



COTERRA

# 3Q25 Earnings Presentation

November 2025

# Disclaimer

## Cautionary Statement Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of federal securities laws. Forward-looking statements are not statements of historical fact and reflect Coterra's current views about future events. Such forward-looking statements include, but are not limited to, statements about returns to shareholders, growth rates, enhanced shareholder value, reserves estimates, future financial and operating performance and goals and commitment to sustainability and ESG leadership, strategic pursuits and goals, and other statements that are not historical facts contained in this presentation. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "predict," "potential," "possible," "may," "should," "could," "would," "will," "strategy," "outlook" and similar expressions are also intended to identify forward-looking statements. We can provide no assurance that the forward-looking statements contained in this presentation will occur as projected and actual results may differ materially from those projected. Forward-looking statements are based on current expectations, estimates and assumptions that involve a number of risks and uncertainties that could cause actual results to differ materially from those projected. These risks and uncertainties include, without limitation, the volatility in commodity prices for crude oil and natural gas; cost increases; changes in U.S. and international economic policy (including tariffs and retaliatory tariffs and the impacts thereof); the effect of future regulatory or legislative actions; the impact of public health crises, including pandemics (such as the coronavirus pandemic) and epidemics and any related governmental policies or actions on Coterra's business, financial condition and results of operations; actions by, or disputes among or between, the Organization of Petroleum Exporting Countries and other producer countries; market factors; market prices (including geographic basis differentials) of oil and natural gas; impacts of inflation; labor shortages and economic disruption (including as a result of the pandemic or geopolitical disruptions such as the war in Ukraine or the conflict in the Middle East); determination of reserves estimates, adjustments or revisions, including factors impacting such determination such as commodity prices, well performance, operating expenses and completion of Coterra's annual PUD reserves process, as well as the impact on our financial statements resulting therefrom; the presence or recoverability of estimated reserves; the ability to replace reserves; environmental risks; drilling and operating risks; results of future marketing and drilling activities (including seismicity and similar data); exploration and development risks; competition; the ability of management to execute its plans to meet its goals; and other risks inherent in Coterra's businesses. In addition, the declaration and payment of any future dividends, whether regular base quarterly dividends, variable dividends or special dividends, will depend on Coterra's financial results, cash requirements, future prospects and other factors deemed relevant by Coterra's Board. While the list of factors presented here is considered representative, no such list should be considered to be a complete statement of all potential risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. For additional information about other factors that could cause actual results to differ materially from those described in the forward-looking statements, please refer to Coterra's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings with the SEC, which are available on Coterra's website at [www.coterra.com](http://www.coterra.com).

Forward-looking statements are based on the estimates and opinions of management at the time the statements are made. Except to the extent required by applicable law, Coterra does not undertake any obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. Readers are cautioned not to place undue reliance on these forward-looking statements that speak only as of the date hereof.

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 growth, and ~5% annual oil growth; expect reinvestment rate  $\leq 50\%$ <sup>1</sup>



**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



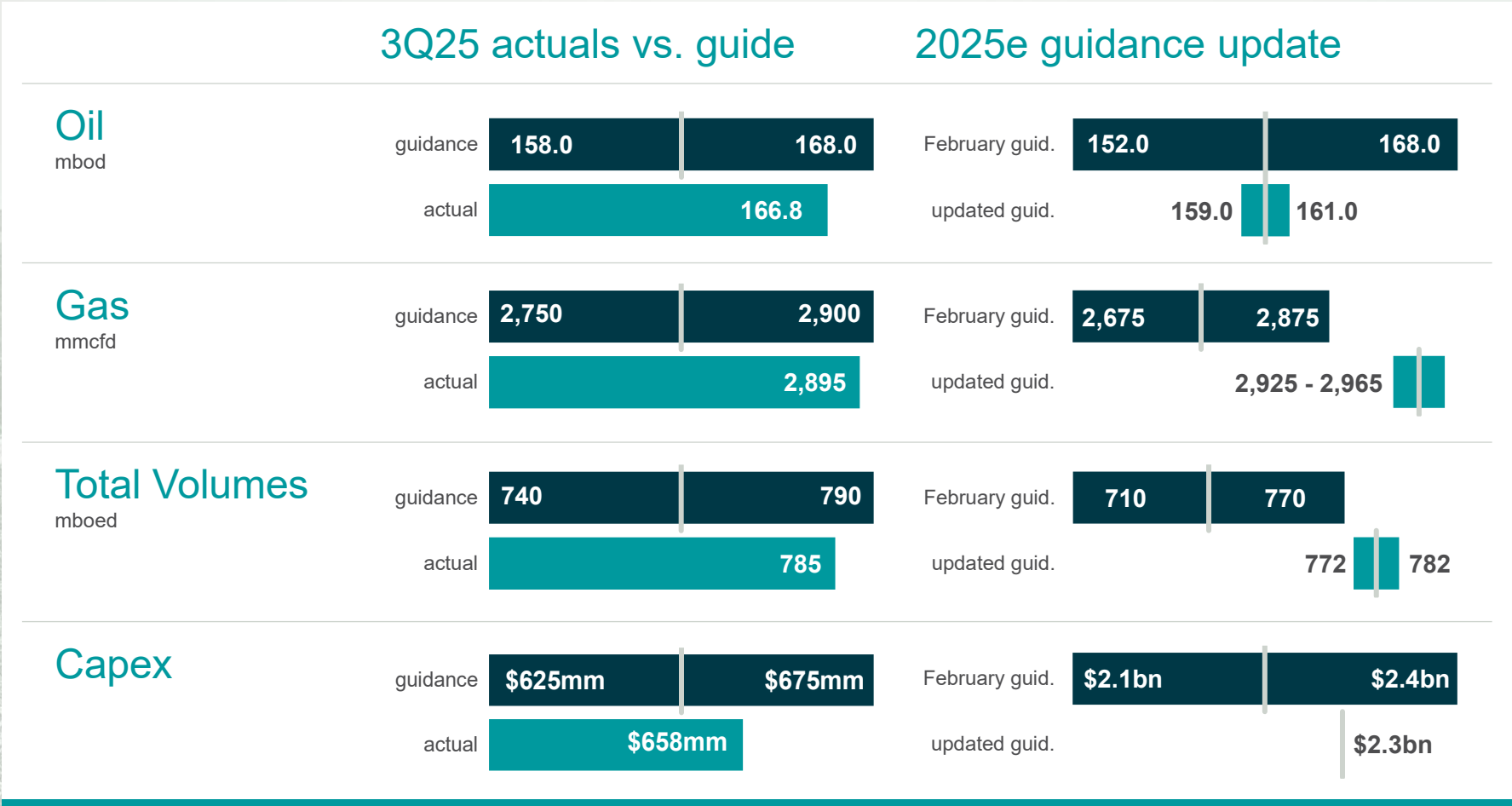
**Durable Free Cash Flow Outlook** | Estimated 2025 Free Cash Flow of ~\$2.0 billion<sup>1</sup>, underpinned by balanced commodity exposure between oil and natural gas



**Balance Sheet Remains Top-Tier** | Pro forma leverage ~0.8x<sup>2</sup>, retired \$600 million of Term Loans YTD; restarted share repurchase program in 4Q25

# Beat 3Q25 Midpoint Production Volumes & Raised for the Year

Higher production & lower capex driving improved capital efficiency



# 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

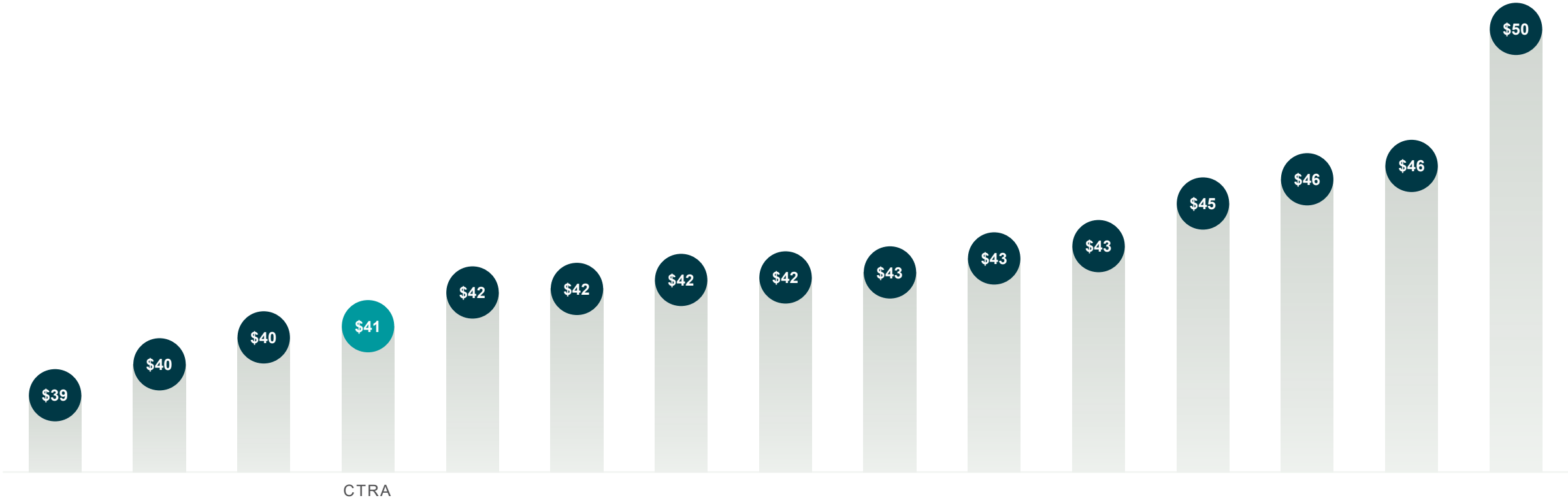


Culture & Strategy

# Asset Quality Demonstrated by Low Break-Evens

## Estimated 15:1 PV-10 Break-Even Oil Price Across L48 Assets<sup>1</sup>

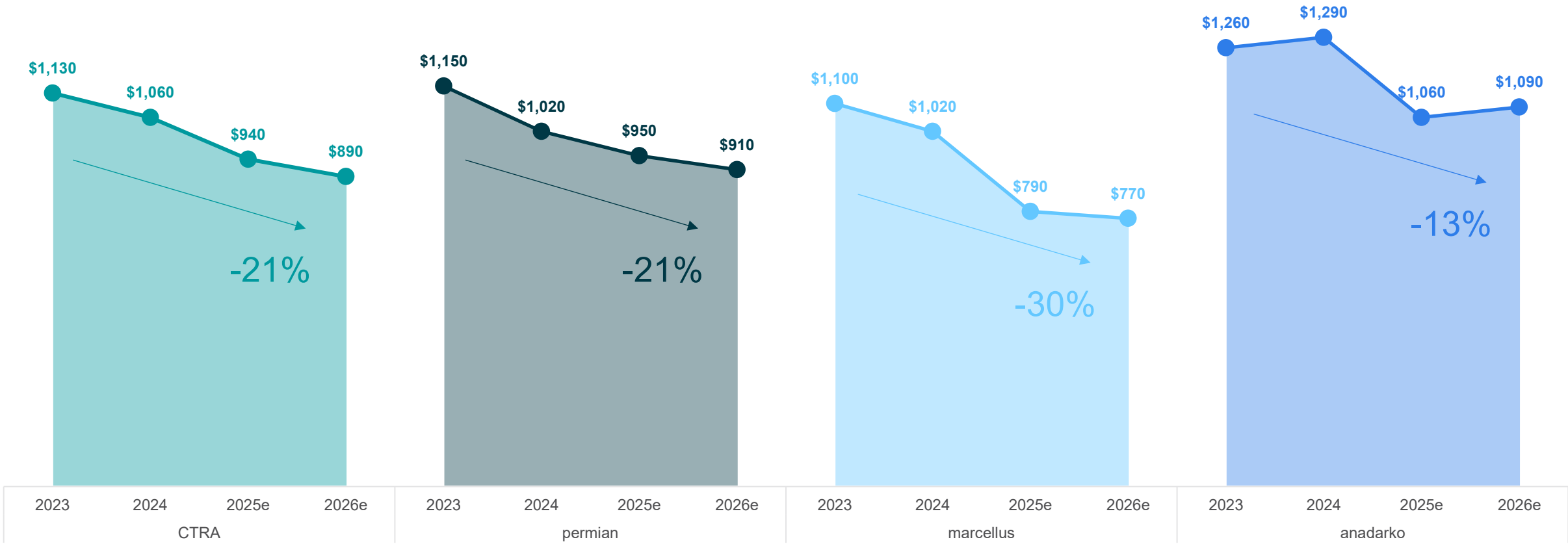
CTRA vs Peers; 15:1 based on recent strip



# Sustained Improvement in Fully Burdened Well Costs, Enhancing Economics

Driven by longer laterals and efficient operations

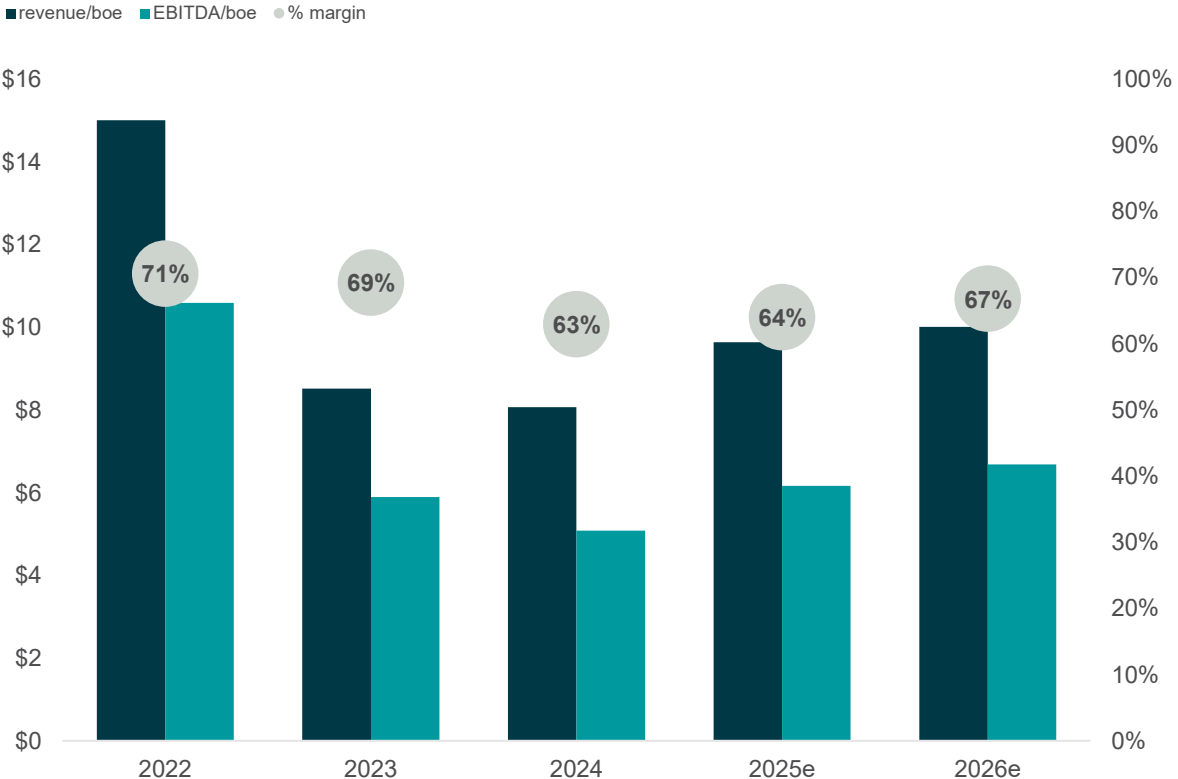
## Annual Average Well Cost per Foot<sup>1</sup>



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

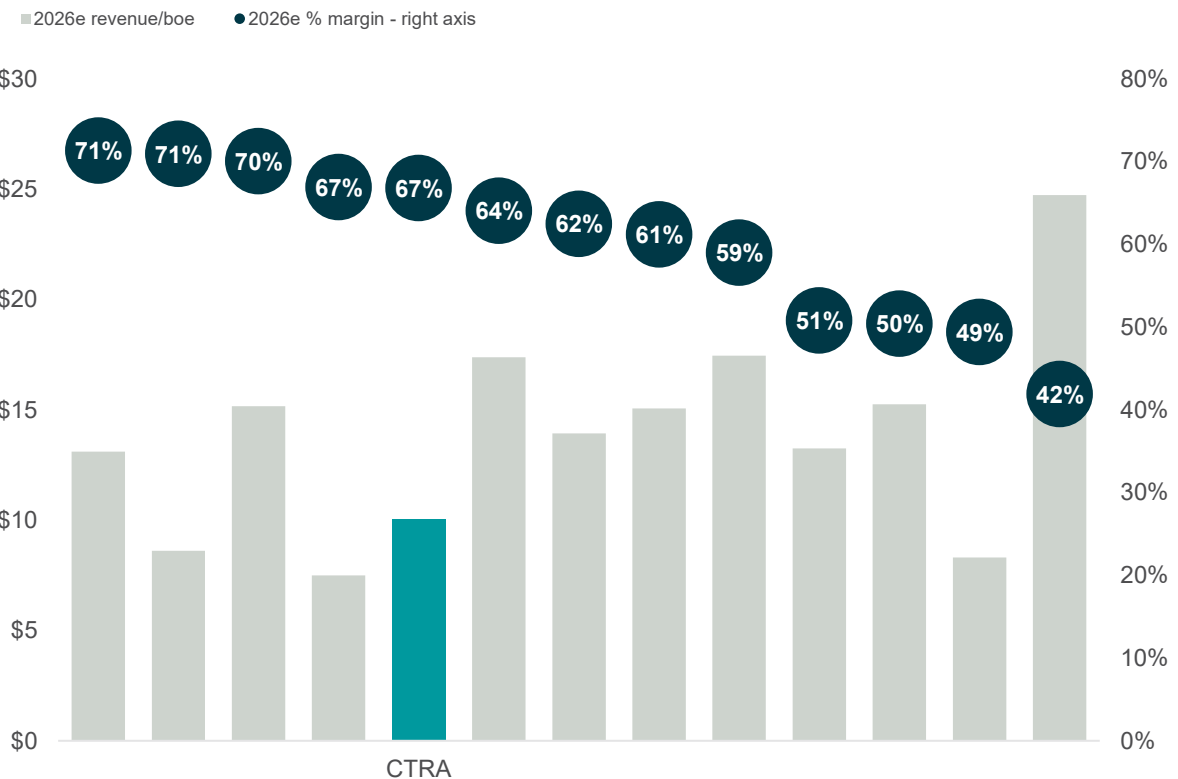
# CTRA's High Quality Assets Produce Top-Tier Margins

## CTRA Margin Consistently ~65-70%



## 2026e Revenue per BOE vs Margin





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



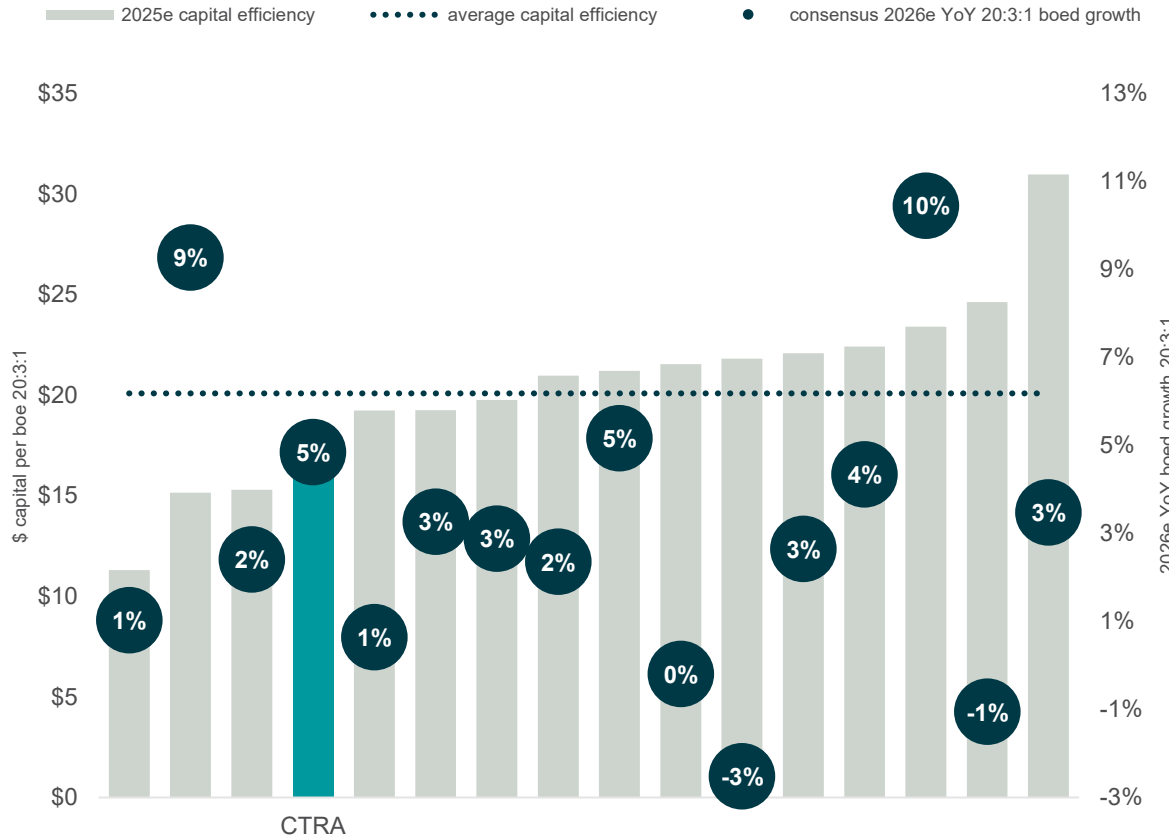
# 2025: Top-Tier Capital Efficiency Paired with Industry-Leading Growth

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<sup>1</sup>
- 
**~\$2.0 billion Free Cash Flow<sup>2</sup>**  
 Diversified commodity mix and disciplined reinvestment
- 
**Production Guidance**  
 772-782 mboed | 159-161 mbod | 2,925-2,965 mmcf/d
- 
**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

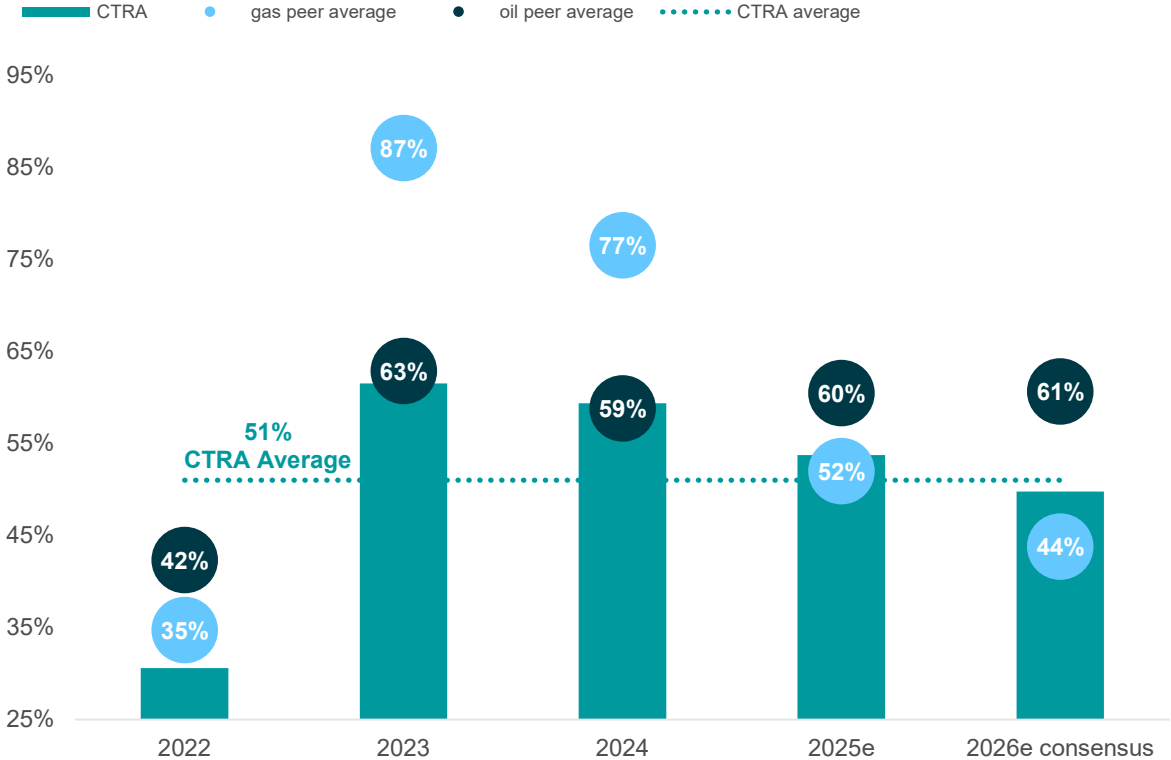


Note: See appendix for non-GAAP reconciliations and definitions. Source: Factset consensus. CTR A capital efficiency based on 2025e guidance calculated as capex per 20:3:1 boe; production growth estimates based on consensus. Peers include APA, AR, CHRD, CIVI, COP, DVN, EOG, EQT, EXE, FANG, MTD R, OVV,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

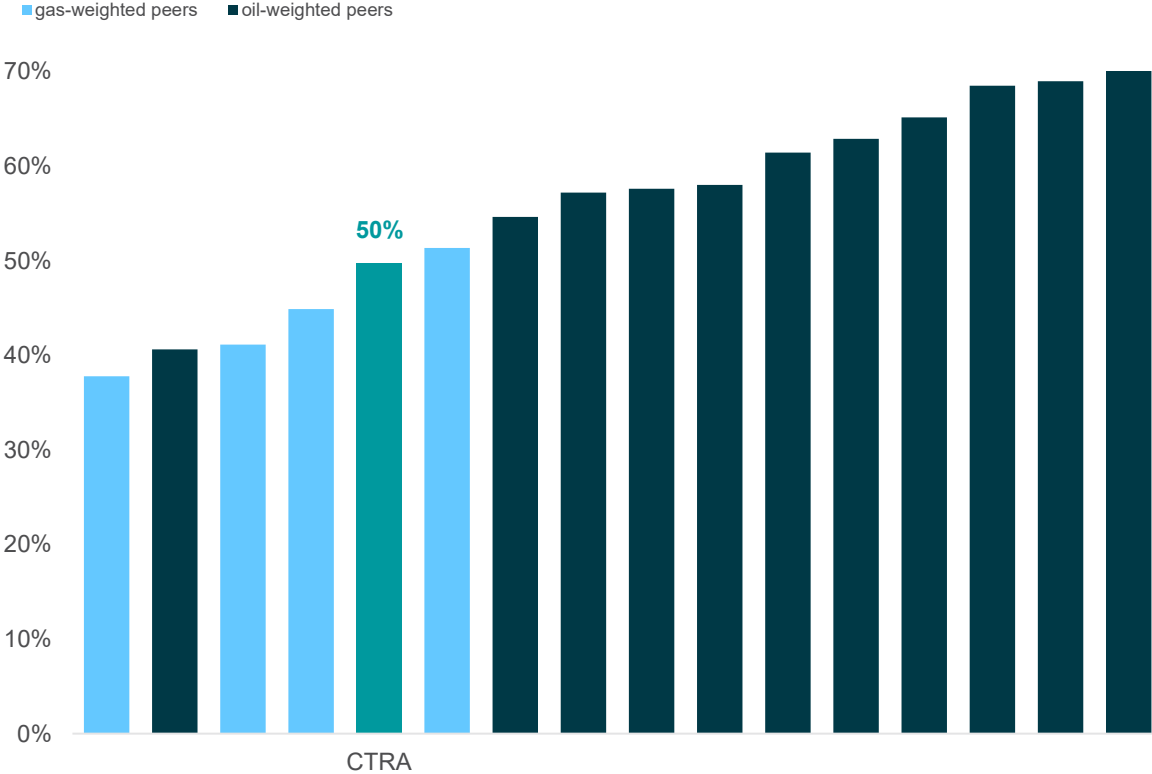
# Disciplined Approach to Capital Investment

Differentiated reinvestment rate through the commodity cycles

## Conservative historical reinvestment rate



## Low reinvestment among peers in 2026



# Long Runway of High-Quality Inventory

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

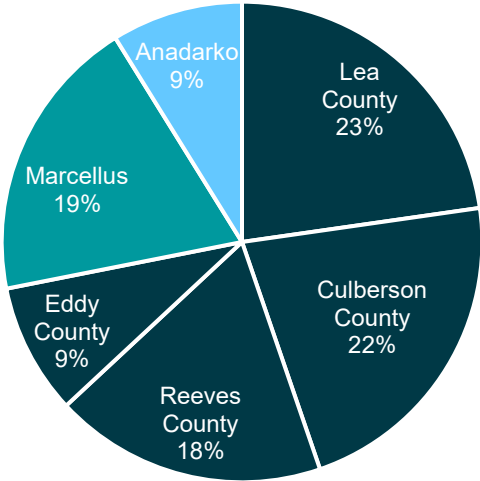
## ~\$31 billion of Economic Capex Opportunities

estimated capex by PVI<sub>10</sub> bucket:



~\$14bn, or ~45%, of capex is expected to generate 2.0x PVI<sub>10</sub> or better

estimated total footage by asset area:



## Implied Inventory Duration<sup>1</sup>

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

# Durable Free Cash Flow Through the Cycles

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

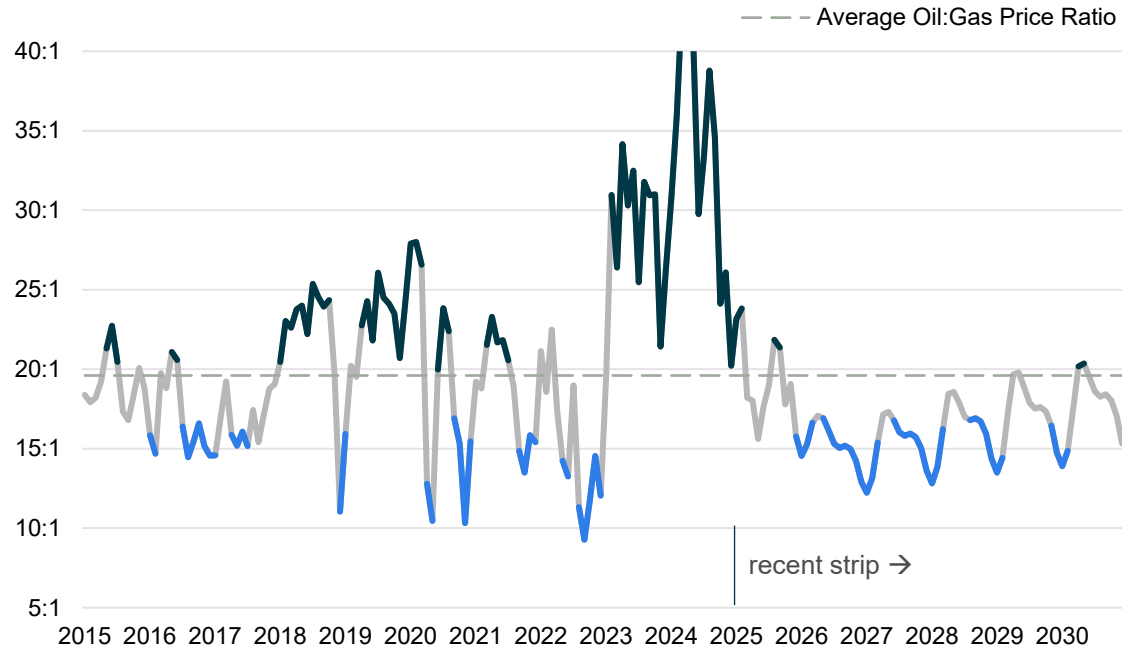
## Uniquely positioned to weather volatility

Diversified commodity portfolio with demonstrated capital flexibility

## Oil:gas price ratios

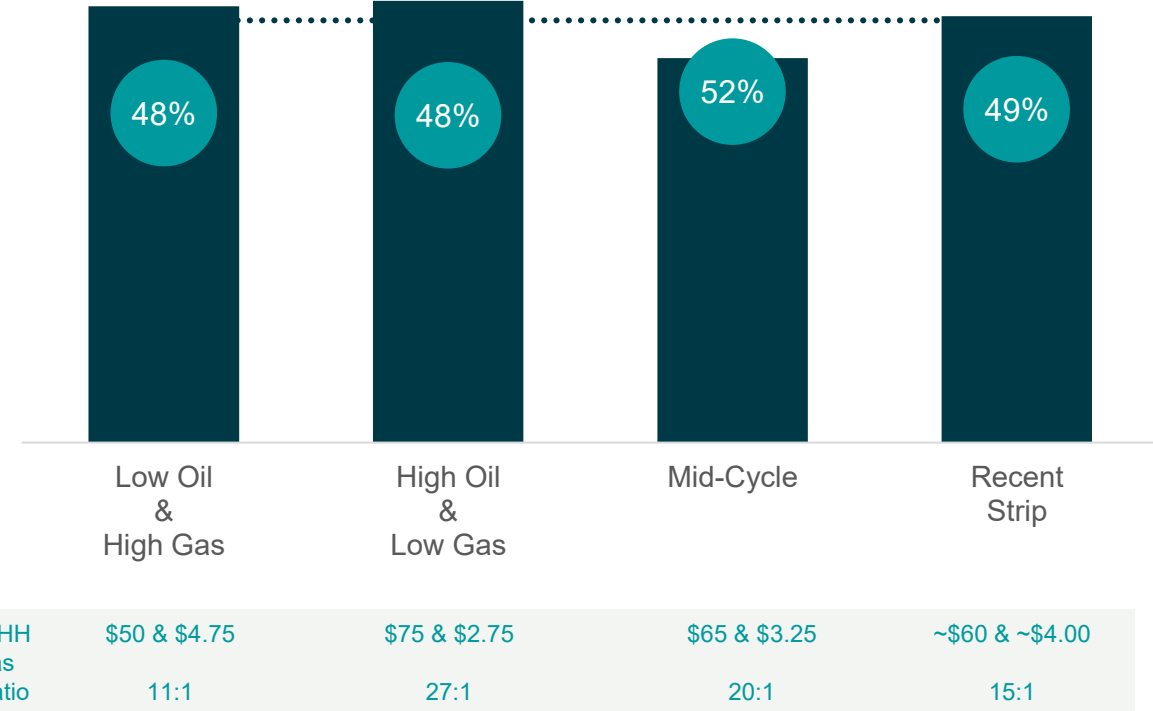
>20:1: **Oil advantaged**, occurred 53% 2015-3Q25, 3% 5-yr Strip

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



## Resilient Future Free Cash Flow & disciplined reinvestment across price environments

■ FCF ● capex as % of DCF



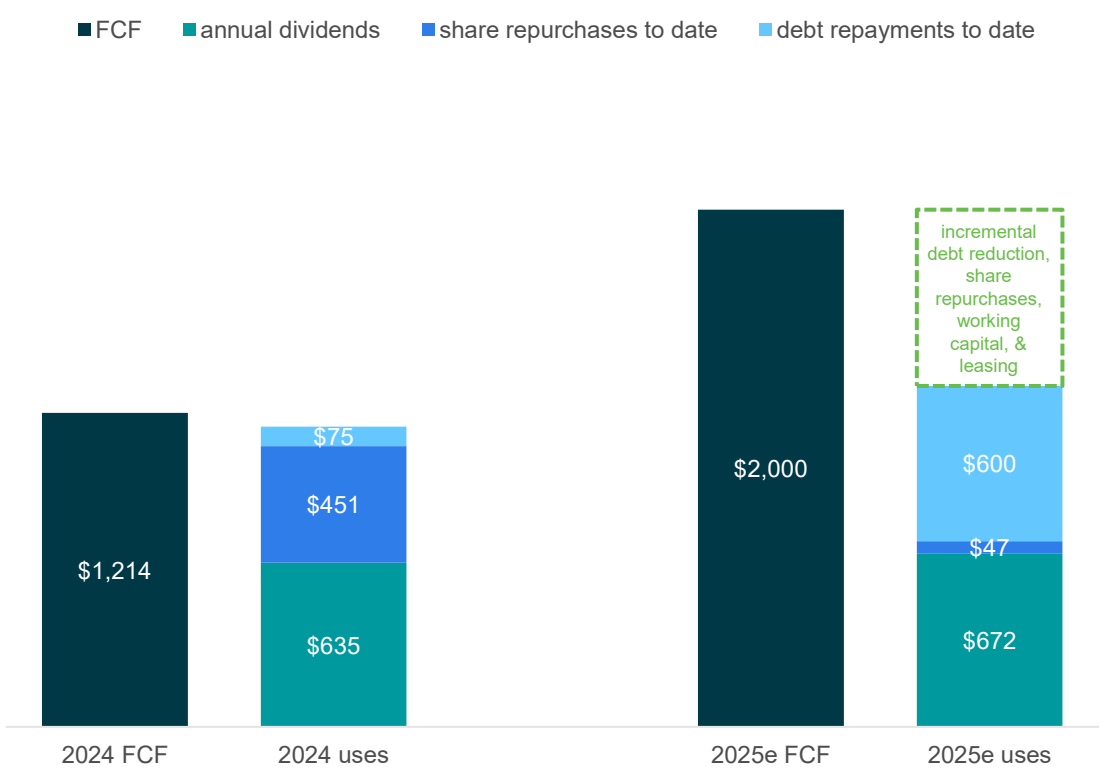
WTI & HH Oil:gas price ratio	Low Oil & High Gas	High Oil & Low Gas	Mid-Cycle	Recent Strip
	\$50 & \$4.75	\$75 & \$2.75	\$65 & \$3.25	~\$60 & ~\$4.00
	11:1	27:1	20:1	15:1

# Returning Value to Shareholders

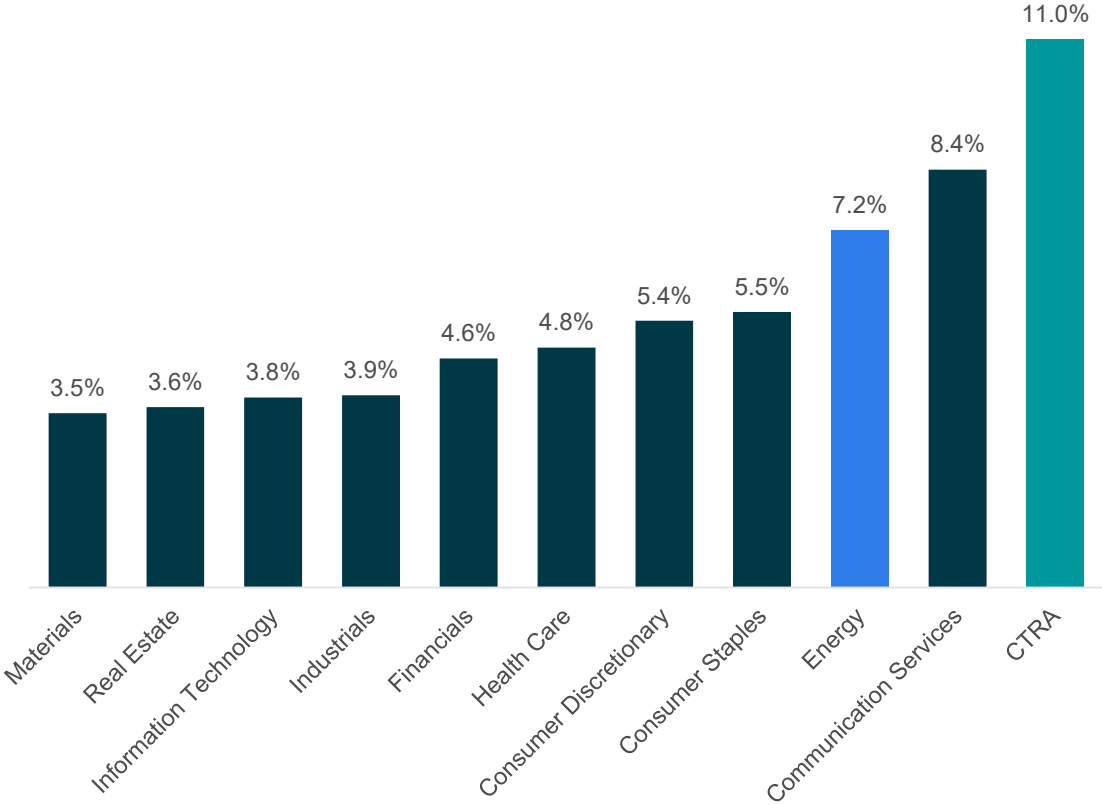
## Free Cash Flow in \$ millions

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

■ FCF ■ annual dividends ■ share repurchases to date ■ debt repayments to date

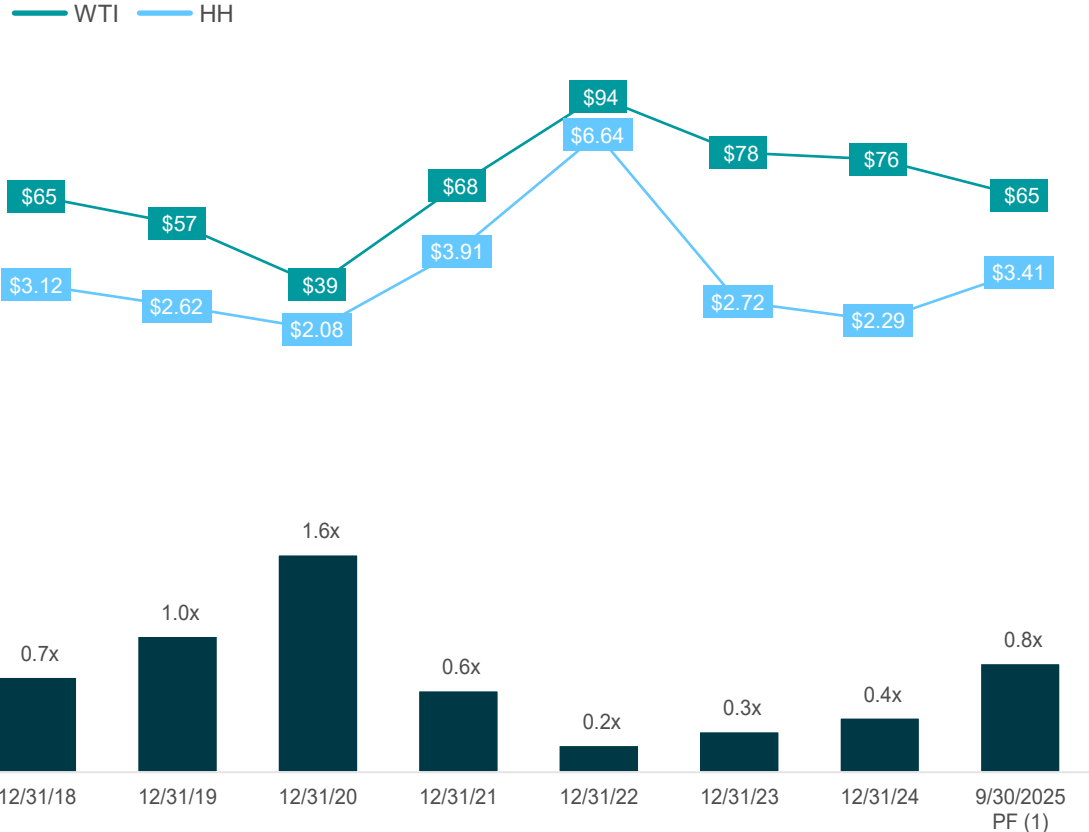


## Top SP500 2025e Free Cash Flow Yield<sup>1</sup>



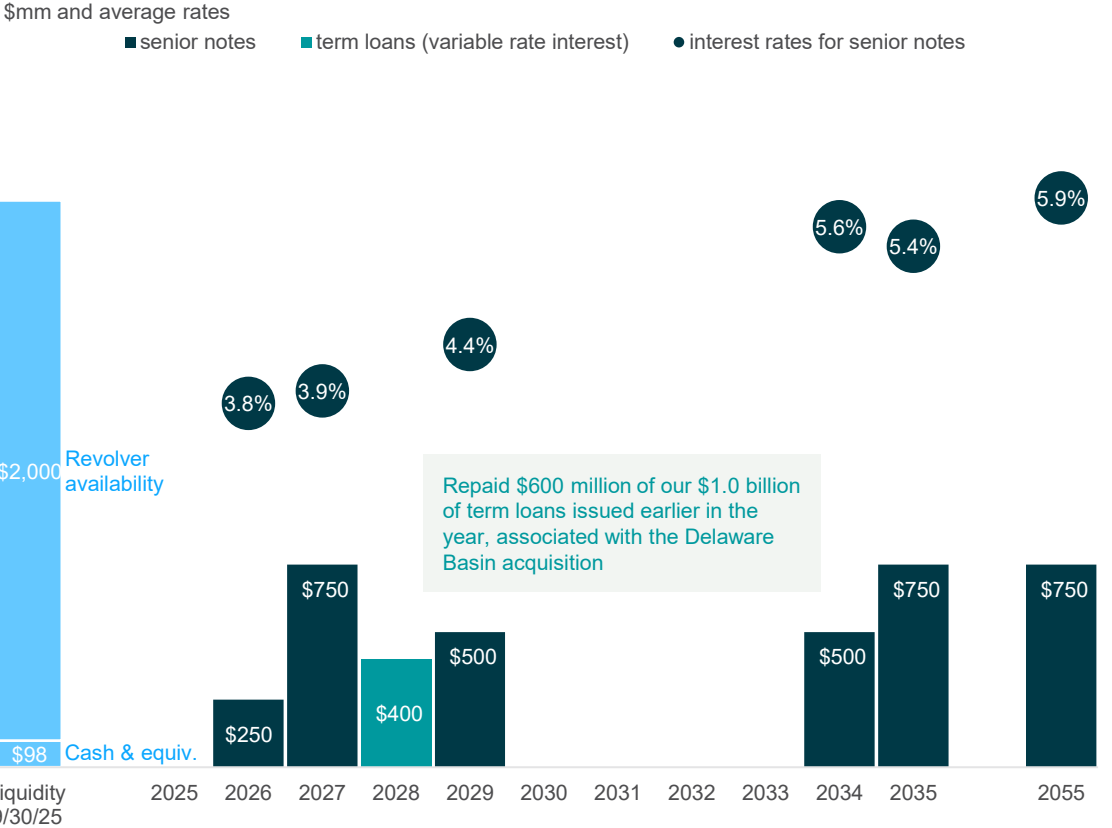
# Prioritizing Financial Flexibility

## 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

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

Defensively positioned and resilient through commodity cycles

## Coterra's Business Strategy

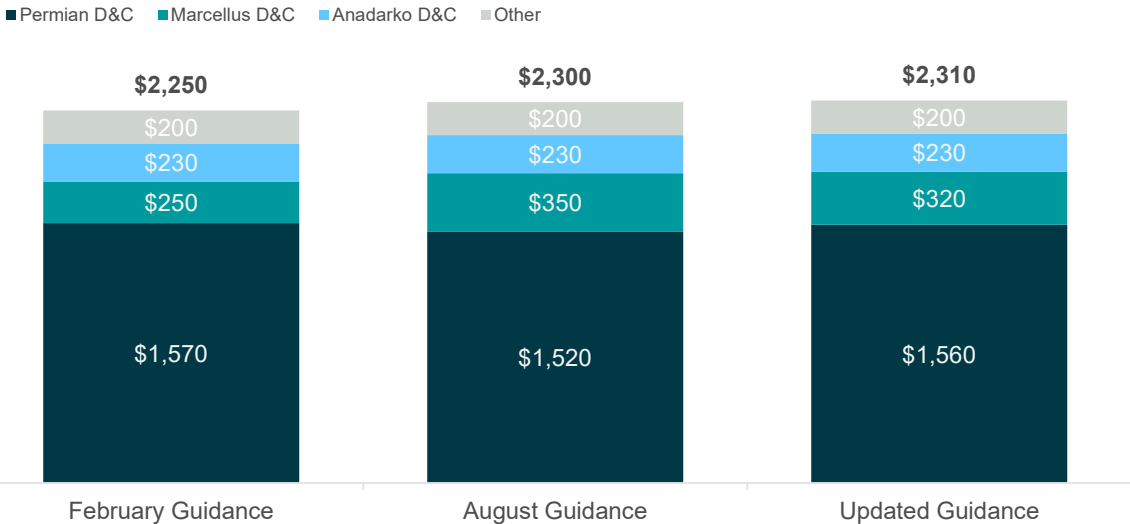
- **Culture of Excellence**  
*Open, non-siloed organization drives internal debate in which the best ideas prevail*
- **Data Driven Approach to Problem Solving**  
*Rigorous scientific and financial analysis*
- **Technical Teams Driving Value Creation**  
*Leveraging AI and custom applications to generate 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<sup>1</sup> and opportunistic share repurchases*
- **Peer-Leading Balance Sheet**  
*Low leverage, high liquidity and a prudent maturity profile*

# 2025e Development Program Key Highlights


## 2025e capex in \$ millions




### Disciplined Capital Program

Currently expect ~\$2.3 billion of 2025e capex  
~55% reinvestment rate<sup>1</sup>


## 2025 Program Key Highlights

- 
**Permian in-line with February guidance**  
 Currently running 9 rigs & 3 crews

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- 
**Marcellus +\$70mm vs. February guidance**  
 Picked up activity through the year

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

# Permian Asset Overview – 2025 Operational Outlook

**\$1,560 million**

Midpoint D&C CapEx

**10,200'**

Avg. Lateral Length<sup>1</sup>

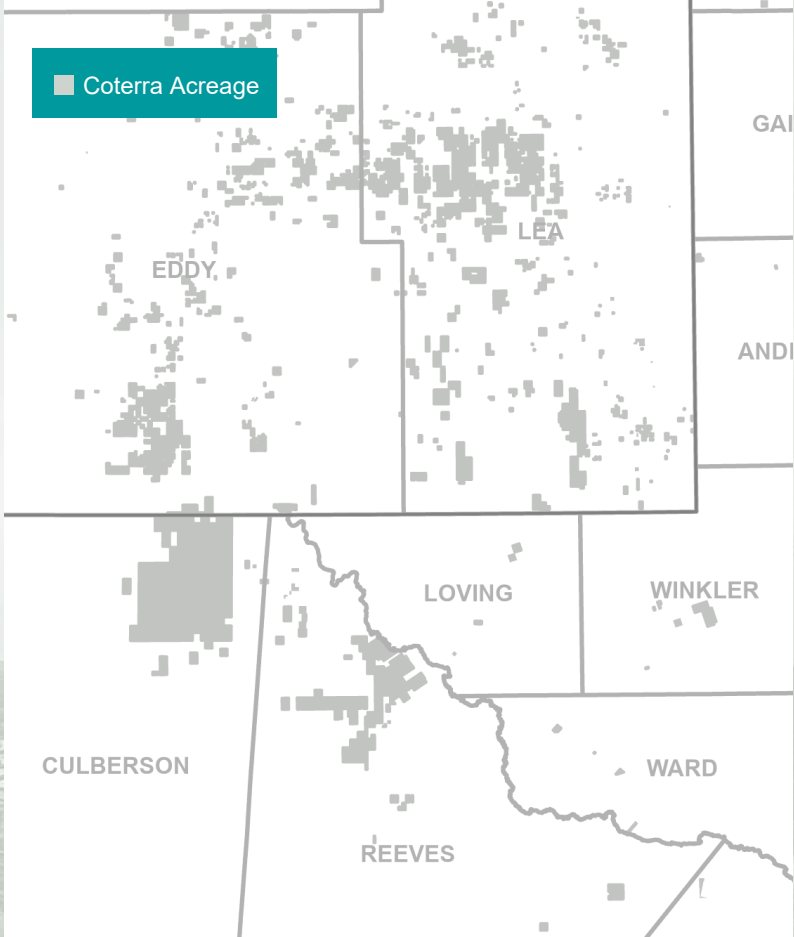
**\$950**

Avg. Well Cost per Foot<sup>1</sup>

-10% cost reduction YoY

**~165**

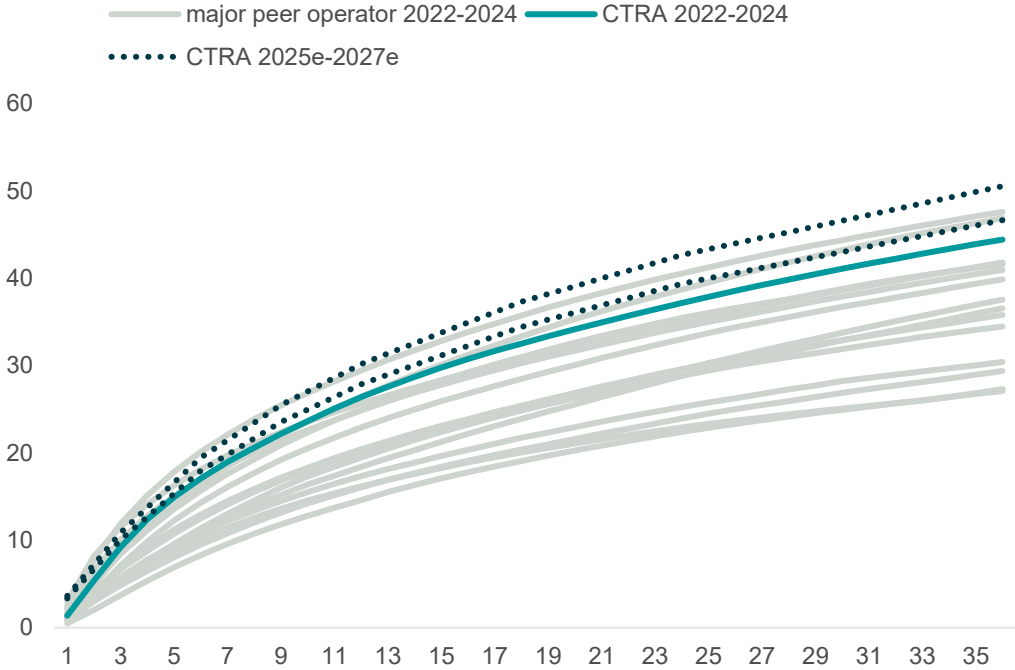
Net Wells Online<sup>2</sup>



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

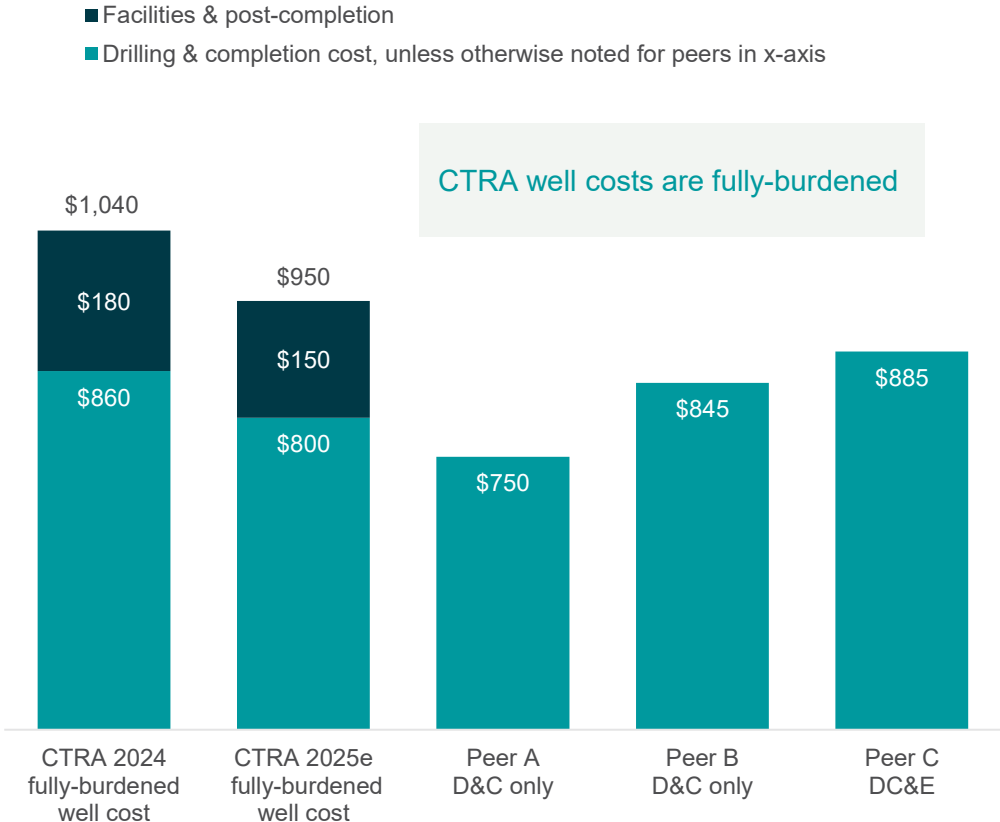
## Delaware Productivity<sup>1</sup>

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<sup>2</sup>



# Marcellus Asset Overview – 2025 Operational Outlook

**\$320 million**

Midpoint D&C CapEx

**17,000'**

Avg. Lateral Length<sup>1</sup>

**\$790**

Avg. Well Cost per Foot<sup>1</sup>

-24% cost reduction YoY

**9-13**

Net Wells Online

~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'**

Avg. Lateral Length<sup>1</sup>

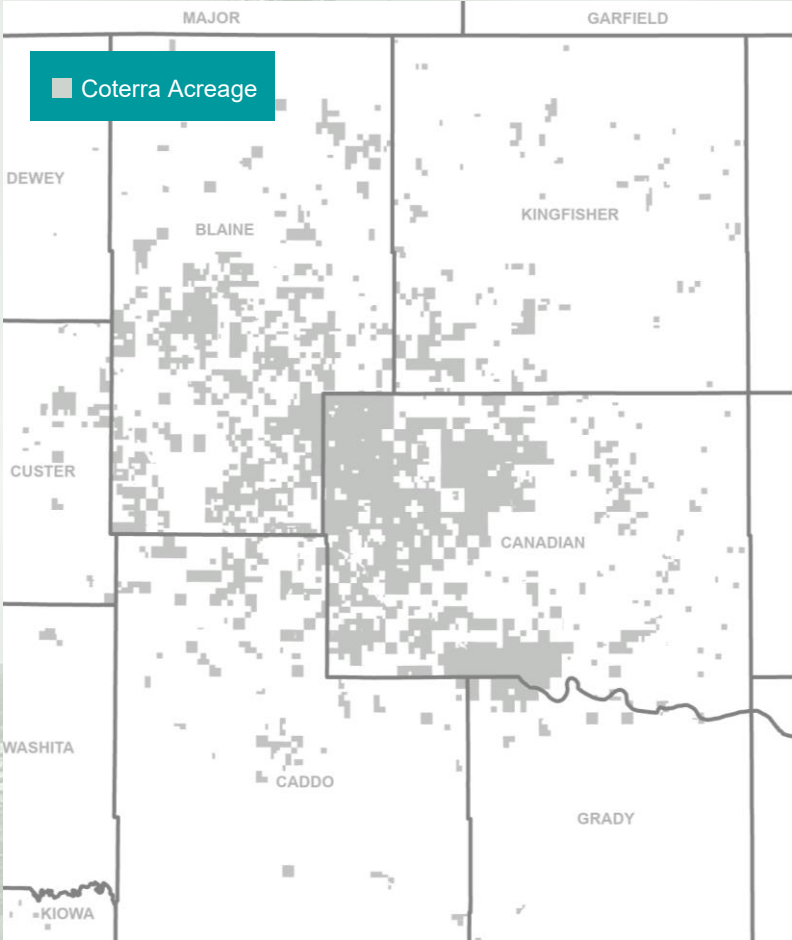
**\$1,060**

Avg. Well Cost per Foot<sup>1</sup>

-15% cost reduction YoY

**20**

Net Wells Online<sup>2</sup>





# Appendix



# High-Quality, Long-Life, Diversified Asset Portfolio

## Multi-Basin Portfolio

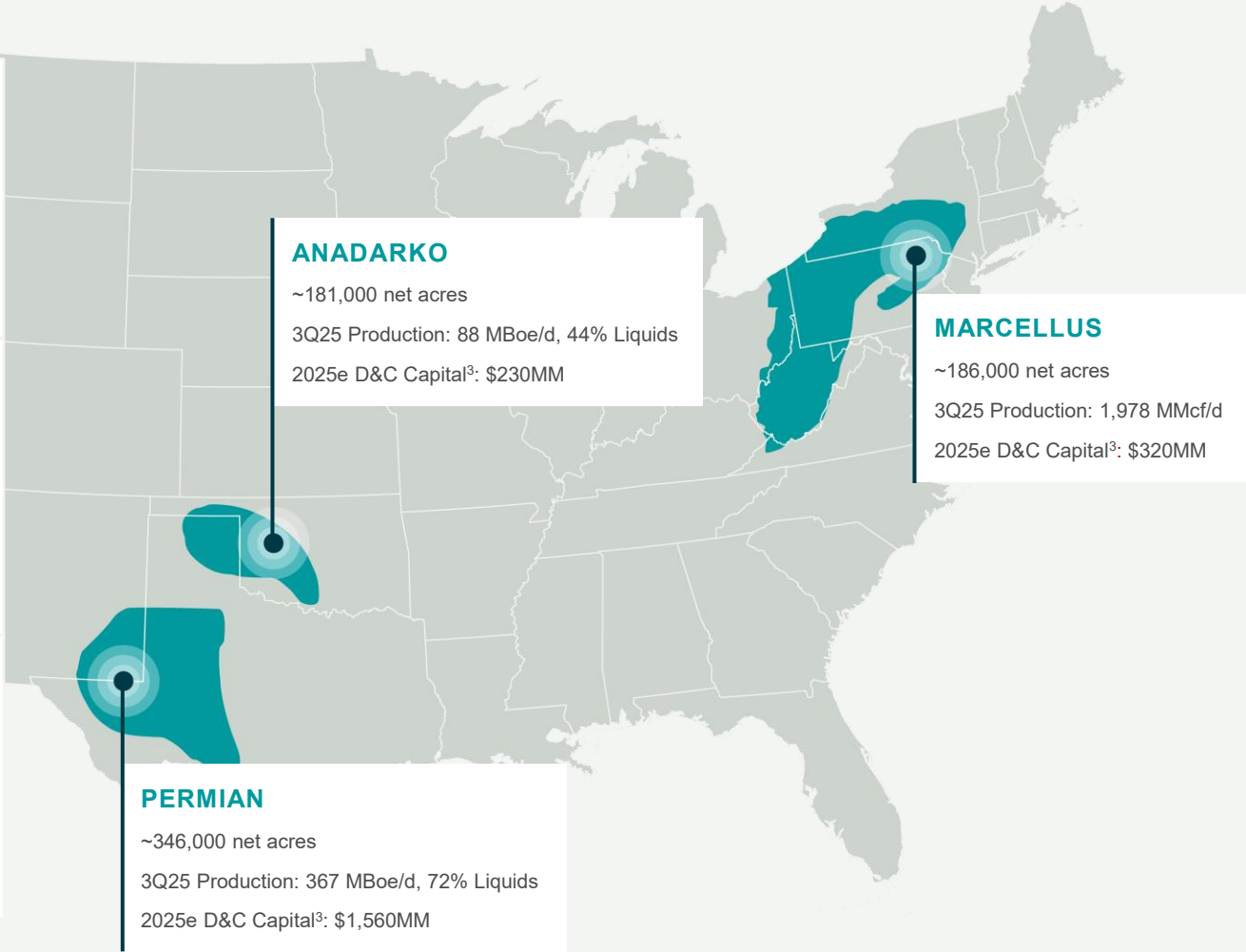
provides commodity diversification and capital allocation optionality

## Top-Tier Acreage Position

with deep inventory, estimated at ~15 years<sup>1</sup>

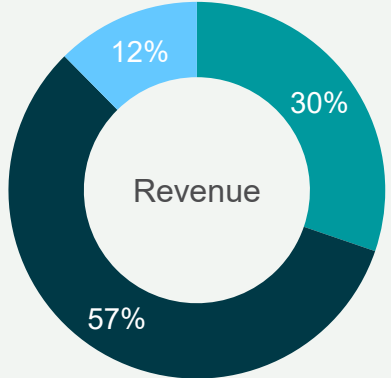
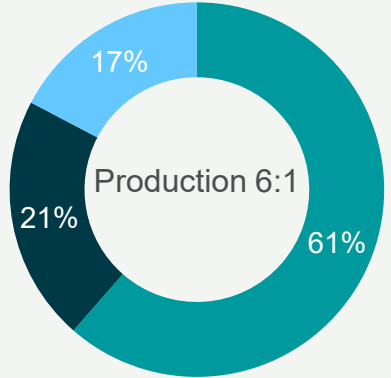
## Low-Cost Operator

with corporate break-even<sup>2</sup> around \$50/bbl WTI & \$2.50/mmbtu HH



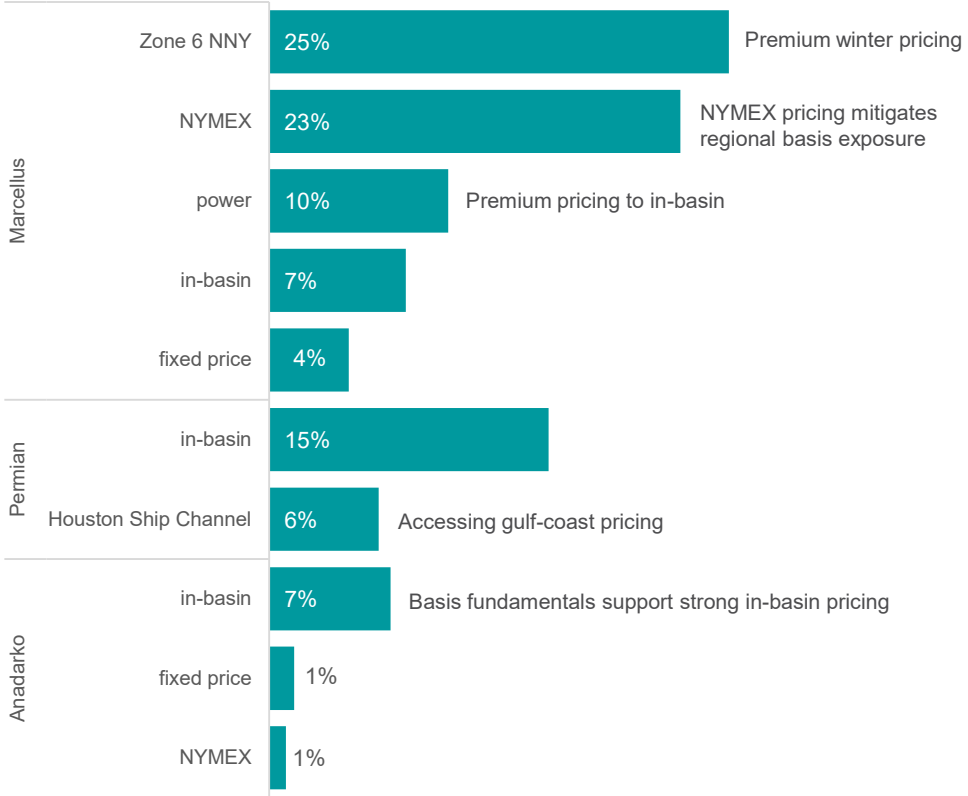
## 3Q25 Commodity Splits

■ natural gas ■ oil ■ NGL

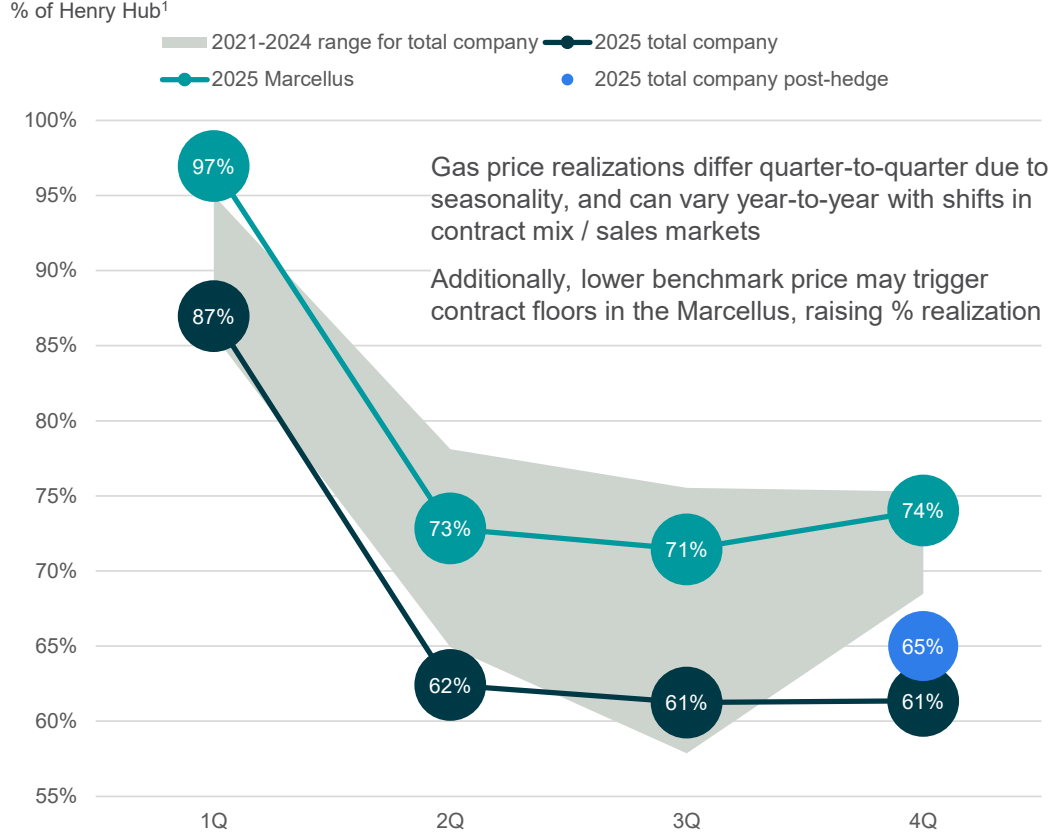


# Diversified Gas Marketing Portfolio

## 2025 Estimated Natural Gas Sales Markets

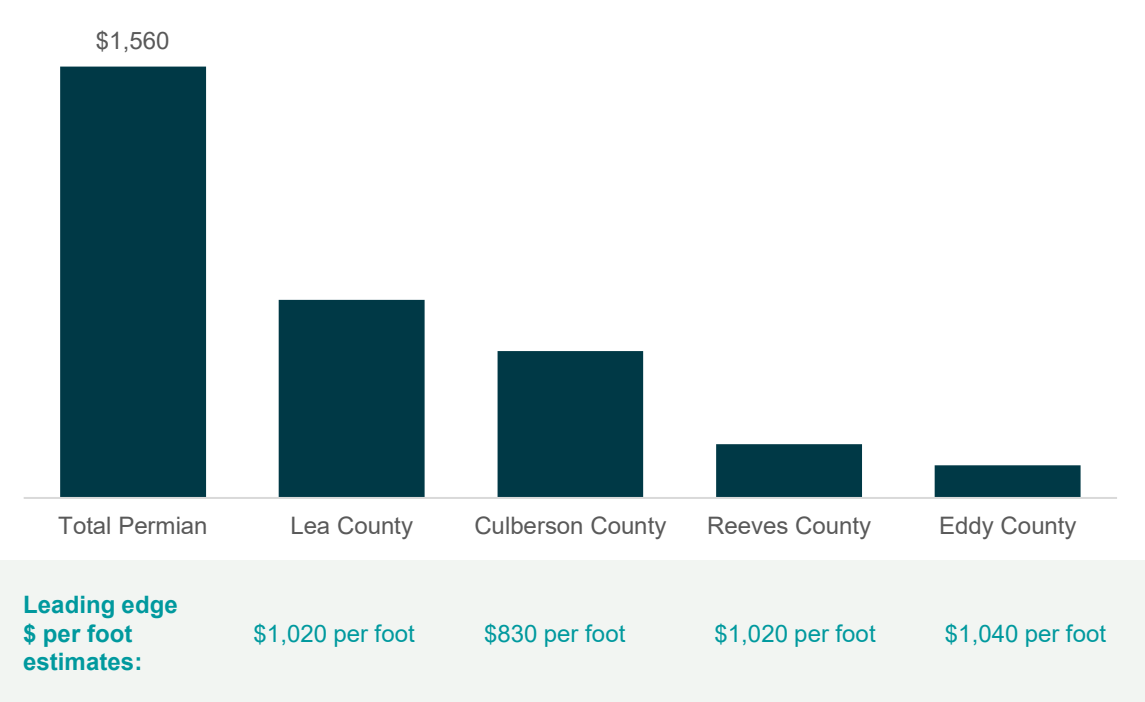


## 2021-2025e Natural Gas Price Realization Range<sup>1</sup>



# 2025 Permian Development Program

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



2025e net wells online



# 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)													
	Gas (mmcf)	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:													
	Incurring 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									
	Incurring Capital Expenditures	\$2.1	\$2.3	\$2.4		\$2.3								
Free Cash Flow (DCF - cash capex)		\$2.7		\$2.0										

# 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 <sup>1</sup>	\$0.10	\$0.05	\$0.08	\$0.10	\$0.15	\$0.07	\$0.09
	% effective tax rate <sup>2</sup>			22%		21%	22%	24%

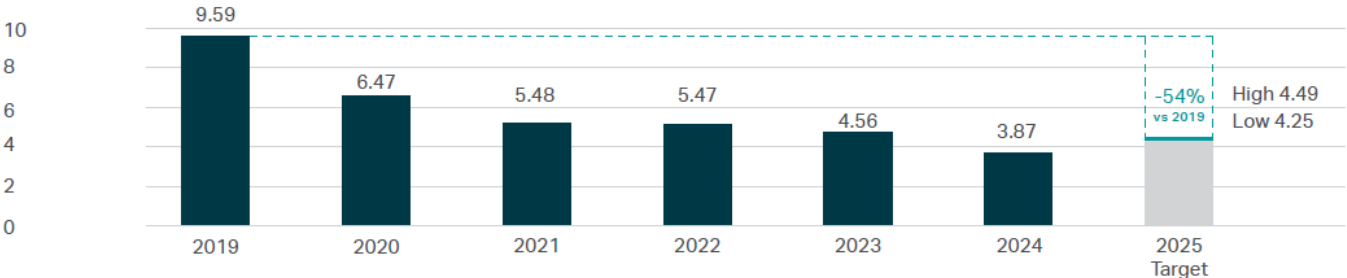
1 Excluding exploratory dry hole costs, includes exploration administrative expense and geophysical expenses

2 Expect no cash taxes in 2H25

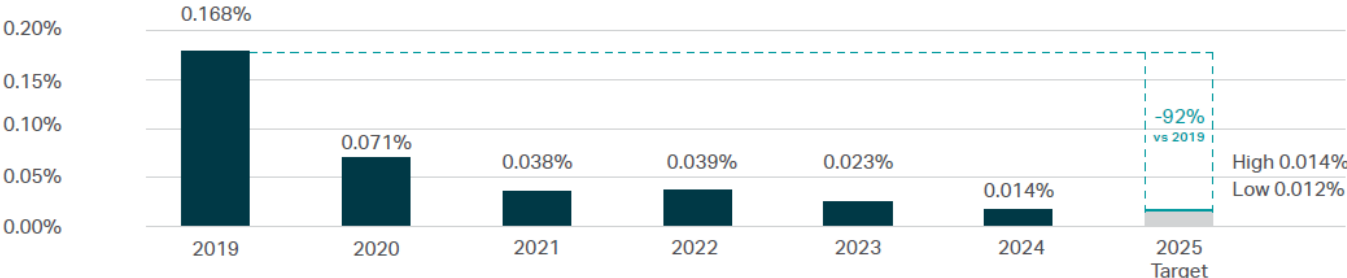
# Published Sustainability Report on August 4, 2025



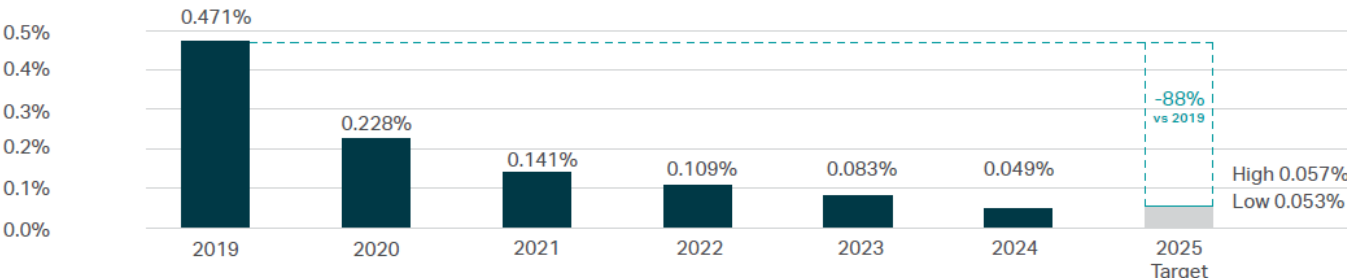
Greenhouse Gas Emissions Intensity (MT CO<sub>2</sub>e / Gross Mboe Produced)



Methane Emissions Intensity (MT CH<sub>4</sub> Emitted / Gross CH<sub>4</sub> Produced)



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



# 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
<b>Cash flow from operating activities</b>	\$ 971
Changes in assets and liabilities	177
<b>Discretionary cash flow</b>	<b>1,148</b>
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(615)
<b>Free cash flow</b>	<b>\$ 533</b>

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	-
<b>Capital expenditures</b>	<b>\$658</b>

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

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
<b>Capital expenditures</b>	<b>\$1,762</b>

# 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 measure 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: (\$ in millions)	September 30		December 31					
	2025	2024	2023	2022	2021	2020	2019	2018
		Coterra			Combined Cabot + Cimarex			
<b>Net income</b>	\$ 1,646	\$ 1,121	\$ 1,625	\$ 4,065	\$ 1,158	\$ 201	\$ 681	\$ 557
<b>Plus (less):</b>								
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	-	-	-
<b>EBITDAX</b>	<b>\$ 4,422</b>	<b>\$ 3,414</b>	<b>\$ 3,928</b>	<b>\$ 6,730</b>	<b>\$ 2,242</b>	<b>\$ 719</b>	<b>\$ 1,412</b>	<b>\$ 1,264</b>
Legacy Cimarex EBITDAX					1,005	935	1,460	1,558
<b>Combined EBITDAX</b>	<b>\$ 4,422</b>	<b>\$ 3,414</b>	<b>\$ 3,928</b>	<b>\$ 6,730</b>	<b>\$ 3,247</b>	<b>\$ 1,654</b>	<b>\$ 2,872</b>	<b>\$ 2,822</b>

(\$ in millions)	September 30		December 31					
	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
<b>Net debt to TTM EBITDAX</b>	<b>0.9x</b>	<b>0.4x</b>	<b>0.3x</b>	<b>0.2x</b>	<b>0.6x</b>	<b>1.6x</b>	<b>1.0x</b>	<b>0.7x</b>

# 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	December 31
	2025	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
<b>Adjusted Pro Forma EBITDAX (trailing twelve months)</b>	<b>\$ 4,712</b>	<b>\$ 4,355</b>

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