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3Q25 Earnings Presentation

November 2025

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This presentation includes non-GAAP financial measures, which help facilitate comparison of company performance across periods. For a reconciliation of non-GAAP measures included herein to the nearest corresponding GAAP measure, please see the appendix to this presentation.

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Key Takeaways from Third Quarter 2025 Update

3Q25 Production Beat | Beat both mid-points of oil & natural gas production guidance by ~2.5%, with in-line capex; Raising FY25 BOE and natural gas guidance and tightening the range around oil production guidance

Looking Ahead to 2026 | Anticipate 2026e capex modestly down YoY, while maintaining 0-5% annual BOE & natural gas growth, and ~5% annual oil growth; expect reinvestment rate ≤50%[1]

Franklin / Avant Acquisitions Exceeding Expectations | Improvements vs. original expectations: ~5% LOE improvement, with line-of-sight to additional savings; well costs -10%; increased the asset's inventory footage >10% through trades, leasing, and successful delineation

Durable Free Cash Flow Outlook | Estimated 2025 Free Cash Flow of ~$2.0 billion[1], underpinned by balanced commodity exposure between oil and natural gas

Balance Sheet Remains Top-Tier | Pro forma leverage ~0.8x[2], retired $600 million of Term Loans YTD; restarted share repurchase program in 4Q25

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Note: See appendix for non-GAAP reconciliations and definitions. Reinvestment rate defined as capex as % of DCF. 1) At recent strip prices. 2) Net debt to pro forma adjusted EBITDAX for the trailing twelve months.

Beat 3Q25 Midpoint Production Volumes & Raised for the Year

Higher production & lower capex driving improved capital efficiency

		3Q25 actuals vs. guide		2025e guidance update
Oil mbod	guidance	158.0 – 168.0	February guid.	152.0 – 168.0
	actual	166.8	updated guid.	159.0 – 161.0
Gas mmcfd	guidance	2,750 – 2,900	February guid.	2,675 – 2,875
	actual	2,895	updated guid.	2,925 - 2,965
Total Volumes mboed	guidance	740 – 790	February guid.	710 – 770
	actual	785	updated guid.	772 – 782
Capex	guidance	$625mm – $675mm	February guid.	$2.1bn – $2.4bn
	actual	$658mm	updated guid.	$2.3bn

Note: Incurred capex shown; not cash basis. See appendix for non-GAAP reconciliations and definitions.

Coterra Energy Key Differentiating Factors

Asset Quality

Competitive Cost Structure

Top-Tier Margin & Capital Efficiency

Consistent Investment in Deep, High-Quality Inventory

FCF Durability, Shareholder Returns, Top-Tier Balance Sheet

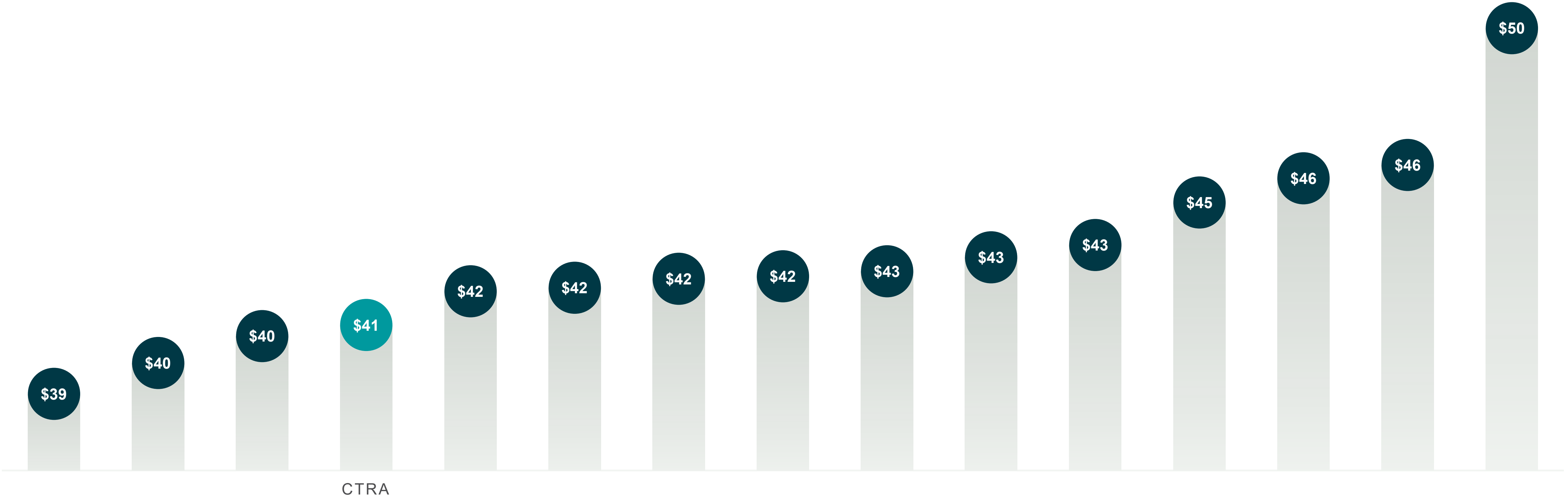
Culture & Strategy

Note: See appendix for non-GAAP reconciliations and definitions.

Asset Quality Demonstrated by Low Break-Evens

Estimated 15:1 PV-10 Break-Even Oil Price Across L48 Assets[1]

CTRA vs Peers; 15:1 based on recent strip

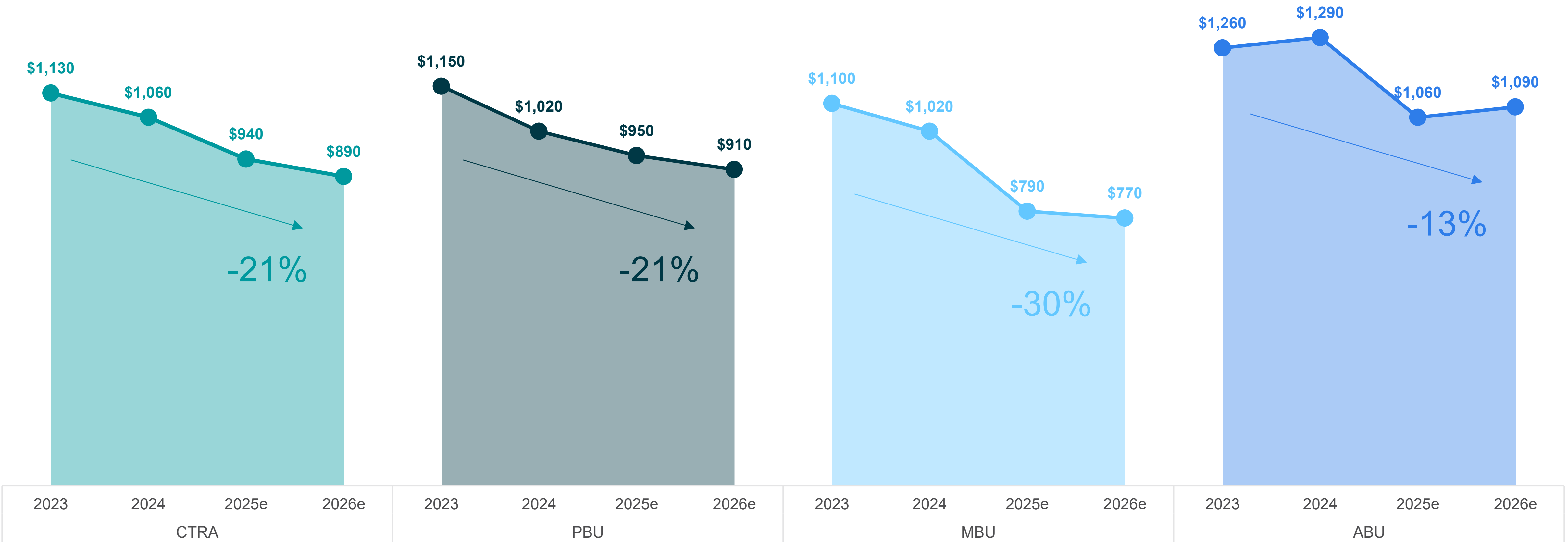


Peers include APA, AR, CHRD, CIVI, DVN, EOG, EQT, EXE, FANG, MTDR, OVV, OXY, PR, RRC. 1) Source: Enverus Intelligence North American Inventory Analysis.

Sustained Improvement in **Fully Burdened** Well Costs, Enhancing Economics

Driven by longer laterals and efficient operations

Annual Average Well Cost per Foot[1]



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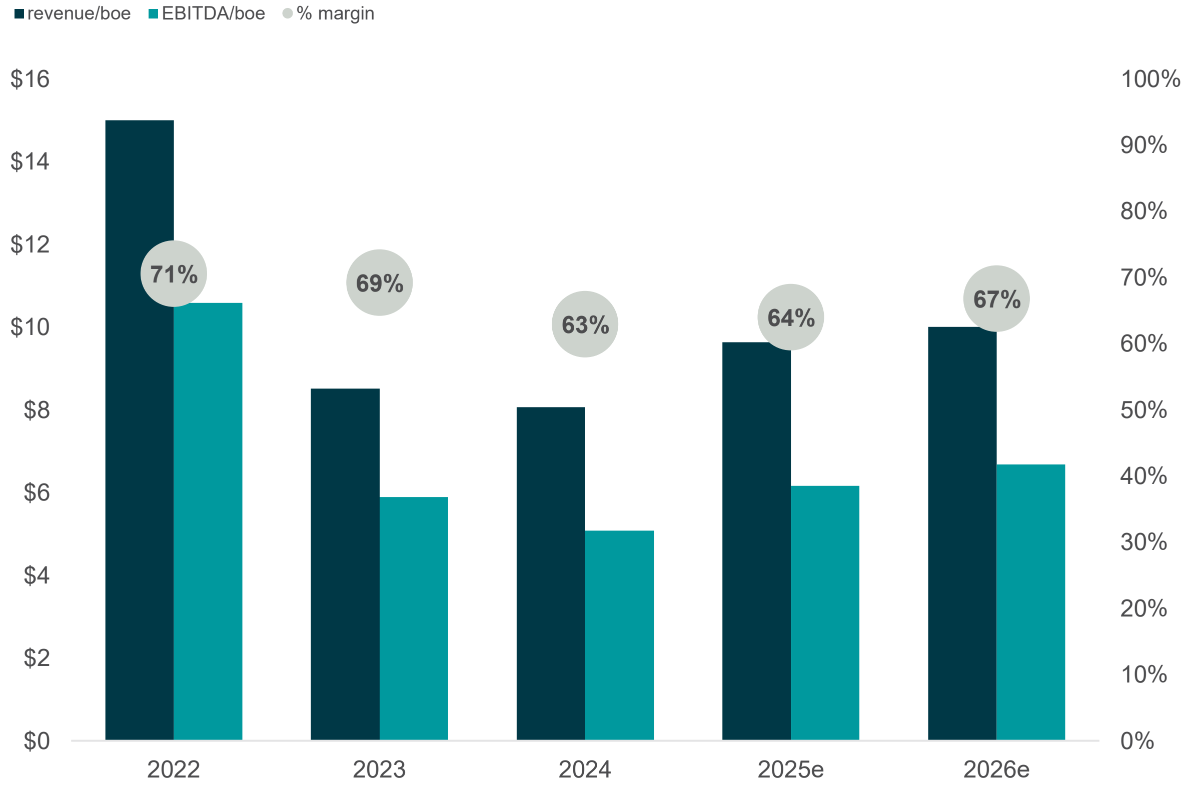
1) $ per foot includes drilling, completion, facilities and post-completion capital for CTRA operated wells.

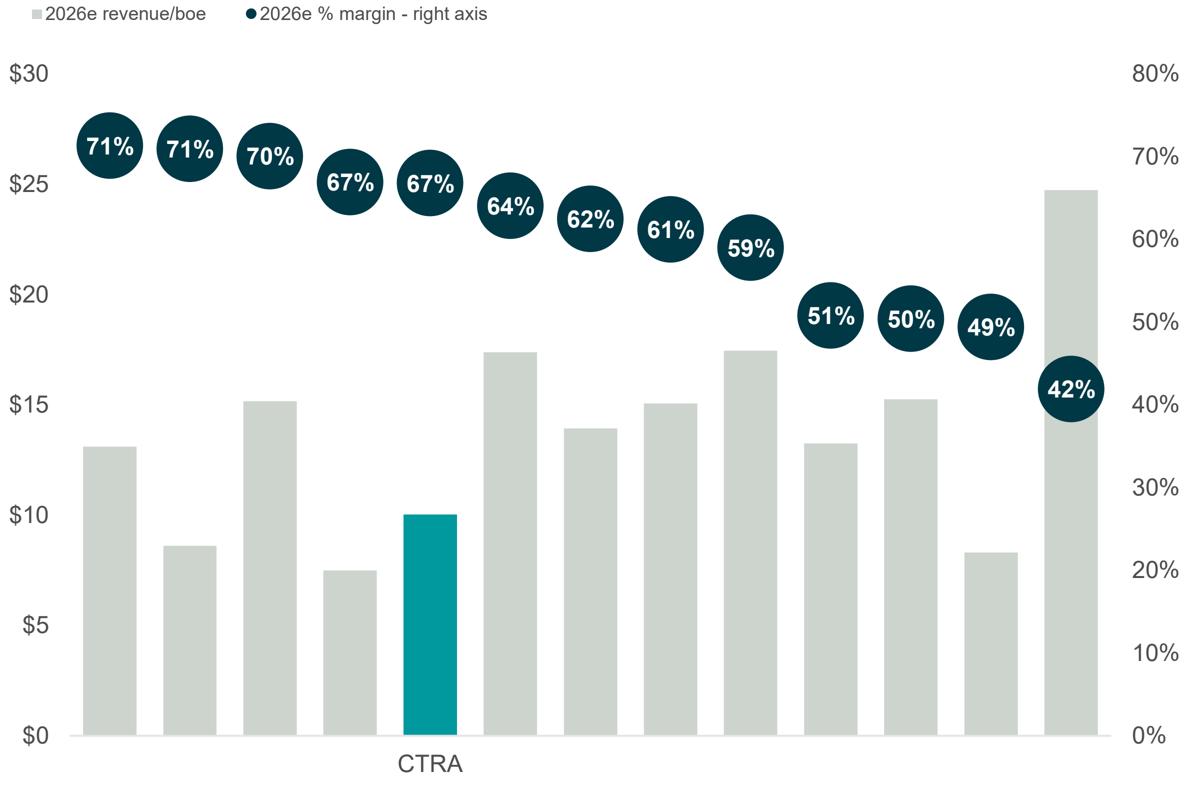
CTRA's High Quality Assets Produce Top-Tier Margins

CTRA Margin Consistently ~65-70%



2026e Revenue per BOE vs Margin

Recent strip: Henry Hub of $4.02/mmbtu & WTI of $60/bbl



Peers include APA, CHRD, COP, DVN, EOG, EQT, EXE, FANG, MTDR, OVV, PR, RRC. Source: Factset consensus estimates.

2025: Top-Tier Capital Efficiency Paired with Industry-Leading Growth

Coterra has one of the highest growth rates with best-in-class capital efficiency

2025e Operational and Financial Outlook

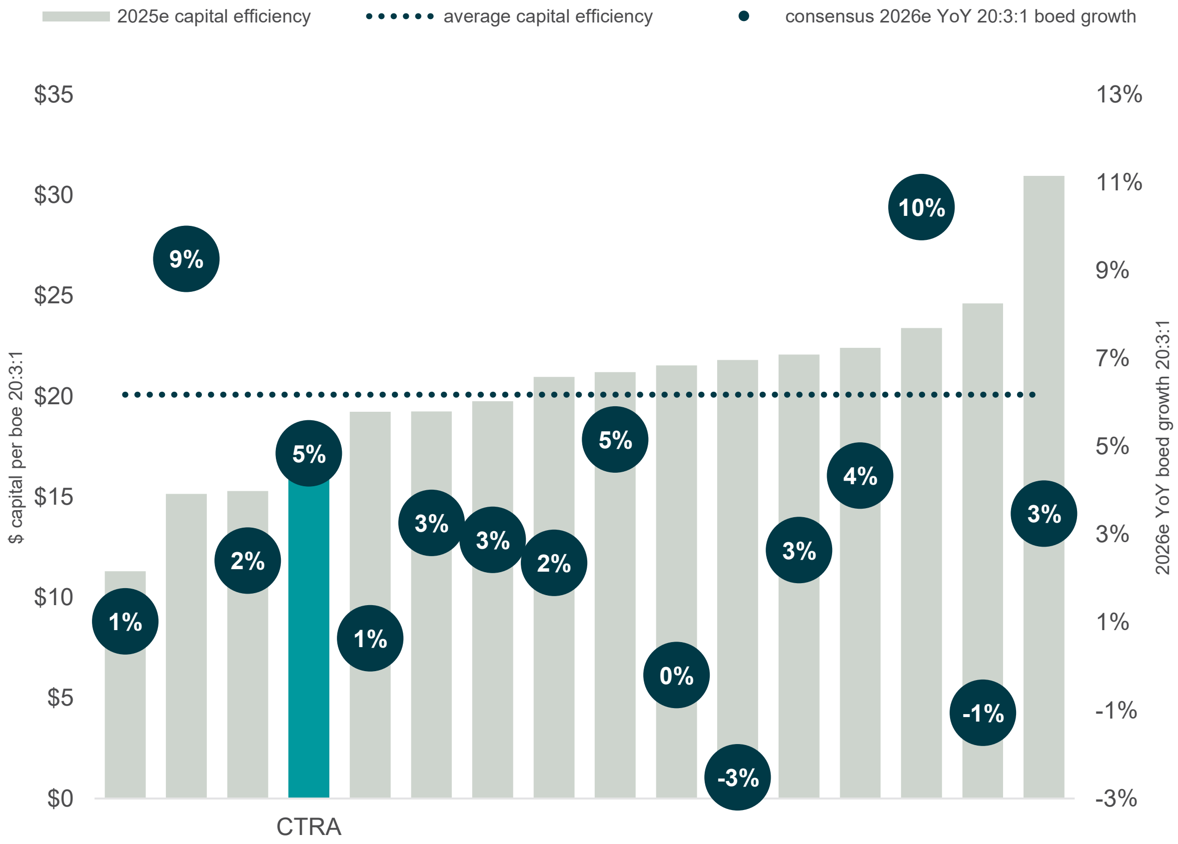
Disciplined Capital Program
~$2.3 billion capex & ~55% reinvestment rate[1]

~$2.0 billion Free Cash Flow[2]
Diversified commodity mix and disciplined reinvestment

Production Guidance
772-782 mboed | 159-161 mbod | 2,925-2,965 mmcfd

Organic Production Growth in 2025e and 2025e-2027e
expect ~5% for oil and 0-5% for BOE and gas

2025e Capital Efficiency and 2026e Production Growth

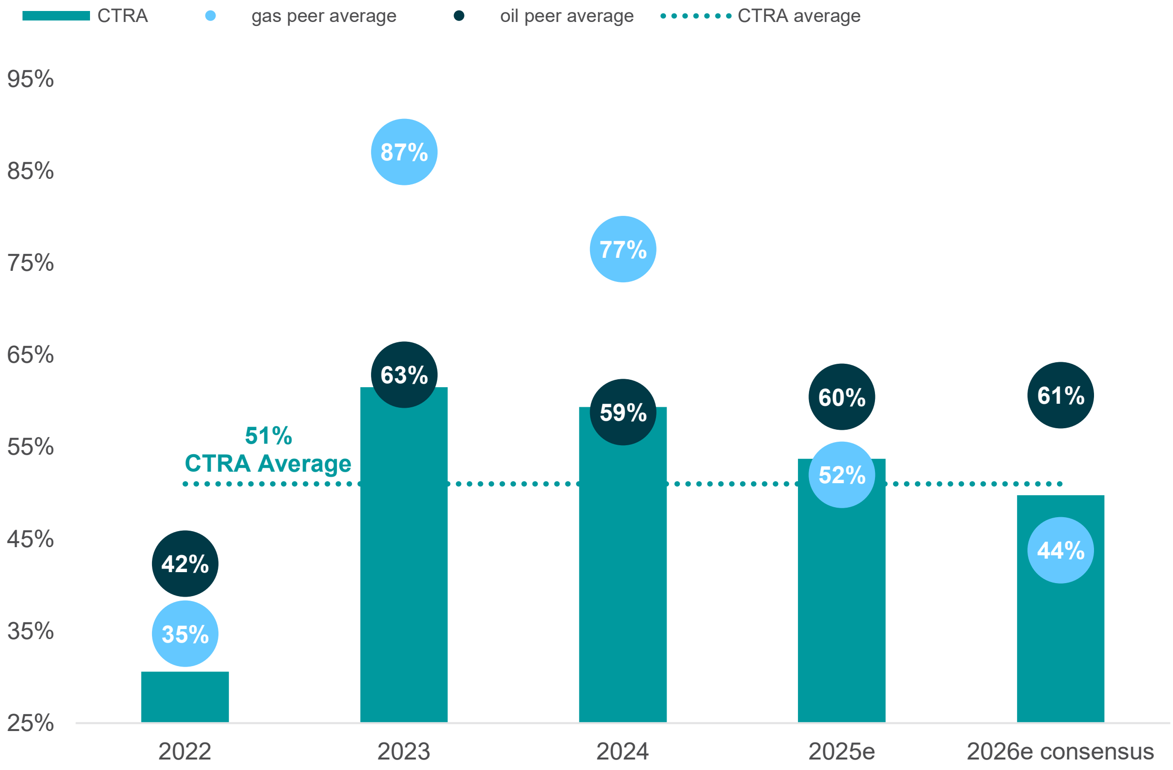


Note: See appendix for non-GAAP reconciliations and definitions. Source: Factset consensus. CTRA capital efficiency based on 2025e guidance calculated as capex per 20:3:1 boe; production growth estimates based on consensus. Peers include APA, AR, CHRD, CIVI, COP, DVN, EOG, EQT, EXE, FANG, MTDR, OVV, OXY, PR, RRC. 1) Reinvestment rate defined as capex as % of DCF. 2) At recent strip prices. See appendix for commodity price assumptions.

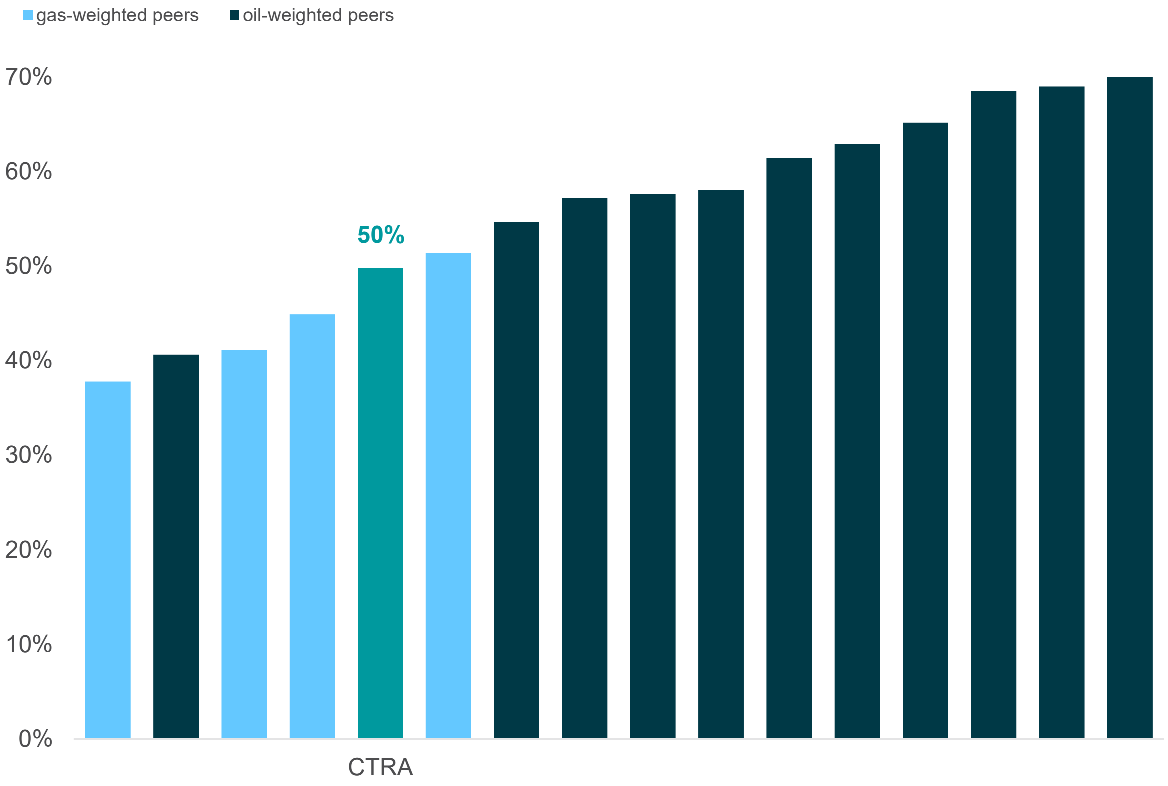
Disciplined Approach to Capital Investment

Differentiated reinvestment rate through the commodity cycles

Conservative historical reinvestment rate



Low reinvestment among peers in 2026



Source: Factset consensus for peers and estimates. Peers include APA, AR, CHRD, CIVI, COP, DVN, EOG, EQT, EXE, FANG, MTDR, OVV, OXY, PR, RRC. Reinvestment rate defined as capex as % of DCF. See appendix for non-GAAP reconciliations and definitions. See appendix for commodity price assumptions.

Long Runway of High-Quality Inventory

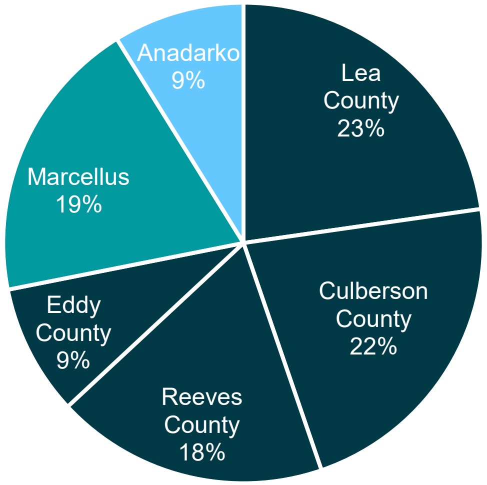
Benchmark price assumptions of $75/bbl and $3.75/mmbtu

~$31 billion of Economic Capex Opportunities

estimated capex by PVI$_{10}$ bucket:

~$14bn, or ~45%, of capex is expected to generate 2.0x PVI$_{10}$ or better

estimated total footage by asset area:



Implied Inventory Duration[1]

estimates can fluctuate based on assumptions around well spacing, cost levels, commodity prices, & activity cadence

Permian	~15 years
Marcellus	~12 years
Anadarko	~15 years
Total company	~15 years

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Note: Estimates as of February 2025. See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) Calculated midpoints based on average 2025e-2027e D&C spend and $75 WTI & $3.75 Henry Hub.

Durable Free Cash Flow Through the Cycles

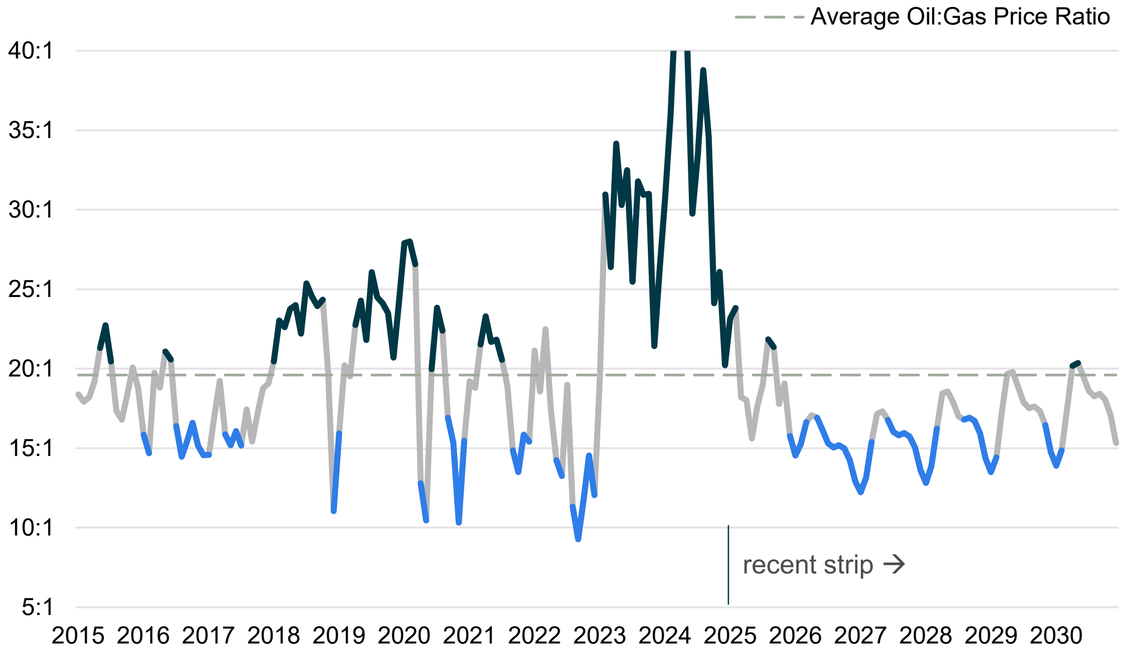
Oil-to-gas price ratios can, and have historically decoupled, especially during periods of extreme volatility

Uniquely positioned to weather volatility

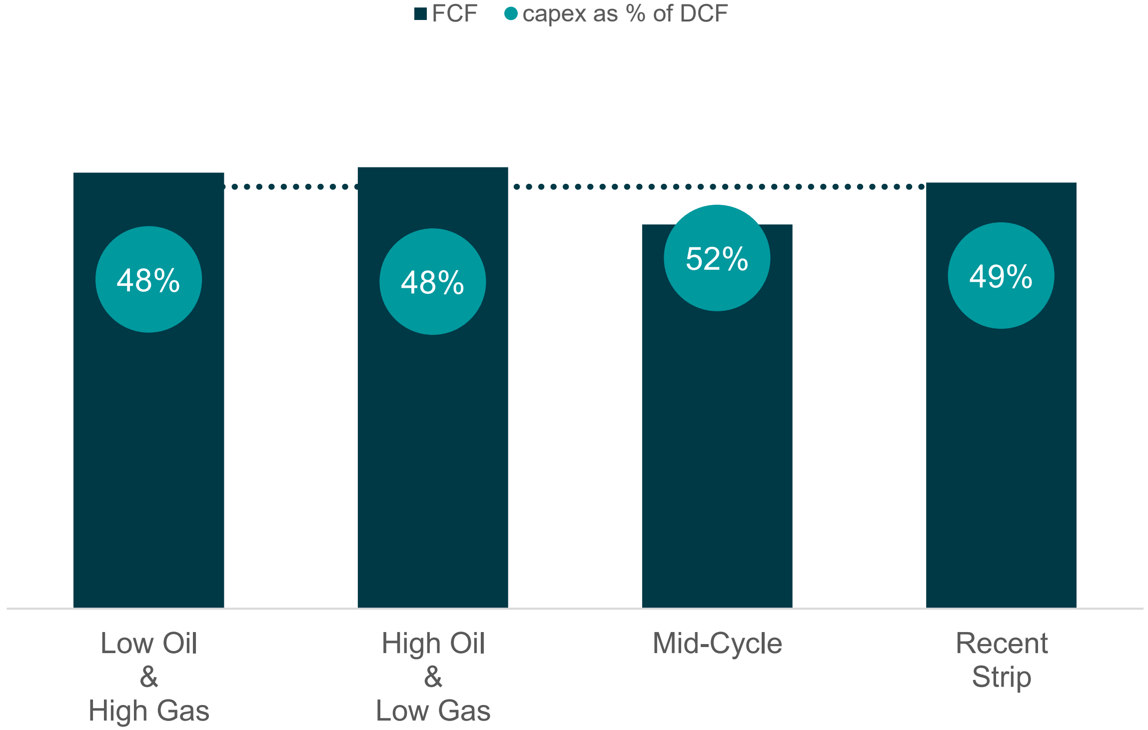
Diversified commodity portfolio with demonstrated capital flexibility

Oil:gas price ratios

>20:1: **Oil advantaged**, occurred 53% 2015-3Q25, 3% 5-yr Strip
<17:1: **Gas advantaged**, occurred 28% 2015-3Q25, 54% 5-yr Strip



Resilient Future Free Cash Flow & disciplined reinvestment across price environments



	Low Oil & High Gas	High Oil & Low Gas	Mid-Cycle	Recent Strip
WTI & HH	$50 & $4.75	$75 & $2.75	$65 & $3.25	~$60 & ~$4.00
Oil:gas price ratio	11:1	27:1	20:1	15:1

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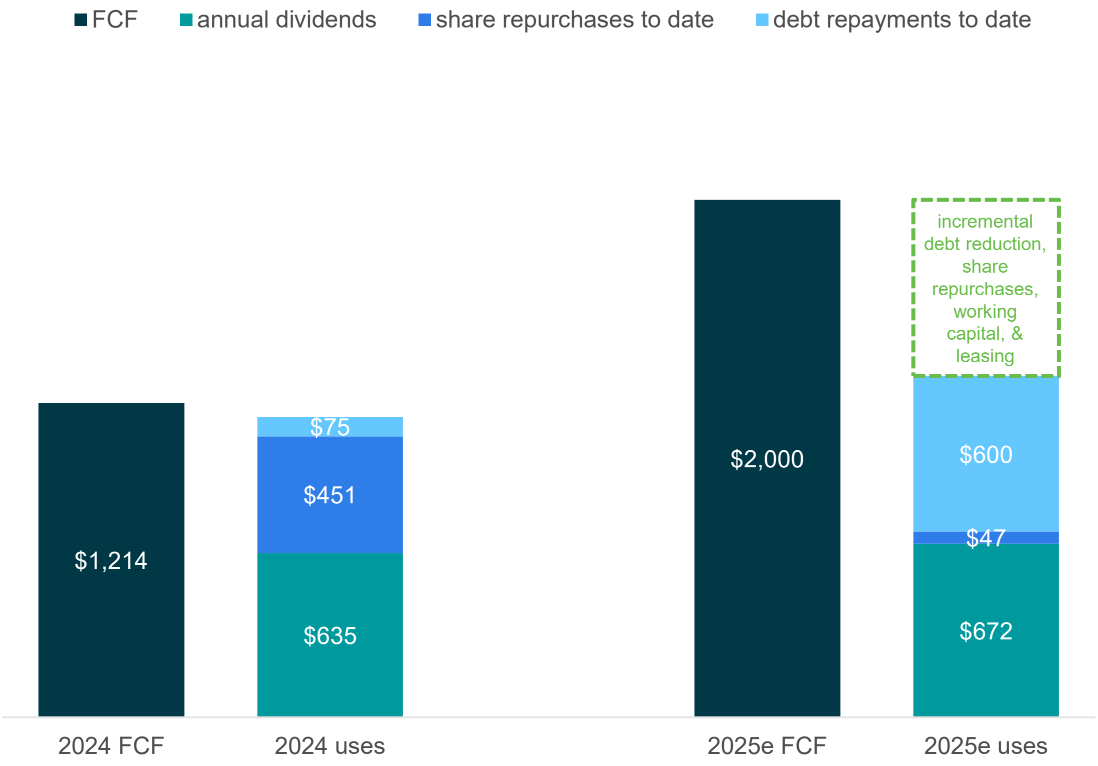
Note: Strip prices as of 10/23/25. Reinvestment rate defined as capex as % of DCF. See appendix for non-GAAP definitions.

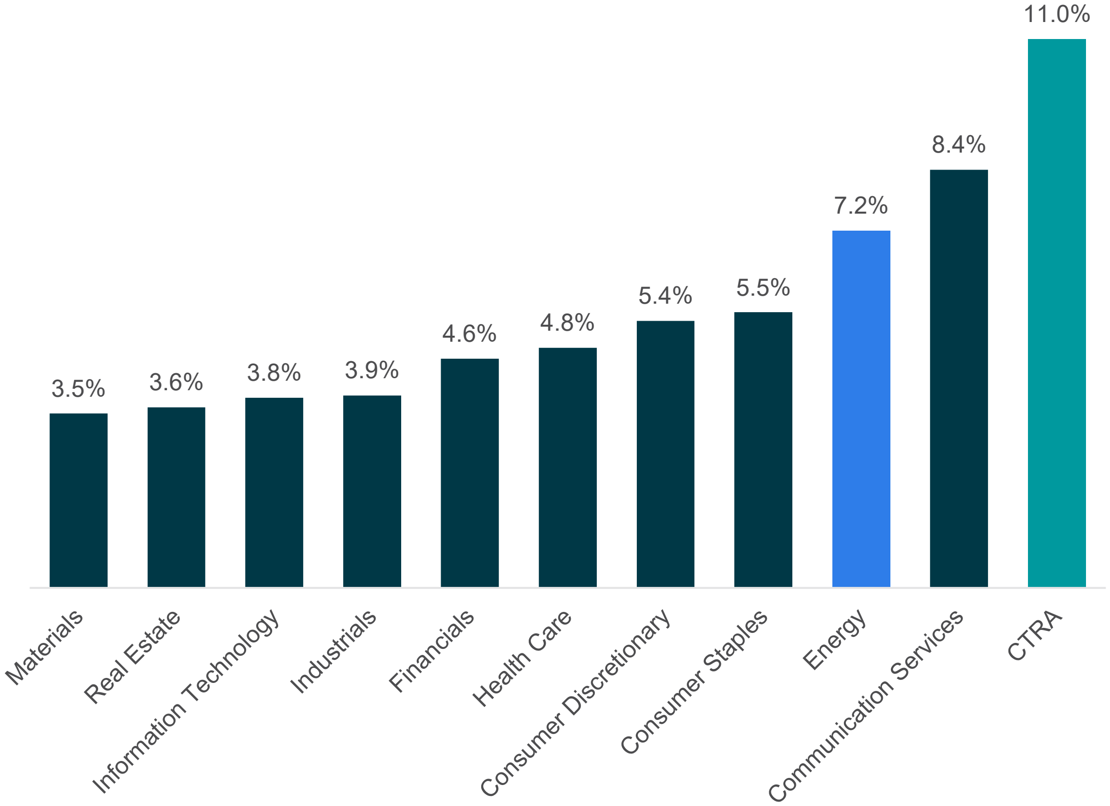
Returning Value to Shareholders

Free Cash Flow in $ millions

YoY increase driven by greater oil volumes from Lea County acquisition, higher gas price, and disciplined reinvestment



Top SP500 2025e Free Cash Flow Yield[1]



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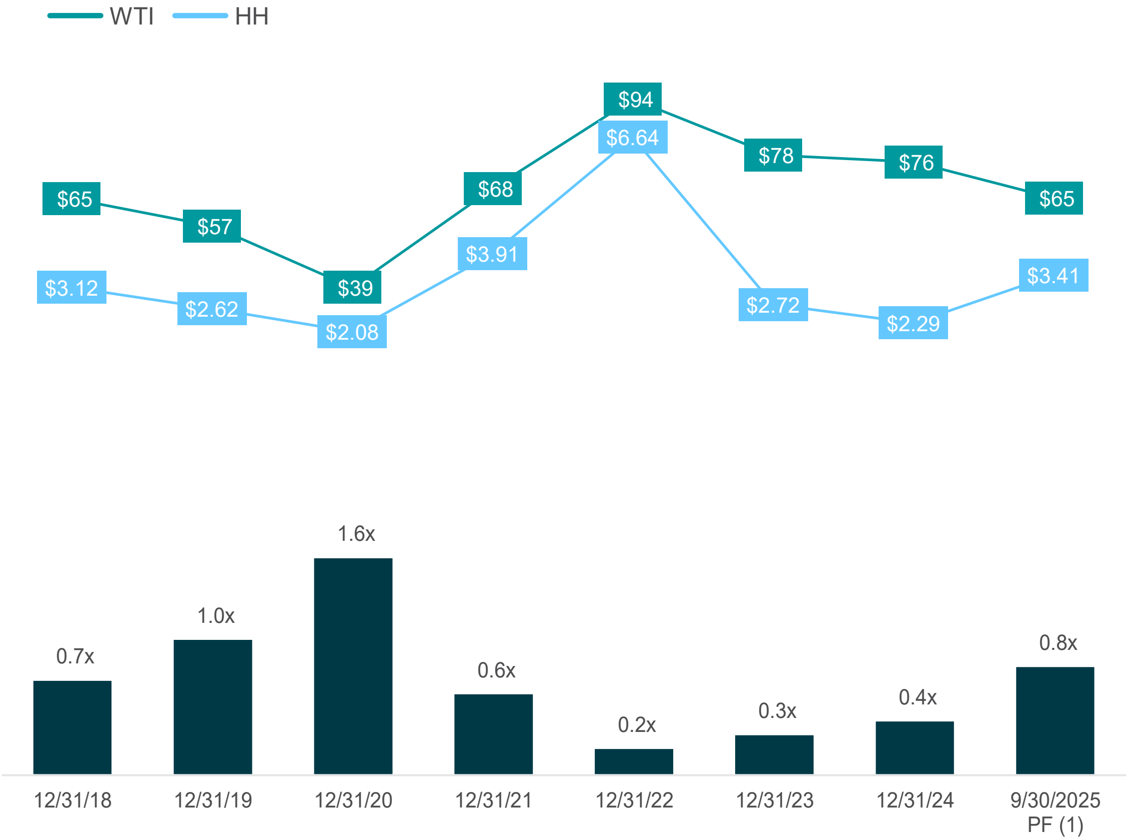
Note: See appendix for commodity price assumptions and non-GAAP reconciliations and definitions. Dividends shown are declared dividends within the year, not cash paid. Share repurchases shown are on cash basis, which excludes 1% excise tax and any shares that settled after the quarter-end. 2025 annual dividends = YTD 2025 declared dividends of $504mm + share count, per cover of 3Q25 10Q * $0.22/sh (for remaining quarter of the year). Future dividends are subject to board approval. 1) Source: Factset consensus and market capitalizations.

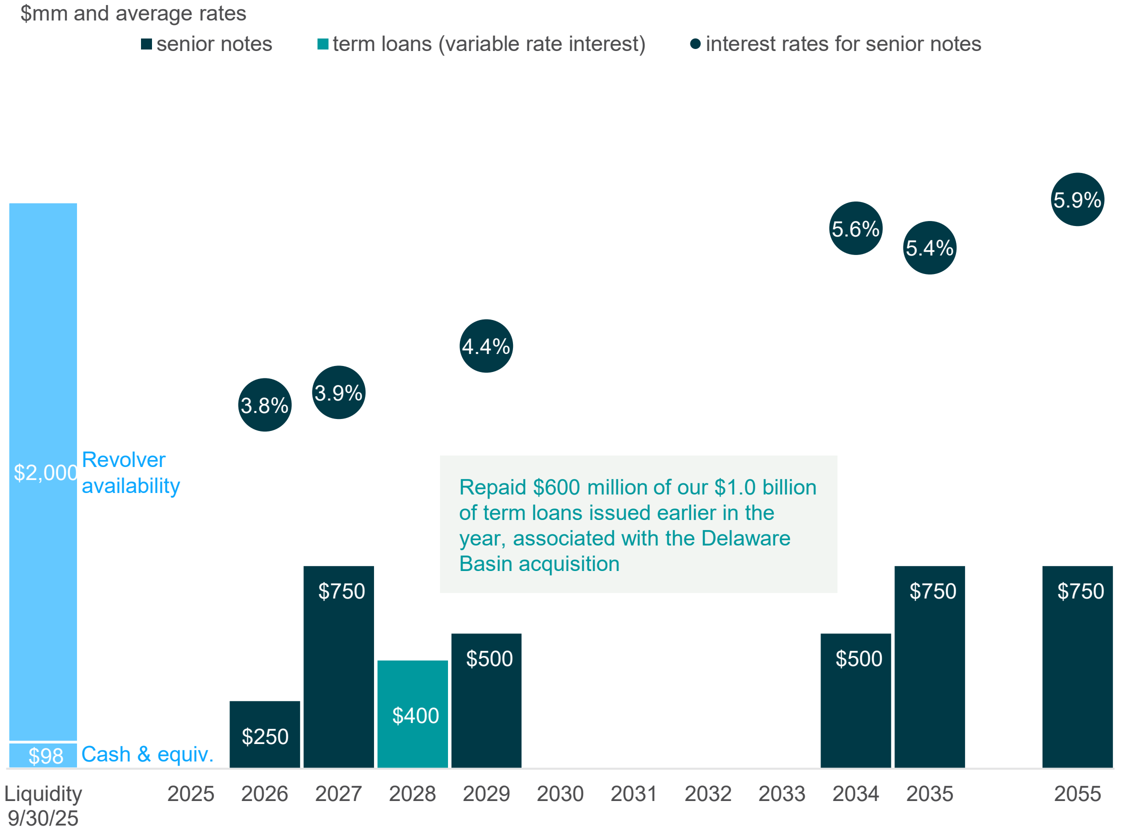
Prioritizing Financial Flexibility

History of Conservative Net Leverage



Target <1x Net Leverage for maximum flexibility through all price cycles

Liquidity & Debt Maturity Profile



Conservative debt balance, low rates, & long-dated maturities with substantial liquidity

Note: See appendix for non-GAAP reconciliations and definitions. Commodity prices are trailing-twelve-month benchmark prices.1) Net debt to pro forma adjusted EBITDAX for the trailing twelve months.

Differentiated by Culture, Asset Quality, Inventory Duration, & Commodity Mix

Defensively positioned and resilient through commodity cycles

Coterra's Business Strategy

- Culture of Excellence
  Open, non-siloed organization drives internal debate in which the best ideas prevail
- Data Driven Approach to Problem Solving
  Rigorous scientific and financial analysis
- Technical Teams Driving Value Creation
  Leveraging AI and custom applications to generate differentiated results
- Iterative Planning Leads to Improved Outcomes
  Flexibility is key to maximizing value
- Conservative and Disciplined Financial Approach
  Focused on long-term value creation

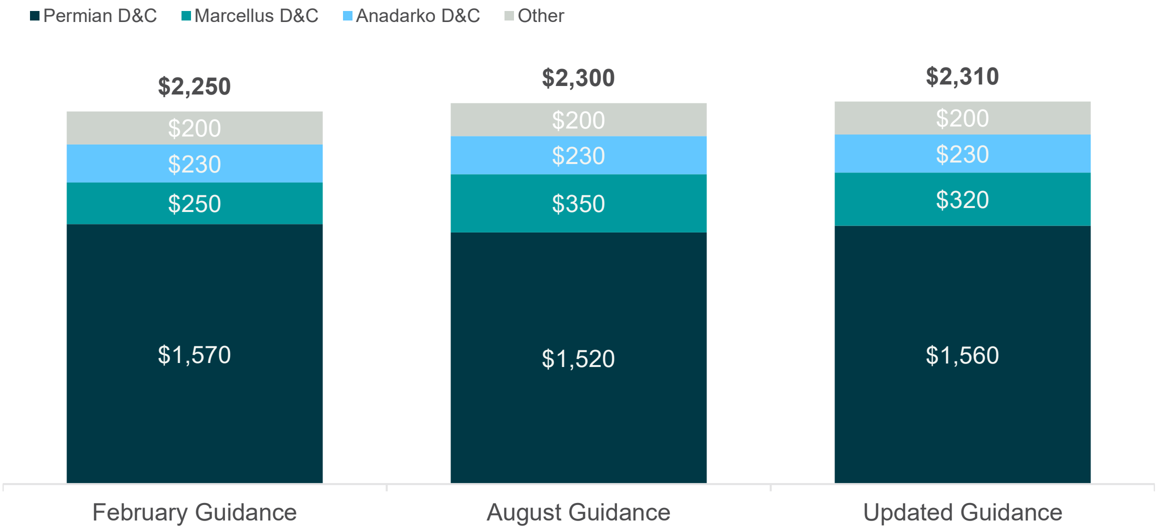
Compelling Investment Thesis

- Consistent, Profitable Growth & Low Reinvestment
  Highly capital-efficient portfolio and development program
- High-Quality Inventory
  Long-lived, high-return inventory provides competitive advantage
- Diversified Portfolio Provides Ability to Pivot
  Ability to redirect capital across commodities and asset footprint
- Durable Free Cash Flow
  Driven by balanced oil and natural gas production mix and price exposure
- Attractive Shareholder Returns
  3.8% dividend yield[1] and opportunistic share repurchases
- Peer-Leading Balance Sheet
  Low leverage, high liquidity and a prudent maturity profile

Note: See appendix for non-GAAP reconciliations and definitions. 1) Annualized 3Q25 declared dividend divided by October 30, 2025 share price.

2025e Development Program Key Highlights

2025e capex in $ millions



Disciplined Capital Program

Currently expect ~$2.3 billion of 2025e capex

~55% reinvestment rate[1]

2025 Program Key Highlights

Permian in-line with February guidance

Currently running 9 rigs & 3 crews

Marcellus +$70mm vs. February guidance

Picked up activity through the year

Anadarko

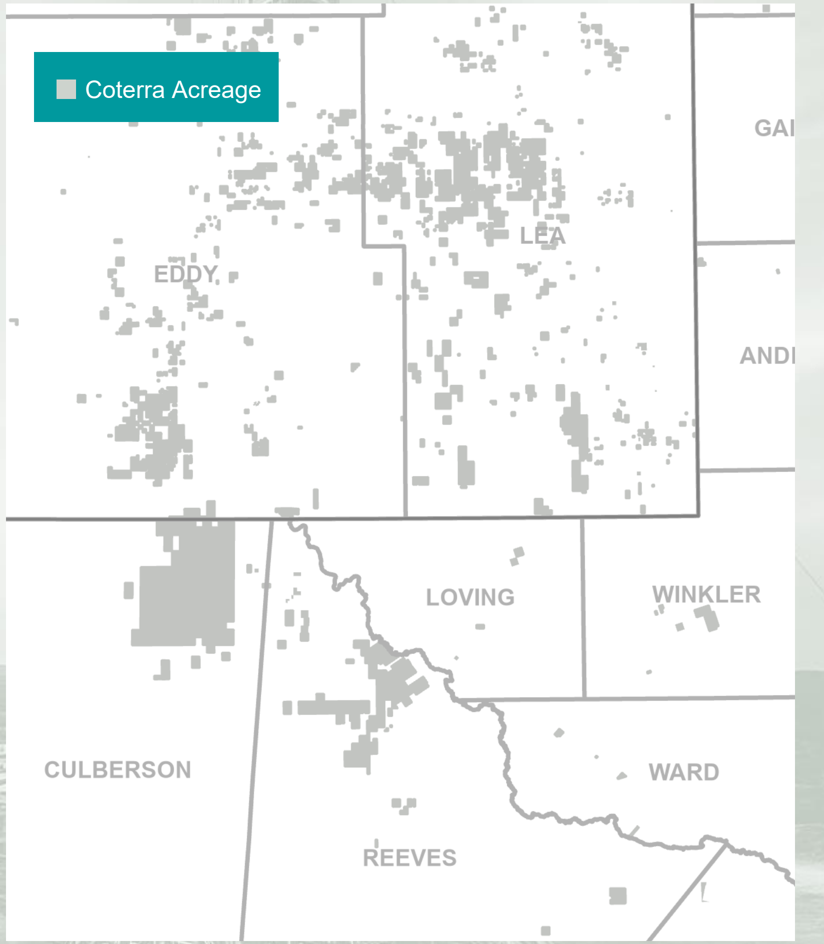
3-mile well project (5 net wells) came online 4Q25

Note: "other" capex includes midstream, saltwater disposal, and infrastructure spend. 1) Defined as capex as % of DCF. See appendix for non-GAAP reconciliations and definitions and commodity price assumptions.

Permian Asset Overview – 2025 Operational Outlook

$1,560 million
Midpoint D&C CapEx

10,200'	$950	~165
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online[2]
	-10% cost reduction YoY	

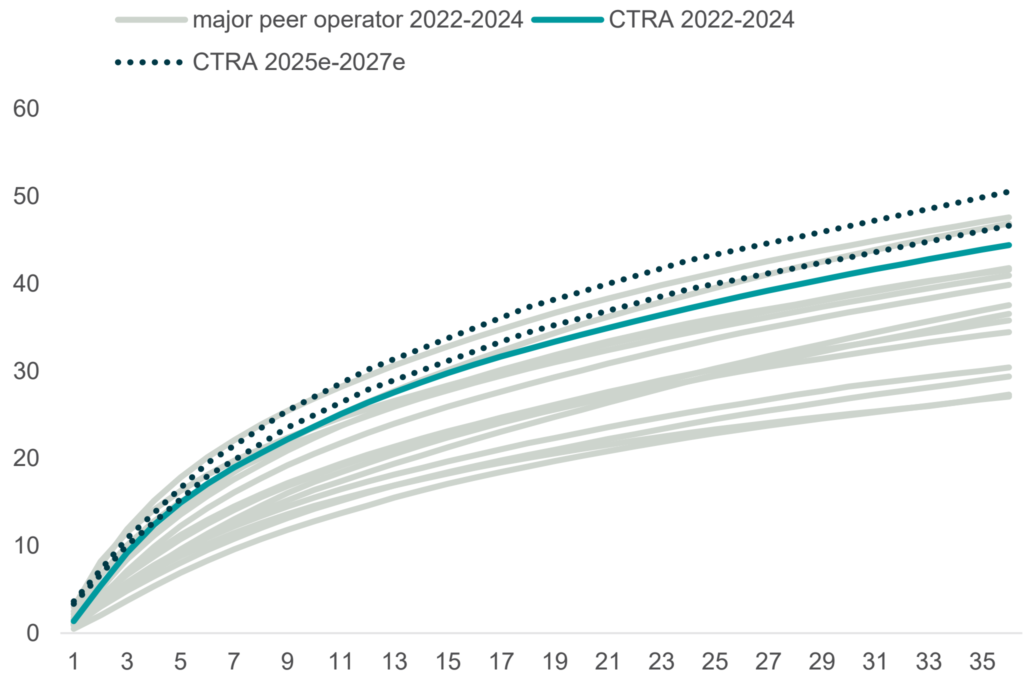


1) Based on 2025e completed, operated wells. 2) Includes non-op. Note: Spend for a well is incurred over a period of 6-12 months, which does not necessarily fall within a single calendar year. $ per foot includes drilling, completion, facilities and post-completion capital

Top-Tier Delaware Producer with Competitive D&C Well Costs

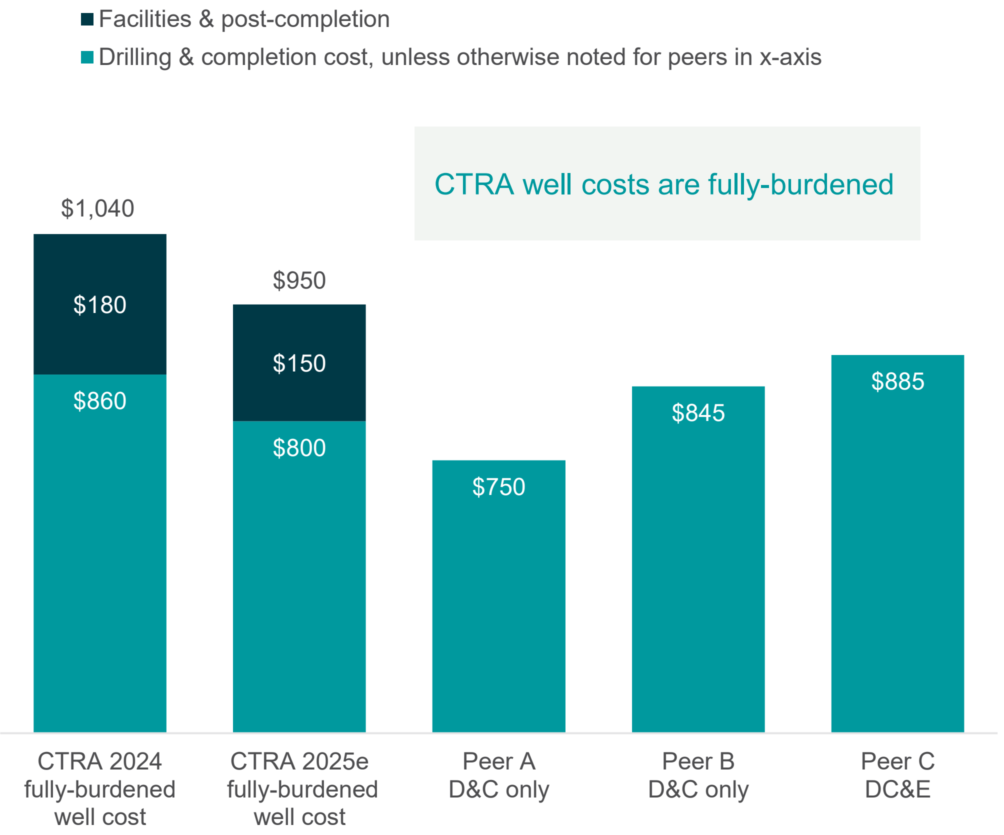
Delaware Productivity[1]

cumulative 2-stream at 20:1 conversion ratio, boe per lateral foot



- Productivity will differ from year to year, depending on project selection & other operational decisions
- Generally, our Permian program will be ~1/2 Texas and ~1/2 New Mexico driven by our large, contiguous positions in Culberson County, Texas and Lea County, New Mexico
- Our program continues to benefit from optimized spacing and completion design decisions that generate resilient returns at various commodity prices

Recent Delaware D&C Well Costs per Foot[2]



1) Source: Enverus Prism for historical data and internal forecasts for future estimates. Filtered to >8,500' laterals. Includes all historical wells from the Franklin Mountain Energy and Avant acquisitions.
2) Sourced from recent company disclosure. CTRA D&C cost estimate based on 2025e completed, operated wells. Peers A, B, and C are companies that publish Delaware Basin well costs.

Marcellus Asset Overview – 2025 Operational Outlook

$320 million
Midpoint D&C CapEx

17,000'	$790	9-13
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online
	-24% cost reduction YoY	~30% Upper & ~70% Lower

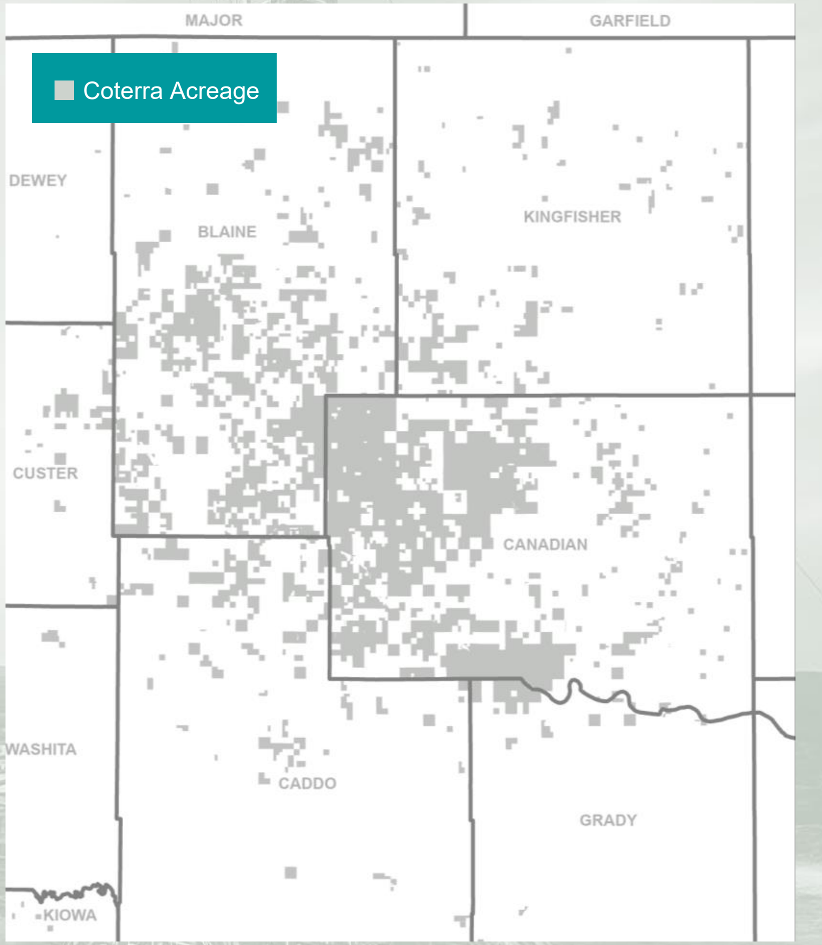
1) Based on 2025e completed, operated wells. Note: Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. $ per foot includes drilling, completion, facilities and post-completion capital.

Anadarko Asset Overview – 2025 Operational Outlook

$230 million

Midpoint D&C CapEx

11,370'	$1,060	20
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online[2]
	-15% cost reduction YoY	



1) Based on 2025e completed, operated wells. Note: Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. $ per foot includes drilling, completion, facilities and post-completion capital. 2) Includes non-op.

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Appendix

High-Quality, Long-Life, Diversified Asset Portfolio

Multi-Basin Portfolio

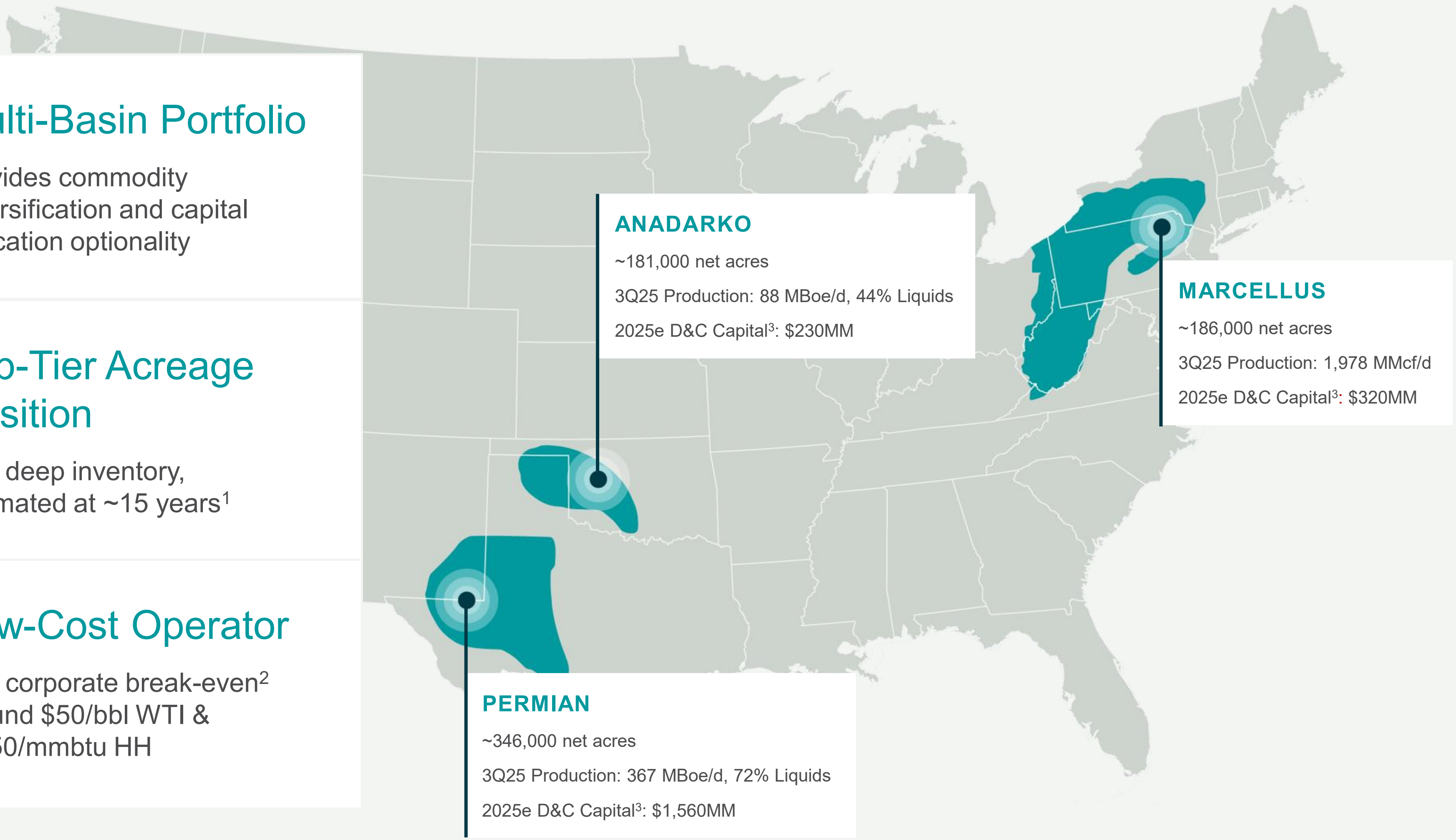
provides commodity diversification and capital allocation optionality

Top-Tier Acreage Position

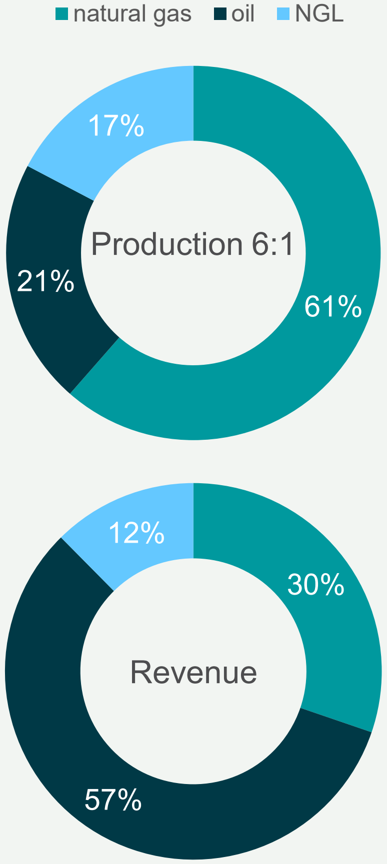
with deep inventory, estimated at ~15 years[1]

Low-Cost Operator

with corporate break-even[2] around $50/bbl WTI & $2.50/mmbtu HH



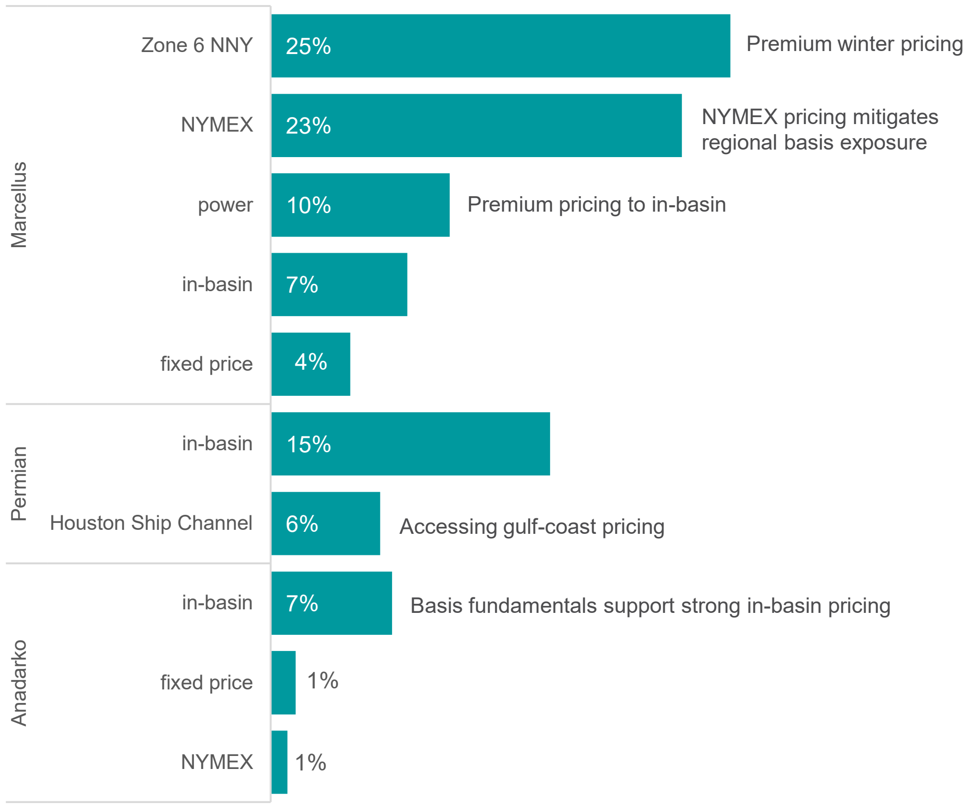
3Q25 Commodity Splits



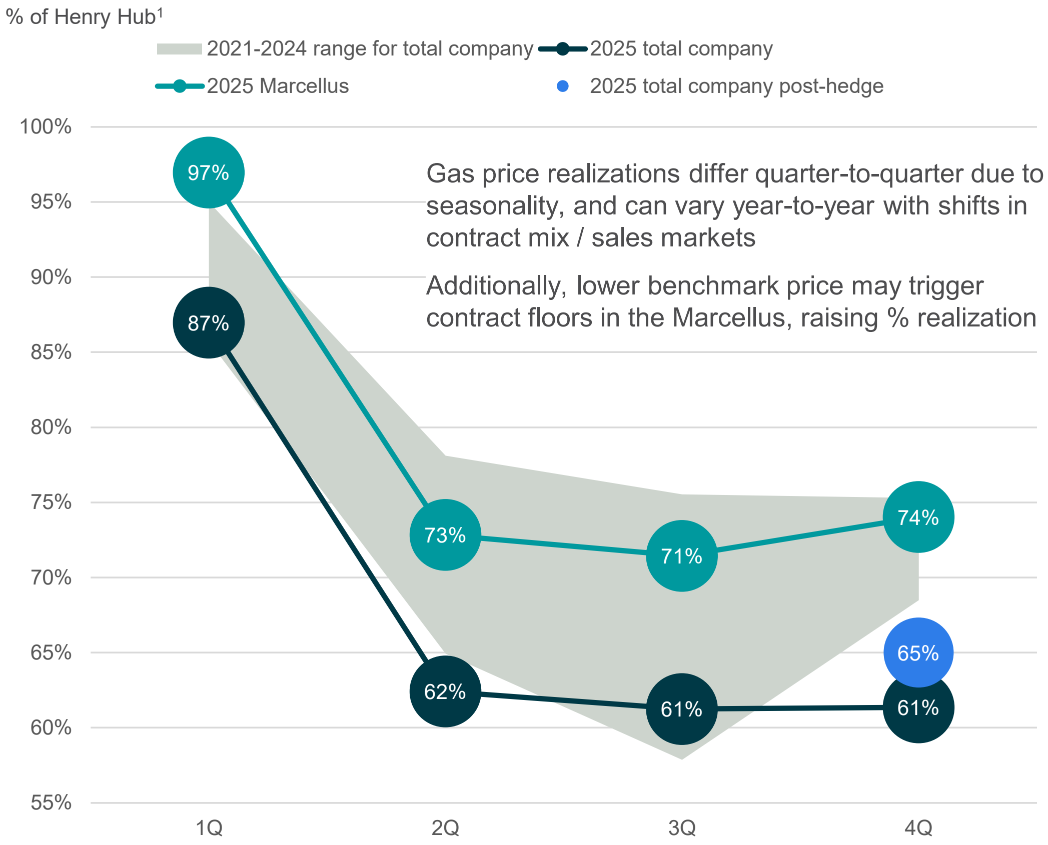
1) Assumes average 2025e-2027e D&C spend and $75 WTI & $3.75 Henry Hub. 2) Meaning FCF covers base dividend for multiple years. See appendix for non-GAAP reconciliations and definitions.
3) D&C Capital = Drilling & Completion Capital, which includes drilling, completion, facilities and post-completion capital.

Diversified Gas Marketing Portfolio

2025 Estimated Natural Gas Sales Markets



2021-2025e Natural Gas Price Realization Range[1]



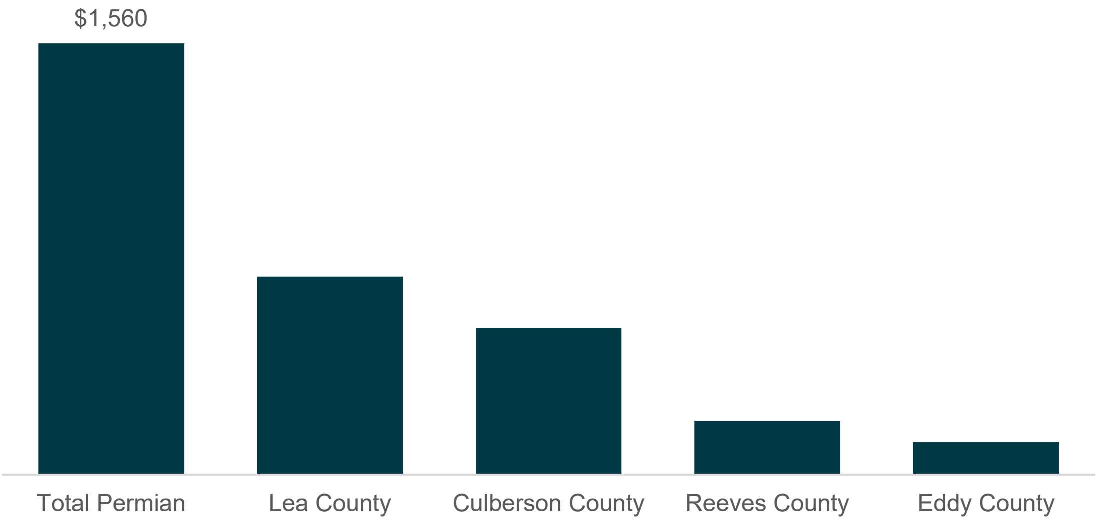
Gas price realizations differ quarter-to-quarter due to seasonality, and can vary year-to-year with shifts in contract mix / sales markets

Additionally, lower benchmark price may trigger contract floors in the Marcellus, raising % realization

Note: Marcellus primarily first-of-month pricing while Anadarko & Permian are primarily Gas Daily Average pricing.1) Pre-hedge price realizations depicted. MMBtu converted at 1.03 multiplier for Mcf value. See guidance tables for benchmark price assumptions.

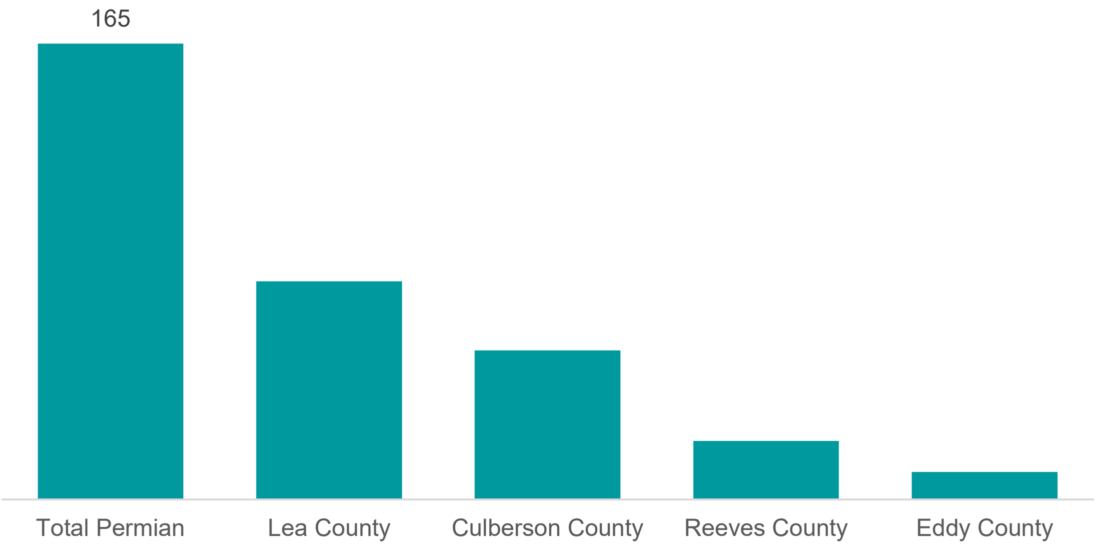
2025 Permian Development Program

2025e mid-point D&C capex in $ millions



Leading edge $ per foot estimates:	$1,020 per foot	$830 per foot	$1,020 per foot	$1,040 per foot

2025e net wells online



Primary target formations:	Upper Wolfcamp & Bone Spring	Upper Wolfcamp	Upper Wolfcamp	Lower Wolfcamp & Bone Spring

Note: See appendix for non-GAAP reconciliations and definitions. D&C costs and $ per foot estimates include drilling, completion, facilities and post-completion costs.

Guidance & Actuals

		2025 Guidance (February)			Updated 2025 Guidance			3Q25 Guidance			3Q25 Actual	4Q25 Guidance		
		Low	Mid	High	Low	Mid	High	Low	Mid	High		Low	Mid	High
Operations	Total Production (mboed)	710 -	740	- 770	772 -	777	- 782	740 -	765	- 790	785	770 -	790	- 810
	Gas (mmcfd)	2,675 -	2,775	- 2,875	2,925 -	2,945	- 2,965	2,750 -	2,825	- 2,900	2,895	2,775 -	2,850	- 2,925
	Oil (mbod)	152.0 -	160.0	- 168.0	159.0 -	160.0	- 161.0	158.0 -	163.0	- 168.0	166.8	172.0 -	175.0	- 178.0
	Net operated wells online													
	Marcellus	10 -	13	- 15	9 -	13			4		4	2 -	6	
	Permian	150 -	158	- 165		165		40 -	45	- 50	38		41	
	Anadarko	15 -	20	- 25		20			6		6		5	
	$ millions:													
	Incurred Capital Expenditures	$2,100 -	$2,250	- $2,400		$2,310		$625 -	$650	- $675	$658		$530	
	Marcellus D&C		$250			$320								
	Permian D&C		$1,570			$1,560								
	Anadarko D&C		$230			$230								
	Midstream, saltwater disposal, infrastructure		$200			$200								
Cash Flow & Investment	Commodity price assumptions:													
	WTI ($ per bbl)		$71			$65								
	Henry Hub ($ per mmbtu)		$4.22			$3.41								
	$ billions:													
	Discretionary Cash Flow		$5.0			$4.3								
	Incurred Capital Expenditures	$2.1 -	$2.3	- $2.4		$2.3								
	Free Cash Flow (DCF - cash capex)		$2.7			$2.0								

Note: See appendix for non-GAAP reconciliations and definitions. Numbers may not sum due to rounding.

Expense Guidance & Actuals

Expense guidance provided for annual 2025

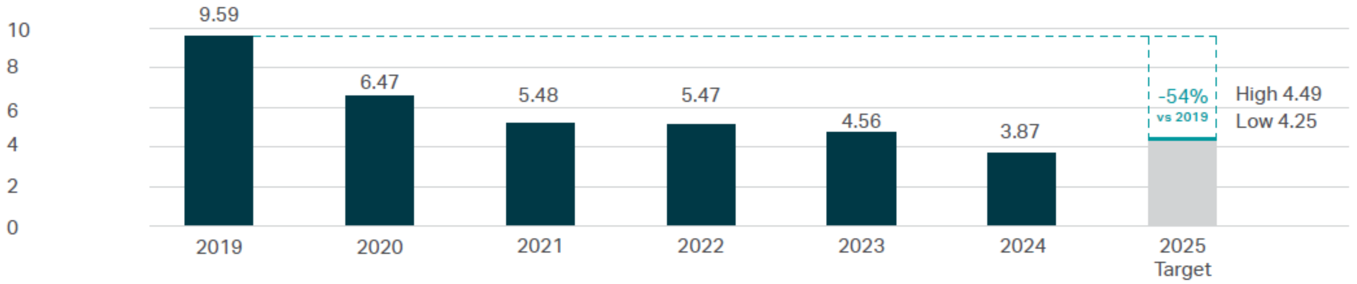
		2024 Actual	2025 Guidance					1Q25 Actual	2Q25 Actual	3Q25 Actual
Expense	$ per boe, unless noted:									
	Lease operating expense + workovers + region office	$2.66	$2.50	-	$3.05	-	$3.60	$3.21	$3.32	$3.80
	Gathering, processing, & transportation	$3.94	$3.25	-	$3.75	-	$4.25	$4.20	$3.81	$3.75
	Taxes other than income	$1.09	$1.25	-	$1.50	-	$1.75	$1.43	$1.21	$1.29
	General & administrative (excluding stock-based compensation)	$0.97	$0.90	-	$1.00	-	$1.10	$1.13	$1.00	$0.97
	Unit Operating Cost	$8.66	$7.90	-	$9.30	-	$10.70	$9.97	$9.34	$9.81
	DD&A	$7.43	$8.00	-	$8.75	-	$9.50	$7.53	$8.11	$8.58
	Exploration[1]	$0.10	$0.05	-	$0.08	-	$0.10	$0.15	$0.07	$0.09
	% effective tax rate[2]				22%			21%	22%	24%

1 Excluding exploratory dry hole costs, includes exploration administrative expense and geophysical expenses

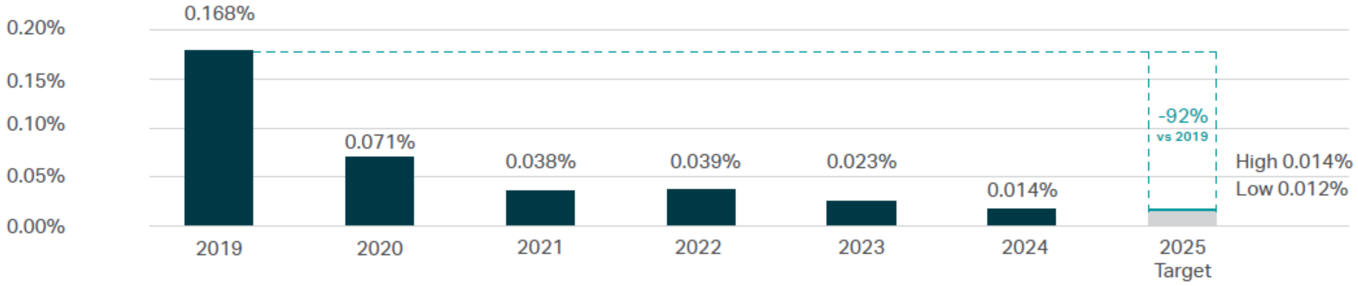
2 Expect no cash taxes in 2H25

Published Sustainability Report on August 4, 2025

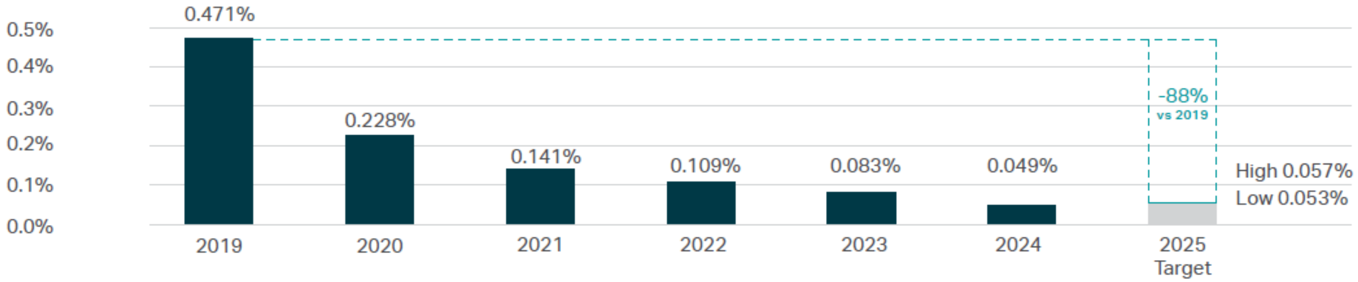
Greenhouse Gas Emissions Intensity (MT CO_2e / Gross Mboe Produced)



Methane Emissions Intensity (MT CH_4 Emitted / Gross CH_4 Produced)



Total Company Flare Intensity (Volume of Gas Flared / Volume of Gas Produced)



Figures listed above include only Scope 1 Subpart W reportable emissions. 2019 to 2021 figures are based on combined results for Cabot & Cimarex. Subsequent figures, including 2025, are Legacy Coterra only and exclude the assets acquired in January 2025. 2024 Actuals are preliminary and not yet finalized by the EPA.

Non-GAAP Reconciliations & Definitions

Supplemental Non-GAAP Financial Measures (Unaudited): We report our financial results in accordance with accounting principles generally accepted in the United States (GAAP). However, we believe certain non-GAAP performance measures may provide financial statement users with additional meaningful comparisons between current results and results of prior periods. In addition, we believe these measures are used by analysts and others in the valuation, rating and investment recommendations of companies within the oil and natural gas exploration and production industry. See the reconciliations below that compare GAAP financial measures to non-GAAP financial measures for the periods indicated.

We have also included herein certain forward-looking non-GAAP financial measures including, among others, the reinvestment rate, which is defined as capital expenditures (non-GAAP) as a percentage of Discretionary Cash Flow (non-GAAP). We believe the reinvestment rate provides investors with useful information on management's projected use and reinvestment of its future cash flows back in Coterra's operations. Due to the forward-looking nature of these non-GAAP financial measures, we cannot reliably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures, such as changes in assets and liabilities (including future impairments) and cash paid for capital expenditures. Accordingly, we are unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures. Reconciling items in future periods could be significant.

Capital expenditures is defined as cash capital expenditures for drilling, completion and other fixed asset additions less changes in accrued capital costs.

Discretionary Cash Flow is defined as cash flow from operating activities excluding changes in assets and liabilities. Discretionary Cash Flow is widely accepted as a financial indicator of an oil and gas company's ability to generate available cash to internally fund exploration and development activities, return capital to shareholders through dividends and share repurchases, and service debt and is used by our management for that purpose. Discretionary Cash Flow is presented based on our management's belief that this non-GAAP measure is useful information to investors when comparing our cash flows with the cash flows of other companies that use the full cost method of accounting for oil and gas produced activities or have different financing and capital structures or tax rates. Discretionary Cash Flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

Free Cash Flow is defined as Discretionary Cash Flow less cash paid for capital expenditures Free Cash Flow is an indicator of a company's ability to generate cash flow after spending the money required to maintain or expand its asset base and is used by our management for that purpose. Free Cash Flow is presented based on our management's belief that this non-GAAP measure is useful information to investors when comparing our cash flows with the cash flows of other companies. Free Cash Flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flow from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

Three Months Ended: ($ in millions)	30-Sep 2025
Cash flow from operating activities	$ 971
Changes in assets and liabilities	177
Discretionary cash flow	**1,148**
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(615)
Free cash flow	**$ 533**

Twelve Months Ended: ($ in millions)	Dec 31 2024
Cash flow from operating activities	$ 2,795
Changes in assets and liabilities	173
Discretionary cash flow	**2,968**
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(1,754)
Free cash flow	**$ 1,214**

Three Months Ended: ($ in millions)	30-Sep 2025
Cash capital expenditures for drilling, completion and other fixed asset additions	$615
Change in accrued capital costs	43
Exploratory dry-hole cost	-
Capital expenditures	**$658**

Twelve Months Ended: ($ in millions)	Dec 31 2024
Cash capital expenditures for drilling, completion and other fixed asset additions	$1,754
Change in accrued capital costs	8
Capital expenditures	**$1,762**

Non-GAAP Reconciliations & Definitions

EBITDAX

EBITDAX is defined as net income plus interest expense, other expense, income tax expense and benefit, depreciation, depletion, and amortization (including impairments), exploration expense, gain and loss on sale of assets, non-cash gain and loss on derivative instruments, earnings and loss on equity method investments, equity method investment distributions, stock-based compensation expense and merger-related costs. EBITDAX is presented on our management’s belief that this non-GAAP measure is useful information to investors when evaluating our ability to internally fund exploration and development activities and to service or incur debt without regard to financial or capital structure. Our management uses EBITDAX for that purpose. EBITDAX is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

The Combined EBITDAX calculations below reflect legacy Cabot and Cimarex results through September 30, 2021 and Coterra results thereafter. Legacy Cimarex operated under the full cost accounting method, unlike legacy Cabot, now Coterra, which operates under the successful efforts accounting method. This difference in accounting methodologies leads to differences in the calculation of company financials and the figures below should not be relied on to predict future performance of the combined business, which operates under the successful efforts accounting method.

Net Debt and Net Debt to EBITDAX (or Net Leverage)

Net Debt is calculated by subtracting cash and cash equivalents from total debt. Net Debt is a non-GAAP measures which our management believes are also useful to investors when assessing our leverage since we have the ability to and may decide to use a portion of our cash and cash equivalents to retire debt. Our management uses this measures for that purpose.

Other Defined Terms

Present Value Index (PVI10) is often used by management as a return-on-investment metric and defined as the estimated net present value (using a 10% discount rate) of the future net cash flows from such reserves (for which we utilize certain assumptions regarding future commodity prices and operating costs), adding back our direct net costs incurred in drilling and adding back our completing, constructing facilities, and flowing back such wells, and then dividing that sum by our direct net costs incurred in drilling, completing, constructing facilities, and flowing back such wells.

Twelve Months Ended:	**September 30**	**December 31**						
($ in millions)	**2025**	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**
	Coterra				Combined Cabot + Cimarex			
Net income	$ 1,646	$ 1,121	$ 1,625	$ 4,065	$ 1,158	$ 201	$ 681	$ 557
Plus (less):								
Interest expense, net					62	54	55	73
Interest expense	185	106	73	80				
Interest income	(23)	(62)	(47)	(10)				
(Gain) loss on debt extinguishment				(28)	-	-	-	-
Other expense (benefit)	(1)			(2)	-	-	1	-
Income tax expense (benefit)	400	224	503	1,104	344	41	219	141
Depreciation, depletion and amortization	2,190	1,840	1,641	1,635	693	391	406	417
Exploration	27	25	20	29	18	15	20	114
(Gain) loss on sale of assets	(5)	(3)	(12)	1	2	0	1	16
Non-cash loss (gain) on derivative instruments	(74)	101	54	(299)	(210)	(26)	58	(86)
(Earnings) loss on equity method investments	-	-	-	-	-	0	(80)	(1)
Equity method investment distributions	-	-	-	-	-	-	17	-
Stock-based compensation	62	62	59	86	57	43	31	33
Severance expense	-	-	12	62	46	-	3	-
Merger-related costs	15	-	-	7	72	-	-	-
EBITDAX	**$ 4,422**	**$ 3,414**	**$ 3,928**	**$ 6,730**	**$ 2,242**	**$ 719**	**$ 1,412**	**$ 1,264**
Legacy Cimarex EBITDAX					1,005	935	1,460	1,558
Combined EBITDAX	**$ 4,422**	**$ 3,414**	**$ 3,928**	**$ 6,730**	**$ 3,247**	**$ 1,654**	**$ 2,872**	**$ 2,822**

	September 30	**December 31**						
($ in millions)	**2025**	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**
	Coterra				Combined Cabot + Cimarex			
Total debt	$3,922	$3,535	$2,161	$2,181	$3,125	$3,134	$3,220	$2,726
Less: Cash and cash equivalents	(98)	(2,038)	(956)	(673)	(1,036)	(413)	(295)	(803)
Less: Short-term investments								
Net debt	$3,824	$1,497	$1,205	$1,508	$2,089	$2,721	$2,925	$1,923
TTM EBITDAX	$4,422	$3,414	$3,928	$6,730	$3,247	$1,654	$2,872	$2,822
Net debt to TTM EBITDAX	**0.9x**	**0.4x**	**0.3x**	**0.2x**	**0.6x**	**1.6x**	**1.0x**	**0.7x**

Non-GAAP Reconciliations & Definitions

Adjusted Pro Forma EBITDAX (trailing twelve months)

Adjusted Pro Forma EBITDAX is defined as pro forma net income plus pro forma interest expense, pro forma interest income, pro forma income tax expense, pro forma depreciation, depletion, and amortization (including impairments), pro forma exploration expense, pro forma gain and loss on sale of assets, pro forma non-cash gain and loss on derivative instruments, pro forma acquisition-related expenses, and pro forma stock-based compensation expense. Adjusted Pro Forma EBITDAX represents the effects of the Franklin Mountain Energy and Avant Natural Resources acquisitions as if they had occurred on January 1, 2024. Adjusted Pro Forma EBITDAX is presented on our management's belief that this non-GAAP measure is useful information to investors when evaluating our ability to internally fund exploration and development activities and to service or incur debt after the acquisitions without regard to financial or capital structure. Our management uses Adjusted Pro Forma EBITDAX for that purpose. Adjusted Pro Forma EBITDAX is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities, pro forma net income or net income, as defined by GAAP, or as a measure of liquidity.

Net Debt to Adjusted Pro Forma EBITDAX

Total debt to net income is defined as total debt divided by net income. Net debt to Adjusted Pro Forma EBITDAX is defined as net debt divided by trailing twelve month Adjusted Pro Forma EBITDAX. Net debt to Adjusted Pro Forma EBITDAX is a non-GAAP measure which our management believes is useful to investors when assessing our credit position and leverage.

Trailing Twelve Months Ended: ($ in millions)	September 30 2025	December 31 2024
Pro forma net income	$ 1,762	$ 1,475
Plus (less):		
Pro forma interest expense	224	250
Pro forma interest income	(23)	(62)
Pro forma other income	(1)	-
Pro forma income tax expense	411	297
Pro forma depreciation, depletion and amortization	2,314	2,195
Pro forma exploration	27	25
Pro forma gain on sale of assets	(5)	(3)
Pro forma non-cash loss on derivative instruments	(74)	101
Pro forma acquisition-related expenses	15	15
compensation	62	62
Adjusted Pro Forma EBITDAX (trailing twelve months)	**$ 4,712**	**$ 4,355**

($ in millions)	September 30 2025	December 31 2024
Net debt (as defined previously)	$ 3,824	$ 1,497
Adjusted Pro Forma EBITDAX (Trailing twelve months)	4,712	4,355
Net debt to Adjusted EBITDAX	**0.8x**	**0.3x**