

DIAMONDBACK ENERGY

3Q 2026 Investor Presentation

November 2026

Forward-Looking Statements & Non-GAAP Financial Measures

Forward-Looking Statements

This presentation contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act, which involve risks, uncertainties, and assumptions. All statements, other than statements of historical fact, that Diamondback Energy, Inc. ("Diamondback," the "Company" or "we") makes, including statements regarding future performance; business strategy; future operations (including drilling plans and capital plans); estimates and projections of revenues, losses, costs, expenses, returns, cash flow, and financial position; reserve estimates and its ability to replace or increase reserves; anticipated benefits or other effects of strategic transactions (including the 2026 Drop Down, the Viper Riverbend acquisition, the Viper McElroy Ranch acquisition, and Viper's Sitio acquisition, divestitures or reorganizations); and plans and objectives of management (including plans for future cash flow from operations and for executing on environmental strategies and targets) are forward-looking statements. When used in this presentation, the words "aim," "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "future," "guidance," "intend," "may," "model," "outlook," "plan," "positioned," "potential," "predict," "project," "seek," "should," "target," "will," "would," and similar expressions (including the negative of such terms) as they relate to the Company are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Although the Company believes that the expectations and assumptions reflected in its forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. Accordingly, forward-looking statements are not guarantees of future performance and the Company's actual outcomes could differ materially from what the Company has expressed in its forward-looking statements.

Factors that could cause the outcomes to differ materially include (but are not limited to) the following: geopolitics and market conditions, including changes in supply and demand levels for oil, natural gas, and natural gas liquids, and the resulting impact on the price for those commodities; changes in U.S. energy, environmental, monetary and trade policies, including with respect to tariffs or other trade barriers and any resulting trade tensions; actions taken by the members of OPEC and its non-OPEC allies (OPEC+) affecting the production and pricing of oil, as well as other domestic and global political, economic, or diplomatic developments; changes in general economic, business or industry conditions, including changes in foreign currency exchange rates, interest rates, inflation rates, and instability in the financial markets; regional supply and demand factors, including delays, curtailments or interruptions of production, or governmental orders, rules or regulations that impose production limits; federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations; physical and transition risks relating to climate change, changing political and social perspectives on climate change and other environmental, social and governance factors, and risks from our publicly disclosed targets related to sustainability and emissions reduction initiatives; challenges in developing our existing leasehold acreage and finding, developing or acquiring additional reserves; restrictions on the use of water, including limits on the use of produced water and a moratorium on new produced water disposal well permits recently imposed by the Texas Railroad Commission in an effort to control induced seismicity in the Permian Basin; significant declines in prices for oil, natural gas, or natural gas liquids, which could require recognition of significant impairment charges; conditions in the capital, financial and credit markets, including the availability and pricing of capital for acquisitions, exploration and development operations; challenges with employee retention and an increasingly competitive labor market; changes in availability or cost of rigs, equipment, raw materials, supplies and oilfield services; changes in safety, health, environmental, tax and other regulations or requirements (including those addressing air emissions, water management, or the impact of global climate change); security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or from breaches of information technology systems of third parties with whom we transact business; lack of, or disruption in, access to adequate and reliable electrical power, internet and telecommunication infrastructure, information and computer systems, transportation, processing, storage and other facilities for our oil, natural gas and natural gas liquids; failures or delays in achieving expected reserve or production levels from existing and future oil and natural gas developments, including due to operating hazards, drilling risks, or the inherent uncertainties in predicting reserve and reservoir performance; inability to keep pace with technological developments in our industry; failure to meet our obligations under our oil purchase contracts; loss of one or more customers or their inability to meet their obligations; geographical concentration of our primary operations; risks from our return of capital activity, and uncertainties over our future dividends and share repurchases; difficulty in obtaining necessary approvals and permits; severe weather conditions and natural disasters; changes in the financial strength of counterparties to our credit facilities and hedging contracts; our substantial indebtedness and restrictions to our operating and financial flexibility; changes in our credit rating; failure to identify, complete and successfully integrate acquisitions, including Viper's Riverbend acquisition, Viper's McElroy Ranch acquisition and Viper's Sitio acquisition; the Endeavor stockholders' ability to significantly influence our business and potential conflicts of interest; and those other risks described in Part I, Item 1A of Diamondback's Annual Report on Form 10-K, filed with the SEC on February 25, 2026, and those risks disclosed in its subsequent filings on Forms 10-K, 10-Q and 8-K, which can be obtained free of charge on the SEC's website at http://www.sec.gov and Diamondback's website at www.diamondbackenergy.com/investors.

In light of these factors, the events anticipated by the Company's forward-looking statements may not occur at the time anticipated or at all. Moreover, the Company operates in a very competitive and rapidly changing environment and new risks emerge from time to time. The Company cannot predict all risks, nor can it assess the impact of all factors on its business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those anticipated by any forward-looking statements it may make. Accordingly, you should not place undue reliance on any forward-looking statements made in this presentation. All forward-looking statements speak only as of the date of this presentation or, if earlier, as of the date they were made. The Company does not intend to, and disclaims any obligation to, update or revise any forward-looking statements unless required by applicable law.

The presentation also contains the Company's updated capital expenditure and production guidance, and certain forward-looking information, with respect to 2026. The actual levels of production, 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, commodity prices 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 2026. 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. The Company's ability to fund its 2026 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, its production estimate assumes there will not be any new federal, state or local regulation of portions of the energy industry in which the Company operates, or an interpretation of existing regulation, that will be materially adverse to its business. For additional discussion of the factors that may cause it not to achieve its production estimates, see the Company's filings with the SEC, including its Forms 10-K, 10-Q and 8-K and any amendments thereto. The Company does not undertake any obligation to release publicly the results of any future revisions it 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 Consolidated 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, (gain) loss on extinguishment of debt, impairment of oil and natural gas properties, non-cash equity-based compensation expense, capitalized equity-based compensation expense, other non-cash transactions and provision for (benefit from) income taxes. 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 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 excludes the items listed above from net income (loss) to determine 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. Further, the Company excludes the effects of significant transactions that may affect earnings but are unpredictable in nature, timing and amount, although they may recur in different reporting periods. 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. 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 and the appendix attached to this presentation under "Non-GAAP Definitions and Reconciliations."

Operating cash flow before working capital changes, which is a non-GAAP financial measure, represents net cash provided by operating activities as determined under GAAP without regard to changes in working capital. The Company believes operating cash flow before working capital changes is a useful measure of an oil and natural gas company's ability to generate cash used to fund exploration, development and acquisition activities and service debt or pay dividends. The Company also uses this measure because changes in working capital relate to the timing of cash receipts and disbursements that the Company may not control and may not relate to the period in which the operating activities occurred.

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. Adjusted Free Cash Flow, which is a non-GAAP financial measure, is Free Cash Flow before the tax impact from divestitures (if any), merger and transaction expenses, costs of early termination of derivatives and settlements of any treasury locks (if any). The Company believes that Free Cash Flow and Adjusted Free Cash Flow are useful to investors as they provide a measure to compare both cash flow from operating activities and additions to oil and natural gas properties across periods on a consistent basis, adjusted, as applicable, for non-recurring impacts from divestitures, merger and transaction expenses, the early termination of derivative contracts and settlements of treasury locks. These measures should not be considered as an alternative to, or more meaningful than, net cash provided by operating activities as an indicator of liquidity. The Company's computation of operating cash flow before working capital changes, Free Cash Flow and Adjusted 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 as determined by the Board of Directors. For reconciliations of net cash provided by operating activities to operating cash flow before working capital changes and to Free Cash Flow and to Adjusted Free Cash Flow, please refer to our earnings release furnished to, and other filings we make with, the SEC and the appendix attached to this presentation under "Non-GAAP Definitions and Reconciliations."

Net debt, which is a non-GAAP measure, is total debt (excluding debt issuance costs, discounts, premiums and unamortized basis adjustments) less cash and cash equivalents and restricted cash that has been irrevocably deposited for the redemption of principal amounts of outstanding senior notes. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. The Company believes this metric is useful to analysts and investors in determining the Company's leverage position because the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt. For a reconciliation of net debt to total debt, please refer to our earnings release furnished to, and other filings we make with, the SEC and the appendix attached to this presentation under "Non-GAAP Definitions and Reconciliations."

Cash Return on Capital Invested, which is a non-GAAP measure, is calculated as debt-adjusted cash flow from operations before working capital changes divided by capital invested. Capital invested is calculated as total assets plus accumulated DD&A minus cash and cash equivalents minus non-interest-bearing current liabilities.

Furthermore, this presentation includes or references certain forward-looking, non-GAAP financial measures, such as estimated free cash flow for 2026, pre-tax income attributable to the Company and certain related estimates regarding future performance, results and financial position. Because the Company provides these measures on a forward-looking basis, it cannot reliably or reasonably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures, such as future impairments, future changes in working capital, future commodity prices, pace of and costs of developing, producing and operating the Company's interest in oil and natural gas properties, future changes in interest rates and various other business factors impacting the Company's financial results. Accordingly, the Company is unable to present a quantitative reconciliation of such forward-looking, non-GAAP financial measures to the respective most directly comparable forward-looking GAAP financial measures. The unavailable information could have a significant impact on our ultimate results. However, the Company believes these forward-looking, non-GAAP measures may be a useful tool for the investment community in comparing the Company's forecasted financial performance to the forecasted financial performance of other companies in the industry.

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, 2025, referenced in this presentation were prepared by our internal reservoir engineers and audited by Ryder Scott Company, L.P., an independent petroleum 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.



Stable Cash Flow Creation Through the Cycles

Best-In-Class Execution

Disciplined Capital Allocator with Differentiated Returns

Development Strategy Maximizes Resource and Returns

High-Quality, Durable Midland Basin Inventory

Investment Grade Balance Sheet



The Premier Permian Pure-Play Operator

Diamondback Value Creation

Stable Cash Flow Through the Cycles

- Expect to generate ~$9.2 billion of Free Cash Flow ("FCF") in 2026 at current commodity prices[(1)(2)]
- Current production levels and base dividend protected down to $36 / Bbl[(3)]

Best-In-Class Execution

- Industry leading cost structure with ~$550 / ft. Midland Basin drilling, completion and equipment well costs

Disciplined Capital Allocator

- Declared a quarterly base cash dividend of $1.18 per share, up 18% year over year ($4.72 per share annually)
- Share repurchase authorization of $16 billion with ~$9.7 billion remaining
- Reduced Diamondback standalone debt by ~$2.4 billion year to date[(4)]

Development Strategy Maximizes Resource and Returns

- Multi-zone co-development execution drives leading well productivity
- Development strategy combined with the lowest well costs in the basin produces the highest returns per well and drilling spacing unit

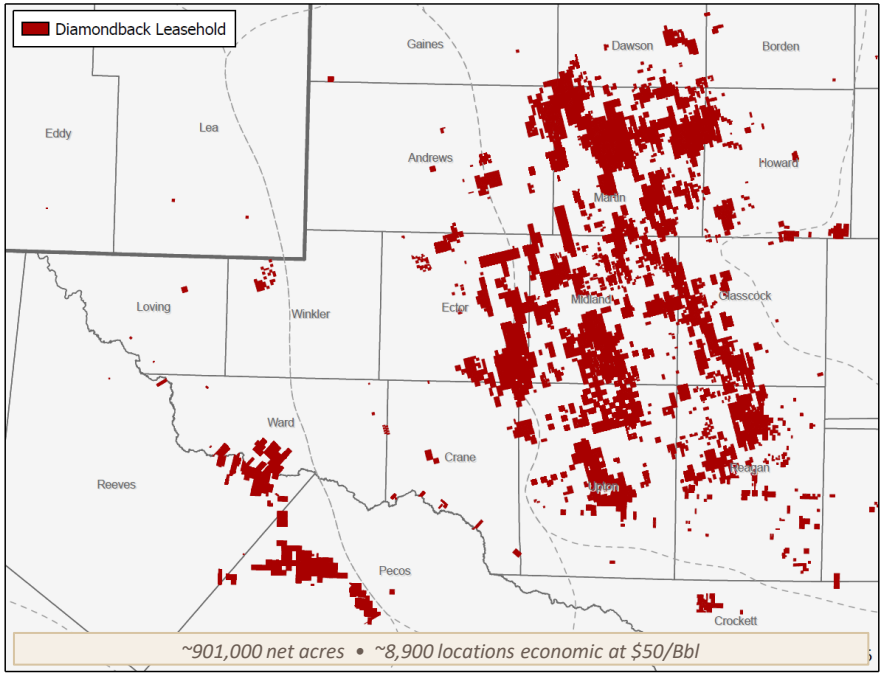
High-Quality, Durable Inventory

- ~901,000 net acres with ~8,900 locations economic at $50 / Bbl

Investment Grade Balance Sheet

- Investment grade credit ratings: Baa2 (Moody's), BBB (S&P) and BBB+ (Fitch)

Diamondback Acreage Map



3Q 2026 Highlights

525 (1,034)	**$2.2B**	**$1.18**
Mbo/d (Mboe/d)	**Adj. FCF[(5)]**	**Declared Base Dividend**
1,875 Bo/d per MM Shares	*$7.68 / share*	*Up 7% QoQ*

FANG	$59.2B	$78.2B	$12.8B	279 MM	2.2%
NASDAQ	Mkt Cap	Enterprise Value	Net Debt[(6)]	Shares	Dividend Yield

Source: Company data, filings and estimates. Financial data as of 9/30/2026. Market data as of 10/30/2026.

(1) Free Cash Flow defined as cash flow from operating activities before changes in working capital in excess of cash capital expenditures.

(2) Based on strip pricing as of 10/30/2026. We are unable to present a quantitative reconciliation because we cannot reliably predict certain necessary components of operating cash flow, such as changes in working capital. See "Forward-Looking Statements and Non-GAAP Financial Measures" on slide 2 for additional cautionary information.

(3) Breakeven WTI oil price calculated as the per barrel price for oil needed to generate cash flow equivalent to the amount of capital required to maintain 2026 oil production levels and pay the $4.72 / share annual base dividend. Assumes $3.00/Mcf Henry Hub gas prices and $20/Bbl NGL prices; excludes the impact of current commodity hedges.

(4) Reflects the $1,497 million reduction from 12/31/2025 to 9/30/2026, pro forma for the retirement of $698 million of 3.250% Senior Notes and $195 million principal repurchased in the open market.

(5) 3Q26 Adjusted Free Cash Flow excludes $2 million of merger and transaction expenses. 2026 year-to-date Adjusted Free Cash Flow excludes $8 million of merger and transaction expenses and $27 million of early termination of derivative payments.

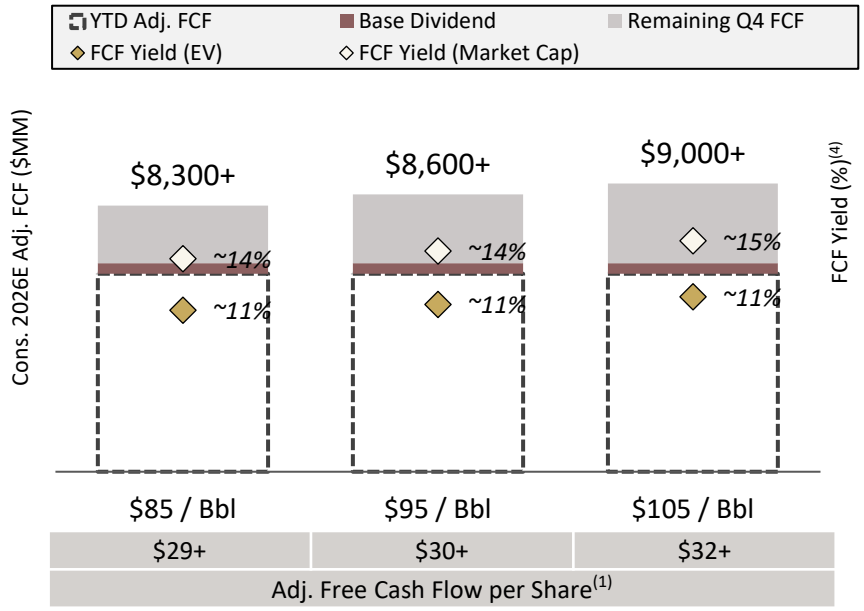
(6) Consolidated net debt, a non-GAAP measure, is defined as total debt (excluding debt issuance costs, discounts, premiums and unamortized basis adjustments) less cash and cash equivalents and restricted cash that has been irrevocably deposited for the redemption of principal amounts of outstanding senior notes.

Overview of the 2026 Plan

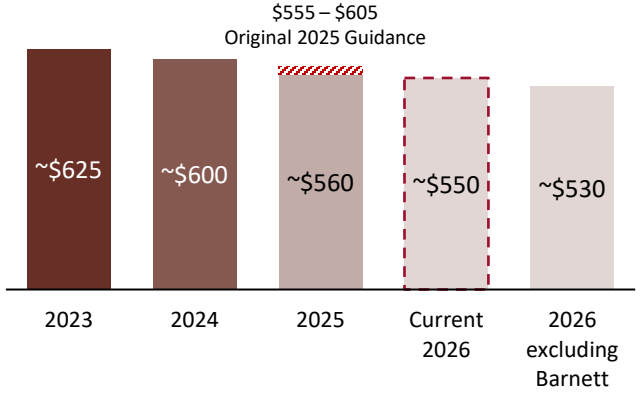
2026 Plan and Implied Improvement vs 2025

	2025A	Original 2026 Plan	Current 2026 Plan	Δ YoY
Oil Production *Net Mbo/d*	497.2	505	~524	+5%
Oil Production / Share(1) *Bo/d per MM Shares*	1,720	1,789	~1,866	+8%
Midland Basin D,C&E Well Costs *$ / Ft.*	$560	$550	$550	-2%
Average Lateral Length *Ft.*	12,138’	12,900’	12,900’	+6%
Adj. Free Cash Flow(2) *$MM*	$5,892	~$4,700	~$9,200	+56%
Base Dividend *$ / Share*	$4.05	$4.20	$4.72	+17%

Consolidated 2026E Adj. Free Cash Flow at Various WTI Prices(3)



Midland Basin D,C&E Well Costs ($ / Ft.)



2026 Midland Basin Well Costs
-12% vs. 2023
-8% vs. 2024
-2% vs. 2025

Source: Company data, filings and estimates.

(1) *Assumes FANG’s 2026 estimated weighted average share count of approximately 281 million shares.*

(2) *Current 2026 plan estimated Adjusted Free Cash Flow based on strip pricing as of 10/30/2026, versus original 2026 plan estimated Adjusted free cash flow based on strip pricing as of 2/20/2026. We are unable to present a quantitative reconciliation because we cannot reliably predict certain necessary components of operating cash flow, such as changes in working capital. See “Forward-Looking Statements and Non-GAAP Financial Measures” on slide 2 for additional cautionary information.*

(3) *Pricing realizations for each scenario assume >98% WTI, $20/Bbl NGL, and $3.00/Mcf Henry Hub net of applicable differentials as of 10/30/2026. Activity, CAPEX, production, and operating/well costs are held constant in each scenario per our 2026 guidance on slide 14 and reflect existing hedges and a $4.72 / share annual base dividend. See footnote 1 on slide 4 for FCF definition, footnote 5 on slide 4 for Adjusted FCF adjustments, and “Forward-Looking Statements and Non-GAAP Financial Measures” on slide 2 for additional cautionary information.*

(4) *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 10/30/2026, respectively.*

Return of Capital Track Record

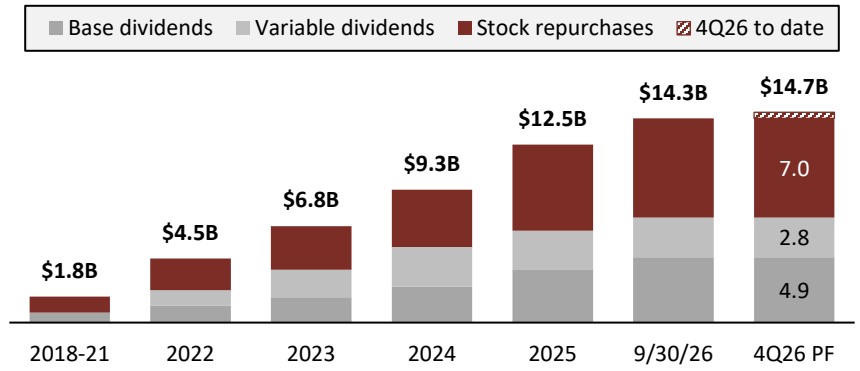
$14.3B
Total return of capital paid[1]

9.4x
Base dividend growth since 2018

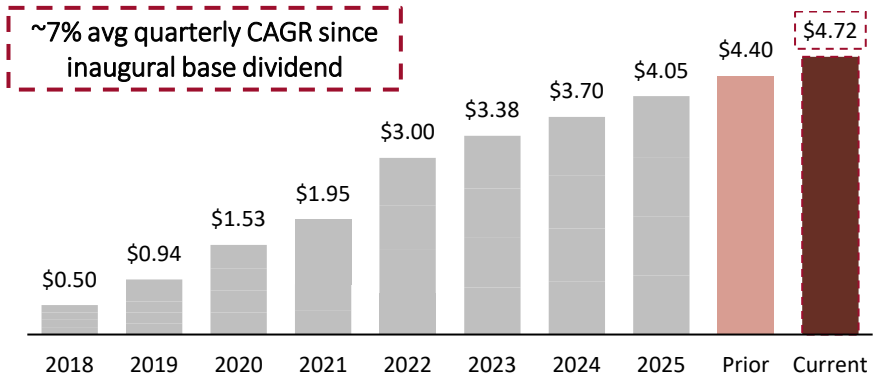
44.2MM
Shares repurchased for $6.3B[4]

$36 / Bbl
Breakeven WTI Oil Price[5]

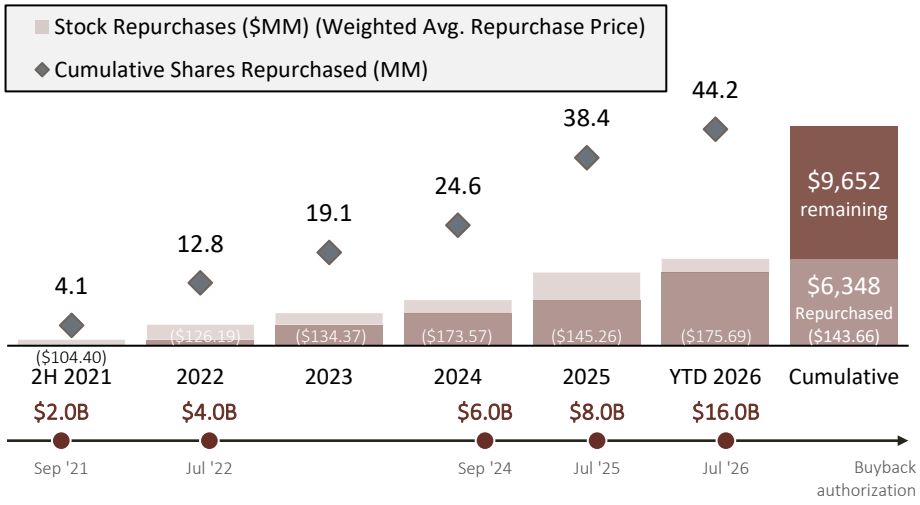
Cumulative Return of Capital Since 2018 ($B)[1][2]



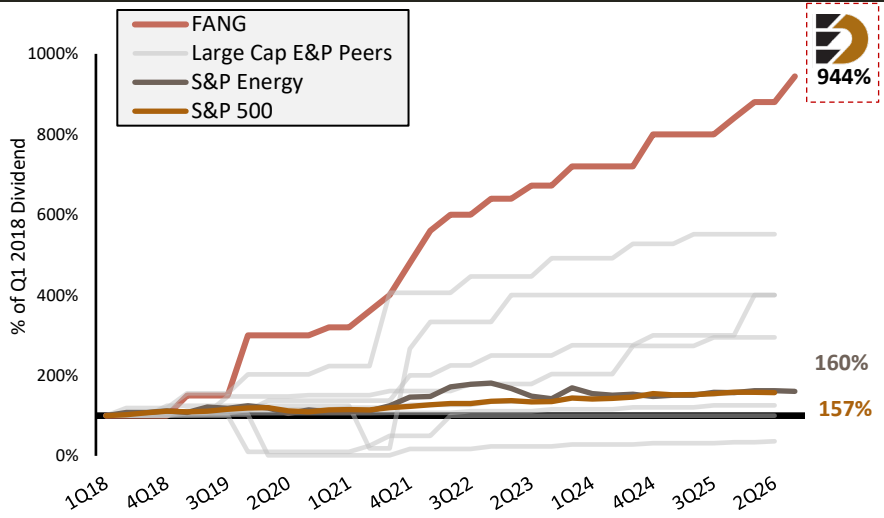
Declared Base Dividends Since 2018 ($ / Share)



$16.0 Billion Authorized Stock Repurchase Program[4]



Dividend Growth Since 1Q 2018 vs. Peers and S&P Indices[3]



Source: Company data, filings and estimates.

(1) Paid Return of Capital through 9/30/2026.

(2) 4Q26 PF ROC includes declared 3Q 2026 dividends payable in 4Q 2026 as well as stock repurchases to date in the fourth quarter.

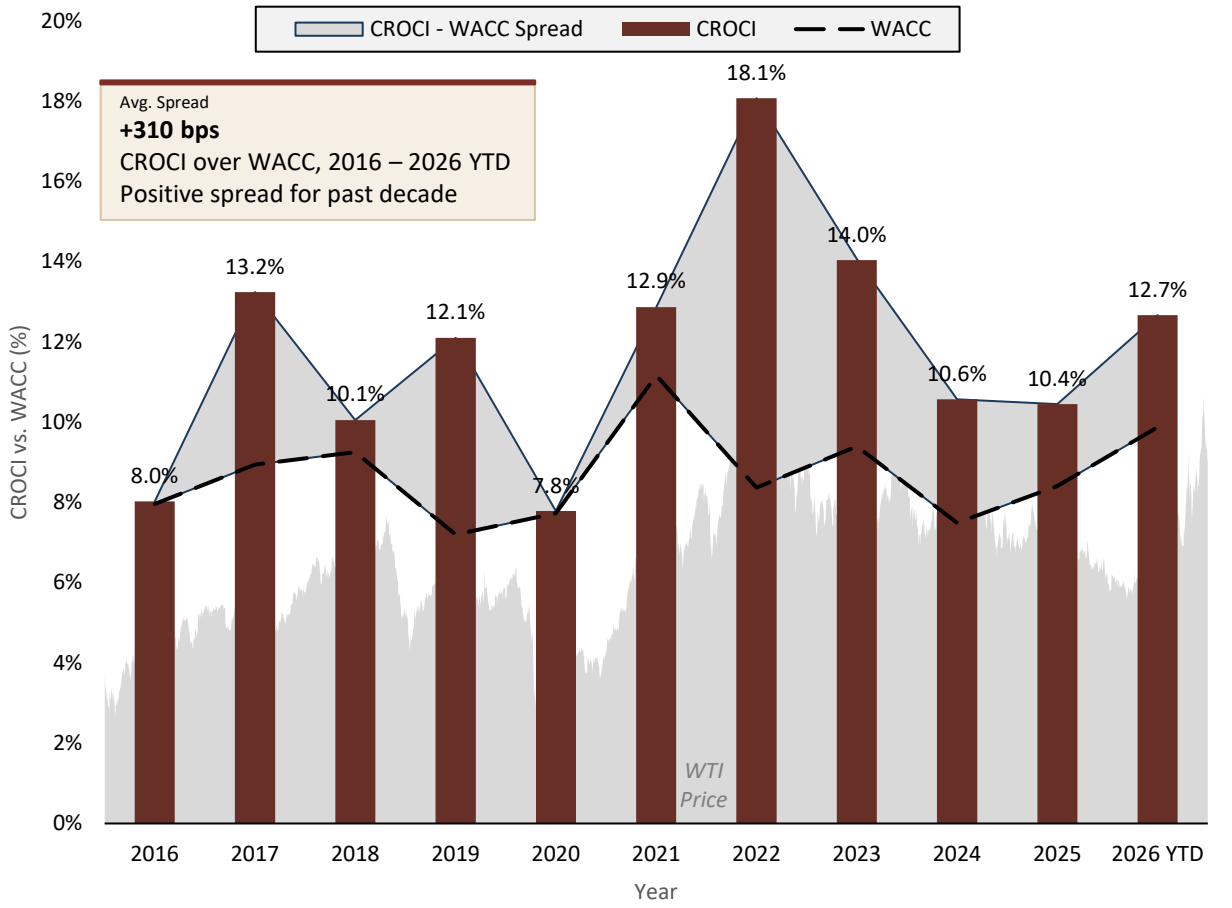
(3) Peer data through 10/30/2026. Peers include EOG, OVV, DVN, COP, CVX, XOM, APA and OXY; peer average is the simple average of the eight. S&P 500 based on quarterly dividends per share through 2Q 2026 vs. 1Q 2018 (S&P Dow Jones Indices); S&P Energy based on XLE regular quarterly distributions per share through 3Q 2026 vs. 1Q 2018 (split-adjusted; excludes the Dec 2019 special distribution).

(4) Shares repurchased through 10/30/2026.

(5) Breakeven WTI oil price calculated as the per barrel price for oil needed to generate cash flow equivalent to the amount of capital required to maintain 2026 oil production levels and pay the $4.72 / share annual base dividend. Assumes $3.00/Mcf Henry Hub gas prices and $20/Bbl NGL prices; excludes the impact of current commodity hedges.

Capital Discipline and Return on Capital Through the Cycles

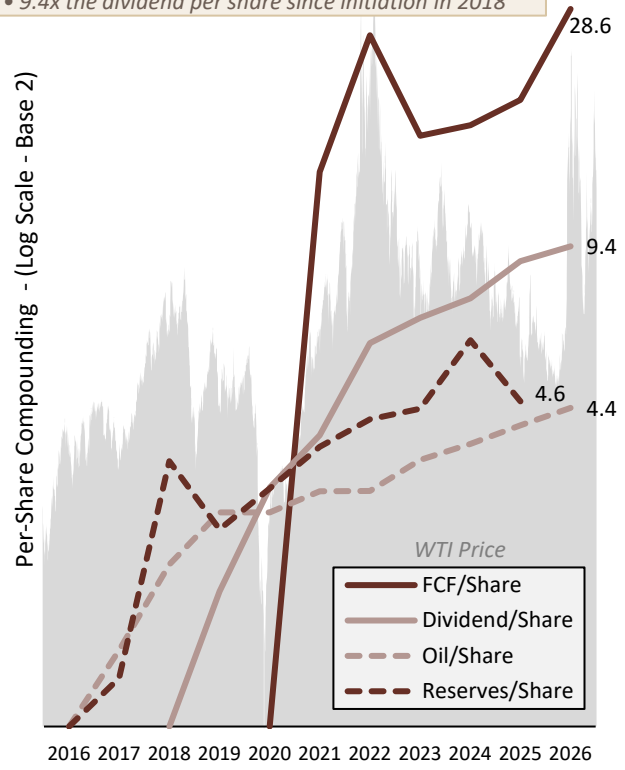
Cash Return on Capital Invested (CROCI)[1] vs. Weighted Average Cost of Capital (WACC)



Accretive Per-Share Compounding[2]

Growth over the last decade has been **accretive**

- *A share held since 2016 would claim 4.4x the oil production and 4.6x the reserves per share vs. 2016*
- *28.6x the free cash flow per share since 2020*
- *9.4x the dividend per share since initiation in 2018*



Throughout the past decade, Diamondback has consistently generated cash returns above its cost of capital while simultaneously compounding per share metrics

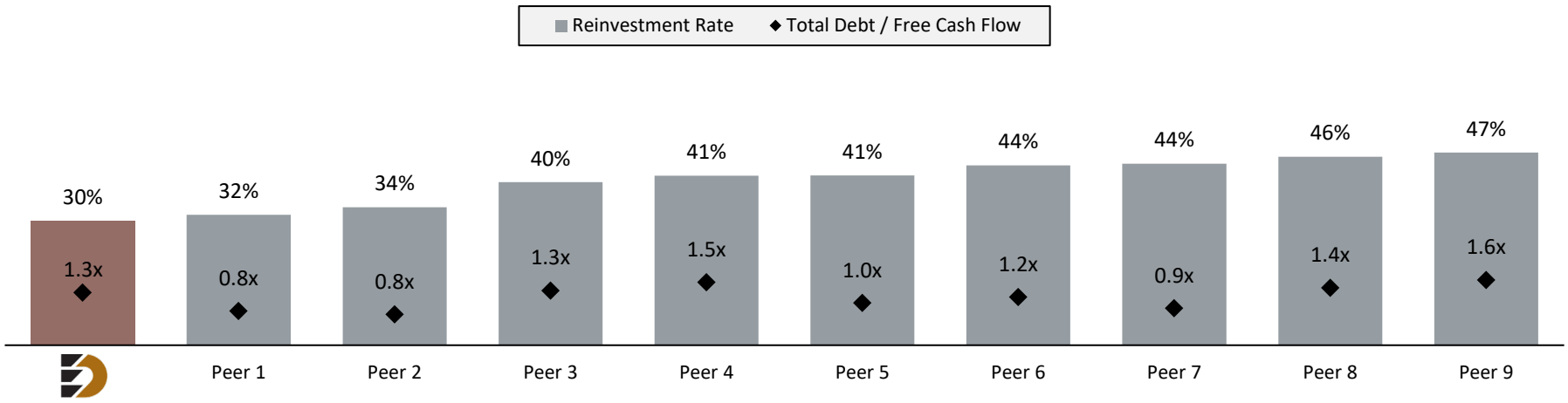
Source: Company data, Bloomberg data, filings and estimates.

(1) Cash Return on Capital Invested calculated as debt-adjusted cash flow from operations before working capital changes divided by capital invested. Capital invested calculated as total assets plus accumulated DD&A minus cash and cash equivalents minus non-interest-bearing current liabilities. 2026 YTD CROCI numerator annualized.

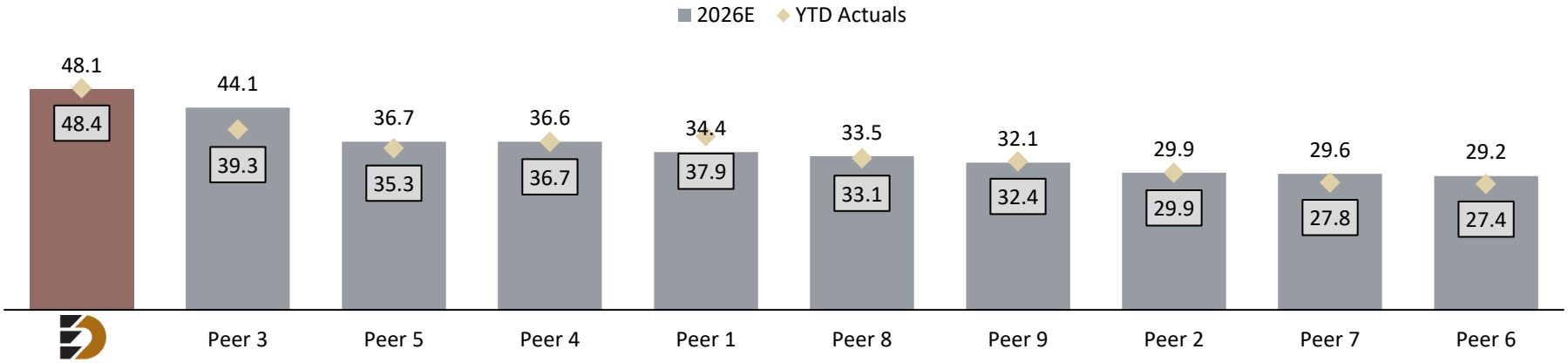
(2) 2026 FCF/share reflects year-to-date Free Cash Flow through 9/30/2026, annualized; 2026 Oil/share is based on current full-year 2026 oil production guidance. Both use FANG's estimated 2026 weighted average share count of approximately 281 million shares. Reserves as of 12/31/2025. Dividend/share growth calculated using the new annual run-rate base dividend of $4.72 per share.

Industry Leading Reinvestment Rate and Capital Efficiency

2026E Reinvestment Rate and Total Debt / Free Cash Flow vs. Peers[1][2][3]



2026E Oil Production per $MM of CAPEX vs. Peers (Mbo / $MM CAPEX)[3][4]



The combination of a high-quality, oil-weighted asset base and a low-cost structure results in an industry-leading reinvestment rate

Source: Company data, filings and estimates. Peers include CVX, XOM, OXY, DVN, PR, APA, EOG, OVV, and COP.

(1) Diamondback estimates based on announced guidance and expected total debt at YE2026. Bloomberg data and estimates used for peers as of 10/30/2026.

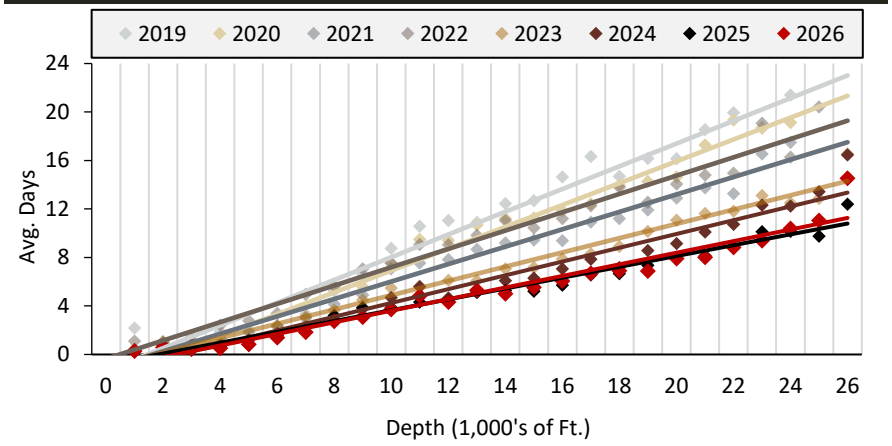
(2) Reinvestment rate defined as cash CAPEX divided by operating cash flow before working capital changes.

(3) CAPEX estimates include the addition of exploration expense estimates from Bloomberg and announced guidance for successful efforts accounting companies.

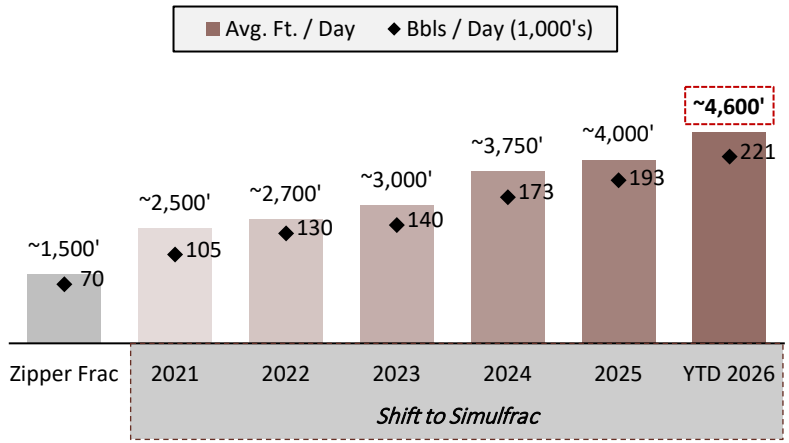
(4) 2026E oil production per $MM of CAPEX based on Diamondback's 2026 guidance and reported 2026 guidance for peers as of 10/30/2026.

Consistent Track Record of Execution

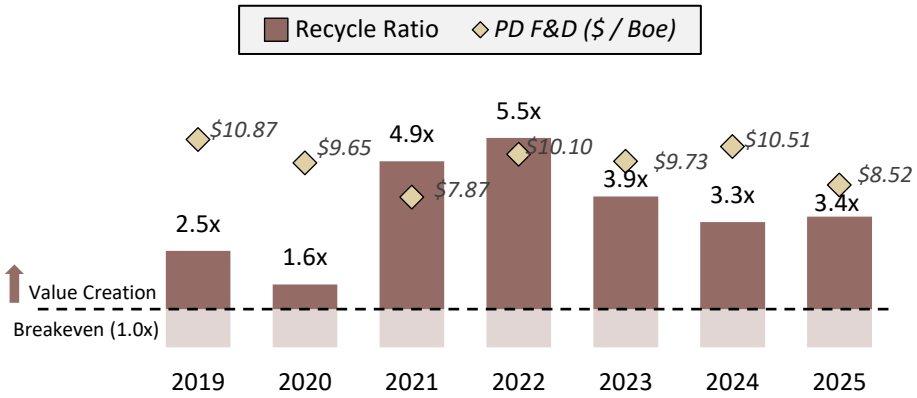
Year over Year Drilling Efficiency



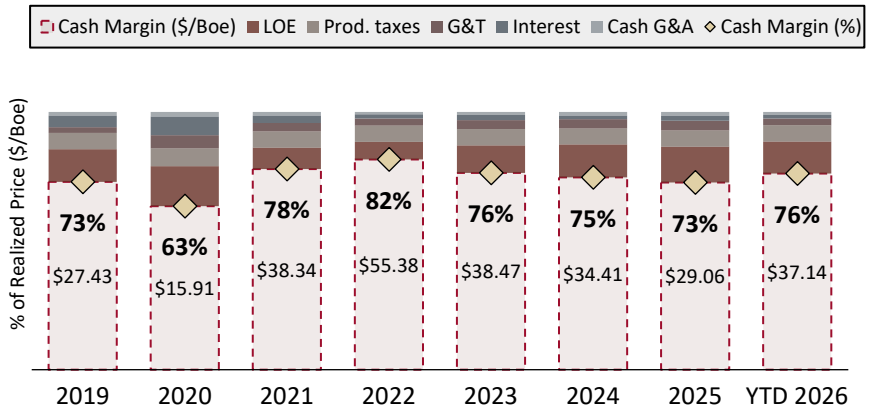
Completion Efficiency



Consolidated PD F&D Costs and Recycle Ratio[1]



Unhedged Cash Margins ($ / Boe; % of Realized Price)[2]



Diamondback continues to drive down costs and improve execution efficiency

Source: Company data, filings and estimates.

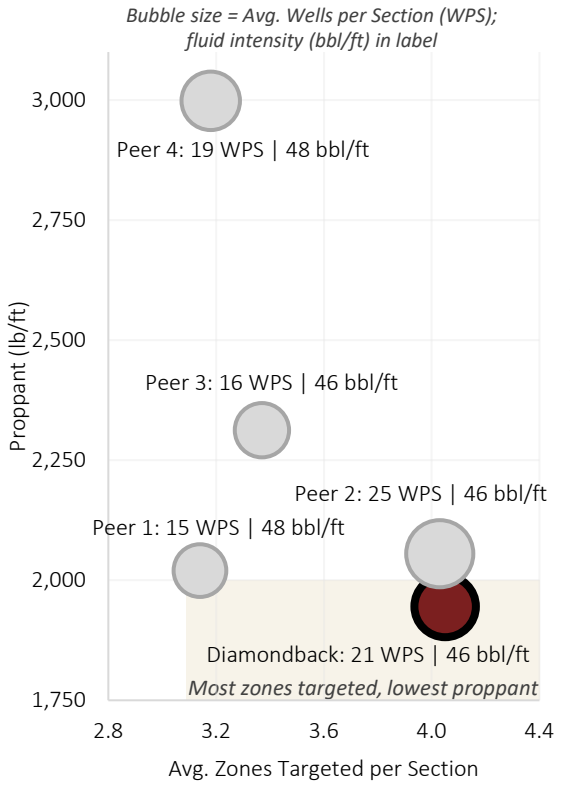
(1) Recycle ratio calculated as unhedged cash margin per Boe including interest expense divided by PD F&D cost per Boe. Please see note 1 on slide 16 for detail on PD F&D cost calculation.

(2) Unhedged cash margin calculated as unhedged realized price per Boe, less cash operating costs including interest per Boe, divided by the unhedged realized price per Boe.

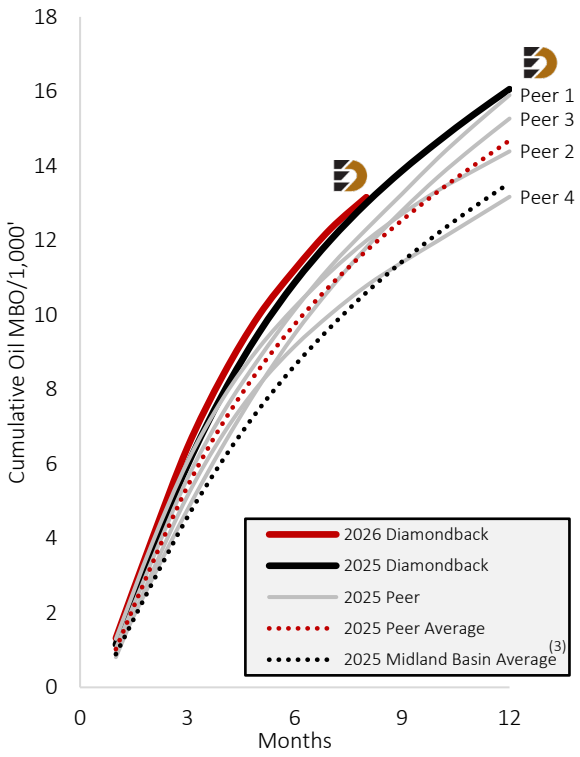
Development Strategy Maximizes Value

- Successful multi-zone co-development execution enables maximum resource extraction per section, generates consistent well results and minimizes potential child well performance degradation
- Diamondback's average well performance consistently ranks among the best in the Midland Basin, despite using the lowest average proppant intensity, drilling near the most wells per section and co-developing the most zones per section
- This development strategy, combined with the lowest well costs in the basin, delivers the highest returns per well and DSU, as well as the lowest corporate breakeven

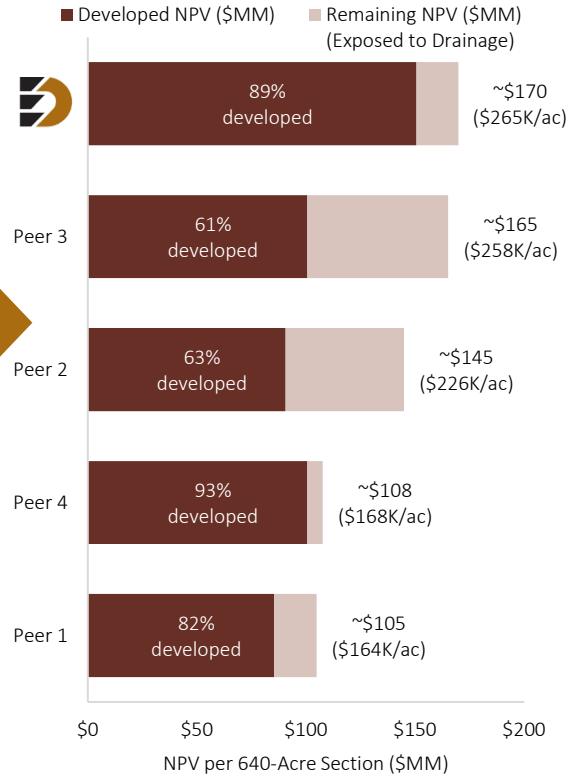
Unique Development Strategy(1)



Produces Top Midland Basin Well Performance(1)



Yields the Most NPV per Section/Acre(2)



A Midland Basin acre is worth significantly more in Diamondback's hands versus a competitor's

Source: Company data, estimates and Enverus.

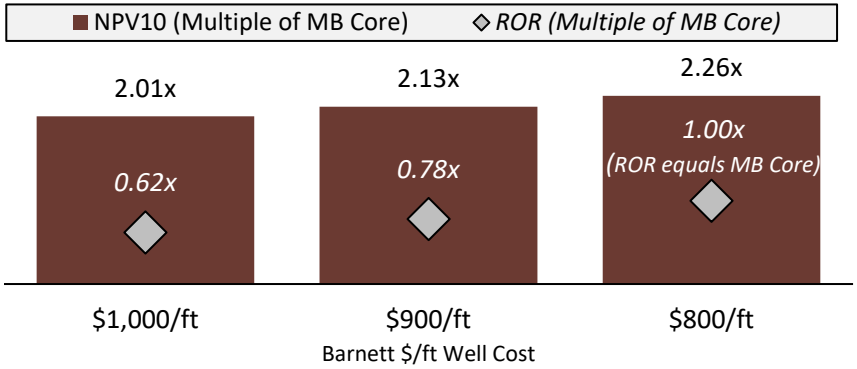
(1) Peer monthly data for 2025 wells. Peers include COP, OXY, XOM and OVV. Wells with completed lateral lengths < 3,000 ft excluded.

(2) Per FLOW Partners, LLC 2026 development study. Diamondback costs based on guided cost per lateral foot; other operators' costs based on FLOW's basin cost model. Developed share includes actual and forecast results from drilled wells; remaining share represents modeled future locations. Assumes $80/Bbl WTI and $3.00/Mcf Henry Hub.

(3) Midland Basin average well performance for all operators excluding Diamondback.

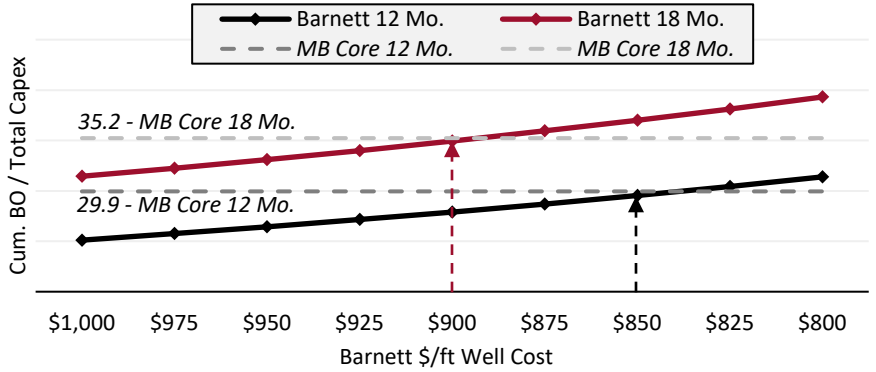
Barnett Update

Barnett Economics as a Multiple of Midland Basin Core



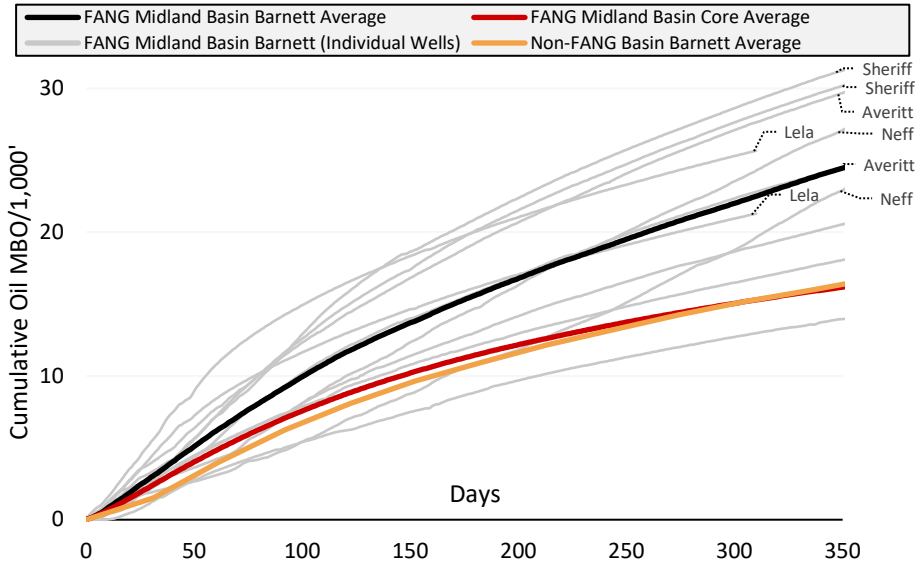
Full-field development is expected to reduce well costs by ~20%

Barnett vs. Midland Basin Core Capital Efficiency (Cumulative BO / Total CAPEX)



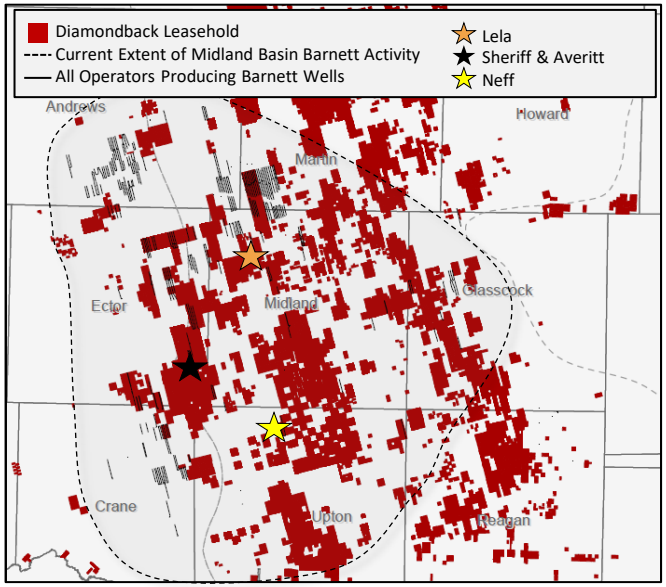
Barnett matches MB core efficiency at ~$900/ft (18 Mo) and ~$850/ft (12 Mo)

Midland Basin Barnett vs. Midland Basin Core Well Performance[1][2]



Diamondback Midland Basin Barnett well productivity has generated ~50% greater 12-month cumulative oil production versus Midland Basin Core

Diamondback Midland Basin Acreage Map[3]



Diamondback has amassed ~224,000 net acres in the core of the Midland Basin Barnett play, supporting an inventory of 878 gross (561 net) locations

Source: Company data, filings and estimates.

(1) Average daily cumulative well productivity for wells completed by Diamondback with first production in 2025 as of 10/21/2026. Midland Basin Core consists of Upper Spraberry, Middle Spraberry, Jo Mill, Lower Spraberry, Dean, Wolfcamp A, Wolfcamp B and Wolfcamp D.

(2) Peer Barnett monthly well performance derived from the average of all non-Diamondback operators' wells with first production in 2025 based on Enverus production data.

(3) Diamondback Midland Basin acreage based on internal company estimates as of 9/30/2026. All operators producing Barnett wells as of 9/30/2026 per IHS data.

Long Duration, High Quality Inventory

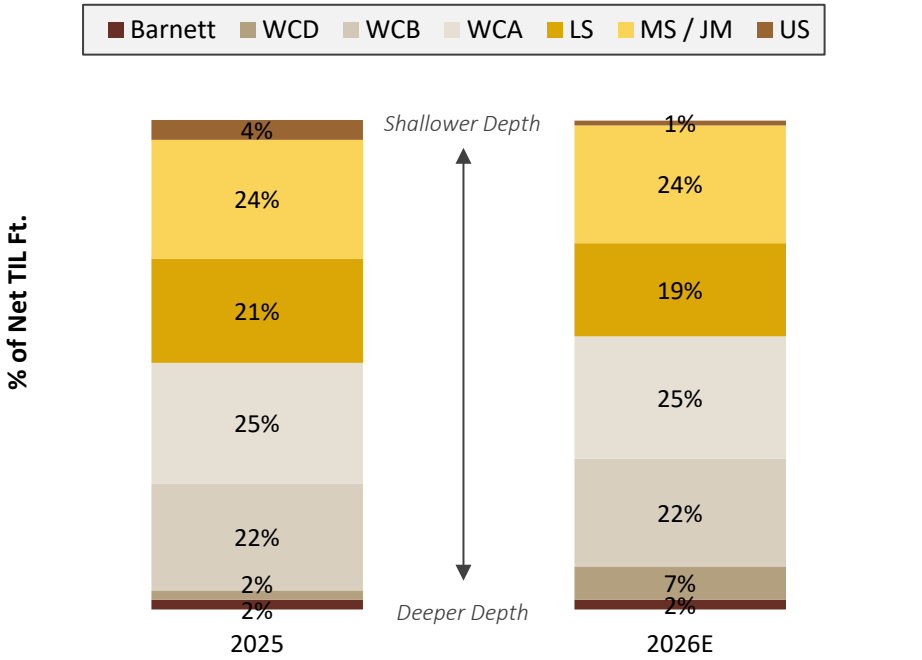
Midland Basin Gross (Net) Locations Economic at $50 / Bbl[1]

	Locations	Avg. Lateral
US	472 (389)	*11,000'*
MS / JM	1,453 (1,158)	*10,800'*
LS	1,026 (792)	*10,700'*
WCA	1,343 (951)	*11,100'*
WCB	1,391 (921)	*10,600'*
WCD	814 (674)	*12,500'*
Barnett	878 (561)	*12,000'*
Other[2]	533 (409)	*9,800'*
Total	7,910 (5,856)	***11,000'***

Delaware Basin Gross (Net) Locations Economic at $50 / Bbl[1]

	Locations	Avg. Lateral
2BS	325 (233)	*10,200'*
3BS	254 (190)	*9,700'*
WCA	117 (73)	*9,200'*
WCB	230 (187)	*10,200'*
Other[2]	18 (3)	*6,700'*
Total	944 (686)	***9,900'***

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



Net Acres & Economic Locations Overview

	Midland Basin	Delaware Basin	Total
Net Acres	~808,000	~93,000	~901,000
Gross Locations *Economic at $50 / Bbl*	7,910	944	8,854

Diamondback's unmatched inventory depth, with nearly 9,000 locations economic at $50 / Bbl, reflects a consistent co-development strategy and best-in-class inventory quality

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 12/31/2025. Acreage as of 9/30/2026.

(1) Defined as locations that can generate at least a 10% rate of return at $50/Bbl oil prices, $20/Bbl NGL prices and $3.00/Mcf gas prices. Assumes 2026 budget capex well costs.

(2) Other zones comprise of Clearfork and Wolfcamp C intervals in the Midland Basin and Avalon, 1st Bone Spring, and Wolfcamp C intervals in the Delaware Basin.

Investment Grade Balance Sheet

Balance Sheet Summary and Recent Highlights:

- Investment grade credit ratings: Baa2 (Moody's), BBB (S&P) and BBB+ (Fitch)
- Standalone liquidity of ~$3.5 billion[(1)]
- Consolidated net debt of ~$12.8 billion[(2)]
- In the third quarter, repurchased $106 million in aggregate principal amount of 2054 and 2064 Senior Notes at a weighted average price of 94.9% of par ($103 million, including accrued interest)
- On October 1, redeemed all $698 million in principal of 2026 Senior Notes at par ahead of December 1 maturity
- To date in the fourth quarter, repurchased $195 million in aggregate principal amount of 2054 and 2064 Senior Notes at a weighted average price of 91.0% of par ($183 million, including accrued interest)
- Reduced Diamondback standalone debt by ~$2.4 billion in 2026 to date[(3)]

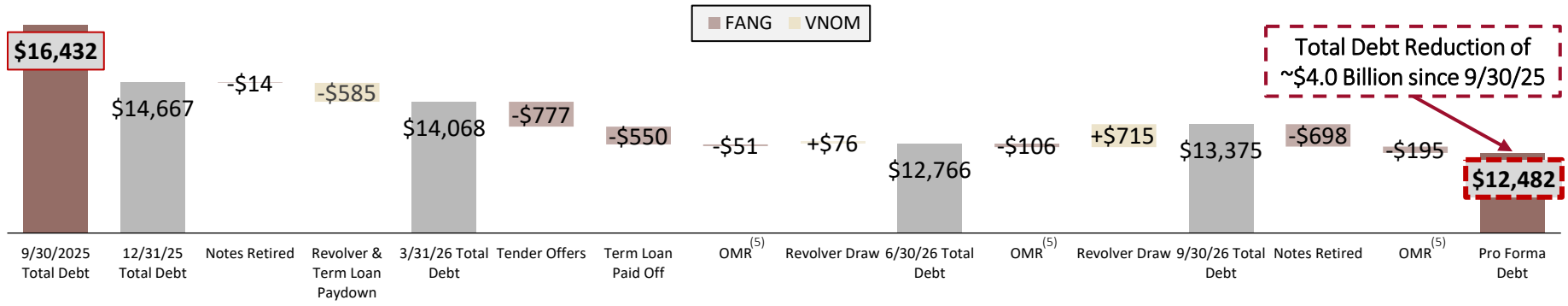
FANG's Liquidity and Capitalization ($MM)

FANG's Consolidated Capitalization	9/30/2026
Cash and cash equivalents	$558
FANG Debt	$10,965
VNOM Debt	$2,410
Total Debt	**$13,375**
Net Debt	**$12,817**
Net Debt / Annualized 3Q Adjusted EBITDA	**0.9x**

FANG's Standalone Liquidity	
Cash[(1)]	$548
Elected commitment	$3,000
Standalone Liquidity[(1)]	**$3,548**



FANG's Consolidated Total Debt Reduction ($MM)



Source: Company data, filings and estimates.

(1) Excludes Viper.
(2) Consolidated net debt, a non-GAAP measure, is defined as total debt (excluding debt issuance costs, discounts, premiums and unamortized basis adjustments) less cash and cash equivalents and restricted cash that has been irrevocably deposited for the redemption of principal amounts of outstanding senior notes.
(3) Reflects the $1,497 million reduction from 12/31/2025 to 9/30/2026, pro forma for the retirement of $698 million of 3.250% Senior Notes and $195 million principal repurchased in the open market.
(4) Based on consolidated senior notes maturity profile as of 10/30/2026.
(5) Open market repurchases of Senior Notes.

Full Year & 4Q 2026 Guidance

Guidance	Diamondback
Full Year 2026	
2026 Net production – Mboe/d	~1,015 *(from 1,000+)*
2026 Oil production – Mbo/d	~524 *(from 522+)*
Unit Costs ($/boe)	
Lease operating expenses, including workovers	$5.95 – $6.20 *(from $5.90 – $6.40)*
Cash G&A	$0.55 – $0.65
Non-cash equity-based compensation	$0.20 – $0.30
DD&A	$13.50 – $14.50
Interest expense (net of interest income)	$0.50 – $0.70
Gathering, processing and transportation	$1.30 – $1.50 *(from $1.40 – $1.60)*
Production and ad valorem taxes (% of revenue)	~6.5% *(from ~7%)*
Corporate tax rate (% of pre-tax income)	23%
Cash tax rate (% of pre-tax income)(1)	19% – 22%
Diamondback Capital Budget ($MM)	
Operated drilling and completion	$3,350 – $3,400 *(from ~$3,310)*
2026 Total capital expenditures(2)	$3,950 – $4,000 *(from ~$3,900)*
Diamondback Capital Activity	
Average lateral length (Ft.)	~12,900’
Net lateral footage completed (1,000’s of Ft.)	6,200’ – 6,600’ *(from 6,100’ – 6,500’)*
4Q 2026 Guidance	
Oil production – Mbo/d	518 – 528
Net production – Mboe/d	1,025 – 1,045
Total capital expenditures ($MM)	$1,000 – $1,050
Cash taxes ($MM)	$500 – $560

Source: Company data, filings and estimates.

(1) Pre-tax income attributable to the Company is a non-GAAP measure. We are not able to forecast the most directly comparable GAAP measure – Income (loss) before income taxes – due to high variability and difficulty in predicting certain items that affect Income (loss) before income taxes, such as future commodity prices, pace of and costs of developing, producing and operating our interests in oil and natural gas properties, future changes in interest rates and various other business factors impacting our financial results.

(2) Includes non-operated drilling and completion, capital workovers, science, infrastructure, midstream and environmental.



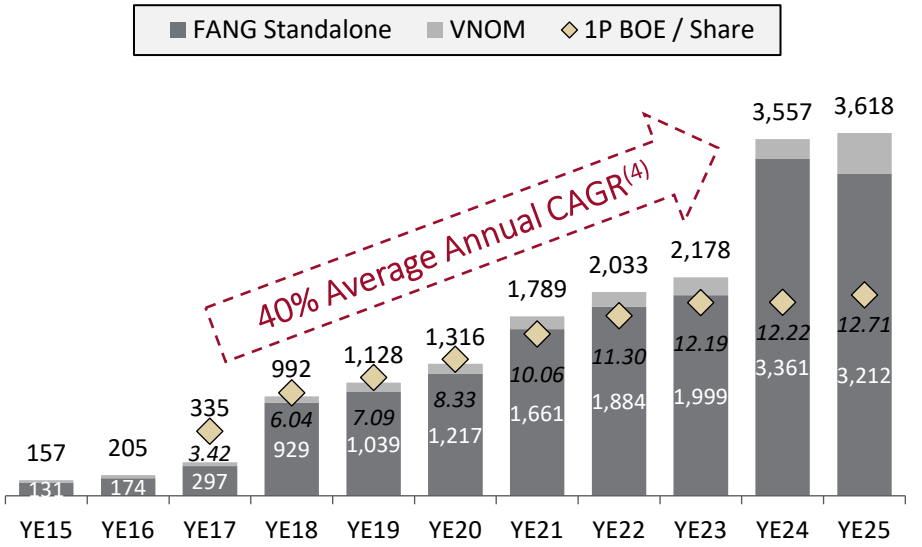
Appendix

Reserves Summary

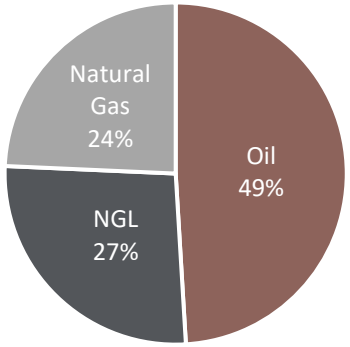
- Year-end 2025 proved reserves increased 2% year over year to 3,618 MMBoe (1,774 MMBo, 70% PDP)
- PDP reserves of 2,521 MMBoe; PDP oil reserves of 1,174 MMBo
- Oil comprised 49% of total proved reserves on 3-stream basis; 56% of total on 2-stream basis
- Consolidated proved developed F&D for 2025 was $8.52 / Boe

F&D Costs		
($/Boe)	2024	2025
Proved Developed F&D(1)	$10.51	$8.52
Reserve Replacement(2)	730%	118%
Organic Reserve Replacement(3)	68%	82%

Total Proved Reserve Growth (MMBoe)

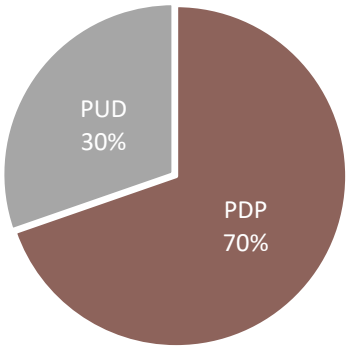


1P Reserves – By Commodity



3,618 MMBOE

1P Reserves – By Category



3,618 MMBOE

Source: Company data, filings and estimates.

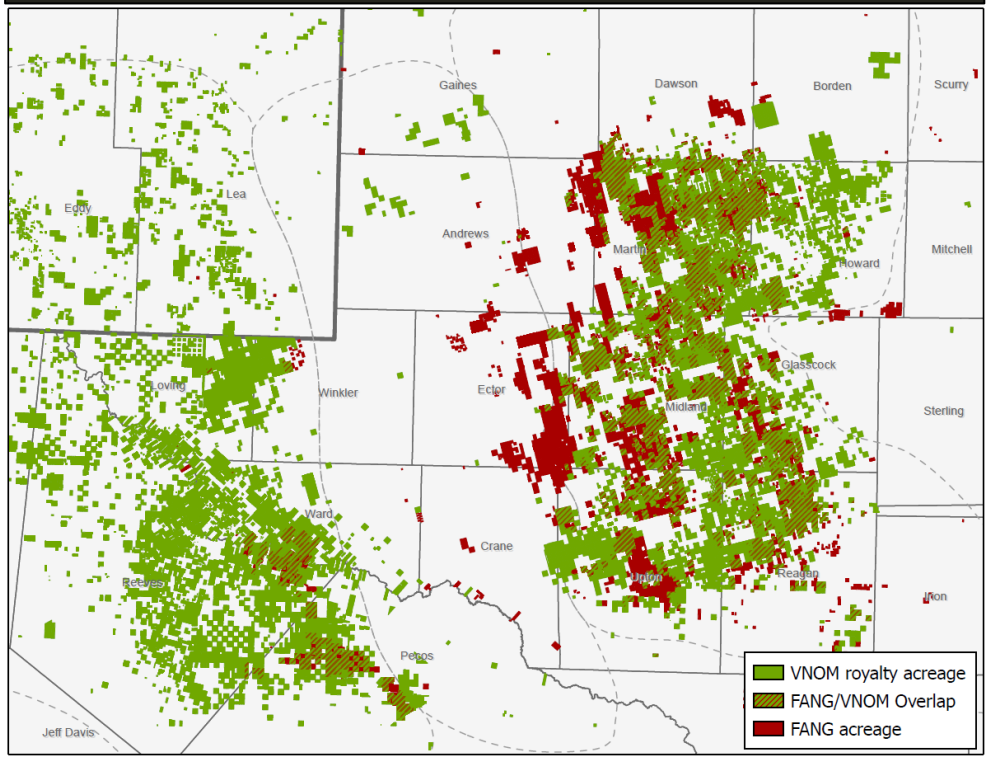
(1) *PD F&D costs defined as exploration and development costs divided by the sum of reserves associated with transfers from proved undeveloped reserves at prior year-end including any associated revisions in current year and extensions and discoveries placed on production during current year.*
(2) *Defined as the sum of extensions and discoveries, revisions, purchases and divestitures, divided by annual production.*
(3) *Defined as the sum of extensions and discoveries and revisions, divided by annual production.*
(4) *Average annual CAGR since IPO.*

Viper Summary

Viper Energy, Inc.:

- 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
- ~98,098 net royalty acres in the Permian Basin, ~38% of which are operated by Diamondback(1)
- Diamondback is incentivized to focus development on Viper's acreage when possible due to improved consolidated returns
  - 101 of Diamondback's 135 third quarter completions were on Viper's acreage, in which Viper owned an 8.9% average NRI(2)
- 3Q 2026 average oil production of 69.1 Mbo/d; generated $520 million of Free Cash Flow(3)
- Beyond the ~45% of Viper's 2026 estimated oil production that Diamondback operates, Viper has diversified exposure to other active operators within the Permian Basin
- 3Q 2026 Return of Capital:
  - Dividend of $0.50 per Class A share; represents a 4.2% annualized yield, based on the October 30, 2026 Class A common share closing price of $47.68
  - Repurchased ~2.1 million shares for an aggregate of $90 million (average price of $43.01/share)

Viper Mineral and Royalty Assets



Viper Market Snapshot

Market Cap: $17.6 billion

Enterprise Value: $20.0 billion

FANG Ownership Value: $7.0 billion (~40%)

Viper's mineral and royalty interests provide perpetual ownership exposure to high margin, largely undeveloped assets and lower Diamondback's consolidated breakevens

Source: Company data, filings and estimates as of 9/30/2026. Market data as of 10/30/2026.

(1) Acreage as of 9/30/2026.

(2) Well count not normalized to 10,000'.

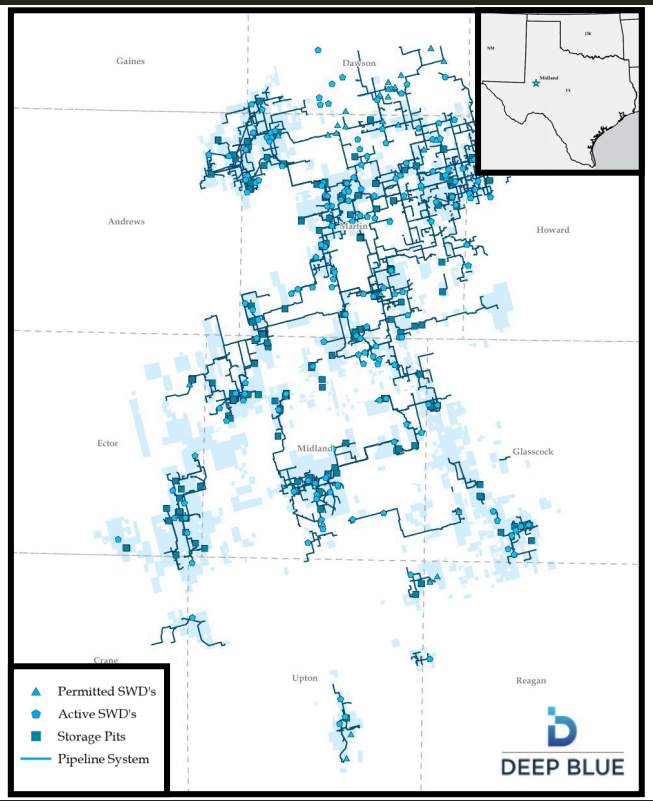
(3) See Non-GAAP definitions and reconciliations in the appendix of the Viper November 2026 Investor Presentation.

Equity Method Joint Venture Highlight: Deep Blue

Deep Blue Overview

- Deep Blue is the largest water infrastructure operator in the Midland Basin
- Established in a joint venture formed in September 2023 between Five Point (70%) and Diamondback (30%)
- Has approximately 840,000 total dedicated acres, including 658,000 acres from Diamondback
- In-basin infrastructure supports >800 Mbpd of water demand for a single simulfrac set, enabling industry-leading completion cycle times through integration with FANG's newly developed continuous pumping program
- Commercial structure focused on long-term (14+ year average contract life) fee-based contracts in the core of the basin
- System scale and operational redundancies minimize downtime and facilitate operational flexibility
- 199 supply pits provide ~142MMbbl of storage capacity, underpinning system reliability
- Future follow-on equity capital of $500 million committed by Five Point and Diamondback

Deep Blue Asset Overview



Key Statistics

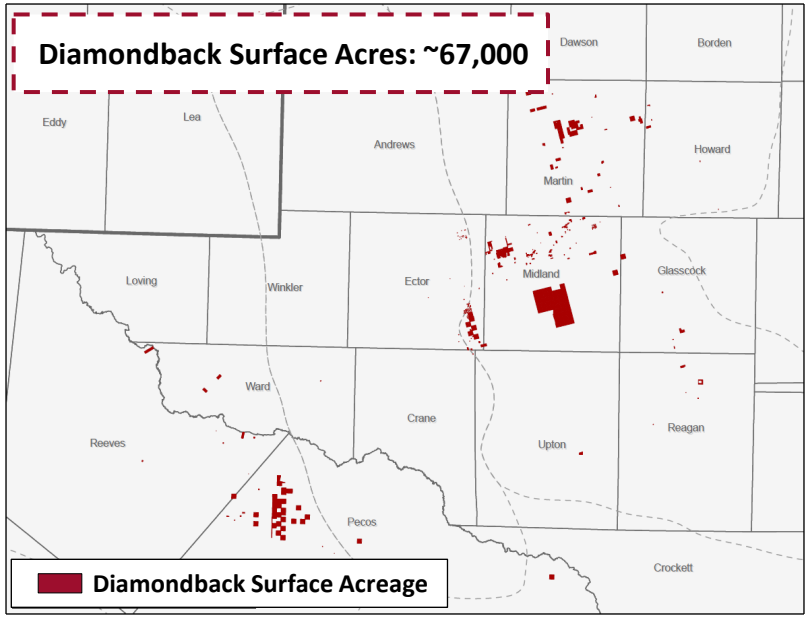
2.25MM	2,050	4.8MM
bpd produced water	*miles of pipeline*	*permitted bpd capacity*

In 2025, Diamondback generated ~$1.7 billion of proceeds through its equity-method joint ventures and other non-core asset sales, reflecting disciplined capital allocation and strategic investment execution

Source: Company data, filings and estimates as of 9/30/2026.

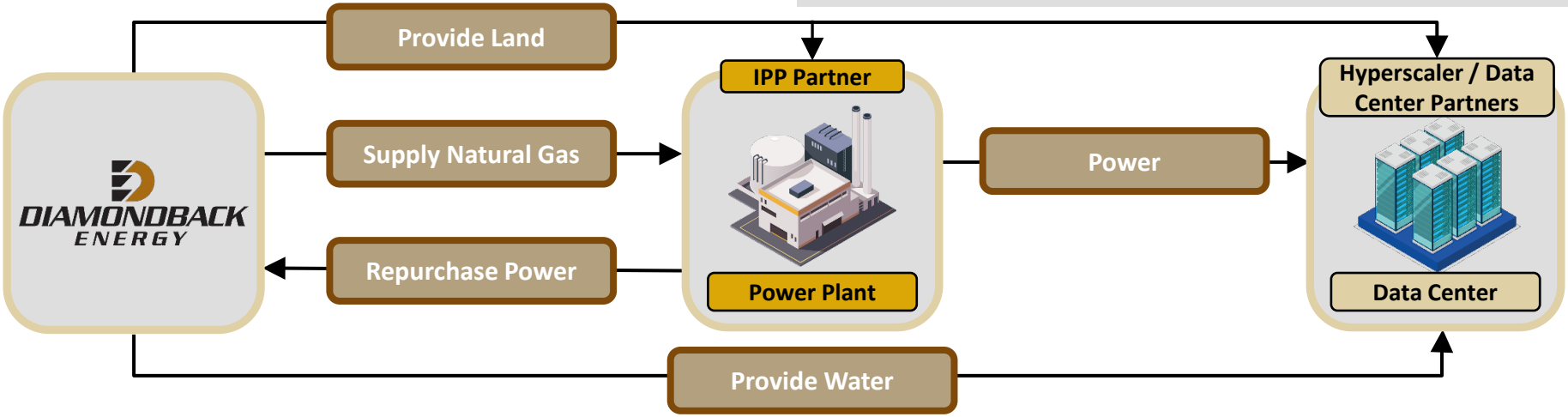
Surface Acreage and Potential Uses: Power Generation

Diamondback Surface Acreage[1]



Diamondback is the Premier Partner

1. **Provides site for power plant and data center construction**
2. **Supplies natural gas for power generation**
3. **Purchases a portion of power for internal operations**
4. **Provides water for data center cooling**



Source: Company data, filings and estimates.
(1) As of 9/30/2026.

Current Hedge Summary: Oil

Consolidated Crude Oil Hedges (Bbl / day; $ / Bbl)

Crude Oil Hedges	4Q 2026	1Q 2027	2Q 2027	3Q 2027	4Q 2027
Long Puts - Brent	**10,000**	**15,000**	**10,000**	**–**	**–**
Price / Premium	$55.00 / -$1.33	$55.00 / -$1.27	$55.00 / -$1.21	–	–
Long Puts - MEH	**75,000**	**75,000**	**60,000**	**30,000**	**10,000**
Price / Premium	$50.67 / -$1.31	$50.00 / -$1.25	$50.00 / -$1.25	$50.00 / -$1.15	$50.00 / -$0.98
Long Puts - WTI	**175,000**	**140,000**	**130,000**	**90,000**	**40,000**
Price / Premium	$50.57 / -$1.28	$50.00 / -$1.28	$50.00 / -$1.24	$50.00 / -$1.22	$50.00 / -$1.15
Total Long Puts	**260,000**	**230,000**	**200,000**	**120,000**	**50,000**
Basis Swaps - WTI	**85,000**	**41,500**	**41,500**	**31,500**	**31,500**
	$1.09	$1.30	$1.30	$1.07	$1.07
Basis Puts - WTI / Brent	**290,000**	**–**	**–**	**–**	**–**
Spread / Deferred Premium	-$41.03 / -$1.44	–	–	–	–
Roll Swaps - WTI	**150,000**	**–**	**–**	**–**	**–**
	$2.89	–	–	–	–

Diamondback's hedge strategy is to maximize upside exposure to commodity prices while protecting the extreme downside

Source: Company data and filings as of 10/30/2026.

Current Hedge Summary: Natural Gas

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

Natural Gas Hedges	4Q 2026	FY 2027	FY 2028
Costless Collars - Henry Hub	**840,000**	**720,000**	**130,000**
Floor / Ceiling	$2.87 / $6.35	$2.88 / $6.37	$2.65 / $5.88
Basis Swaps - Waha	**650,000**	**370,000**	**60,000**
	($1.75)	($1.27)	($1.51)
Basis Swaps - HSC	**100,000**	**300,000**	**150,000**
	($0.35)	($0.31)	($0.33)

- Current outright gas position: >60% of estimated 4Q 2026 gas production protected
- Current basis position: Waha/HSC basis protection covering ~50% of estimated 4Q 2026 gas production
- ~60% of estimated 2027 production receives non-Waha pricing

Diamondback's hedge strategy is to maximize upside exposure to commodity prices while protecting the extreme downside

Source: Company data and filings as of 10/30/2026.

Non-GAAP Definitions and Reconciliations

Adjusted EBITDA:

- 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, (gain) loss on extinguishment of debt, impairment of oil and natural gas properties, non-cash equity-based compensation expense, capitalized equity-based compensation expense, other non-cash transactions and provision for (benefit from) income taxes. Adjusted EBITDA is not a measure of net income as determined by United States generally accepted accounting principles ("GAAP"). Management believes Adjusted EBITDA is useful because the measure allows it to 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 excludes the items listed above from net income (loss) to determine 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. Further, the Company excludes the effects of significant transactions that may affect earnings but are unpredictable in nature, timing and amount, although they may recur in different reporting periods. 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. Certain items excluded from 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 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. The following tables present a reconciliation of the GAAP financial measure of net income (loss) attributable to Diamondback Energy, Inc. to the non-GAAP financial measure of Adjusted EBITDA:

(in millions)	Three Months Ended September 30, 2026	Nine Months Ended September 30, 2026
Net income (loss) attributable to Diamondback Energy, Inc.	$ 1,603	$ 3,510
Net income (loss) attributable to non-controlling interest	168	460
Net income (loss)	1,771	3,970
Non-cash (gain) loss on derivative instruments, net	85	165
Interest expense, net	55	174
Depreciation, depletion, amortization and accretion	1,320	3,885
Depreciation and interest expense related to equity method investments	13	39
(Gain) loss on extinguishment of debt	(4)	(137)
Impairment of oil and natural gas properties	—	1,400
Non-cash equity-based compensation expense	37	101
Capitalized equity-based compensation expense	(11)	(29)
Other non-cash transactions	(15)	12
Provision for (benefit from) income taxes	501	1,113
Consolidated Adjusted EBITDA	$ 3,752	$ 10,693
Less: Adjustment for non-controlling interest	359	1,047
Adjusted EBITDA attributable to Diamondback Energy, Inc.	$ 3,393	$ 9,646

Source: Company data and filings.

Non-GAAP Definitions and Reconciliations

Operating Cash Flow before Working Capital Changes and Free Cash Flow:

- Operating cash flow before working capital changes, which is a non-GAAP financial measure, represents net cash provided by operating activities as determined under GAAP without regard to changes in working capital. The Company believes operating cash flow before working capital changes is a useful measure of an oil and natural gas company's ability to generate cash used to fund exploration, development and acquisition activities and service debt or pay dividends. The Company also uses this measure because changes in working capital relate to the timing of cash receipts and disbursements that the Company may not control and may not relate to the period in which the operating activities occurred. This allows the Company to compare its operating performance with that of other companies without regard to financing methods and capital structure. The Company defines Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operating activities before changes in working capital in excess of cash capital expenditures. The Company defines Adjusted Free Cash Flow, which is a non-GAAP financial measure, as Free Cash Flow before the tax impact from divestitures (if any), merger and transaction expenses, costs of early termination of derivatives and settlements of any treasury locks (if any). The Company believes that Free Cash Flow and Adjusted Free Cash Flow are useful to investors as they provide a measure to compare both cash flow from operating activities and additions to oil and natural gas properties across periods on a consistent basis, adjusted, as applicable, for non-recurring impacts from divestitures, merger and transaction expenses, the early termination of derivative contracts and settlements of treasury locks. These measures should not be considered as an alternative to, or more meaningful than, net cash provided by operating activities as an indicator of liquidity. The Company's computation of operating cash flow before working capital changes, Free Cash Flow and Adjusted Free Cash Flow may not be comparable to other similarly titled measures of other companies. The following tables present a reconciliation of the GAAP financial measure of net cash provided by operating activities to the non-GAAP measure of operating cash flow before working capital changes and to the non-GAAP measures of Free Cash Flow and Adjusted Free Cash Flow:

(in millions)	Three Months Ended September 30, 2026	Nine Months Ended September 30, 2026	Year Ended December 31, 2025
Net cash provided by operating activities	$ 2,599	$ 8,016	$ 8,758
Less: Changes in cash due to changes in operating assets and liabilities:			
Accounts receivable	(476)	(1,039)	386
Accounts payable and accrued liabilities	71	(133)	(343)
Income taxes payable	(138)	(138)	(399)
Revenues and royalties payable	(54)	270	15
Other	22	(82)	27
Total working capital changes	(575)	(1,122)	(314)
Operating cash flow before working capital changes	3,174	9,138	9,072
Additions to oil and natural gas properties	(1,026)	(2,955)	(3,523)
Total Cash CAPEX	(1,026)	(2,955)	(3,523)
Free Cash Flow	2,148	6,183	5,549
Tax Impact from divestitures[(1)]			170
Merger and transaction expenses[(2)]	2	8	105
Early termination of derivatives	—	27	67
Treasury locks			1
Adjusted Free Cash Flow	$ 2,150	$ 6,218	$ 5,892

Source: Company data and filings.

(1) Includes the tax impact for the disposal of certain non-core assets.

(2) Includes $4 million of Viper's transaction expenses primarily related to the Sitio Acquisition for the nine months ended September 30, 2026.

Non-GAAP Definitions and Reconciliations

Net Debt:

- The Company defines the non-GAAP measure of net debt as total debt (excluding debt issuance costs, discounts, premiums and unamortized basis adjustments) less cash and cash equivalents and restricted cash that has been irrevocably deposited for the redemption of principal amounts of outstanding senior notes. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. The Company believes this metric is useful to analysts and investors in determining the Company's leverage position because the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt.

(in millions)	September 30, 2026	Net Q3 Principal Borrowings/ (Repayments)	June 30, 2026	March 31, 2026	December 31, 2025	September 30, 2025
Diamondback total debt[(1)]	$ 10,965	$ (106)	$ 11,071	$ 12,448	$ 12,462	$ 13,792
Diamondback cash and cash equivalents	(548)		(385)	(146)	(91)	(106)
Diamondback net debt	$ 10,417		$ 10,686	$ 12,302	$ 12,371	$ 13,686
Viper total debt[(1)]	$ 2,410	$ 715	$ 1,695	$ 1,620	$ 2,205	$ 2,640
Viper cash and cash equivalents	(10)		(77)	(28)	(13)	(433)
Viper net debt	$ 2,400		$ 1,618	$ 1,592	$ 2,192	$ 2,207
Total debt	$ 13,375	$ 609	$ 12,766	$ 14,068	$ 14,667	$ 16,432
Cash and cash equivalents	(558)		(462)	(174)	(104)	(539)
Net debt	$ 12,817		$ 12,304	$ 13,894	$ 14,563	$ 15,893

Source: Company data and filings.

(1) Excludes debt issuance costs, discounts, premiums and unamortized basis adjustments.

Non-GAAP Definitions and Reconciliations

Cash Return on Capital Invested:

- Cash Return on Capital Invested, which is a non-GAAP measure, is calculated as debt-adjusted cash flow from operations before working capital changes divided by capital invested. Capital invested is calculated as total assets plus accumulated DD&A minus cash and cash equivalents minus non-interest-bearing current liabilities.

(in millions)	YE 2015	YE 2016	YE 2017	YE 2018	YE 2019	YE 2020	YE 2021	YE 2022	YE 2023	YE 2024	YE 2025	2026 YTD
Debt-Adjusted Cash Flow												
Net Cash Provided by (used in) operating activities ("CFO")		$332	$889	$1,565	$2,739	$2,118	$3,944	$6,325	$5,920	$6,413	$8,758	$8,016
- Working Capital Changes ("WC")		($16)	($48)	$6	($167)	$97	$36	($199)	$296	($96)	($314)	($1,122)
CFO Before WC		$348	$937	$1,559	$2,906	$2,021	$3,908	$6,524	$5,624	$6,509	$9,072	$9,138
Interest Expense, net		$41	$41	$87	$172	$197	$199	$159	$159	$135	$244	$174
Statutory Rate		35%	35%	21%	21%	21%	21%	21%	21%	21%	21%	21%
After-Tax Interest Expense		$27	$26	$69	$136	$156	$157	$126	$126	$107	$193	$137
CROCI Numerator: CFO before WC + After-Tax Interest Expense		**$374**	**$963**	**$1,628**	**$3,042**	**$2,177**	**$4,065**	**$6,650**	**$5,750**	**$6,616**	**$9,265**	**$9,276**
										2026 YTD Annualized		*$12,368*
Capital Invested												
Total Assets	$2,751	$5,350	$7,771	$21,596	$23,531	$17,619	$22,898	$26,209	$29,001	$67,292	$71,059	$72,110
+ Accumulated DD&A	$1,417	$1,836	$2,161	$2,774	$5,003	$12,314	$13,545	$14,844	$16,429	$19,208	$27,782	$33,000
– Cash & Cash Equivalents	$0	$1,667	$112	$215	$123	$104	$654	$157	$582	$161	$104	$558
– Non-Interest-Bearing Current Liabilities	$141	$209	$577	$1,019	$1,263	$1,045	$1,393	$1,706	$2,108	$3,911	$3,837	$4,191
Year-End Capital Invested	$4,026	$5,310	$9,243	$23,136	$27,148	$28,784	$34,396	$39,190	$42,740	$82,428	$94,900	$100,361
CROCI Denominator: Average Capital Invested (Beg + End ÷ 2)	--	$4,668	$7,276	$16,190	$25,142	$27,966	$31,590	$36,793	$40,965	$62,584	$88,664	$97,631
CROCI (%): CROCI Numerator ÷ CROCI Denominator		**8.0%**	**13.2%**	**10.1%**	**12.1%**	**7.8%**	**12.9%**	**18.1%**	**14.0%**	**10.6%**	**10.4%**	**12.7%**

Source: Company data, filings and estimates.

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