



COTERRA

2Q25 Earnings Presentation

August 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.

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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COTERRA.COM

Differentiated by Asset Quality, Duration, and 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**
3.6% dividend yield¹ and opportunistic share repurchases
- **Peer-Leading Balance Sheet**
Low leverage, high liquidity and a prudent maturity profile

Durable Free Cash Flow Through the Cycles

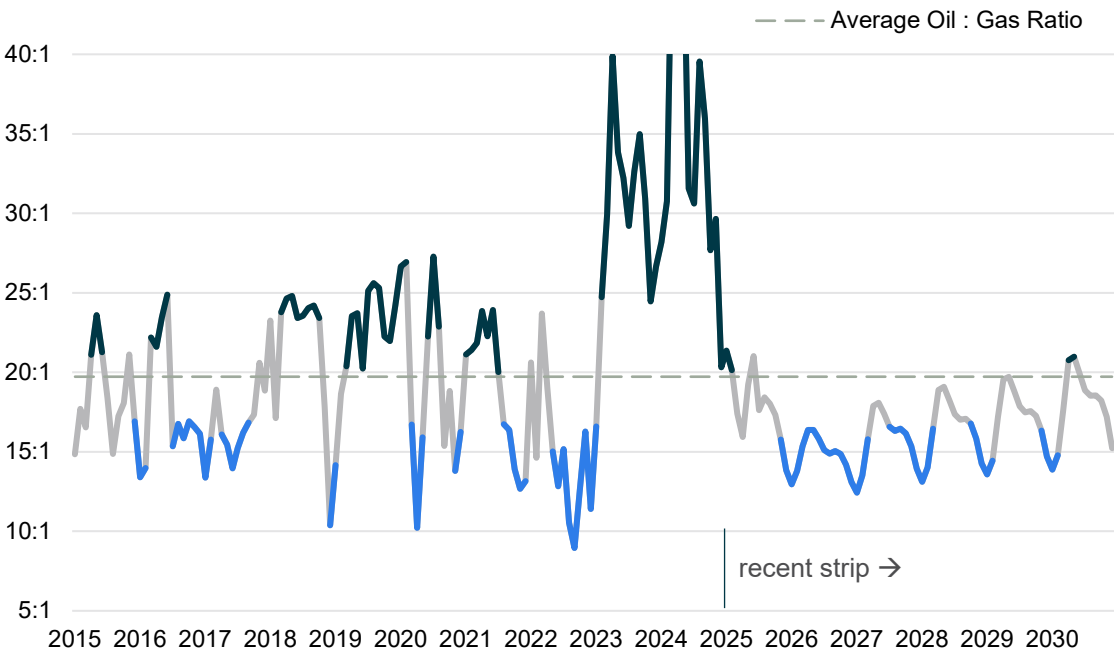
Oil-to-gas price ratios can, and have historically decoupled, especially during periods of extreme volatility

Uniquely positioned to weather volatility

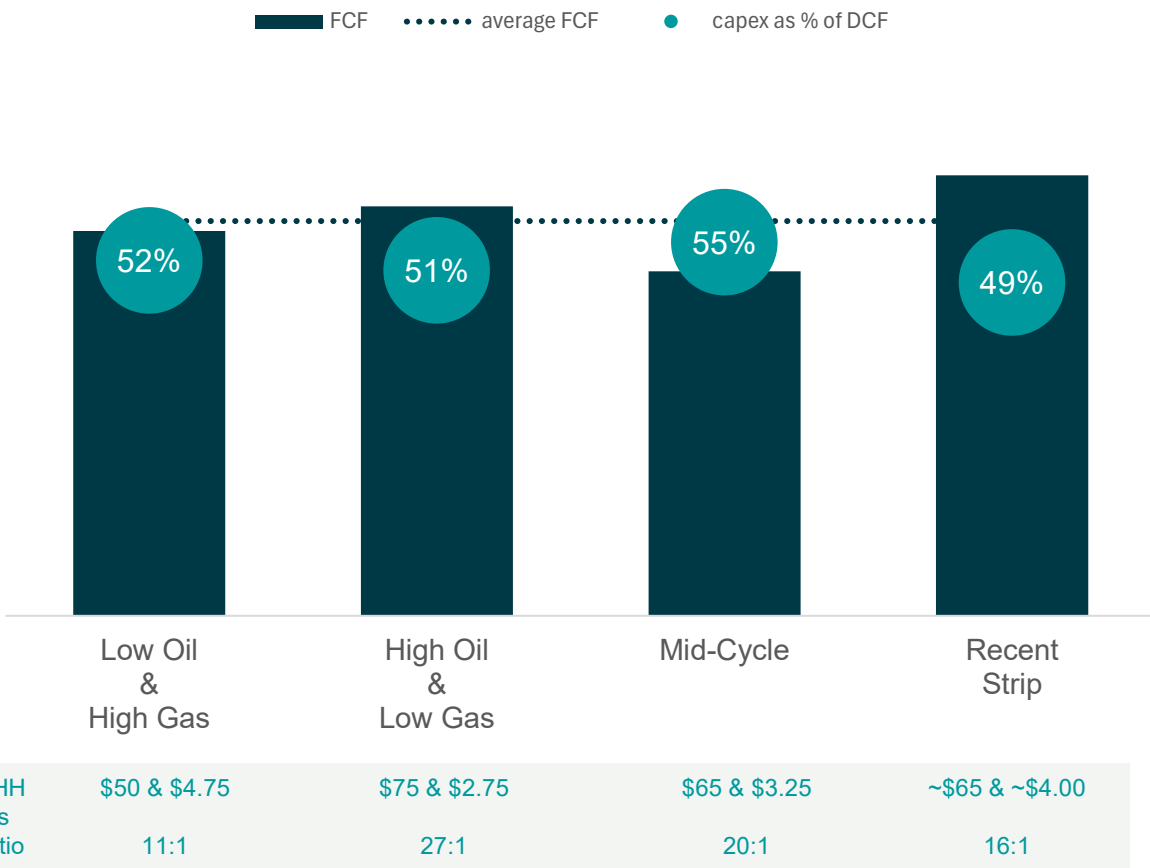
Diversified commodity portfolio with demonstrated capital flexibility

Oil:gas price ratios

>20:1: **Oil advantaged**, occurred 54% 2015-24, 3% 5-yr Strip
<17:1: **Gas advantaged**, occurred 35% 2015-24, 52% 5-yr Strip



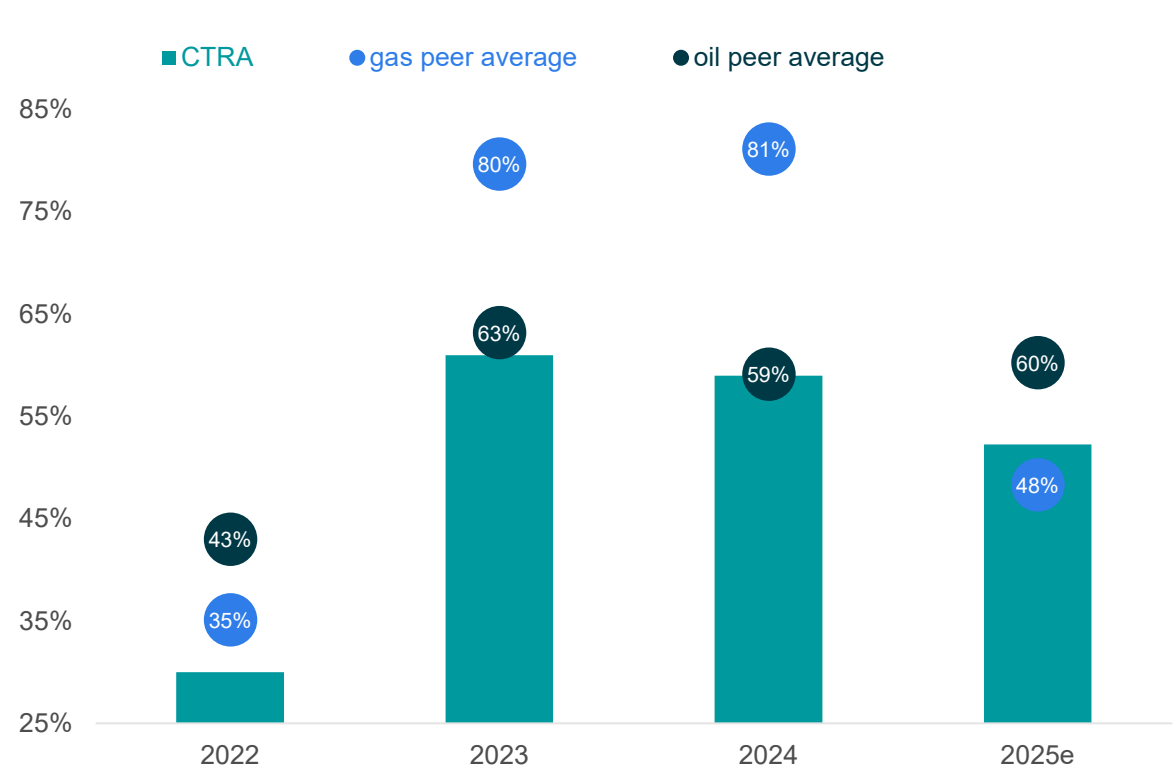
Resilient Free Cash Flow & disciplined reinvestment across price environments



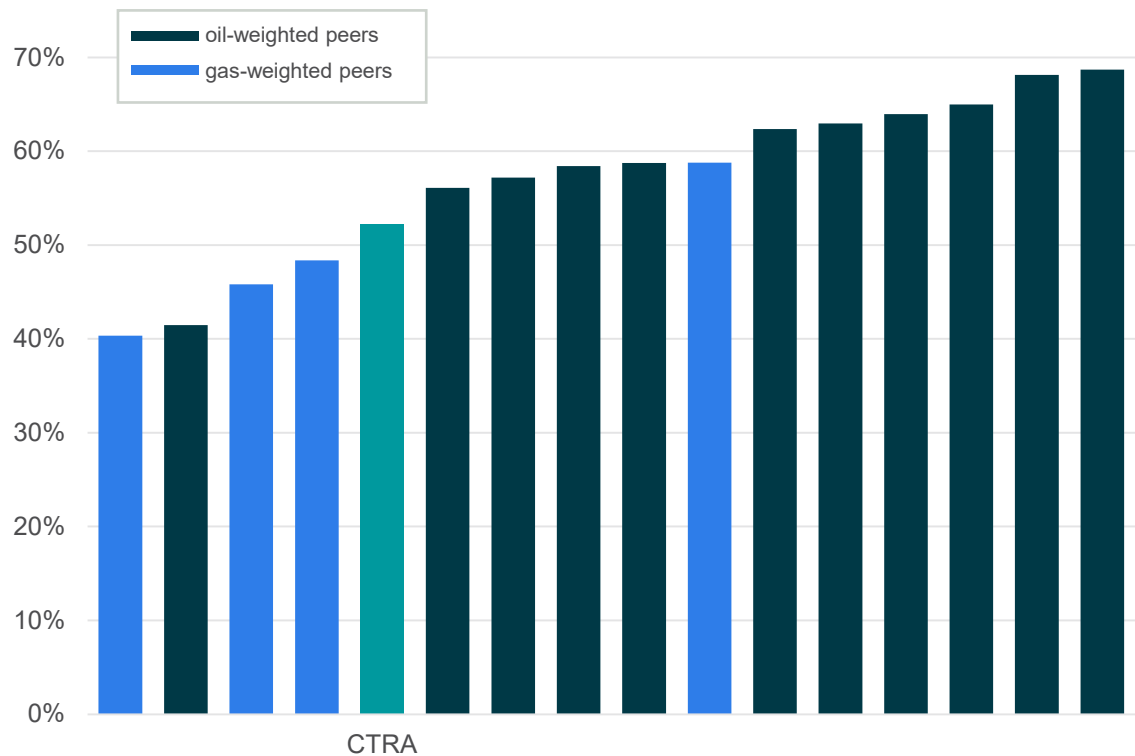
Disciplined Approach to Capital Investment

Differentiated reinvestment rate through the commodity cycles

Conservative historical reinvestment rate



Low reinvestment among peers in 2025



Key Takeaways



2Q25 Production Beat, FY25 Raise | Beat the mid-point of oil production guidance, and the high-end of gas and BOE production guidance; Raising FY25 BOE guidance 4% at the midpoint vs. Feb guide



Consistent 2H25 Activity | Expect 9 Permian rigs in 2H25; Added \$100mm of activity to Marcellus YTD with 2 rigs in 2H25, driving FY25 capex to ~\$2.3bn; Maintaining 3-year outlook¹



New Harkey Results | 6 new Harkey wells in Culberson row developments showing strong results; All wells used new well design



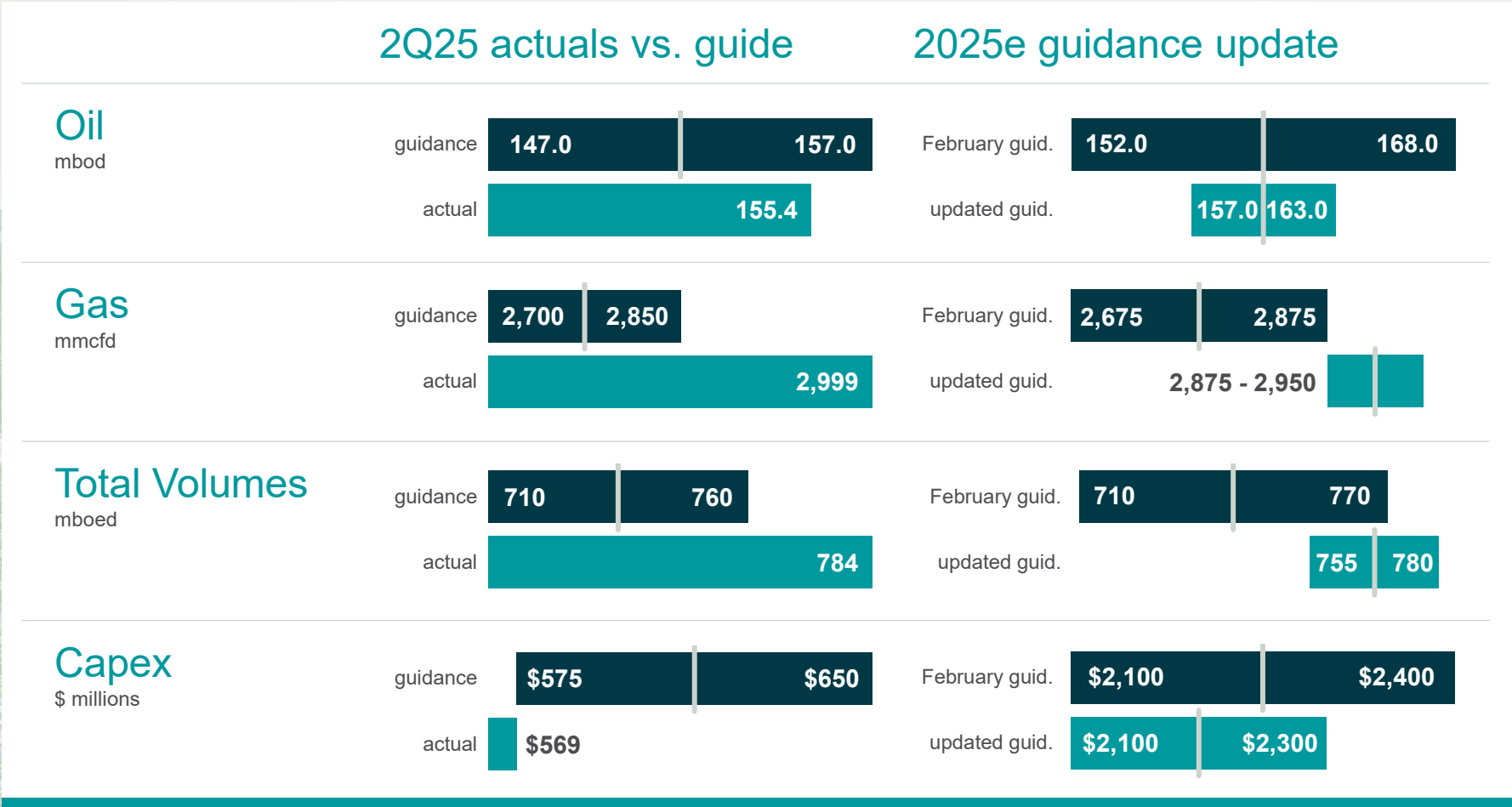
Durable Free Cash Flow Outlook | Estimated 2025 Free Cash Flow of \$2.1 billion, supported by balanced commodity exposure between oil and natural gas



Balance Sheet Top-Tier | Pro forma leverage ~0.9x², retired \$350 million of Term Loans during 1H25

Beat 2Q25 Gas Volumes & Raised for the Year

Higher production & lower capex driving improved capital efficiency



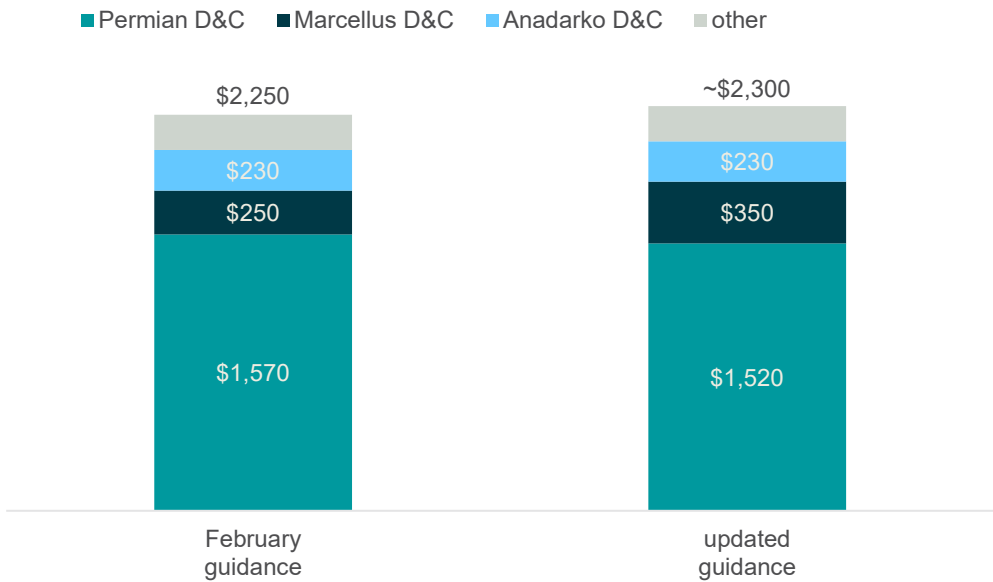
2025e Development Program Key Highlights



Disciplined Capital Program

Currently expect to be near the high end of the \$2.1 to \$2.3 billion 2025e capex guidance range, given increased gas activity
~52% reinvestment rate¹

2025e capex \$ millions



2025 Program Key Highlights

Permian

- Maintaining 9 rigs into 2H25
- Roughly half of spend focused on Lea County

Marcellus

- Added \$100mm of activity YTD, in response to positive gas outlook
- Extended second rig into 2H25
- Activity cadence positions production growth for winter 2025 and into 2026
- Including 4 Dimock wells, all Upper, expected in December 2025

Anadarko

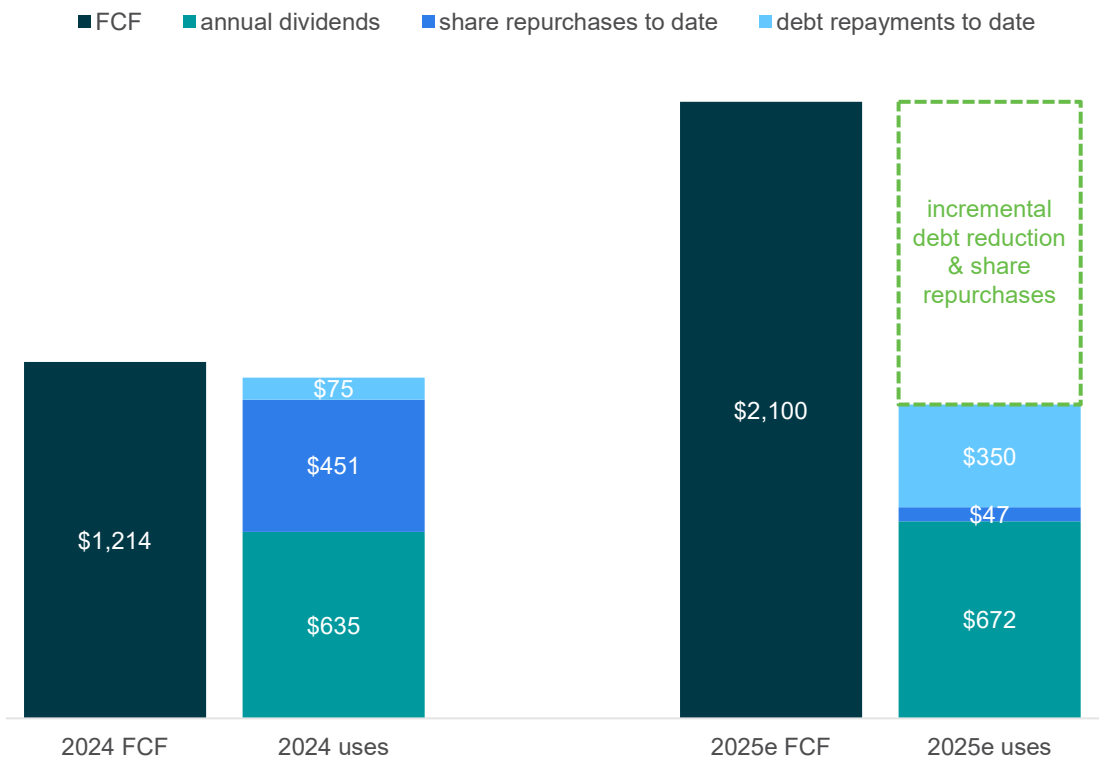
- Our largest gas development (9 gross wells) in the basin to date came online 2Q25
- Our first 3-milers (6 gross wells) in the Anadarko are expected to come online in 4Q25

Returning Value to Shareholders

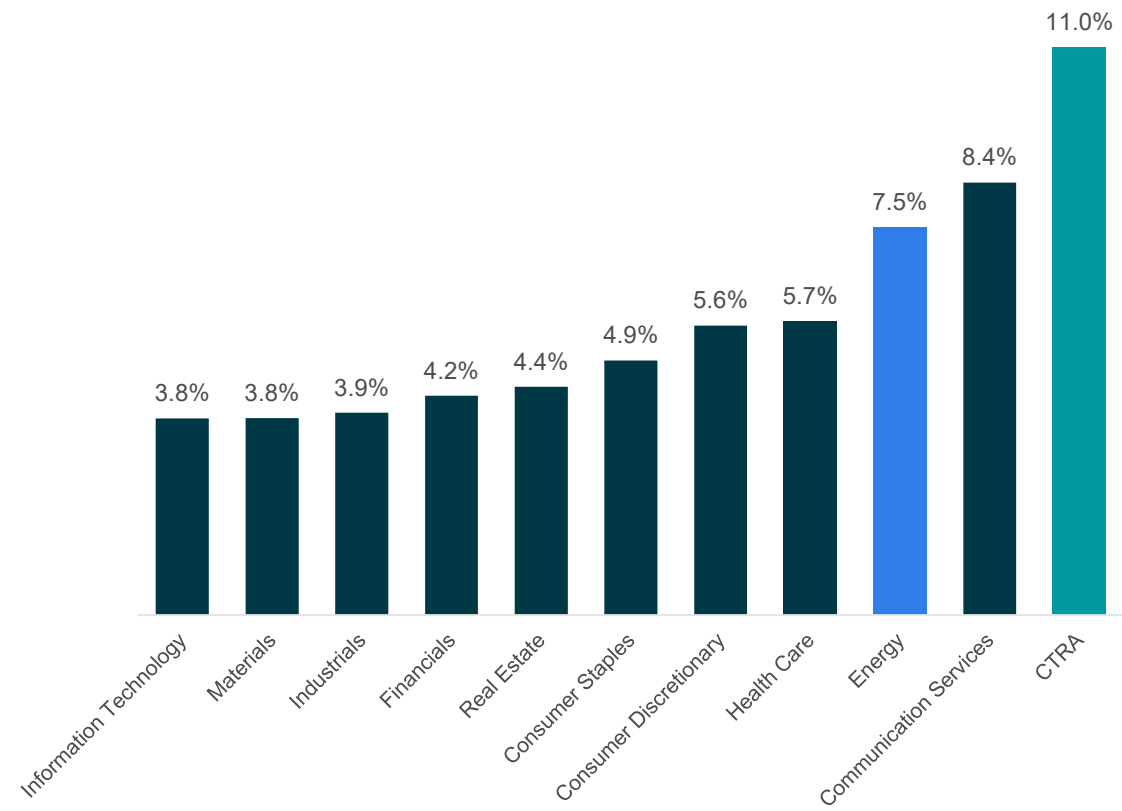
2025e FCF +73% YoY

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

\$ millions



Top SP500 2025e Free Cash Flow Yield



Long Runway of High-Quality Inventory

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

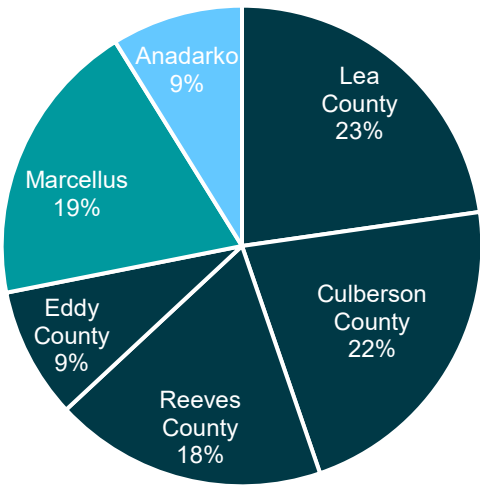
~\$31 billion of Economic Capex Opportunities

estimated capex by PVI₁₀ bucket:



~\$14bn, or ~45%, of capex is expected to generate 2.0x PVI₁₀ or better

estimated total footage by asset area:



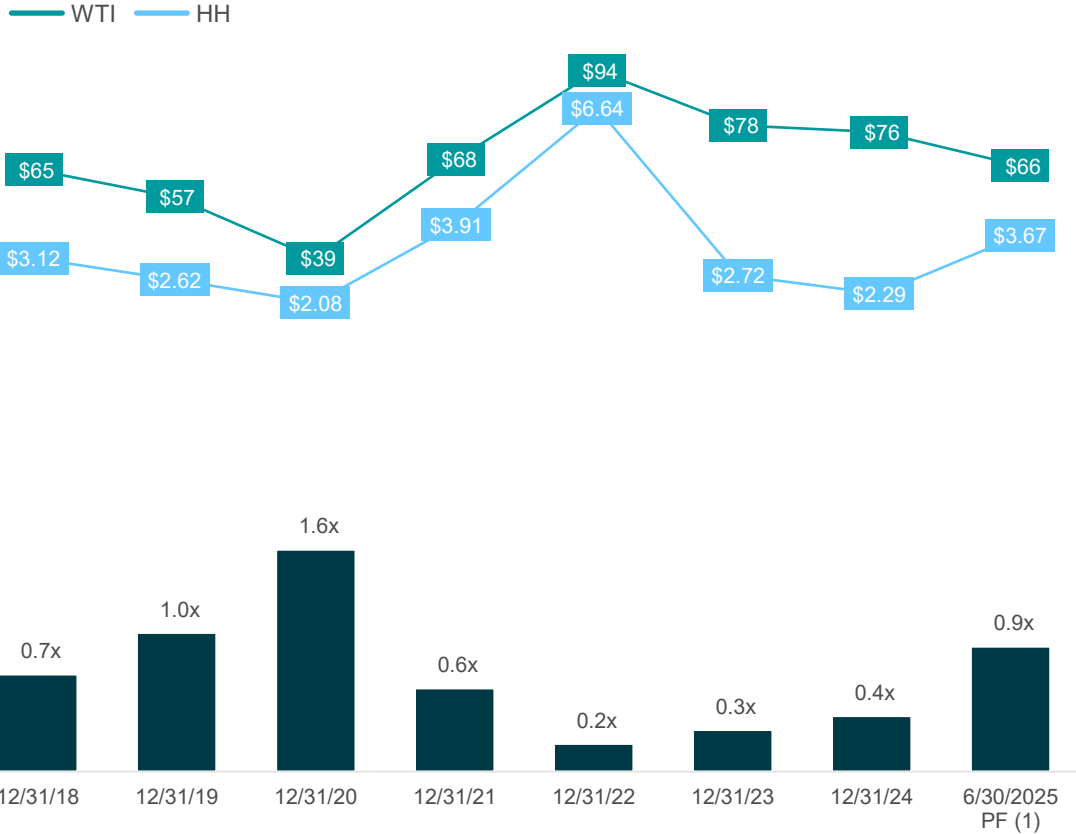
Implied Inventory Duration¹

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

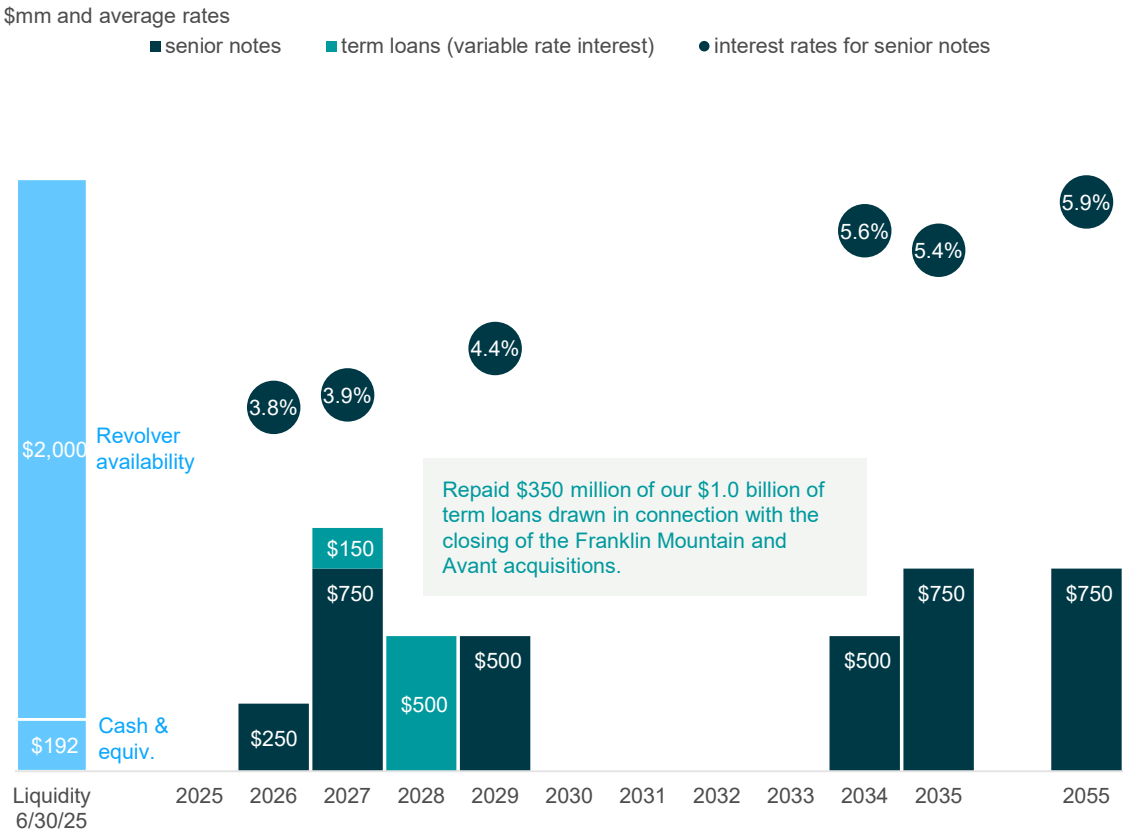
Prioritizing Financial Flexibility

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

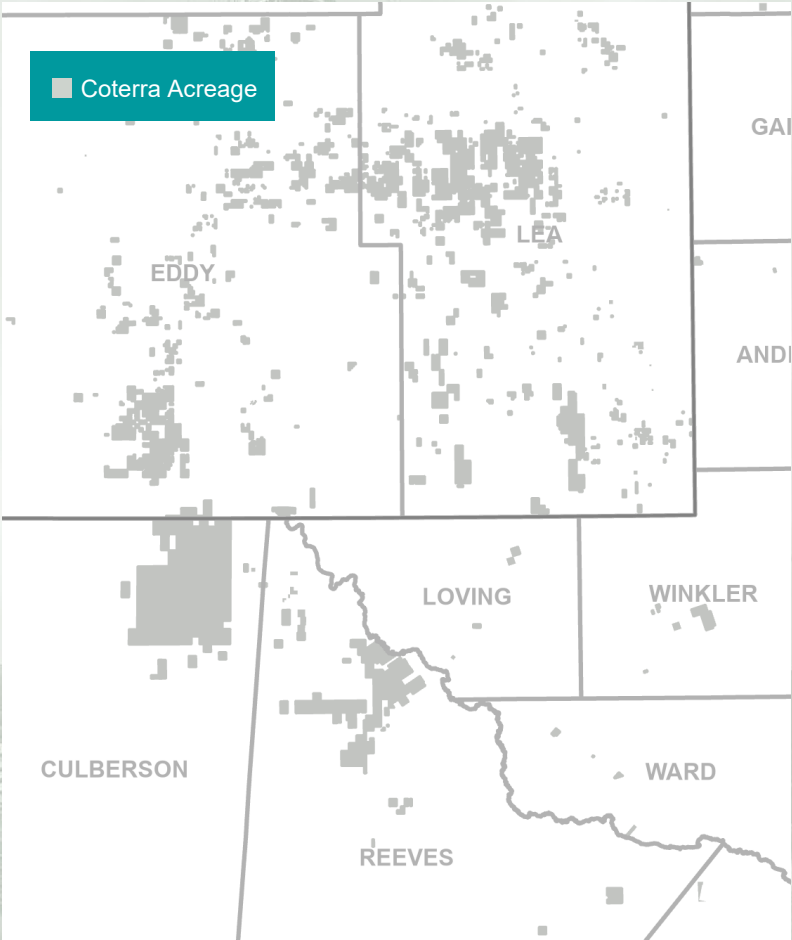
Permian Asset Overview – 2025 Operational Outlook

\$1,520 million
Midpoint D&C CapEx

10,600'
Avg. Lateral
Length¹

\$940
Avg. Well Cost
per Foot¹
-12%
cost reduction YoY

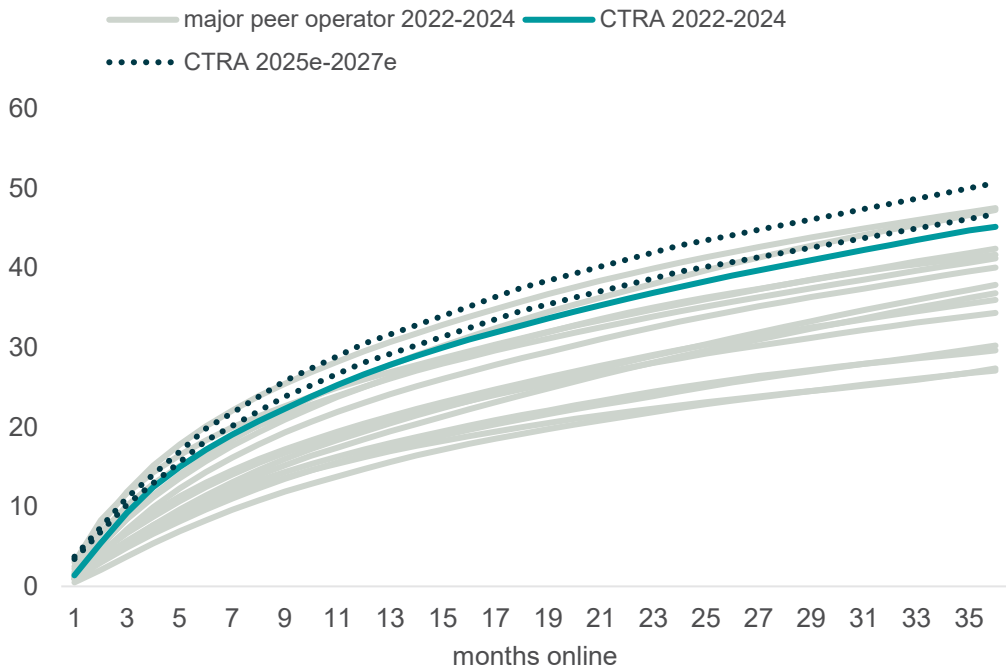
150-165
Net Wells
Online²



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

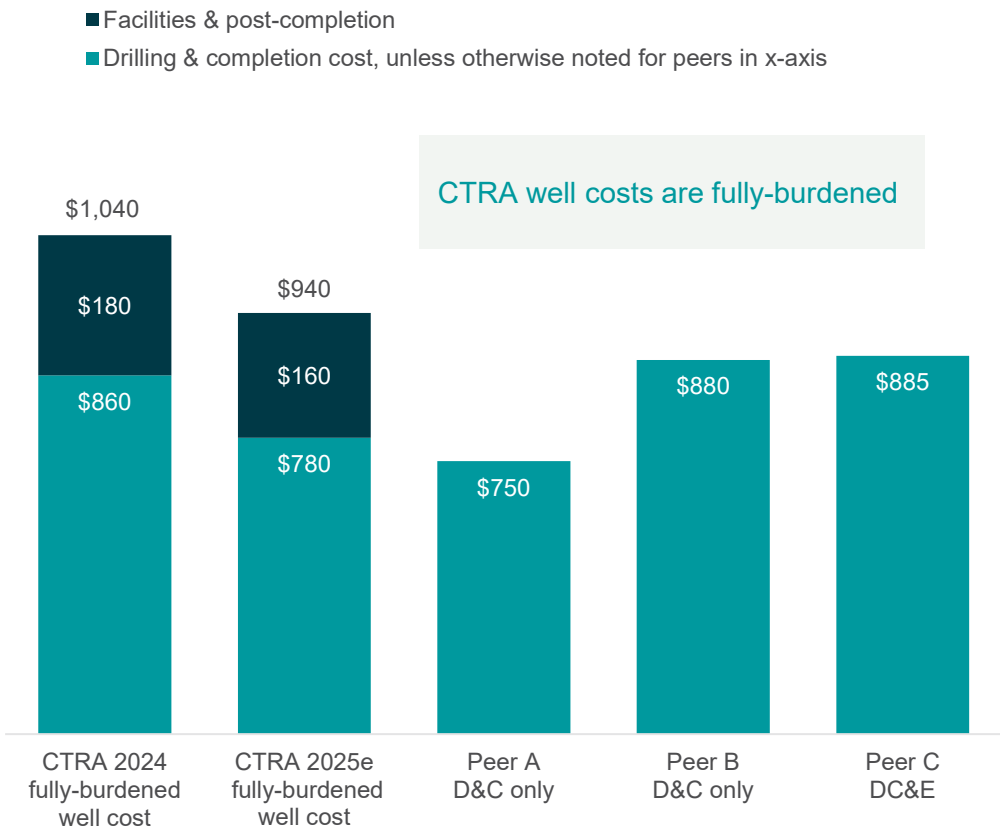
Delaware Productivity¹

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 Foot²



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.

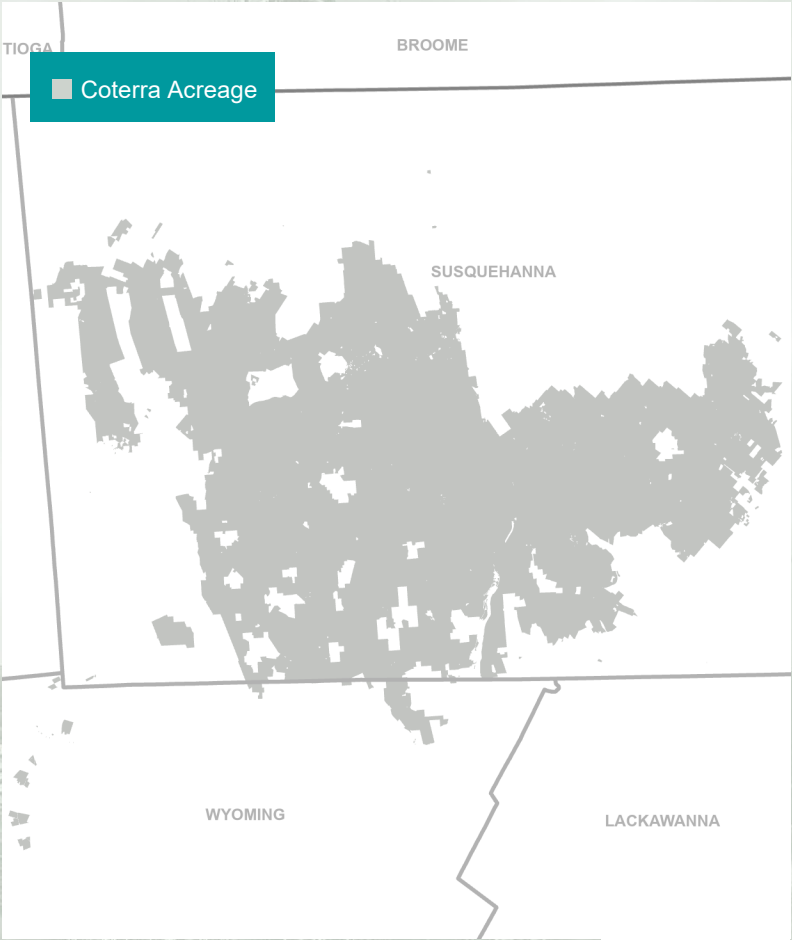
Marcellus Asset Overview – 2025 Operational Outlook

\$350 million
Midpoint D&C CapEx

19,000'
Avg. Lateral
Length¹

\$800
Avg. Well Cost
per Foot¹
-23%
cost reduction YoY

10-15
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

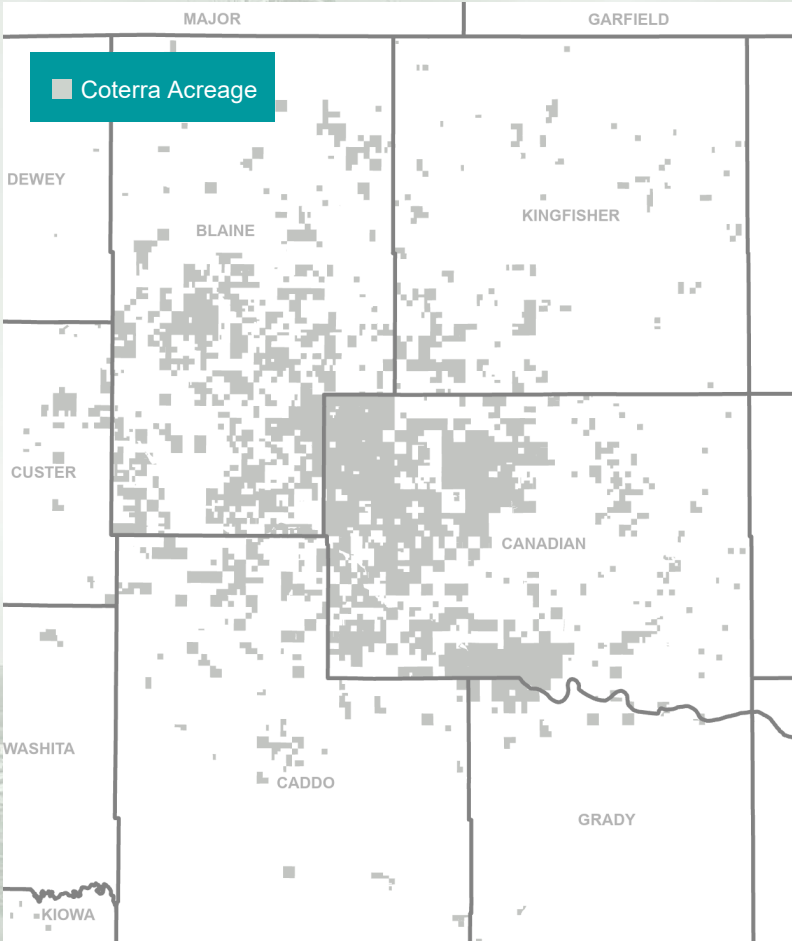
\$230 million
Midpoint D&C CapEx

11,060'
Avg. Lateral
Length¹

\$1,070
Avg. Well Cost
per Foot¹

-18%
cost reduction YoY

15-25
Net Wells
Online²





Appendix



High-Quality, Long-Life, Diversified Asset Portfolio

✓ Multi-Basin Portfolio

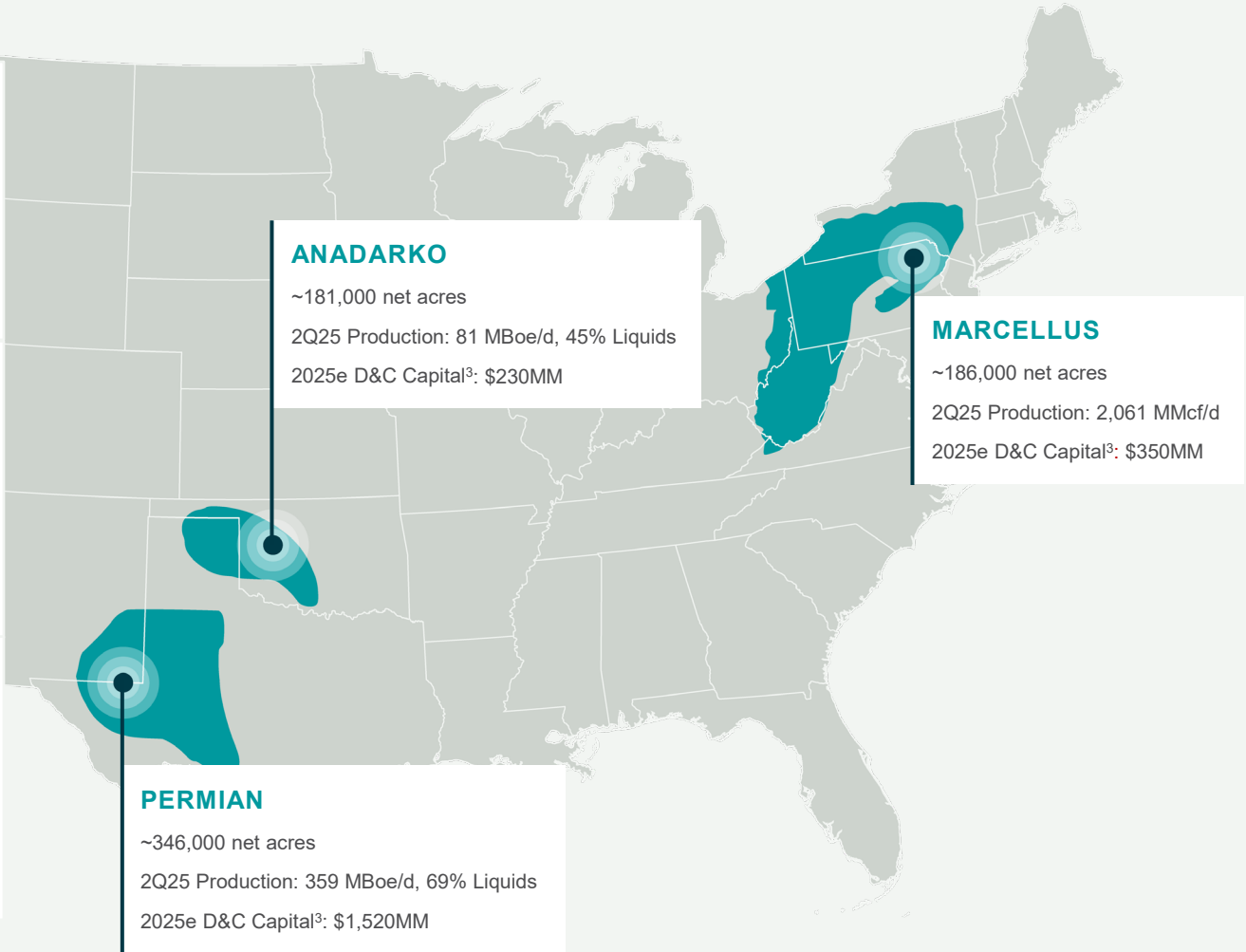
provides commodity diversification and capital allocation optionality

✓ Top-Tier Acreage Position

with deep inventory, estimated at ~15 years¹

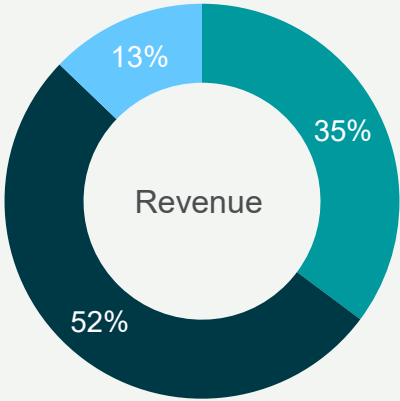
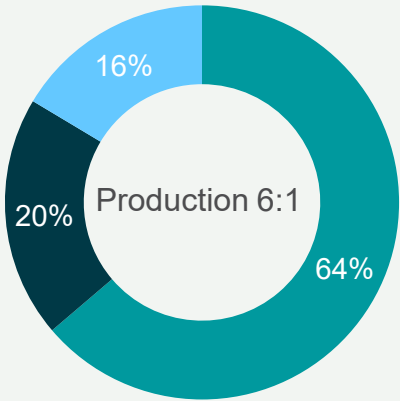
✓ Low-Cost Operator

with corporate break-even² around \$50/bbl WTI & \$2.50/mmbtu HH



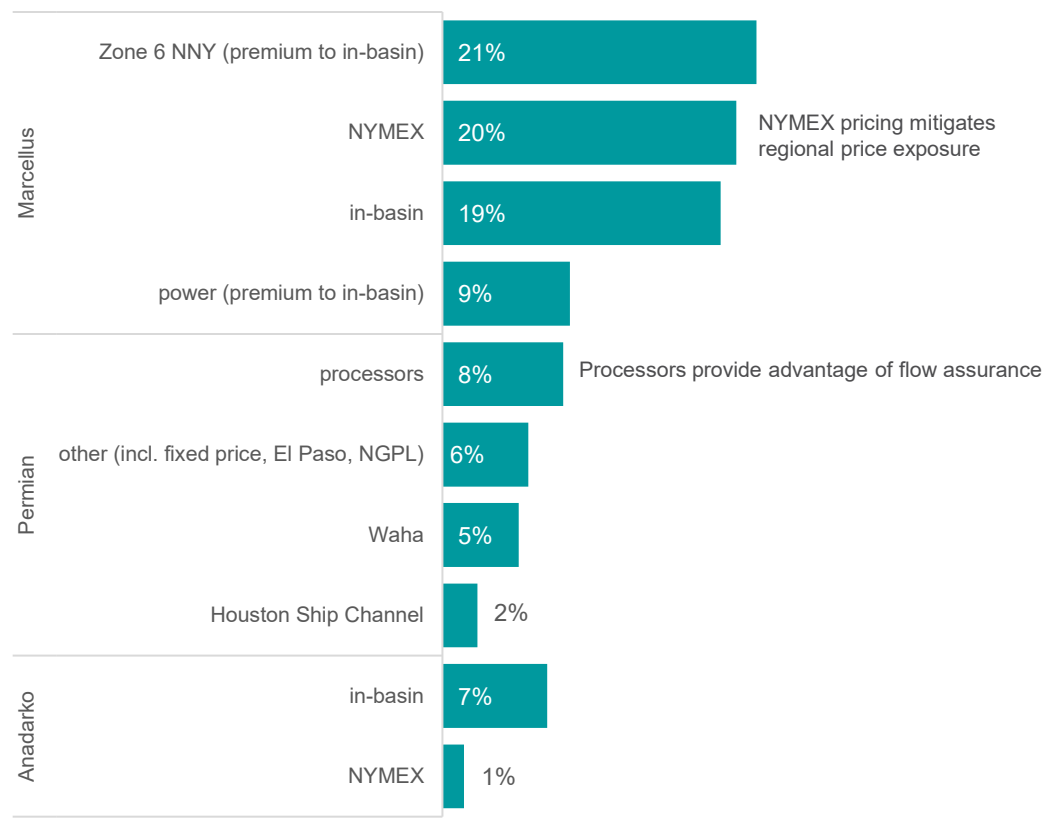
2Q25 Commodity Splits

■ natural gas ■ oil ■ NGL

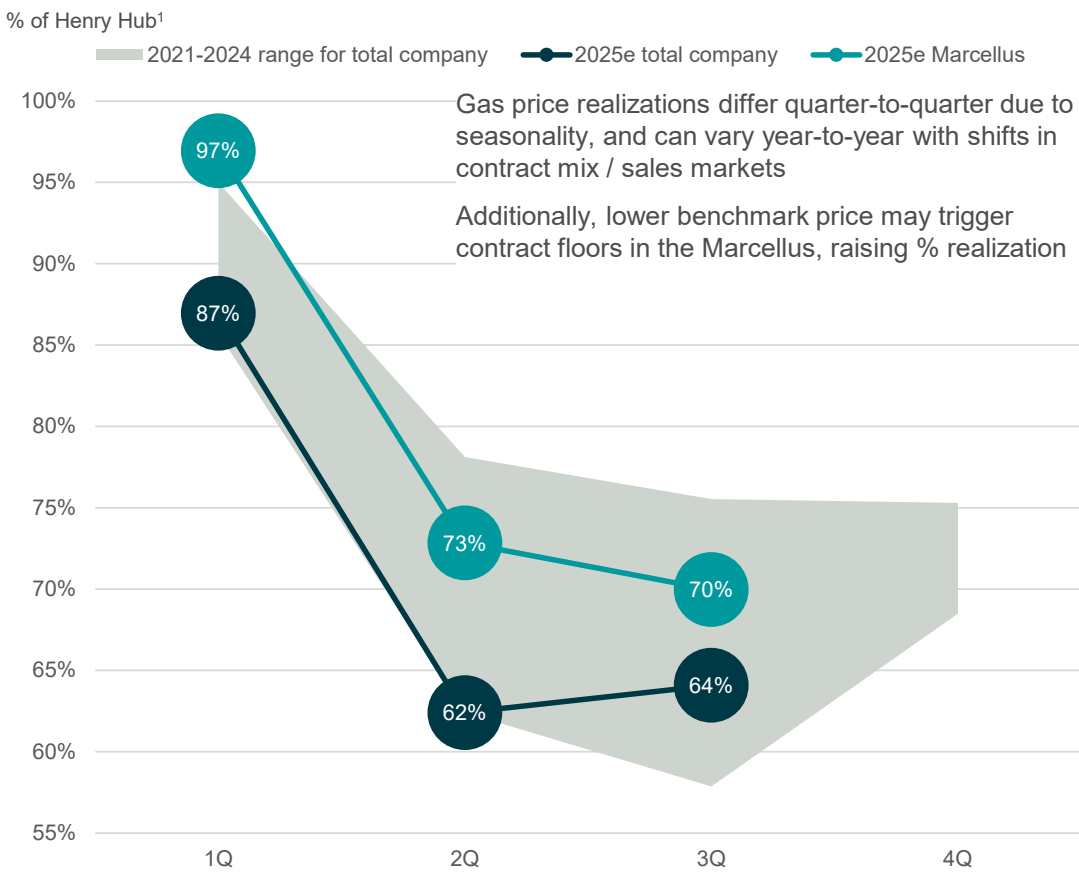


Diversified Gas Marketing Portfolio

2025 Estimated Natural Gas Sales Markets

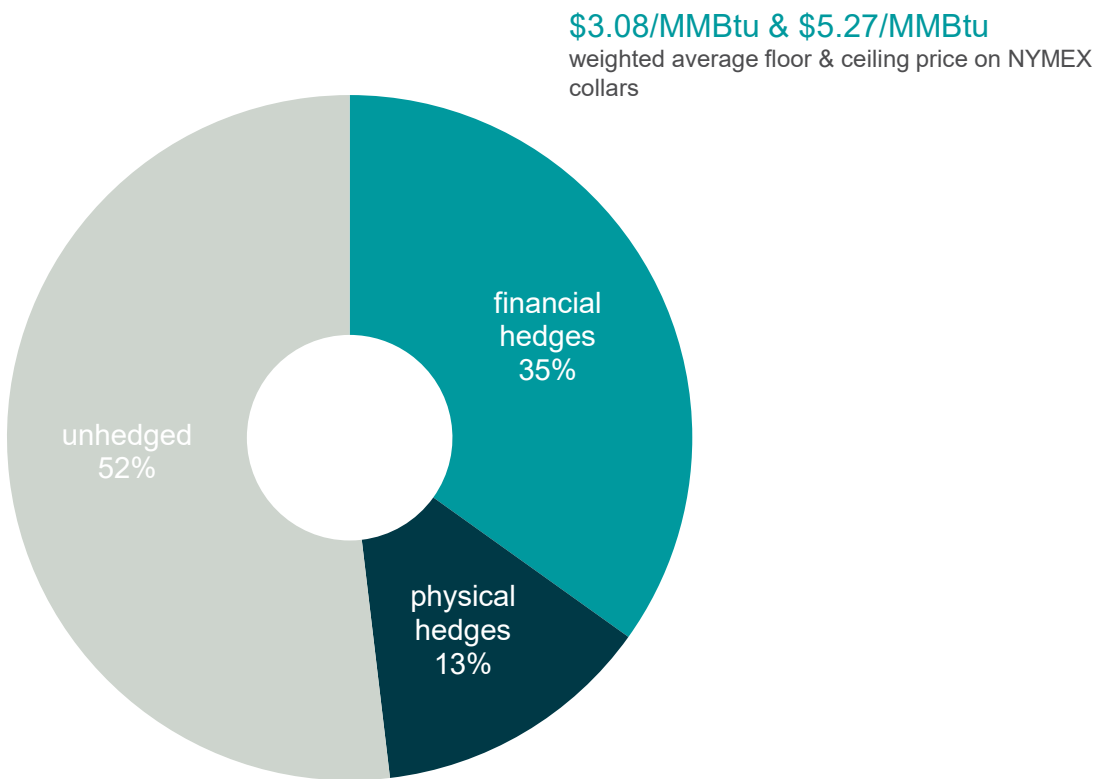


2021-2025e Natural Gas Price Realization Range¹

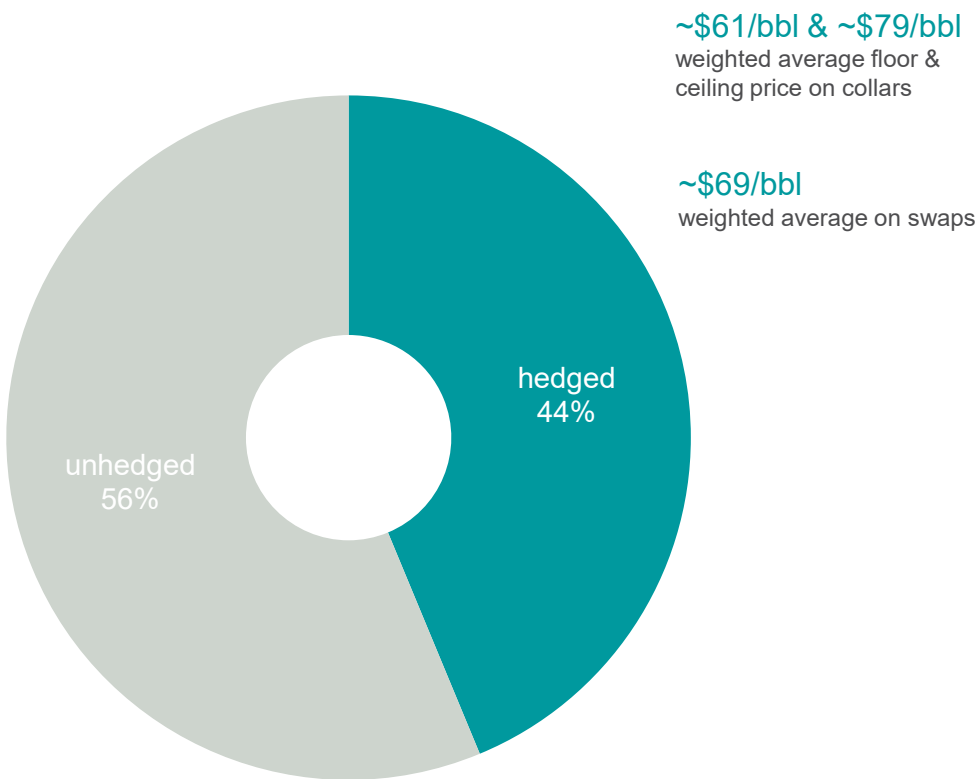


2025 Hedge Summary

Remaining 2025e gas volumes ~50% hedged

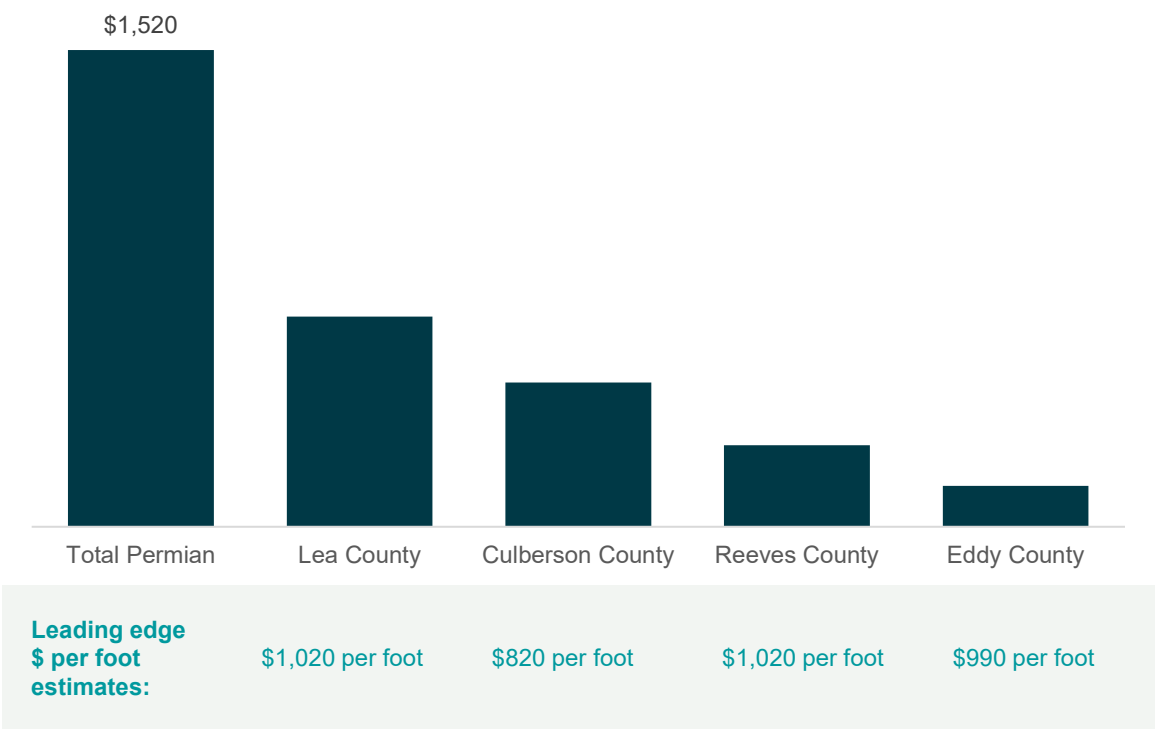


Remaining 2025e oil volumes >40% hedged

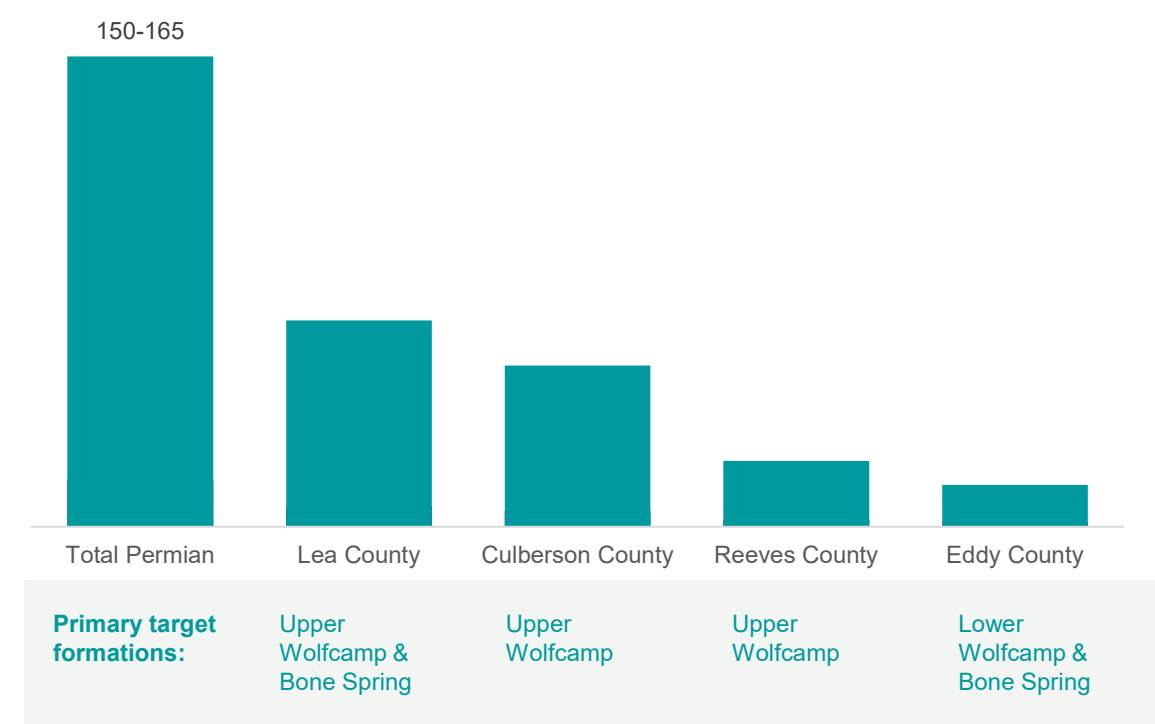


2025 Permian Development Program

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

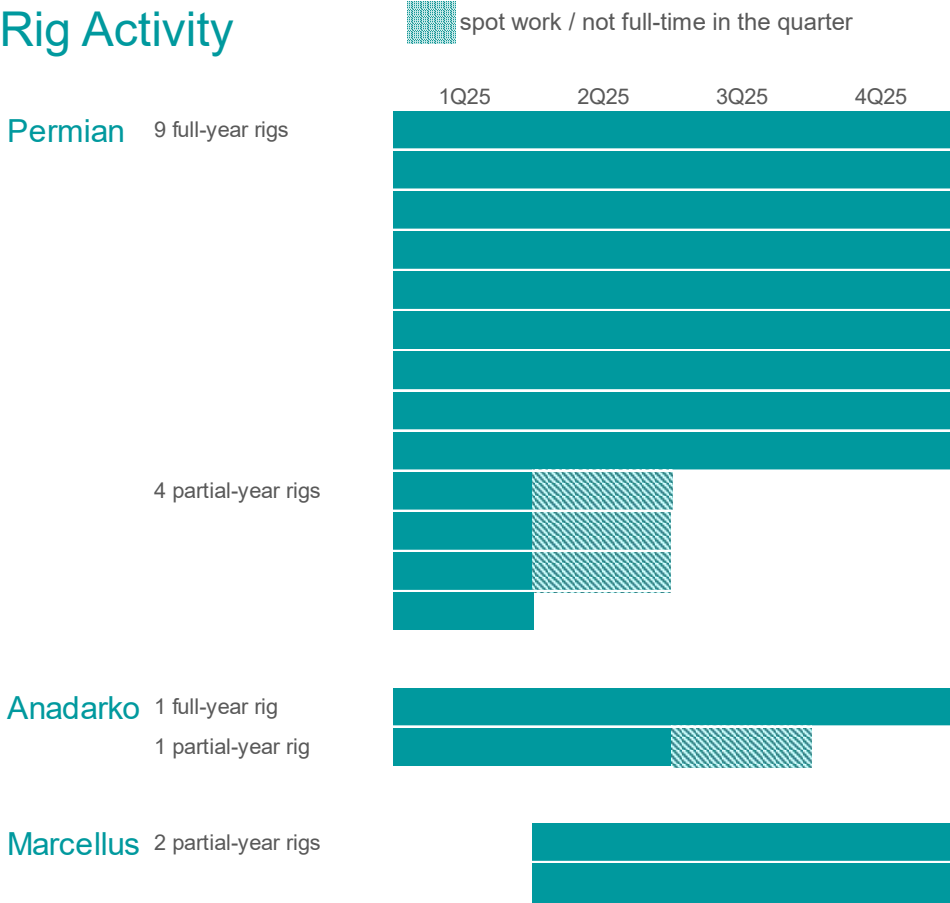


2025e net wells online

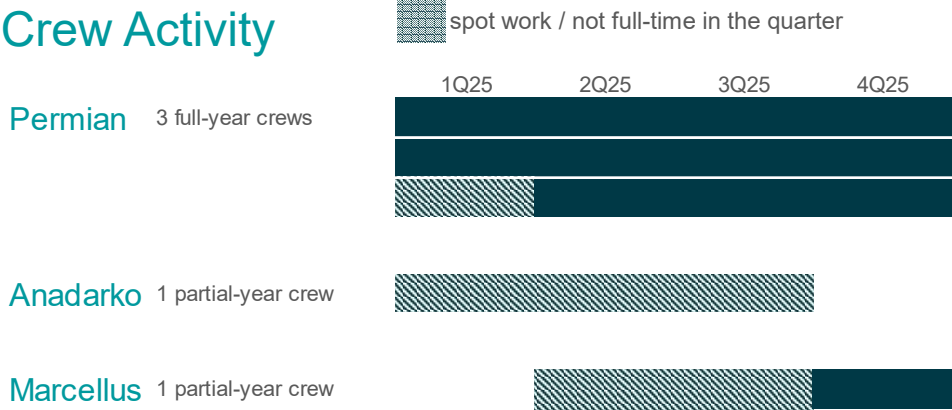


Expected 2025 Operational Cadence

Rig Activity



Crew Activity



← Second spot rig has been extended into the fourth quarter, increasing capex by an incremental ~\$50mm

Guidance & Actuals

		2025 Guidance (February)			Updated 2025 Guidance			2Q25 Guidance			2Q25 Actual	3Q25 Guidance		
		Low	Mid	High	Low	Mid	High	Low	Mid	High		Low	Mid	High
Operations	Total Production (mboed)	710	- 740	- 770	755	- 768	- 780	710	- 735	- 760	784	740	- 765	- 790
	Gas (mmcf)	2,675	- 2,775	- 2,875	2,875	- 2,913	- 2,950	2,700	- 2,775	- 2,850	2,999	2,750	- 2,825	- 2,900
	Oil (mbod)	152.0	- 160.0	- 168.0	157.0	- 160.0	- 163.0	147.0	- 152.0	- 157.0	155.4	158.0	- 163.0	- 168.0
	Net operated wells online													
	Marcellus	10	- 13	- 15	No change				3		3		4	
	Permian	150	- 158	- 165	No change			45	- 55	- 65	49	40	- 45	- 50
	Anadarko	15	- 20	- 25	No change				9		9		6	
	\$ millions:													
	Incurred Capital Expenditures	\$2,100 - \$2,250 - \$2,400			\$2,100 - \$2,200 - \$2,300			\$575 - \$613 - \$650			\$569	\$625 - \$650 - \$675		
	Marcellus D&C	\$250 midpoint			\$350						\$81			
	Permian D&C	\$1,570 midpoint			\$1,520						\$394			
Cash Flow & Investment	Anadarko D&C	\$230 midpoint			\$230						\$50			
	Midstream, saltwater disposal, infrastructure	\$200 midpoint			\$200						\$44			
	Commodity price assumptions:													
	WTI (\$ per bbl)	\$71			\$66									
	Henry Hub (\$ per mmbtu)	\$4.22			\$3.67									
	\$ billions:													
	Discretionary Cash Flow	\$5.0			\$4.4									
	Incurred Capital Expenditures	\$2.1 - \$2.3 - \$2.4			\$2.1 - \$2.2 - \$2.3									
	Free Cash Flow (DCF - cash capex)	\$2.7			\$2.1									

Expense Guidance & Actuals

Expense guidance provided for annual 2025

		2024 Actual				2025 Guidance		1Q25 Actual	2Q25 Actual
Expense	\$ per boe, unless noted:								
	Lease operating expense + workovers + region office	\$2.66	\$2.50	-	\$3.05	-	\$3.60	\$3.21	\$3.32
	Gathering, processing, & transportation	\$3.94	\$3.25	-	\$3.75	-	\$4.25	\$4.20	\$3.81
	Taxes other than income	\$1.09	\$1.25	-	\$1.50	-	\$1.75	\$1.43	\$1.21
	General & administrative ¹	\$0.97	\$0.90	-	\$1.00	-	\$1.10	\$1.13	\$1.00
	Unit Operating Cost	\$8.66	\$7.90	-	\$9.30	-	\$10.70	\$9.97	\$9.34
	DD&A	\$7.43	\$8.00	-	\$8.75	-	\$9.50	\$7.53	\$8.11
	Exploration ²	\$0.10	\$0.05	-	\$0.08	-	\$0.10	\$0.15	\$0.07
	% effective tax rate					22%		21%	22%
	current income tax as % of total income tax					40% - 60%		92%	66%

1 Excludes stock-based compensation, merger-related expenses, and severance expense

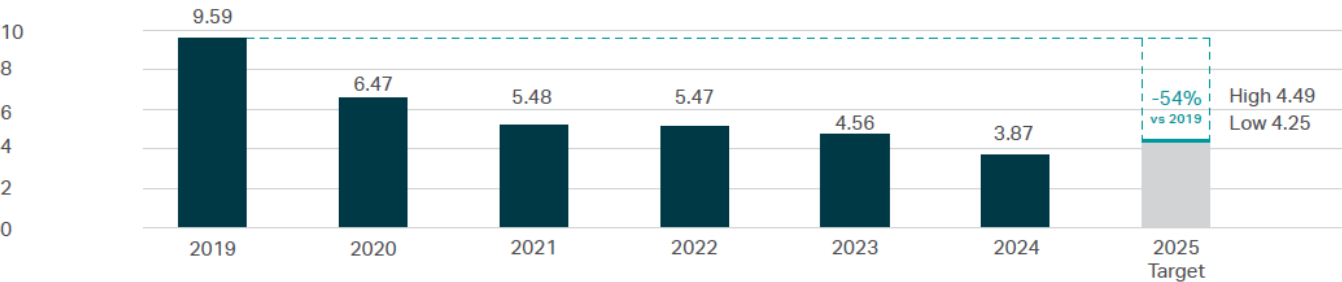
2 Excluding exploratory dry hole costs, includes exploration administrative expense and geophysical expenses

Updated tax guidance for current expectations around One Big Beautiful Bill

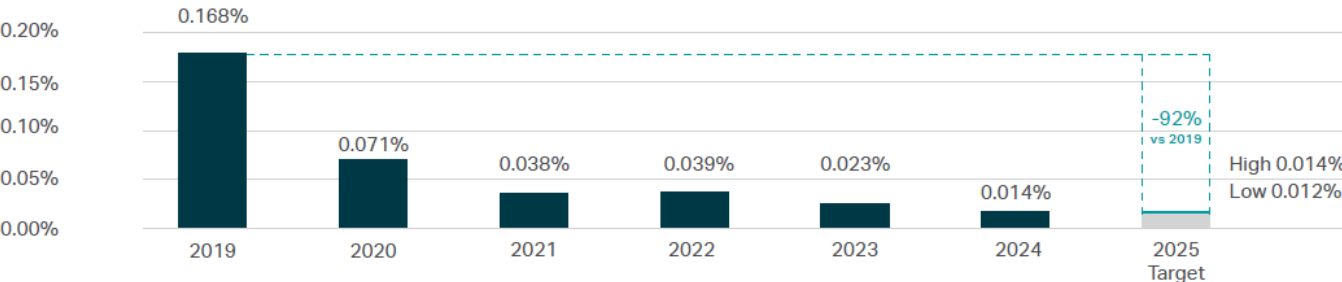
Published Sustainability Report on August 4, 2025



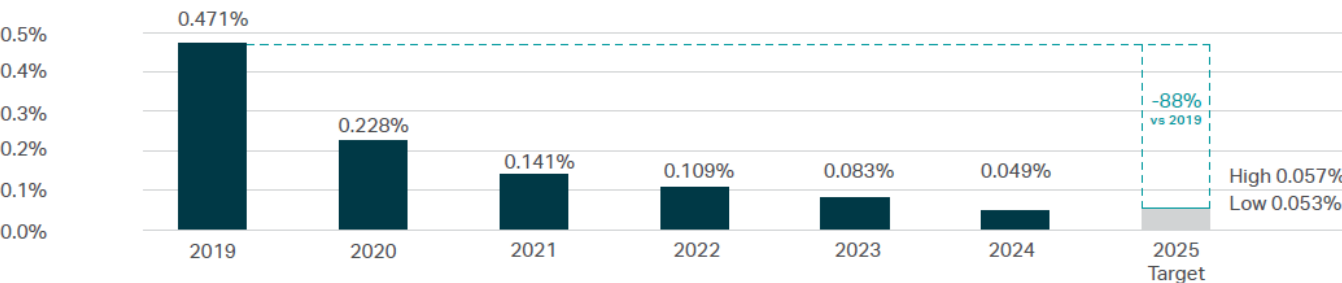
Greenhouse Gas Emissions Intensity (MT CO₂e / Gross Mboe Produced)



Methane Emissions Intensity (MT CH₄ Emitted / Gross CH₄ 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-Jun 2025
Cash flow from operating activities	\$ 937
Changes in assets and liabilities	12
Discretionary cash flow	949
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(620)
Free cash flow	\$ 329

Three Months Ended: (\$ in millions)	30-Jun 2025
Cash capital expenditures for drilling, completion and other fixed asset additions	\$620
Change in accrued capital costs	(51)
Exploratory dry-hole cost	-
Capital expenditures	\$569

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

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: (\$ in millions)	June 30	December 31						
	2025	2024	2023	2022	2021	2020	2019	2018
	Coterra				Combined Cabot + Cimarex			
Net income	\$ 1,576	\$ 1,121	\$ 1,625	\$ 4,065	\$ 1,158	\$ 201	\$ 681	\$ 557
Plus (less):								
Interest expense, net					62	54	55	73
Interest expense	159	106	73	80				
Interest income	(37)	(62)	(47)	(10)				
(Gain) loss on debt extinguishment				(28)	-	-	-	-
Other expense (benefit)	(1)			(2)	-	-	1	-
Income tax expense (benefit)	366	224	503	1,104	344	41	219	141
Depreciation, depletion and amortization	2,046	1,840	1,641	1,635	693	391	406	417
Exploration	29	25	20	29	18	15	20	114
(Gain) loss on sale of assets	(7)	(3)	(12)	1	2	0	1	16
Non-cash loss (gain) on derivative instruments	(84)	101	54	(299)	(210)	(26)	58	(86)
(Earnings) loss on equity method investments	-	-	-	-	-	0	(80)	(1)
Equity method investment distributions	-	-	-	-	-	-	17	-
Stock-based compensation	63	62	59	86	57	43	31	33
Severance expense	-	-	12	62	46	-	3	-
Merger-related costs	14	-	-	7	72	-	-	-
EBITDAX	\$ 4,124	\$ 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	\$ 4,124	\$ 3,414	\$ 3,928	\$ 6,730	\$ 3,247	\$ 1,654	\$ 2,872	\$ 2,822

(\$ in millions)	June 30	December 31						
	2025	2024	2023	2022	2021	2020	2019	2018
	Coterra				Combined Cabot + Cimarex			
Total debt	\$4,175	\$3,535	\$2,161	\$2,181	\$3,125	\$3,134	\$3,220	\$2,726
Less: Cash and cash equivalents	(192)	(2,038)	(956)	(673)	(1,036)	(413)	(295)	(803)
Less: Short-term investments								
Net debt	\$3,983	\$1,497	\$1,205	\$1,508	\$2,089	\$2,721	\$2,925	\$1,923
TTM EBITDAX	\$4,124	\$3,414	\$3,928	\$6,730	\$3,247	\$1,654	\$2,872	\$2,822
Net debt to TTM EBITDAX	1.0x	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)	June 30 2025	December 31 2024
Pro forma net income	\$ 1,795	\$ 1,475
Plus (less):		
Pro forma interest expense	234	250
Pro forma interest income	(37)	(62)
Pro forma other income	(1)	-
Pro forma income tax expense	404	297
Pro forma depreciation, depletion and amortization	2,267	2,195
Pro forma exploration	29	25
Pro forma gain on sale of assets	(7)	(3)
Pro forma non-cash loss on derivative instruments	(84)	101
Pro forma acquisition-related expenses	14	14
compensation	63	62
Adjusted Pro Forma EBITDAX (trailing twelve months)	\$ 4,677	\$ 4,354

	June 30 2025	December 31 2024
Net debt (as defined previously)	\$ 3,983	\$ 1,497
Adjusted Pro Forma EBITDAX (Trailing twelve months)	4,677	4,354
Net debt to Adjusted EBITDAX	0.9x	0.3x