	Q3 2021

Non-Core Permian Basin Asset Divestitures

Upton County



Non-Op New Mexico



Permian Basin Non-Core Divestitures Overview	
Gross Proceeds	$87 million
Net Acres	~8,300
2021E Production (Bo/d)	~900
2021E Production (Boe/d)	~2,650
Close	Closed June 2021

Announced divestitures of QEP's Williston Basin asset and non-core Permian assets for $832 million; net proceeds expected to be used to accelerate debt reduction

Source: Company data, filings and estimates.

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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 \$1.60 - \$1.75 billion in 2021; implies 10% decrease relative to standalone CAPEX for 2020
- At current commodity prices, Diamondback expects to generate substantial pre-dividend Free Cash Flow in 2021
- Prioritizing protecting the base dividend while maintaining pro forma Q4 2020 oil volumes; expect additional free cash flow as a result of improving commodity prices to accelerate debt reduction

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

FY 2021 Assumptions

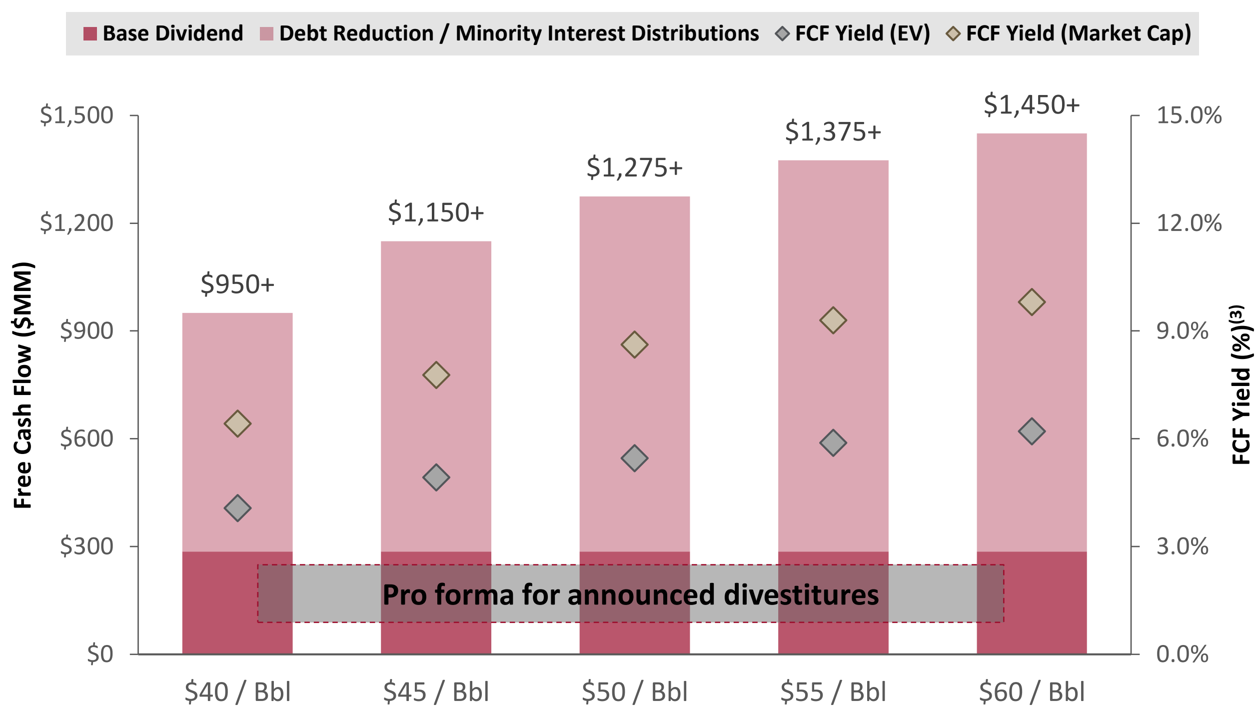
212 - 216 Mbo/d
Oil Production

\$1.60 - \$1.75 billion
Cash CAPEX[2]

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

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

\$1.60 / Share
Annual Shareholder Dividend



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 \$2,625MM at \$40/Bbl, over \$2,825MM at \$45/Bbl, over \$2,950MM at \$50/Bbl, over \$3,050MM at \$55/Bbl, and over \$3,125MM at \$60/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 4/30/2021, respectively.

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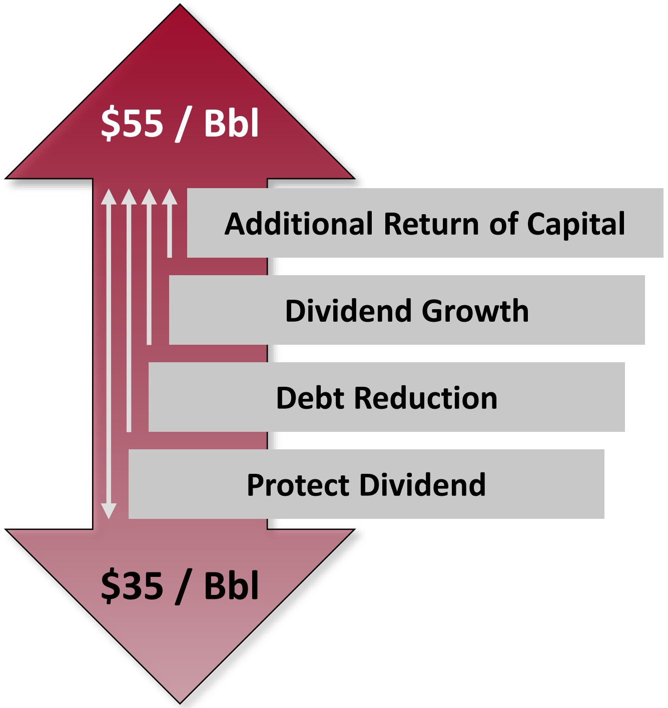
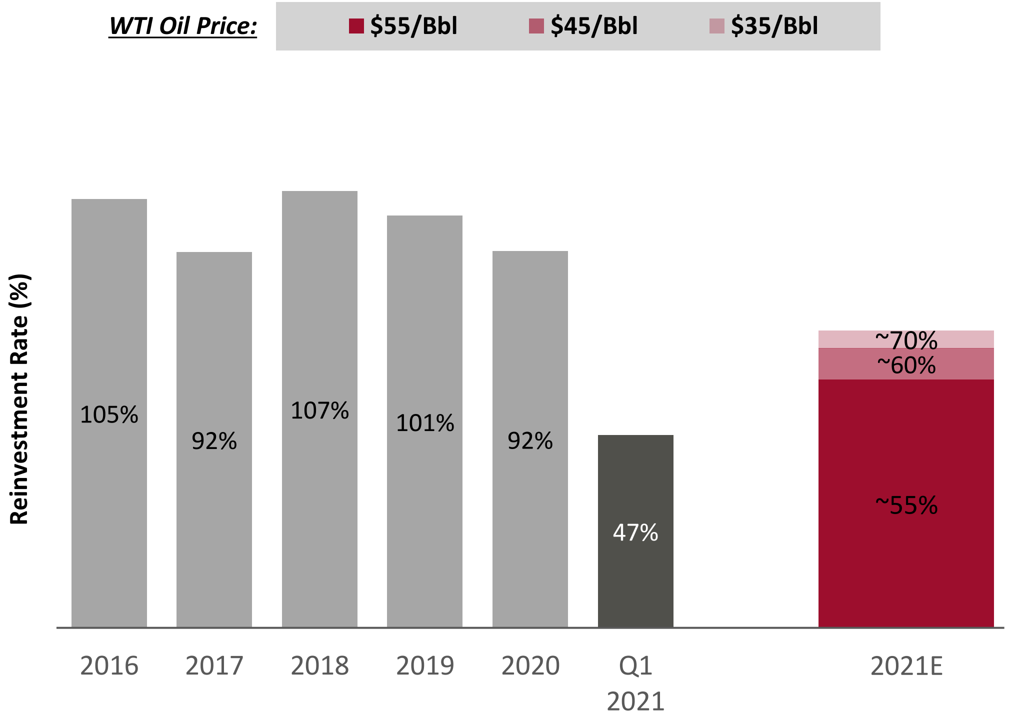
Diamondback Investment Framework

- 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 inevitable upcycle
- Diamondback's investment framework and capital allocation philosophy at current oil prices remains very simple: protect and consistently grow our base dividend, spend maintenance capital to hold oil production flat, and use excess Free Cash Flow to pay down debt
- Recent commodity price strength does not change this capital allocation framework

Investment Framework



Historical and Future Reinvestment Rates (%)[(1)]



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) Reinvestment rate calculated as cash CAPEX (defined below) divided by pre-dividend cash flow from operations before changes in working capital. See slide 8 for additional detail.

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Midland Basin Inventory and Development Strategy

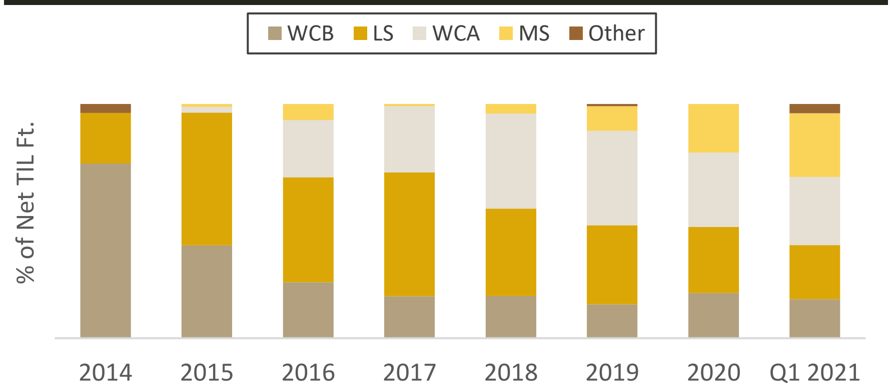
Diamondback Midland Basin Inventory:

- 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.

Delaware Basin Inventory and Development Strategy

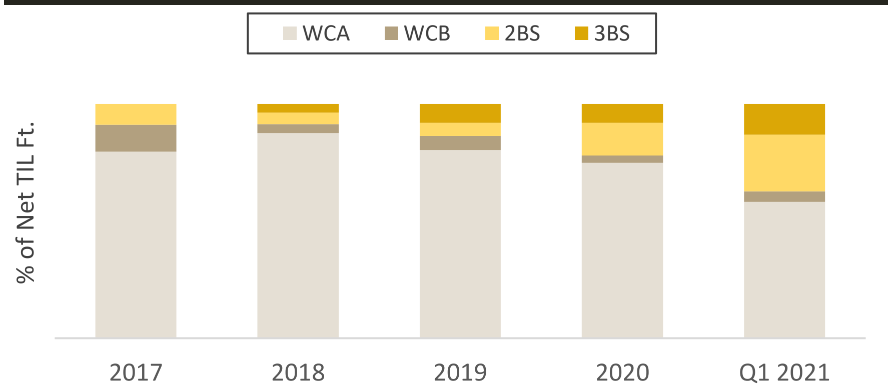
Diamondback Delaware Basin Inventory:

- 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.

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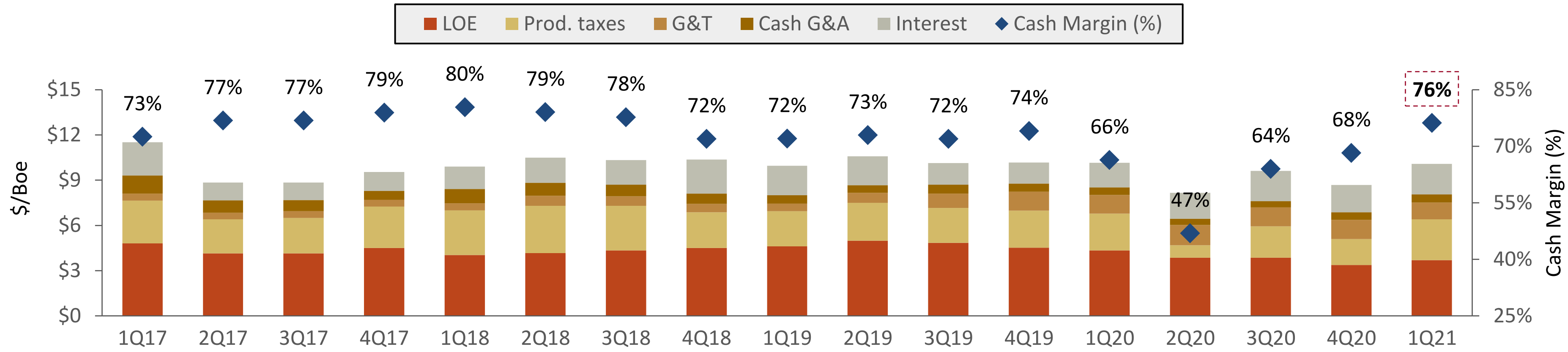
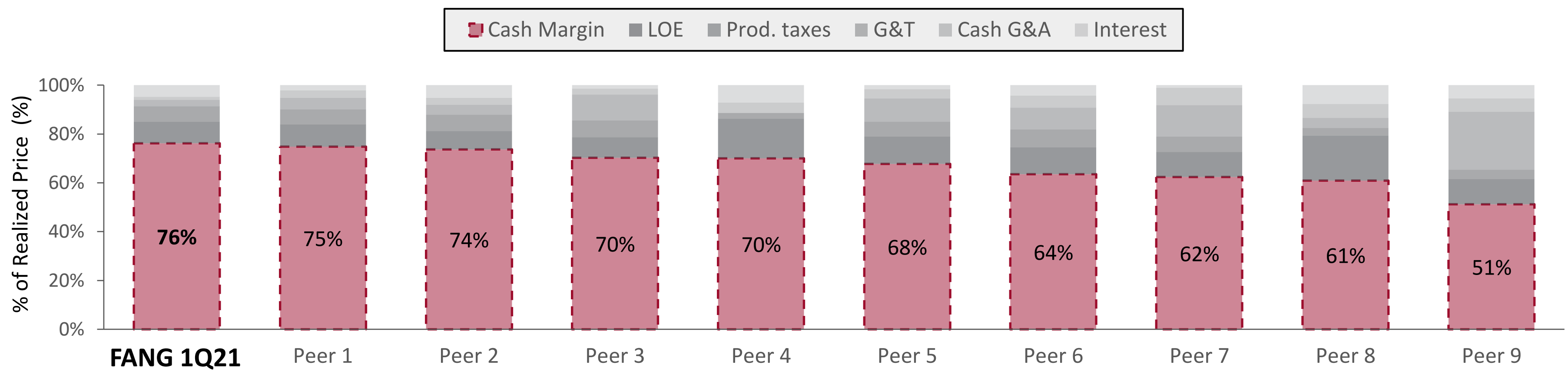
Peer-Leading Cash Margins and Operating Costs

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

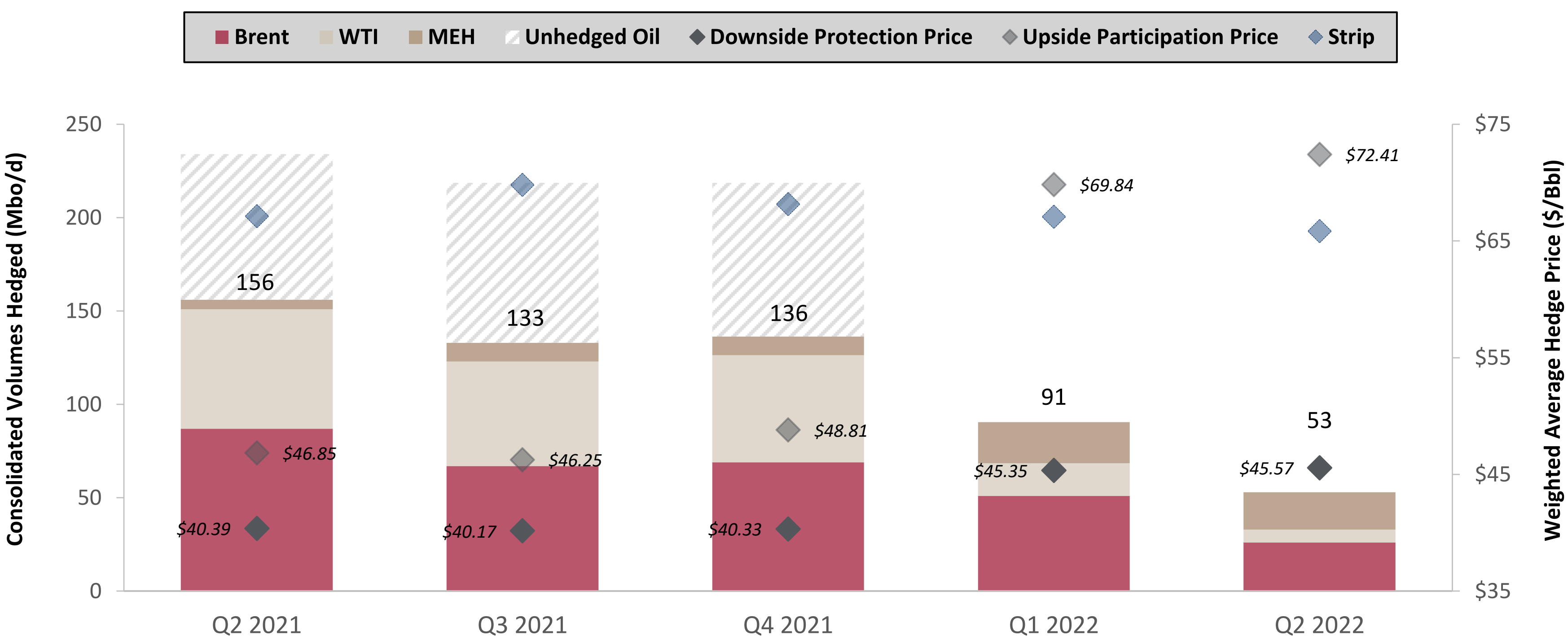
Source: Company data and latest peer filings as of 6/8/2021. Extended peers include PXD, CLR, EOG, HES, XEC, DVN, MRO, APA and OVV.
(1) Cash operating costs including interest calculated as the sum of LOE, G&T, production taxes, cash G&A expense and interest expense per boe.
(2) Unhedged cash margins 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

Current Hedges Maximize Downside Protection

- Current oil hedges provide downside protection on ~65% of expected FY 2021 oil production[(1)], with percentage protected declining through Q2 2022
- Strategy focused on maximizing downside protection to secure appropriate level of cash flow to hold oil production flat, protect our dividend and reduce debt
- Diamondback will continue to add hedges, primarily in the form of two-way collars, to protect our capital allocation strategy and retain exposure to the commodity

Consolidated Oil Hedges (Mbo/d)[(2)]



Source: Company data, filings and estimates and Bloomberg as of 6/8/2021.
(1) Based on FY 2021 production guidance of 212 – 216 Mbo/d.
(2) Excludes basis and roll swaps. See slides 27-28 for additional detail.

Capital Structure and Liquidity

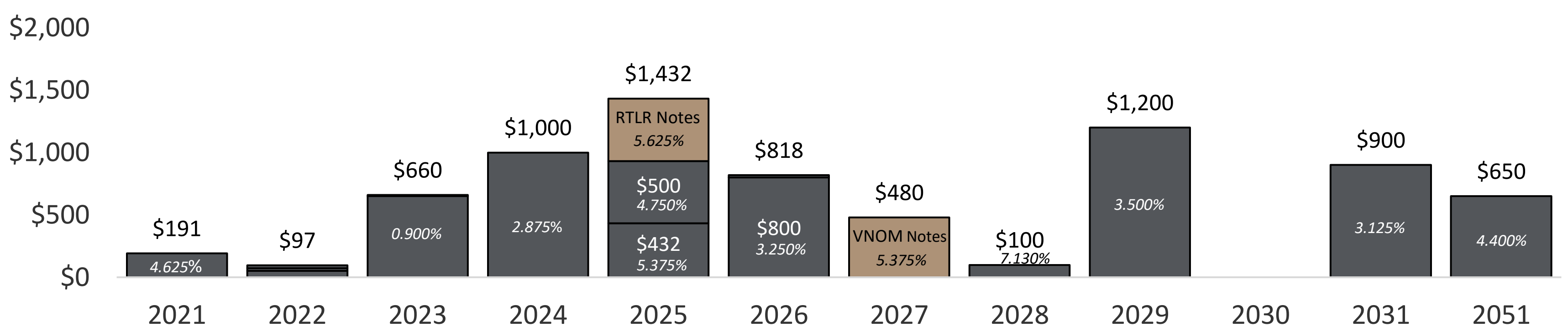
- As of March 31, 2021, FANG had $52 million of outstanding borrowings under its credit facility with standalone liquidity of >$2.0 billion[(1)]
- In March 2021, Diamondback raised $2.2 billion of investment grade debt at 2.84%; proceeds used to fund the purchase prices for the tender offers of FANG's callable 2025 notes and QEP debt
- This liability management exercise reduces annual interest expense by over $40 million
- Future free cash flow in excess of our dividend as well as proceeds from our announced non-core asset sales are expected to be used to reduce callable debt by up to $1.2 billion by year-end 2021

FANG's Liquidity and Capitalization ($MM)

FANG's Consolidated Capitalization	3/31/2021
Cash and cash equivalents	$121
FANG's Revolving Credit Facility	$52
VNOM's Revolving Credit Facility	57
RTLR's Revolving Credit Facility	54
Senior Notes	7,477
DrillCo Agreement	75
Total Debt	***$7,715***
Net Debt	***$7,594***

FANG's Standalone Liquidity	3/31/2021
Cash[(1)]	$100
Elected commitment amount	2,000
Liquidity	***$2,048***

FANG's Debt Maturity Profile ($MM)



Source: Company Filings, Management data and Estimates.
(1) Excludes Viper and Rattler.

DIAMONDBACK Energy

2021 Guidance – Pro Forma for Announced Divestitures

- Full year 2021 oil production guidance of 212.0 – 216.0 Mbo/d; 2021 plan aimed at maintaining pro forma Q4 production levels net of asset sales
- Full year 2021 CAPEX budget of $1.60 - $1.75 billion; implies 10% reduction compared to 2020 CAPEX
- Expect to complete 275 – 285 gross horizontal wells with an average lateral length of ~10,300 feet

2Q 2021 Guidance

- Q2 2021 oil production guidance of 232.0 – 236.0 Mbo/d (387.0 – 394.0 Mboe/d)
- Q2 2021 cash CAPEX guidance of $350 – $400 million

Diamondback 2021 Capital Activity Guidance

Gross (net) horizontal wells drilled	200 – 215 (178 – 192)
Gross (net) horizontal wells completed	275 – 285 (250 – 259)
Average lateral length (ft.)	~10,300’
Midland Basin well costs per lateral foot[1]	$520 – $580
Delaware Basin well costs per lateral foot[1]	$720 – $800
Midland Basin net lateral feet (%)	~75%
Delaware Basin net lateral feet (%)	~25%

	Diamondback	Viper
Net Production – Mboe/d	350.0 – 360.0	25.00 – 27.00
Oil Production – Mbo/d	212.0 – 216.0	15.00 – 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 – $3.50
Production and Ad Valorem Taxes (% of Revenue)[2]	7%	7%
Corporate Tax Rate (% of Pre-tax Income)	23%	

Diamondback Capex Budget ($MM)	
Operated D,C&E	$1,300 – $1,400
Non-Operated Properties / Capital Workovers	$160 – $180
Midstream (ex. long-haul pipeline investments)	$60 – $80
Infrastructure and Environmental	$80 – $90
Total 2021 Capital Budget	**$1,600 – $1,750**

Source: Company filings, management data and estimates.
(1) Well costs assume gross Rattler costs.
(2) Includes production taxes of 4.6% for crude oil and 7.5% for natural gas and NGLs and ad valorem taxes.

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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% currently** ◊ 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.

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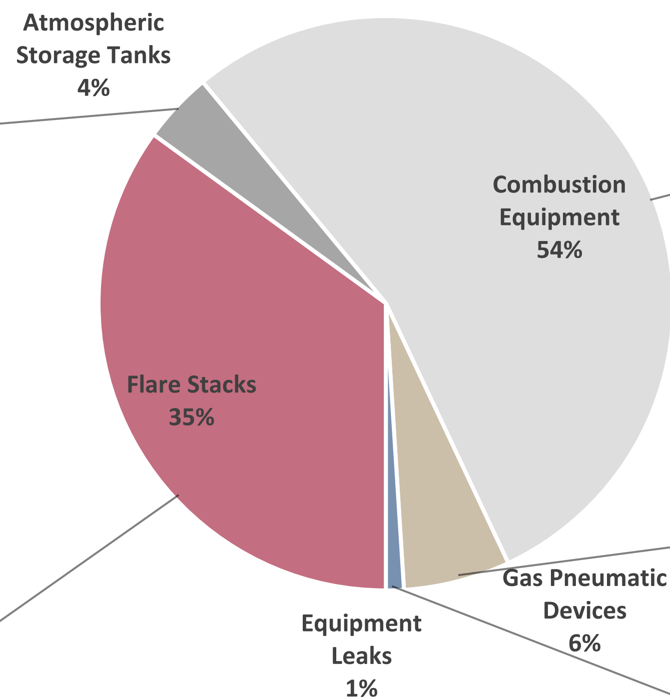
CO2e Emissions Breakdown and Strategic Reduction Initiatives

Diamondback 2020 CO2e Emissions Detail and Current Strategic Initiatives:

<u>Atmospheric Storage Tanks:</u>
~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 4Q21; limited tank design proven as a retrofit option, second case by 3Q21



<u>Combustion Equipment:</u>
~54% of CO2e emissions

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

Initiatives: Maximize electrification of current gas-driven engines; remove / replace > 200 electrical generation and gas driven compression units by 2023; work to electrify Drilling operation.

<u>Gas Pneumatic Devices:</u>
~6% of CO2e emissions

Drivers: >1000 tank batteries at FANG today; legacy batteries run off natural gas pneumatic systems

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

<u>Flare Stacks:</u>
~35% of CO2E emissions

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

Initiatives: Minimize flaring; currently at ~0.75% of gross gas produced(1); down >85% from ~5.6% in 2019

<u>2020 Scope 1 GHG Emissions:</u>
~1.2 million mt of CO2e
Intensity: 10.84 mt / net mboe produced
9.49 mt / gross mboe (AXPC)

<u>Equipment Leaks:</u>
~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

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 3/31/2021; 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

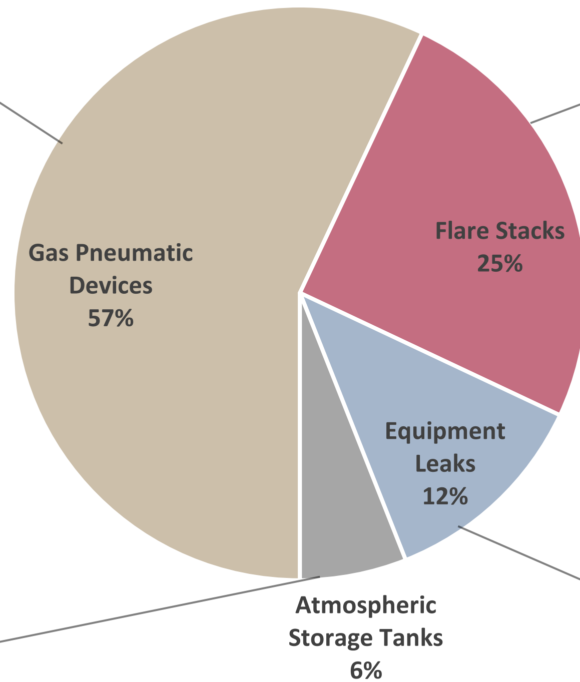
Drivers: >1000 tank batteries at FANG currently; legacy batteries run off gas pneumatic systems

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

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 4Q21; limited tank design proven as a retrofit option, second case by 3Q21



Flare Stacks:
~25% of methane emissions

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

Initiatives: Minimize flaring; currently at ~0.75% of gross gas produced[1]; down >85% from ~5.6% in 2019

Flare stacks rated to 98% destruction efficiency; reducing flaring directly reduces methane emissions from flaring

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

2020 Methane Emissions:
5,079 tons of methane
Methane Intensity: 0.15%[2]
AXPC Methane Intensity: 0.05%[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 3/31/2021; excludes QEP.
*(2) Methane intensity % is calculated as (tons of methane emissions) / ((gross gas produced) * (average mole fraction of methane in produced gas) * (methane density of .0192 kg/scf)).*
(3) AXPC defines Methane Intensity as metric tons of CH4 divided by gross annual production (Mboe).

DIAMONDBACK Energy

Governance and Compensation Changes

- Diamondback continues to respond to investor feedback and make appropriate changes to compensation and governance practices to reflect incentives that translate to stockholder value creation
- 2021 proxy report now available at www.diamondbackenergy.com

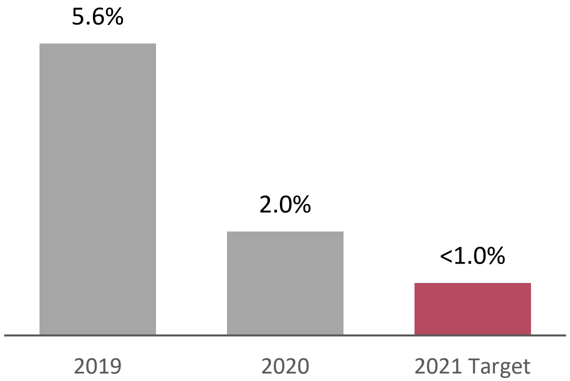
Recent Changes to Governance and Compensation	
Long-term Incentive Compensation (“LTI”)	◆ Chief Executive Officer's Long Term Incentive ("LTI") compensation target amount reduced by 20% from 2020 ◆ Remainder of executive team 2021 LTI compensation target amount reduced by 10% from 2020 ◆ Added both the S&P 500 and the XOP Index as peers to the 2021 peer group
Short-term Incentive Compensation (“STI”)	◆ No upward salary adjustments or change to STI targets for all members of the executive team ◆ 2020 STI scorecard performance capped at 100% target for all executives despite actual scorecard performance of 160% of target ◆ Updated annual metrics to include a FCF per share metric with expected 20% weighting ◆ Increased ESG component weighting to 20% from 15% previously ◆ 2021 scorecard metrics also include: capital budget (D,C&E, non-op and capital workovers, midstream, infrastructure and environmental), PDP F&D costs, controllable cash costs (LOE and G&A), ROACE and ESG

Source: Company data and filings.

Environmental, Social and Governance ("ESG")

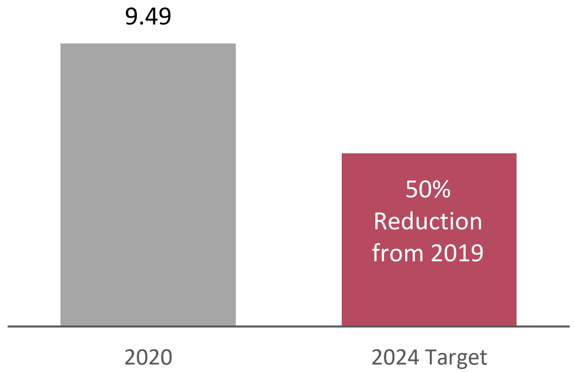
Flaring (% of Gross Gas Production)

2021 Goal: Flare <1.0% of Gross Gas



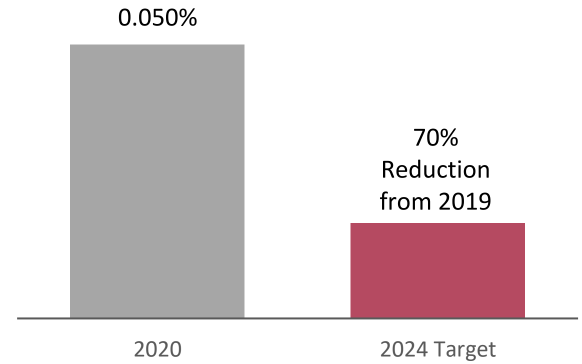
GHG Intensity (mt / mboe Produced)(1)

Goal: Reduce 2019 intensity by 50% by 2024



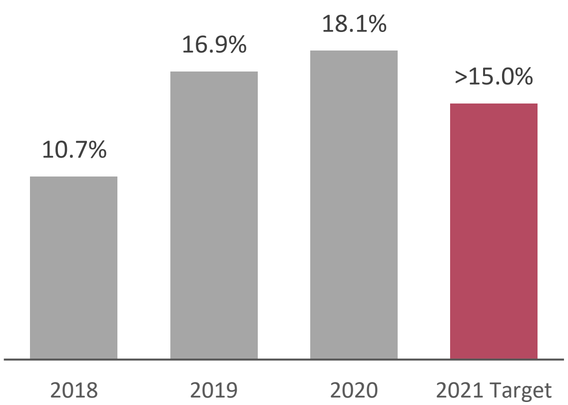
Methane Intensity (%)(1)

Goal: Reduce 2019 intensity by 70% by 2024



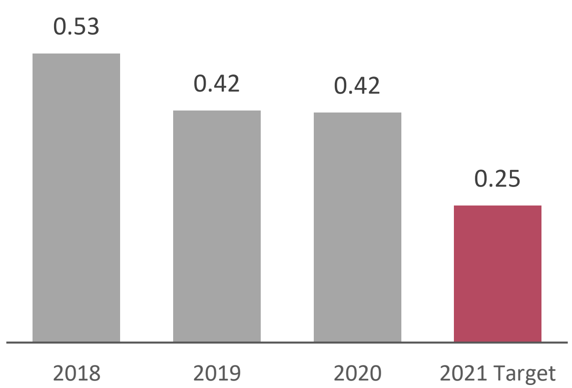
Water Recycling (% of Produced)

2021 Goal: >15% Water Recycling



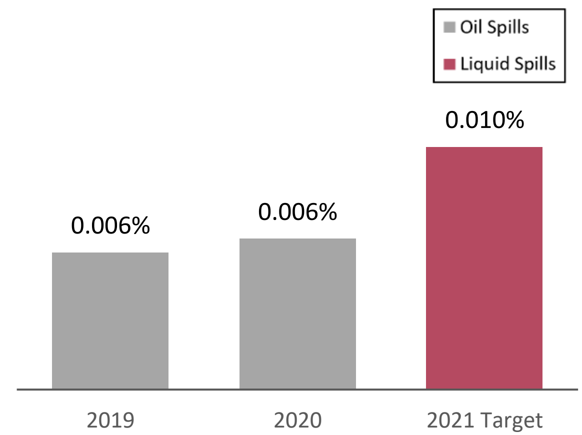
Workplace Safety (TRIR)

2021 Goal: TRIR at or below 0.25



Liquids Spill Rate (%)

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




APPENDIX

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

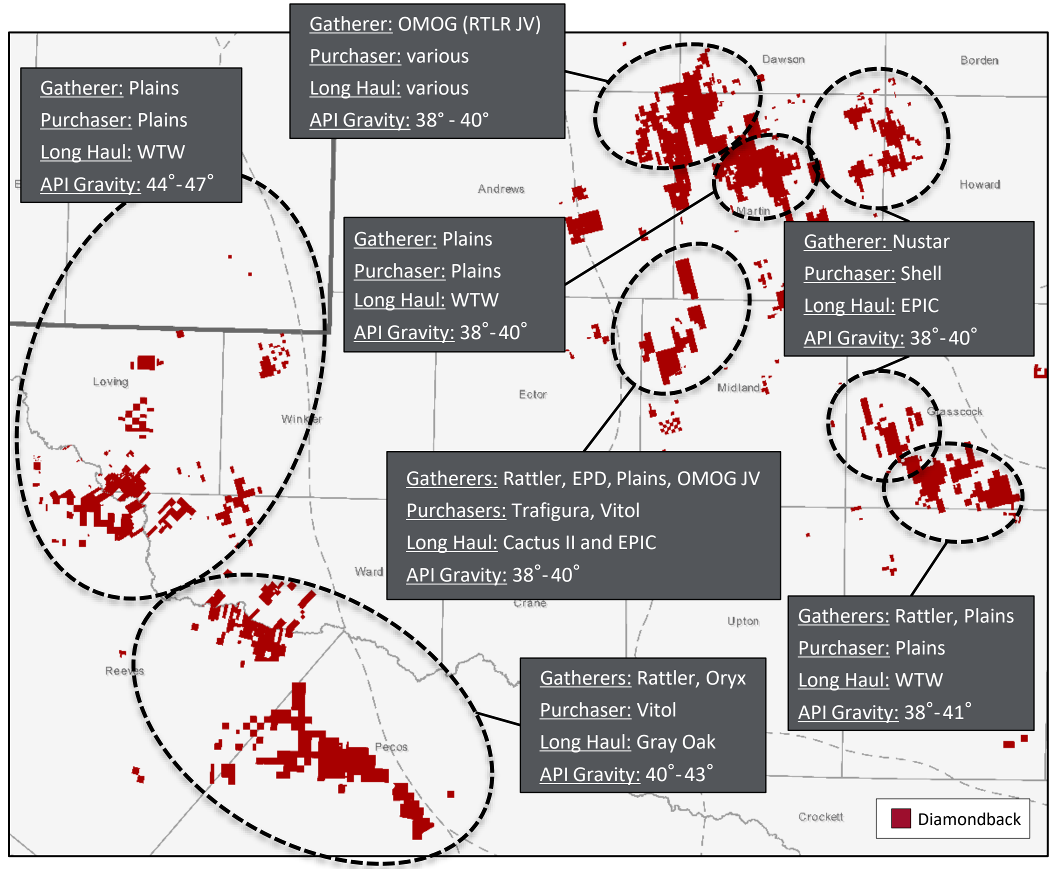
Obligations and Pricing Exposure:

- 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

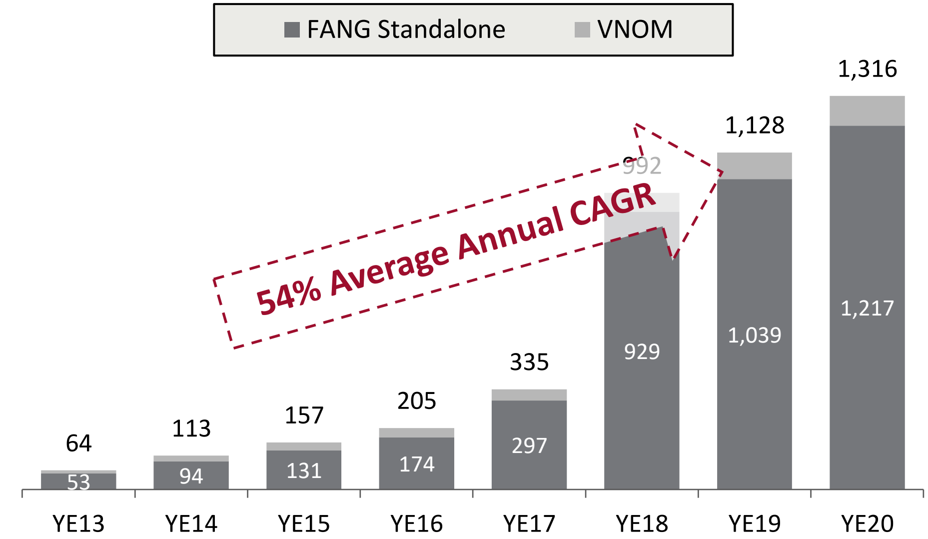
2020 Reserves

- 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

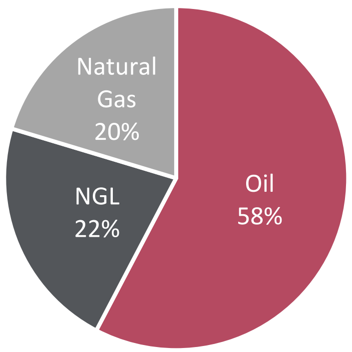
F&D Costs

($/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)

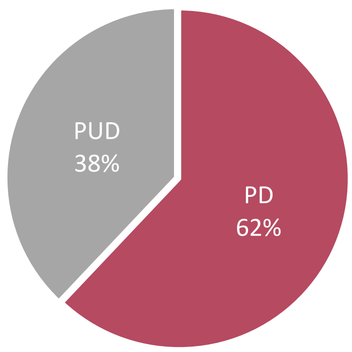


1P Reserves – By Commodity



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	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**
Swaps - WTI	**43,341**	**38,348**	**30,674**	**1,000**	**1,000**	**–**	**–**
	$44.60	$42.82	$42.36	$45.00	$45.00	–	–
Swaps - MEH	**5,000**	**5,000**	**5,000**	**–**	**–**	**–**	**–**
	$37.78	$37.78	$37.78	–	–	–	–
Swaps - Brent[(1)]	**5,000**	**5,000**	**5,000**	**–**	**–**	**–**	**–**
	$41.62	$41.62	$41.62	–	–	–	–
Total Oil Swaps	**53,341**	**48,348**	**40,674**	**1,000**	**1,000**	**--**	**--**
Costless Collars - WTI	**20,670**	**17,685**	**26,663**	**13,500**	**6,000**	**–**	**–**
Floor / Ceiling	$35.78 / $47.08	$35.27 / $46.50	$38.69 / $53.80	$45.00 / $68.89	$45.00 / $68.75	–	–
Costless Collars - MEH	**–**	**5,000**	**5,000**	**22,000**	**20,000**	**–**	**–**
Floor / Ceiling	–	$45.00 / $57.90	$45.00 / $78.75	$45.91 / $70.95	$46.00 / $71.29	–	–
Costless Collars - Brent	**82,000**	**62,000**	**64,000**	**51,000**	**26,000**	**5,000**	**5,000**
Floor / Ceiling	$39.40 / $48.84	$39.61 / $48.42	$39.78 / $48.90	$45.20 / $70.11	$45.38 / $75.18	$45.00 / $75.56	$45.00 / $75.56
Total Costless Collars	**102,670**	**84,685**	**95,663**	**86,500**	**52,000**	**5,000**	**5,000**
Long Puts - WTI[(2)]	**–**	**–**	**–**	**3,000**	**–**	**–**	**–**
	–	–	–	$47.53	–	–	–
Total Long Puts	**--**	**--**	**--**	**3,000**	**--**	**--**	**--**
Total Crude Oil Hedges	**156,011**	**133,033**	**136,337**	**90,500**	**53,000**	**5,000**	**5,000**
Basis Swaps - WTI	**39,000**	**34,000**	**34,000**	**10,000**	**10,000**	**10,000**	**10,000**
	$0.83	$0.91	$0.91	$0.84	$0.84	$0.84	$0.84
Total Basis Swaps	**39,000**	**34,000**	**34,000**	**10,000**	**10,000**	**10,000**	**10,000**
Roll Swaps - WTI	**46,000**	**44,000**	**44,000**	**10,000**	**10,000**	**10,000**	**10,000**
	$0.16	$0.33	$0.33	$0.50	$0.50	$0.50	$0.50
Total Roll Swaps	**46,000**	**44,000**	**44,000**	**10,000**	**10,000**	**10,000**	**10,000**

Source: Company data as of 6/8/2021.
(1) Includes 5,000 BO/d of swaps in the first half of 2021 whereby the counterparty has the right to extend the hedge into the second half of 2021 at an average price of $51/Bbl.
(2) Excludes a deferred premium at the weighted-average price of $2.12/Bbl.

DIAMONDBACK Energy

Current Hedge Summary: Natural Gas and Natural Gas Liquids

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

Natural Gas Hedges	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Swaps - Henry Hub	**245,000**	**245,000**	**245,000**	–	–	–	–
	$2.65	$2.65	$2.65	–	–	–	–
Swaps - Waha *Fixed Price*	**50,000**	**50,000**	**50,000**	–	–	–	–
	$1.92	$1.92	$1.92	–	–	–	–
Total Swaps	**295,000**	**295,000**	**295,000**	–	–	–	–
Costless Collars - Henry Hub	–	–	–	**100,000**	**100,000**	–	–
Floor / Ceiling	–	–	–	$2.50 / $3.58	$2.50 / $3.58	–	–
Total Costless Collars	–	–	–	**100,000**	**100,000**	–	–
Total Natural Gas Hedges	**295,000**	**295,000**	**295,000**	**100,000**	**100,000**	–	–
Basis Swaps - Waha	**250,000**	**250,000**	**250,000**	**210,000**	**210,000**	**210,000**	**210,000**
	($0.66)	($0.66)	($0.66)	($0.34)	($0.34)	($0.34)	($0.34)
Total Basis Swaps	**250,000**	**250,000**	**250,000**	**210,000**	**210,000**	**210,000**	**210,000**

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

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

Source: Company data as of 6/8/2021.

DIAMONDBACK Energy

Build-out of Midstream Assets Through Rattler Midstream

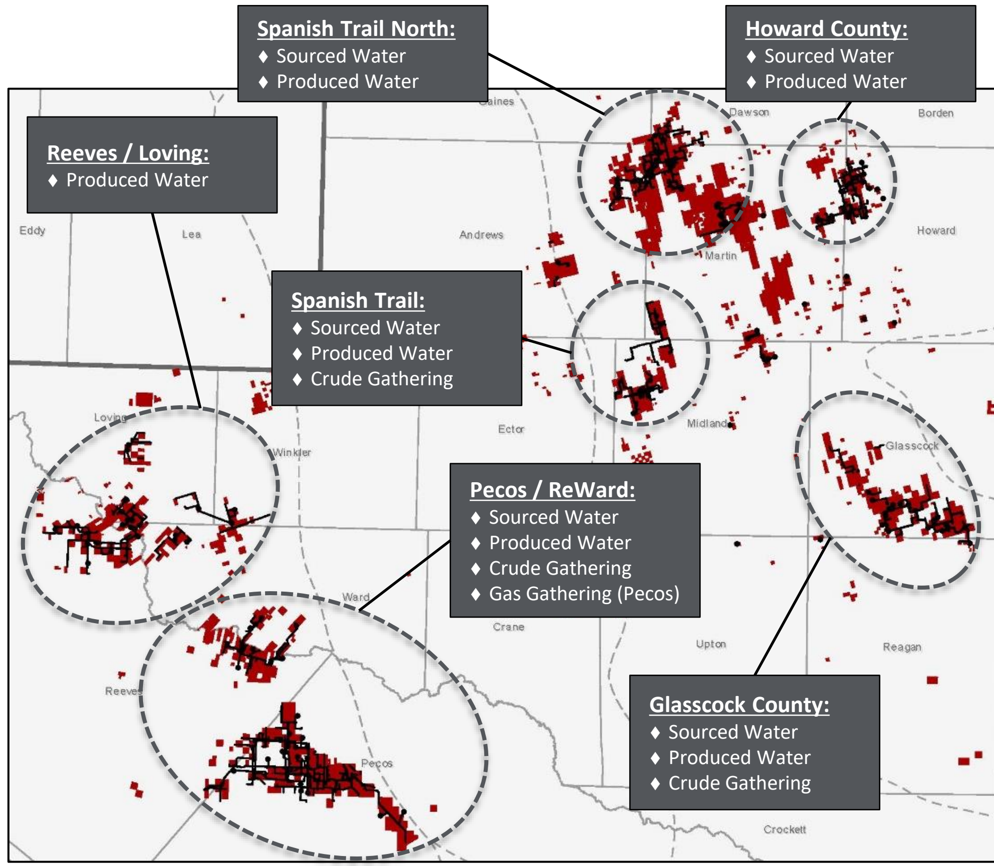
Rattler Midstream:

- 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 (7.0% yield)(1)

Rattler Capacity Overview

Fee Stream	Midland	Delaware
Produced Water – Bbl/d	1,805,000	1,330,000
Sourced Water – Bbl/d	455,000	120,000
Crude Oil – Bbl/d	65,000	210,000
Natural Gas – Mcf/d	--	180,000(2)
Total	**~2,320,000**	**~1,840,000**

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

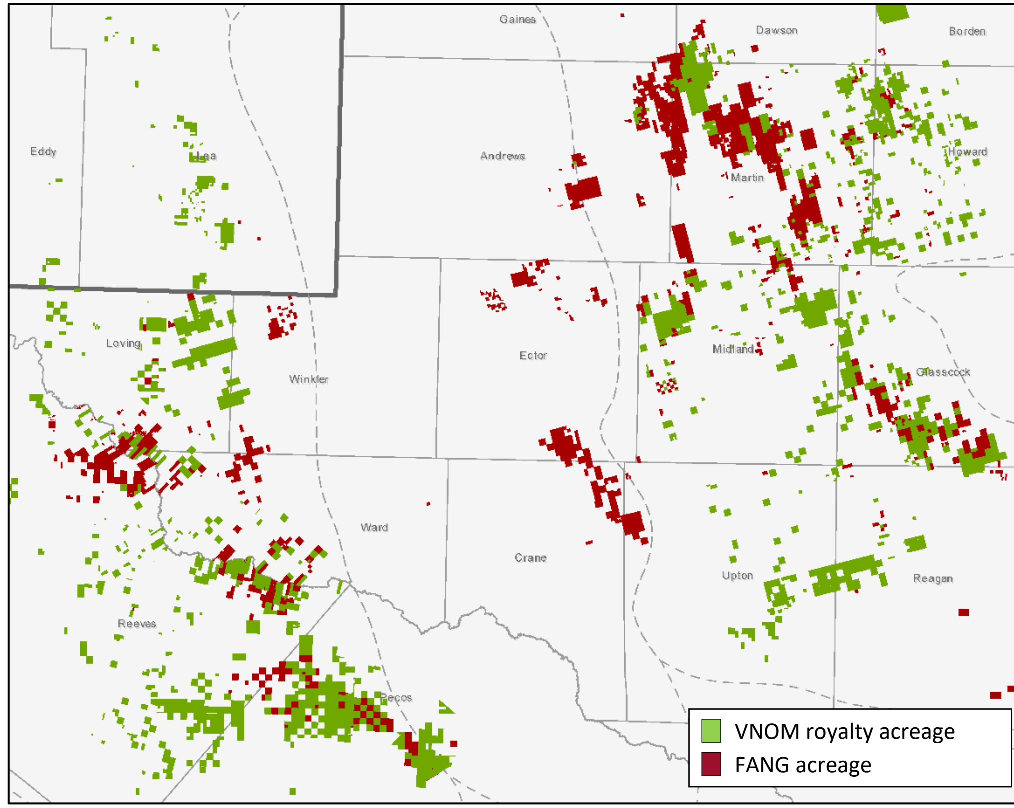
Source: Company filings, management data and estimates.
(1) Based on Rattler's most recent quarterly distribution announced on 2/24/2021. Yield based on RTLR's closing price as of 4/30/2021.
(2) 151,000 Mcf/d compression capacity.

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
- 24,350 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
  - 50 of Diamondback's 67 Q1 2021 completions on Viper's acreage, in which Viper owned a 4.2% average NRI
- Q1 2021 average oil production of 15.5 Mbo/d; generated $0.42 / 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 3/31/2021.

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