Premium Rock, Returns, Runway

3Q 2022 EARNINGS / NOVEMBER 1, 2022

CHESAPEAKE ENERGY

Forward-Looking Statements

This presentation includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than statements of historical fact. They include statements that give our current expectations, management’s outlook guidance or forecasts of future events, expected natural gas and oil growth trajectory, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, dividend plans, future production and commodity mix, plans and objectives for future operations, ESG initiatives, the ability of our employees, portfolio strength and operational leadership to create long-term value, and the assumptions on which such statements are based. Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time.

Factors that could cause actual results to differ materially from expected results include those described under “Risk Factors” in Item 1A of our annual report on Form 10-K and any updates to those factors set forth in Chesapeake’s subsequent quarterly reports on Form 10-Q or current reports on Form 8-K (available at http://www.chk.com/investors/sec-filings). These risk factors include: the impact of inflation and commodity price volatility resulting from Russia’s invasion of Ukraine, COVID-19 and related supply chain constraints, along with the effect on our business, financial condition, employees, contractors, vendors and the global demand for natural gas and oil and U.S. and world financial markets; the acquisitions of Vine Energy Inc. (“Vine”) and Chief E&D Holdings, LP and affiliates of Tug Hill, Inc. (together, “Chief”), including our ability to successfully integrate the businesses of Vine and Chief into the Company and achieve the expected synergies from these acquisitions within the expected timeframes; our ability to comply with the covenants under our reserve-based revolving credit facility and other indebtedness; our ability to realize anticipated cash cost reductions; the volatility of natural gas, oil and NGL prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles; a deterioration in general economic, business or industry conditions; uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to replace reserves and sustain production; drilling and operating risks and resulting liabilities; our ability to generate profits or achieve targeted results in drilling and well operations; the limitations our level of indebtedness may have on our financial flexibility; our ability to achieve and maintain ESG certifications/goals; our inability to access the capital markets on favorable terms; the availability of cash flows from operations and other funds to fund cash dividends and repurchases of equity securities, to finance reserve replacement costs and/or satisfy our debt obligations; write-downs of our natural gas and oil asset carrying values due to low commodity prices; charges incurred in response to market conditions; limited control over properties we do not operate; leasehold terms expiring before production can be established; commodity derivative activities resulting in lower prices realized on natural gas, oil and NGL sales; the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations; potential OTC derivatives regulations limiting our ability to hedge against commodity price fluctuations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used; pipeline and gathering system capacity constraints and transportation interruptions; legislative, regulatory and ESG initiatives, addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal; terrorist activities and/or cyber-attacks adversely impacting our operations; an interruption in operations at our headquarters due to a catastrophic event; federal and state tax proposals affecting our industry; competition in the natural gas and oil exploration and production industry; negative public perceptions of our industry; effects of purchase price adjustments and indemnity obligations..

In addition, disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are also dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. We caution you not to place undue reliance on our forward-looking statements that speak only as of the date of this presentation, and we undertake no obligation to update any of the information provided in this presentation, except as required by applicable law. In addition, this presentation contains time-sensitive information that reflects management’s best judgment only as of the date of this presentation.

Premium Rock, Returns, Runway

STRATEGIC PILLARS		
Superior Capital Returns	✓	**Most efficient operator, returning more cash to shareholders** than any other gas peer in the U.S.
Deep, Attractive Inventory	✓	Premier operator with **>15 years of inventory** **>2,200 gas locations** at $4.00 flat pricing **>100% IRR**
Premier Balance Sheet	✓	Investment grade quality balance sheet **~0.4x net debt-to-2023 EBITDAX ratio**[1]
ESG Excellence	✓	**Achieved Grade "A" MiQ and EO100™ certification** Highest available grade for legacy Marcellus and Haynesville operations – On track to achieve full gas asset certification by YE'22

(1) A non-GAAP measure as defined in the appendix; 9/30/2022 net debt balance as a ratio to consensus 2023 EBITDAX as of 10/27/2022

3Q 2022 Highlights

Dividend payable
$3.16 / **55%** **of 3Q FCF**
per share on 12/1/2022

~2/3rds of outstanding warrants eliminated

Reduced short interest by(1) **55%**

~$1.9B
returned to equity holders YTD

~$400mm
of additional share repurchases since 3Q'22

Adjusted free cash flow(2)
$773mm FY'22E projection $2.1B – $2.2B

Adjusted EBITDAX(2)
$1,256mm FY'22E projection $4.45B – $4.55B

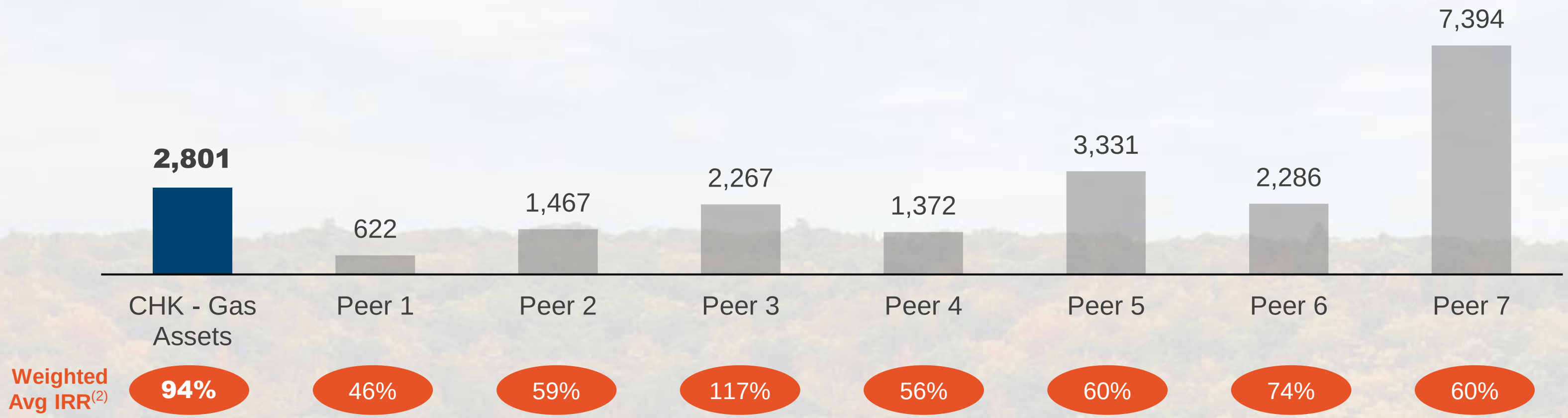
Delivered expected TILs and average IP30 volumes
10 Marcellus @ ~26 mmcf/d / **19** Haynesville @ ~24 mmcf/d

~1 bcf/d of total delivery to the LNG corridor beginning in 2024 with a commitment to Momentum Midstream pipeline project

(1) Change in CHK short interest 9/30/2022 to 10/15/2022
(2) Assumes projections and outlook as of 11/1/2022; a non-GAAP measure as defined in the appendix

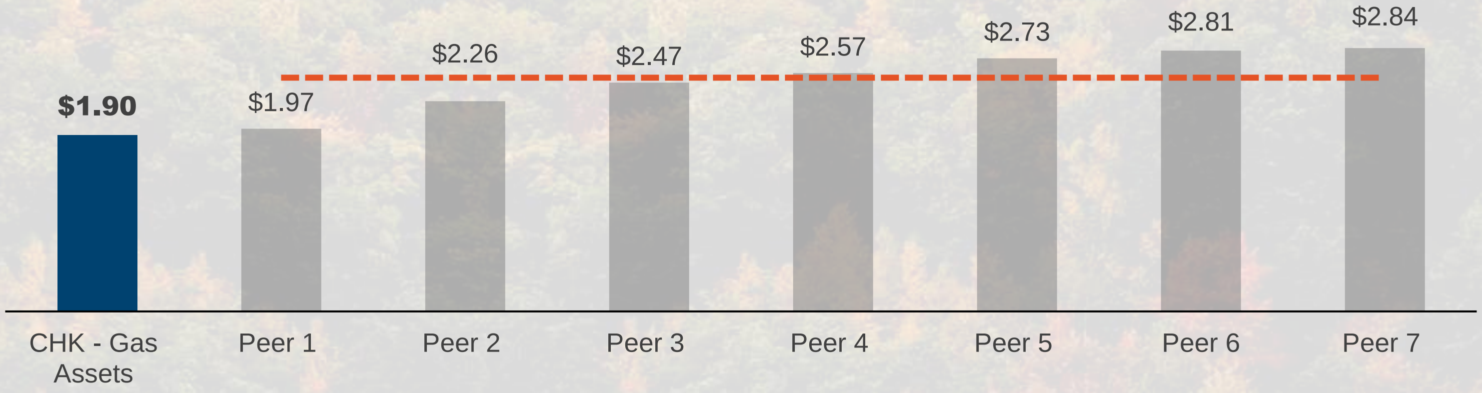
Leading Our Peers: Better Rock, Better Returns, Better Runway

Depth of Inventory – Marcellus and Haynesville Enverus Gross Locations[1]



CHK has the best combination of scale and asset quality

Best Capital Efficiency – Enverus $/mcfe[3]



CHK wells are ~25% more capital efficient than peer average

Peer group includes: AR, CNX, CRK, CTRA (Marcellus only), EQT, RRC, SWN
(1) Source: Public filings and Enverus, gross inventory locations per Enverus estimates
(2) Source: Enverus, calculated at $3.50 HHUB / $70 WTI
(3) Source: Enverus, calculated as avg. total capex / avg. total 12-month production and includes all wells that started production since 2018 with 12 months of reported production

Fulfilling Our Promise: Best-in-Class Shareholder Return Program

#1 returns program of any gas peer – returned ~$1.9B to equity holders YTD

- Largest commitment (50% post base dividend FCF + $2.0B buyback authorization)

3Q'22 dividend of $3.16/share (payable in Dec)

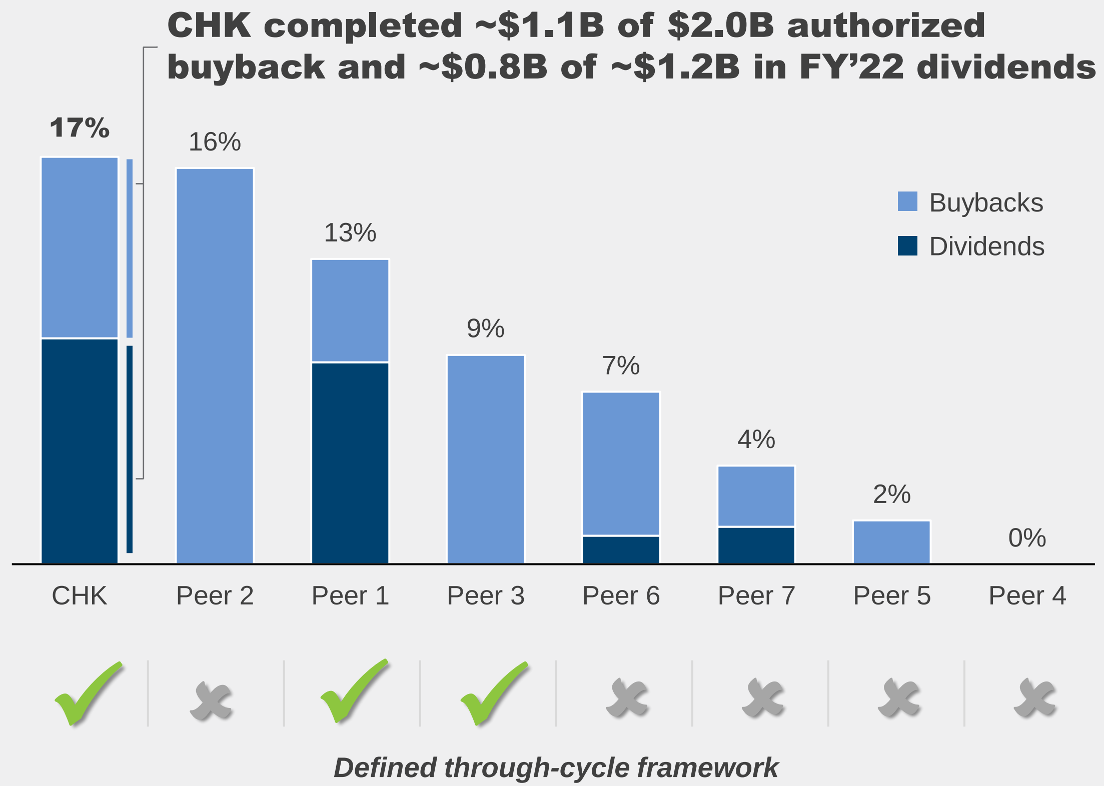
- $0.55 base / $2.61 variable

2022 Dividends ($mm)			
Mar	Jun	Sep	Dec
~$210	~$298	~$280	~$424

Executed ~$1.1B of share repurchases YTD

- ~11.6mm common shares purchased through 11/1 at a weighted average price of ~$91.96 per share
- >80% of shares repurchased from former creditors

2022E Implied Capital Return Yields(1,2)

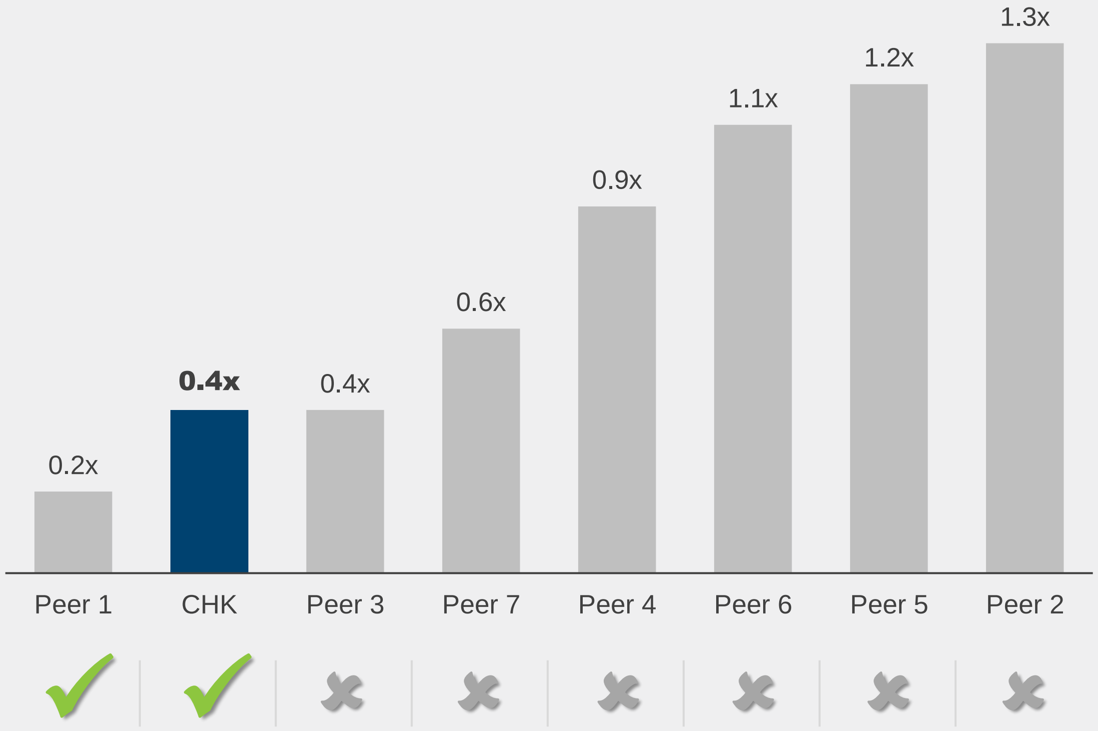


Peer group includes: AR, CNX, CRK, CTRA, EQT, RRC, SWN
(1) CHK assumes ~$1.1 billion of common shares repurchased during 2022; buyback yield annualizes YTD buybacks for peers without a defined framework
(2) Based on consensus estimates as of 10/27/2022 and share price data as of 10/27/2022; through-cycle framework defined as peers with a committed percent of FCF or CFO return

Enhancing a Strategic Lever: Premier Balance Sheet

- **Committed to maintaining strong balance sheet, net debt-to-EBITDAX of <1.0x**
  - Only gas peer publicly targeting resiliency to <$2.50/mcf
- **S&P upgrade to BB in October 2022 with an investment grade quality balance sheet**
- **Eliminated ~2/3rd of outstanding warrants**
  - Short interest reduced 55% post tender (9/30 vs. 10/15)
  - Simplifies capital structure and prevents meaningful future dilution
- **Disciplined, well-timed and accretive use of balance sheet (Vine / Chief)**

9/30/2022 Net Debt / 2023 Consensus EBITDAX[1]



Resilient <1.0x net debt-to-EBITDAX down to $2.50/mcfe

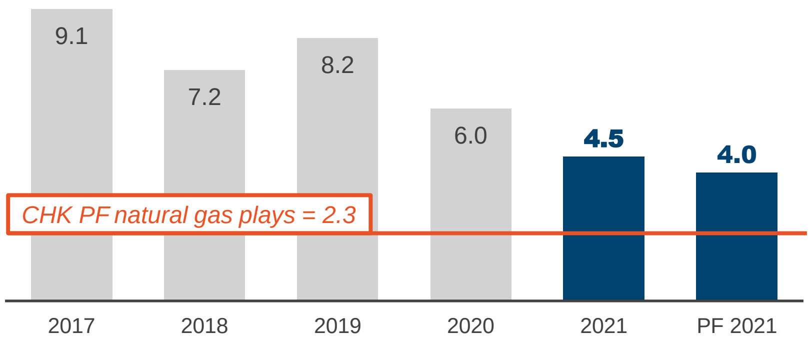
Peer group includes: AR, CNX, CRK, CTRA, EQT, RRC, SWN
(1) Source: Public filings, investor presentations, FactSet as of 10/27/2022
Note: Net debt and EBITDAX are non-GAAP measures which are defined in the appendix

Strengthening Our Company Through Sustainability

- Hired company's first Chief Sustainability Officer
- >2,000 continuous methane monitoring devices operating today
- ~18,000 pneumatic devices retrofitted
- Conducting aerial Gas Mapping LiDAR scans to detect emissions across all assets
- Achieved Grade "A" MiQ and EO100™ certification for legacy Marcellus and Haynesville

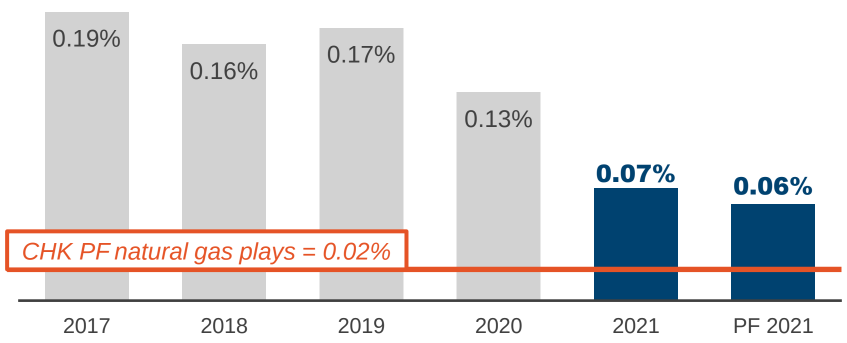
CHK GHG Emissions Intensity

Metric tons CO_2e/gross mboe produced



CHK Methane Intensity

Volume methane emissions/volume gross natural gas produced

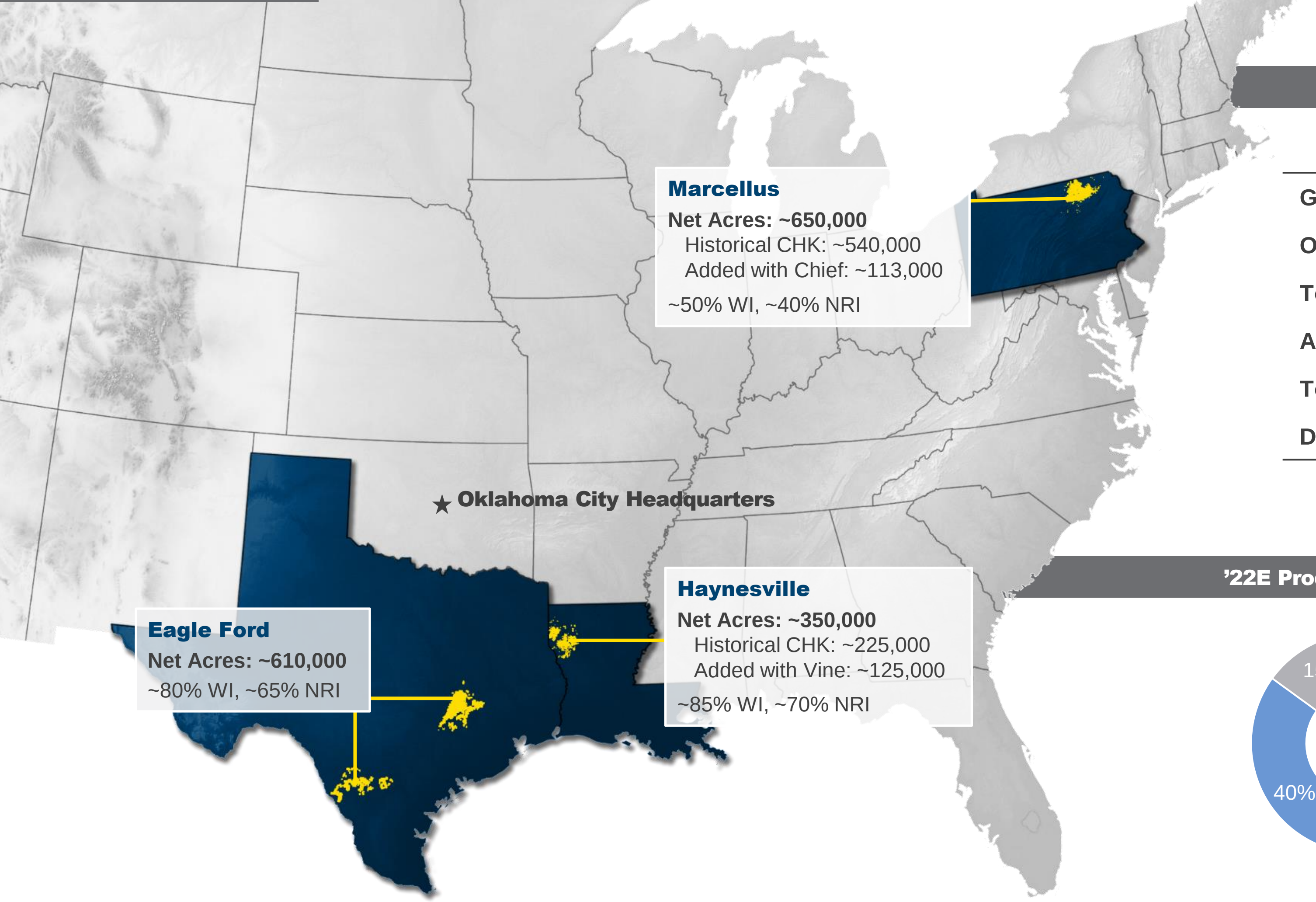


Visit our sustainability site at esg.chk.com for more information.

RSG certification of entire gas portfolio by YE'22

2022 Operating Plan

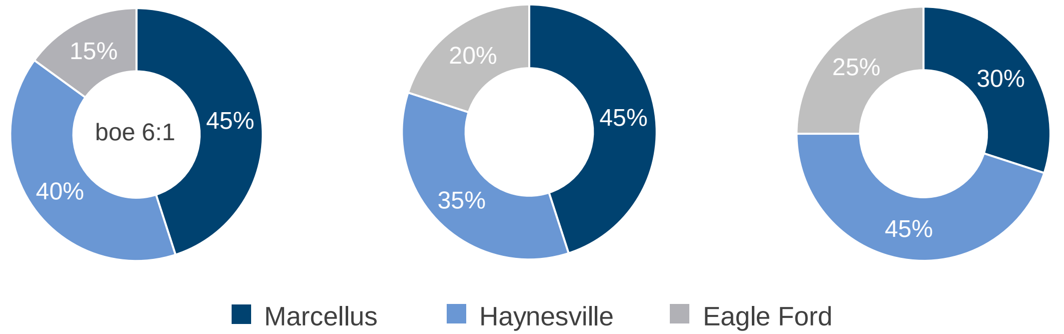
’22E Activity



3Q’22 Actual and 2022E Projected Results

	3Q’22	4Q’22E	FY’22E
Gas Production (bcf/d)	3.7	3.6 – 3.8	3.6 – 3.7
Oil Production (mbo/d)	50	50 – 54	51 – 56
Total Production (mmcfe/d)	4,108	4,000 – 4,240	4,020 – 4,140
Adj. EBITDAX ($mm)(1)	$1,256	$1,015 – $1,115	$4,450 – $4,550
Total Capex ($mm)(2)	$619	$445 – $475	$1,750 – $1,950
Dividends Paid ($mm)	$280	$424	$1,212

’22E Production Outlook **’22E EBITDAX Outlook** **’22E Capital Plan**



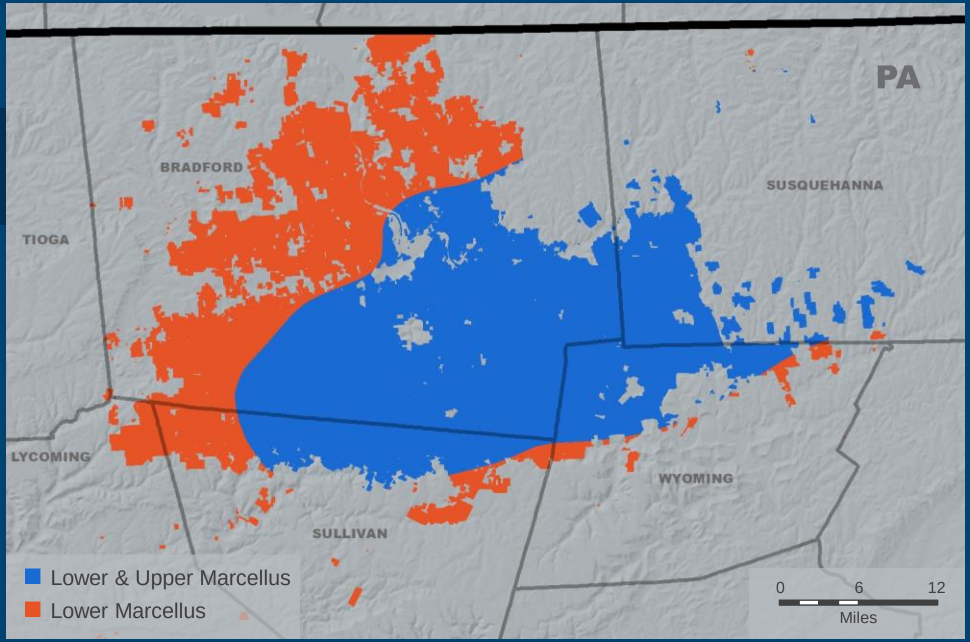
Note: All values assume closing of Chief assets on 3/9/2022 and divestiture of Powder River Basin assets on 3/25/2022
(1) Reflects strip prices as of 10/27/2022; a non-GAAP measure as defined in the appendix
(2) Total capex FY’22E reconciliation included in appendix

Marcellus: Premium Scale, Leading Returns

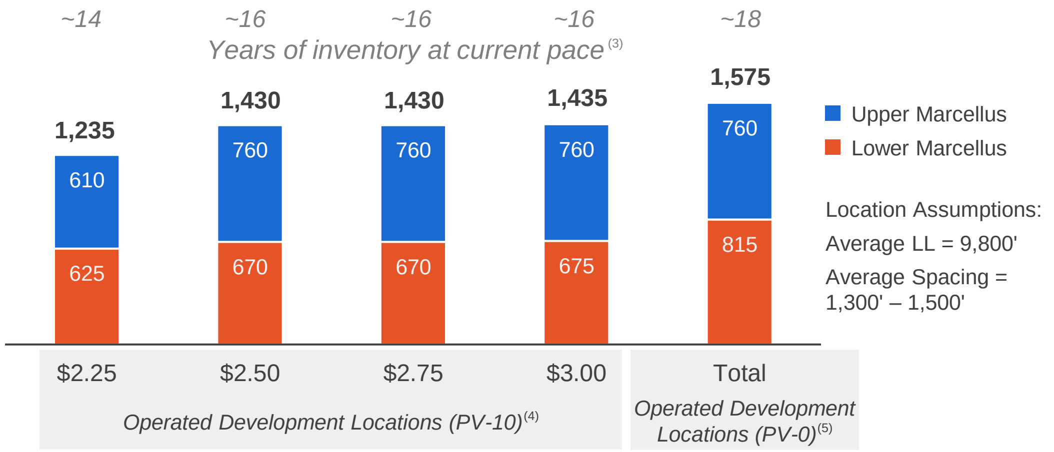
- ~16 years of drilling assuming 5-rig pace (~90 wells per year)
- 2022E BU EBITDAX[1,2] $3.45B – $3.55B
- Chief integration complete – incremental ~160 gross mmcf/d capacity through gathering system optimization to date
- Acquiring ~4,000 acres, 25+ premium well locations through organic leasing with Pennsylvania State Game Lands
- Upper Marcellus delivering quality returns above Southwest Appalachia peers

$6B

5-year projected FCF[2] *net of allocated hedges, corporate items and taxes*



Gross Inventory by Breakeven



2023	Avg. LL	12mo Cum. mcf/ft	Capex/ft[6]	IRR ($4.00)	% Program
CHK Lower Marcellus	~11.0K	~580	~$850	>175%	55%
CHK Upper Marcellus	~12.5K	~450	~$870	~125%	45%
		– vs –			
Peers – SW App[7]	~11.5K	~320	~$975	~90%	–

(1) BU level EBITDAX based on outlook as of 11/1/2022 and excludes hedges and corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 10/27/2022 for 2022 ($6.57 HHUB / $96 WTI) and 2023 ($5.11 / $81), then $4.00 / $75 thereafter
(3) Assumes ~90 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
(6) Includes forward looking inflation for 2023 expectations
(7) Southwest Appalachia; Weighted average from Enverus development models for AR, CNX, EQT, RRC, SWN and assumes 10% inflation for 2023
Note: Free cash flow and EBITDAX are non-GAAP measures which are defined in the appendix

Marcellus: Premium Scale, Leading Returns

Asset Overview	3Q'22	4Q'22E	FY'22E
Net Production (bcf/d)	1.99	1.95 – 2.05	1.8 – 1.9
Average Rigs	5	5	4 – 5
Wells Drilled	23	22 – 26	75 – 85
Wells TIL'd	10	32 – 36	85 – 95
% of TILs in Lower Marcellus	100%	75%	70%
Average LL (feet)			~11,000
Cost/Lateral Foot			\$750 – \$850
PDP Decline (5 year)			~20%
2022 TIL Decline (1 year)			~60%

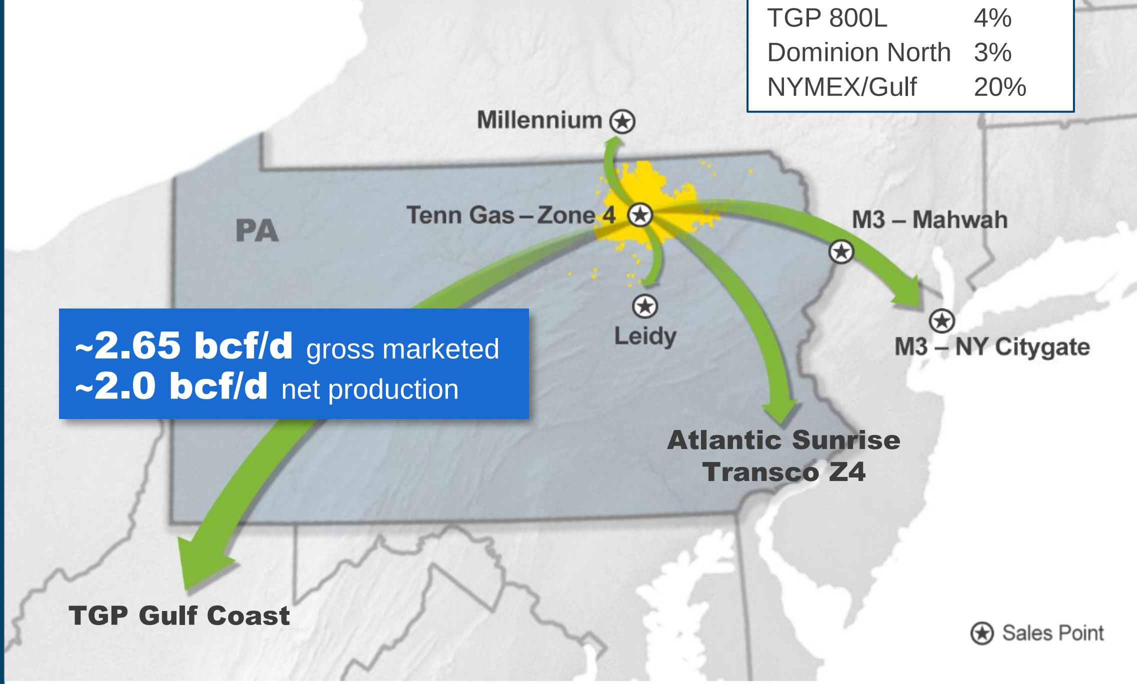
Cost Assumptions (net)	3Q'22	4Q'22E	FY'22E
Differential to NYMEX (\$/mcf)	(\$0.95)		(\$0.60) – (\$0.70)
LOE (\$/mcf)	\$0.12		\$0.09 – \$0.11
GP&T (\$/mcf)	\$0.58		\$0.60 – \$0.70
D&C Capital (\$mm)	\$151	\$105 – \$115	\$400 – \$440
Total Capital (\$mm)	\$166	\$135 – \$145	\$450 – \$525

Marcellus Sales Points

HISTORICAL DEDUCT FROM NYMEX (\$)[1]	
TGP 800L	(\$0.11)
Transco Z4	(\$0.03)
TETCO M3	(\$0.30)
TGP Z4	(\$0.90)
Leidy	(\$0.83)
19% of NYMEX	

CURRENT DEDUCT FROM NYMEX (\$)[1]	
TGP 800L	(\$0.18)
Transco Z4	\$0.45
TETCO M3	\$0.32
TGP Z4	(\$1.11)
Leidy	(\$1.03)
11% of NYMEX	

MARCELLUS TOTAL PRODUCTION	
In Basin	**56%**
TGP Z4	23%
Leidy	28%
Millennium	5%
Out of Basin	**44%**
TETCO M3	16%
TGP 210/App	1%
TGP 800L	4%
Dominion North	3%
NYMEX/Gulf	20%



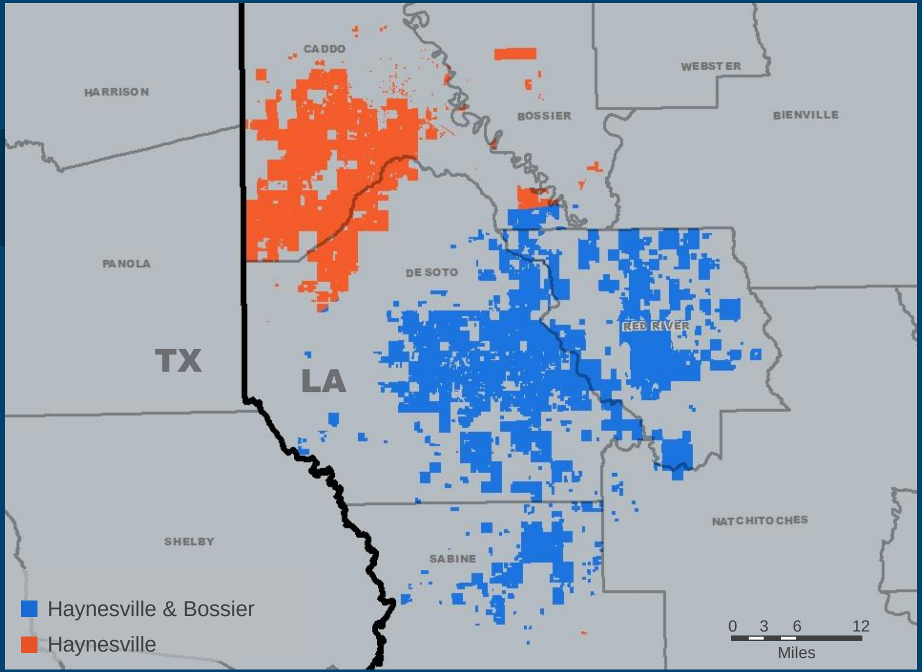
(1) Historical prices based on NYMEX contract settlement prices for Jan 2020 – Dec 2021; current prices based on NYMEX settled and future prices for Jan 2022 – Dec 2023, strip as of 10/27/2022, and compared to FY 2022 guided midpoint

Haynesville: Profitable Growth, Advantaged Markets

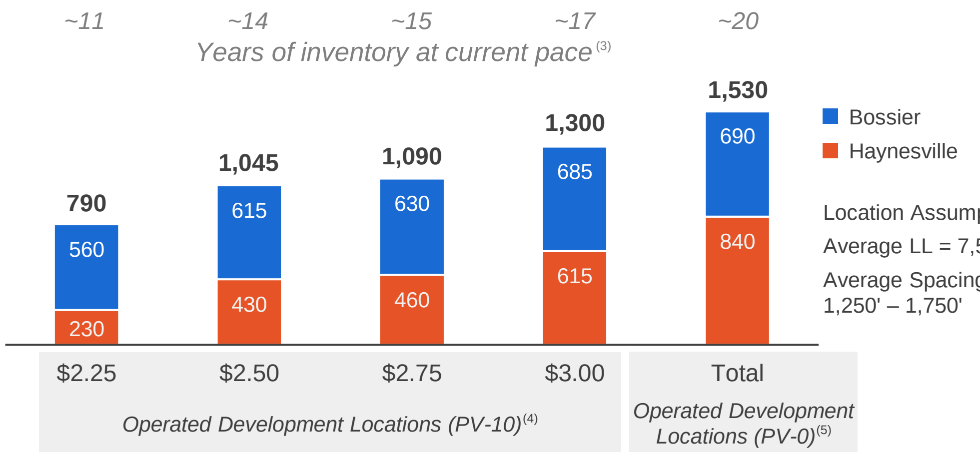
- ~17 years of drilling assuming ~7-rig pace (~75 wells per year)
- 2022E BU EBITDAX[1,2] $2.85B – $2.95B
- First operator to achieve RSG certification basin-wide
- ~20% increase in gas gathering and treatment capacity by 2H’23
- Spud-to-TIL cycle times have decreased YoY, despite inflationary environment

$3B

5-year projected FCF[2] *net of allocated hedges, corporate items and taxes*



Gross Inventory by Breakeven



Location Assumptions:
Average LL = 7,500'
Average Spacing = 1,250' – 1,750'

2023	Avg. LL	12mo Cum. mcf/ft	Capex/ft[6]	IRR ($4.00)	% Program
CHK Haynesville	~9.0K	~820	~$1,575	>100%	80%
CHK Bossier	~8.5K	~770	~$1,875	~70%	20%
– vs –					
Peers – Haynesville[7]	~10.0K	~560	~$1,700	~65%	–

(1) BU level EBITDAX based on outlook as of 11/1/2022 and excludes hedges and corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 10/27/2022 for 2022 ($6.57 HHUB / $96 WTI) and 2023 ($5.11 / $81), then $4.00 / $75 thereafter
(3) Assumes 75 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
(6) Includes forward looking inflation for 2023 expectations
(7) Weighted average from Enverus development models for Aethon, CRK, SWN and assumes 10% inflation for 2023
Note: Free cash flow and EBITDAX are non-GAAP measures which are defined in the appendix

Haynesville: Profitable Growth, Advantaged Markets

Asset Overview	3Q'22	4Q'22E	FY'22E
Net Production (bcf/d)	1.61	1.52 – 1.62	1.6 – 1.7
Average Rigs	6	7	5 – 7
Wells Drilled	17	14 – 20	60 – 66
Wells TIL'd	19	7 – 13	65 – 71
% of TILs Haynesville	75%	35%	70%
Average LL (feet)			~9,000
Cost/Lateral Foot			$1,400 – $1,500
PDP Decline (5 year)			~30%
2022 TIL Decline (1 year)			~60%

Cost Assumptions (net)	3Q'22	4Q'22E	FY'22E
Basis Differential to NYMEX ($/mcf)	($0.60)		($0.55) – ($0.65)
BTU Factor	976		970 – 980
LOE ($/mcf)	$0.26		$0.25 – $0.35
GP&T ($/mcf)	$0.60		$0.45 – $0.55
D&C Capital ($mm)	$237	$200 – $210	$750 – $800
Total Capital ($mm)	$259	$230 – $240	$825 – $900

Haynesville Sales Points

HISTORICAL DEDUCT FROM NYMEX ($)(1)	
CGML	($0.28)
TGT	($0.20)
10% of NYMEX	

CURRENT DEDUCT FROM NYMEX ($)(1)	
CGML	($0.49)
TGT	($0.42)
7% of NYMEX	

HAYNESVILLE TOTAL PRODUCTION	
CGML	61%
TGT	30%
Other Gulf Coast	9%

56% of basis hedged for 4Q'22

(1) Historical prices based on NYMEX contract settlement prices for Jan 2020 – Dec 2021; current prices based on NYMEX settled and future prices for Jan 2022 – Dec 2023, strip as of 10/27/2022, and compared to FY 2022 guided midpoint

Haynesville Market Strategy: Be LNG Ready

Remaining Flexible with the U.S. Gas Growth Engine

Continued Cost Leadership	➤ **Longest-tenured and largest-basin operator** ➤ **Efficiency gains from decade plus improvements = lowest capital cost Louisiana operator**
Grow Responsibly	➤ **Program to flex between 5 – 8 rigs, yielding marginal volume decline up to double digit growth** ➤ **Current plan expected to be flat with modest growth exit-to-exit (market conditions dependent)**
Optimize Midstream Build-out	➤ **Strategically securing gathering, treating and transportation, de-risking gas delivery to premium markets** ➤ **Added ~1 bcf/d of transport to the LNG corridor beginning in 2024 and option for equity participation in Momentum**
Be LNG Ready	➤ **Increase market share of already under-construction liquefaction that will pull an additional ~5.7 bcf/d by 2025** ➤ **Utilize portfolio depth, scale and expertise to pursue international priced opportunities**

Peer-Leading Capital Execution

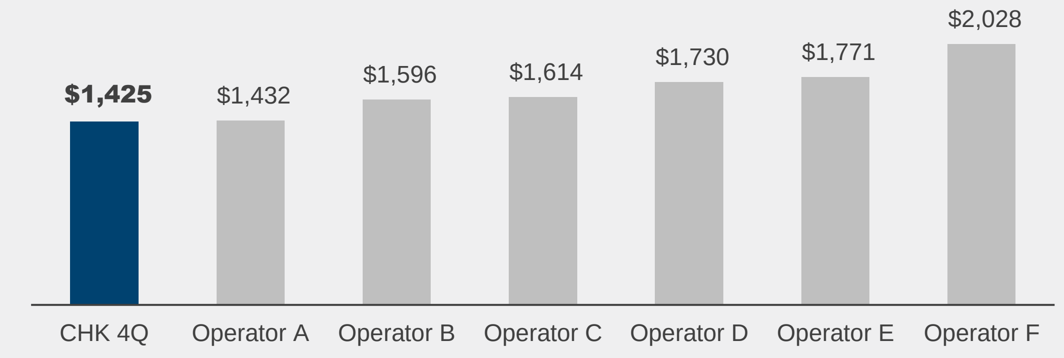
CHK Today

- **Lowest capital cost execution in Louisiana**
- **Decade+ of consistent improvements translates to lower cost wells today**

How We Deliver

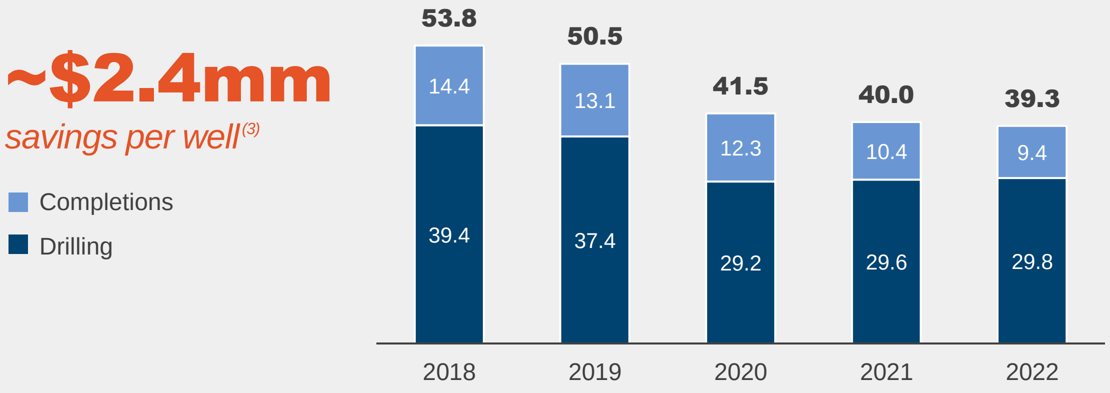
- **Basin scale = preferred rigs / crews**
- **Mixture of long- and short-term contracts lowers volatility but retains pricing flexibility**
- **Operations Center providing complete geologic and drilling support 24/7**
- **Optimal zone targeting from advanced subsurface characterization**

Haynesville Well Costs – Average $/ft(1)



Haynesville Efficiency Gains – Normalized Days per Well(2)

~$2.4mm
savings per well(3)



(1) Internal and other operator AFEs from July to October
(2) Normalized days required to drill and complete a current 2022 Haynesville frac design and 10K lateral length
(3) 2022 relative to 2018 efficiency assuming current spread rates

Our Path to Being LNG Ready

Gathering and Treating

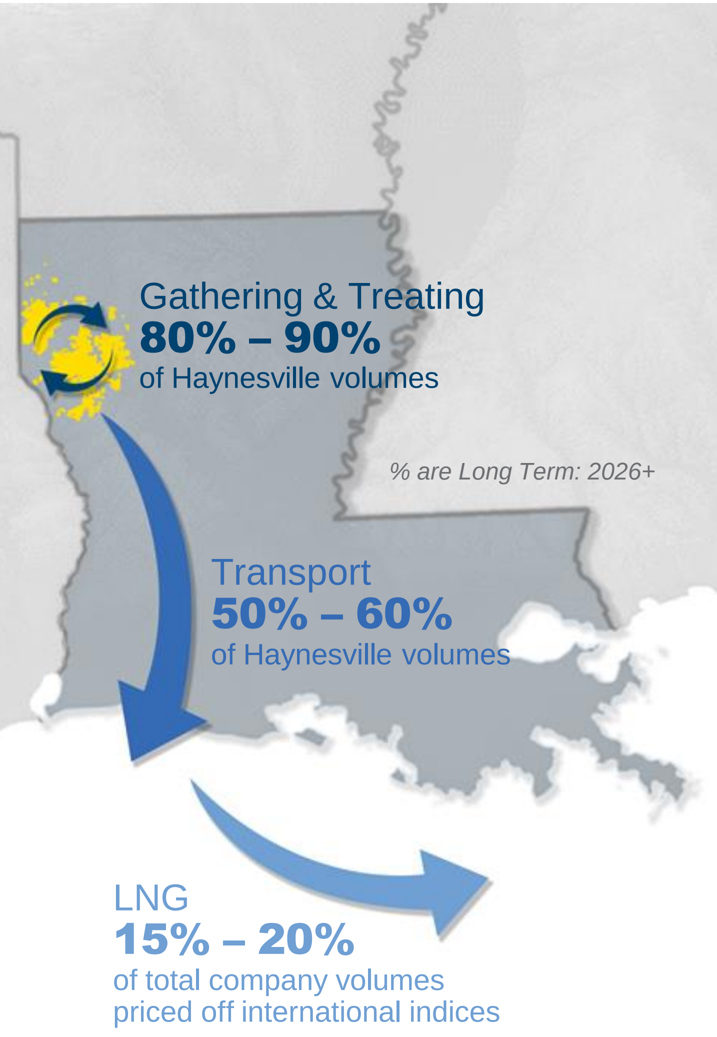
- Targeting 80% – 90% secured long-term with near-term coverage at 100%
- Execution of firm gathering and flexible offloads de-risk growth deliverability without impeding activity flexibility
- Negotiated additional ~1.4 bcf/d of gathering and treating capacity since beginning of 2022

Transportation and Term Sales

- Targeting 50% – 60% committed through firm transportation, allowing for flexibility to ramp commitments as pricing / activity allows
- Long-haul positions augmented by physical sales to distribute timing, price and execution risk
- Negotiated additional ~1.0 bcf/d of out-of-basin takeaway since beginning of 2022

LNG

- Targeting 15% – 20% of total company volumes to LNG, priced off international indices
- Pursuing pre-FID projects in next wave of new facilities to capture optimal pricing
- Actively exploring interim, shorter-term LNG opportunities

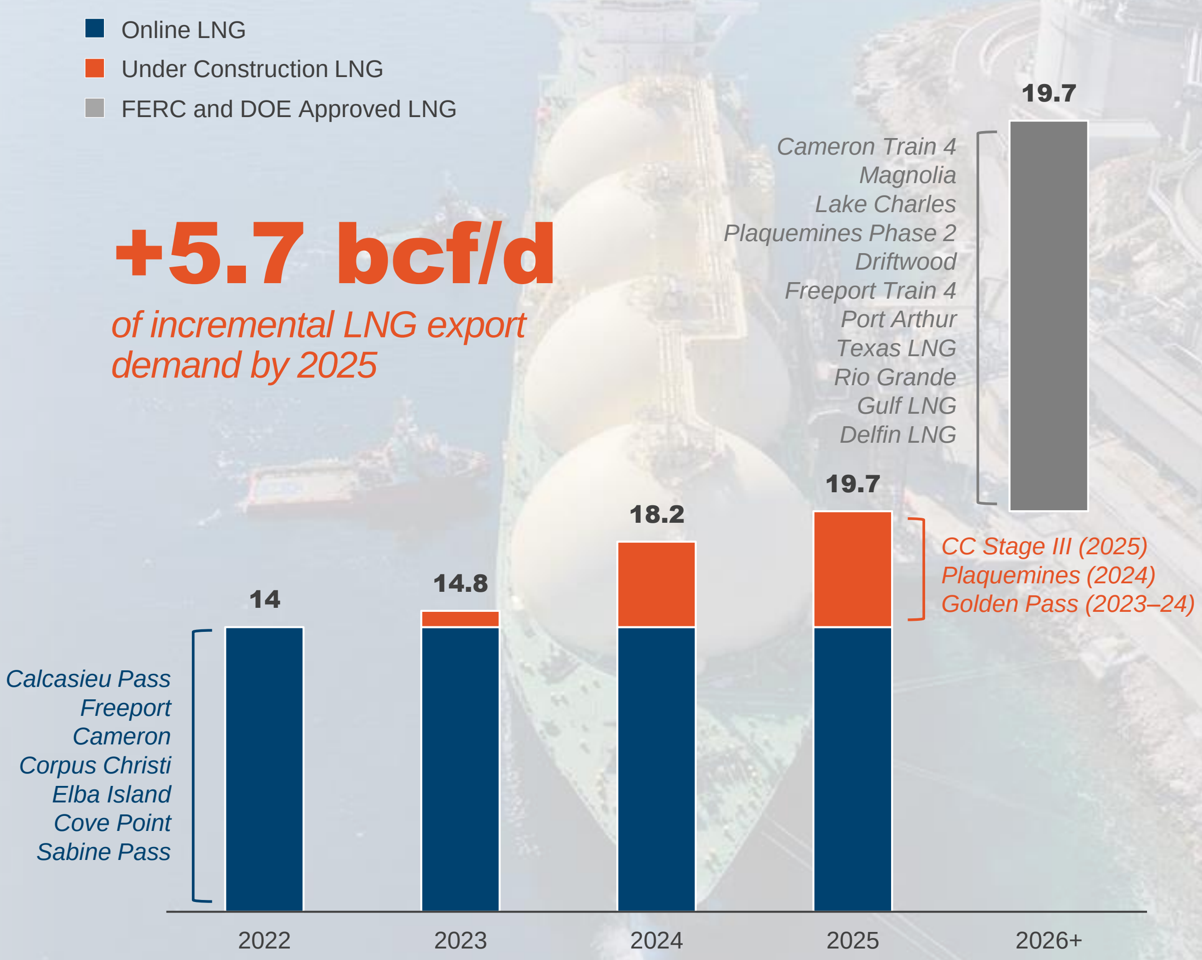


Macro Gas Demand: LNG Tailwinds Persist

- **Growth from core basins will be insufficient to meet already under construction LNG volumes**
- **Gas prices should align to the marginal cost of supply by 2025**
- **CHK portfolio uniquely positioned to meet growing LNG demand**

Implied Gas Growth (bcf/d)[1]	
	Δ 2022 – 2025
Haynesville	4.4
Other Low-Cost Gas (Permian, Eagle Ford, Anadarko)	4.6
Total Gas Additions	9.0
Non-Export Demand[2]	(4.6)
Net Gas Available for Export	4.4
LNG Export Demand	5.7
Gas Shortfall in 2025	**(1.2)**

U.S. LNG Capacity (bcf/d)[3]



(1) Broker U.S. dry gas supply model
(2) EIA AEO gas demand growth excluding export
(3) EIA liquefaction capacity; Includes Freeport as part of 2022 online volumes

Most Compelling Natural Gas Opportunity

Superior Capital Returns	✓ Unwavering commitment to returning cash flow to shareholders
Deep, Attractive Inventory	✓ Capital efficient assets that sustainably generate returns
Premier Balance Sheet	✓ Resilient credit metrics that de-risk equity returns through commodity price cycles
ESG Excellence	✓ Leading emissions profile, commitment to social initiatives and shareholder-aligned compensation incentives

Appendix

Non-GAAP Financial Measures

This document includes non-GAAP financial measures. Such non-GAAP measures should not be considered as an alternative to, or more meaningful than, GAAP measures. The Company's management believes that these measures provide useful information to external users of the Company's consolidated financial statements, such as industry analysts, lenders and ratings agencies. Due to the forward-looking nature of adjusted EBITDAX, net debt, projected free cash flow, free cash flow yield and free cash flow per share used herein, management cannot reliably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures. Accordingly, the Company is unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures without unreasonable effort. Amounts excluded from these non-GAAP measures in future periods could be significant.

EBITDAX: Adjusted EBITDAX is a non-GAAP measure used by management to evaluate the Company's operational trends and performance relative to other oil and natural gas producing companies. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The most directly comparable GAAP measure is net income (loss). Items excluded from net income (loss) to arrive at adjusted EBITDAX include interest expense, income taxes, depreciation, depletion and amortization expense, and exploration expense as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Net Debt: Net debt is defined as total GAAP debt excluding premiums, discounts, and deferred issuance costs less cash and cash equivalents. Net debt is presented as a widely understood measure of liquidity, but should not be considered as an alternative to, or more meaningful than, total debt presented in accordance with GAAP.

Free Cash Flow, Free Cash Flow Yield and Free Cash Flow Per Share:

- Adjusted free cash flow is defined as net cash provided by operating activities (GAAP), less cash capital expenditures.
- Adjusted free cash flow yield is defined as adjusted free cash flow divided by market capitalization.
- Adjusted free cash flow per share is defined as adjusted free cash flow divided by the Company's outstanding shares of common stock.

Adjusted free cash flow, free cash flow yield and adjusted free cash flow per share are non-GAAP supplemental financial measures used by the Company's management to assess liquidity, including the Company's ability to generate cash flow in excess of its capital requirements and return cash to shareholders. Adjusted free cash flow, adjusted free cash flow yield and adjusted free cash flow per share should not be considered as alternatives to, or more meaningful than, net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP.

Glossary

BE: Breakeven – the minimum price at which cumulative cash flows are zero

BU: Business Unit

CFFO: Cash flow from Operations

CROCI: Cash Returned on Capital Invested is the 3-year EBITDA – Interest Expense – G&A / Total Net D&C and Non-D&C Capital

D&C: Drilling and Completion expense

DOE: Department of Energy

ESG: Environmental, Social, Governance

FCF: Free Cash Flow

FDSO: Fully Diluted Shares Outstanding

FERC: Federal Energy Regulatory Commission

FID: Final Investment Decision

G&A: General and Administrative expense

G&G: Geological and Geophysical expense

GHG: Greenhouse Gas

GP&T: Gathering, Processing and Transport expense

IP30: Initial production rate for the first 30 days

IP90: Initial production rate for the first 90 days

IRR: Internal Rate of Return is the discount rate at which cumulative cash flows equal to zero

LHC: Leasehold Capital expense

LiDAR: Light Detection and Ranging

LL: Lateral length is the length from the point at which a wellbore enters the target zone to the terminus point of the wellbore

MVC: Minimum Volume Commitment

NAV: Net Asset Value

NPV: Net Present Value

NRI: Net revenue interest is a share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest

PDP: Proved Developed Producing – Reserve classification for a producing well

PIR: Profit Investment Ratio = (PV-10 less capex) / total net capital

PP&E: Property, Plant, and Equipment expense

PV-0: Present Value at a 0% discount rate

PV-10: Present Value at a 10% discount rate

RBL: Reserve Based Lending

RSG: Responsibly Sourced Gas

SPUD: To start the well drilling process

TIL: Turn-In-Line; a well turned to sales

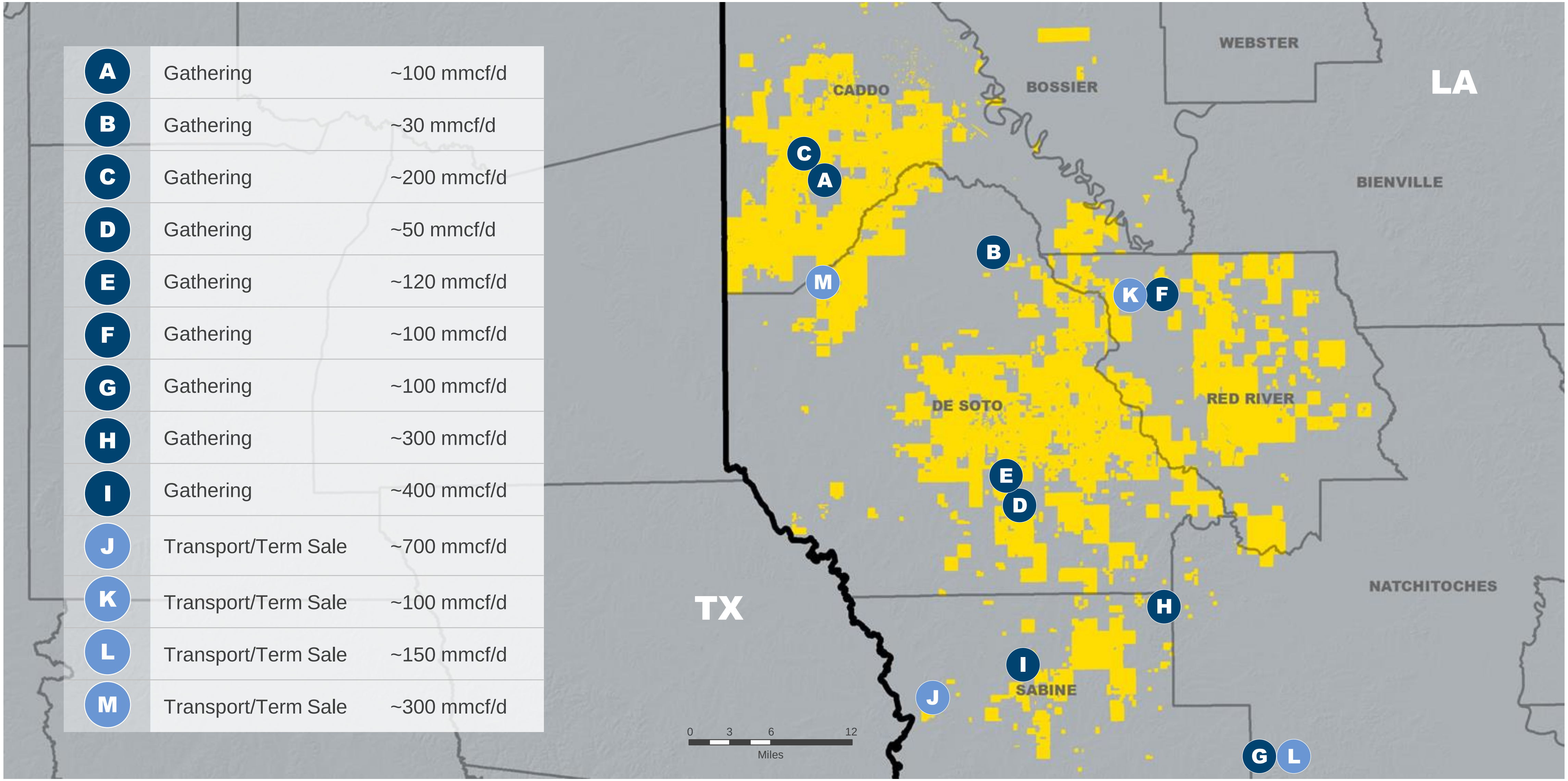
UAC: Upper Austin Chalk

WI: Working Interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill and produce hydrocarbons from a tract of property

WPS: Wells Per Section

Making Progress: 2022+ Haynesville Midstream Additions

A	Gathering	~100 mmcf/d
B	Gathering	~30 mmcf/d
C	Gathering	~200 mmcf/d
D	Gathering	~50 mmcf/d
E	Gathering	~120 mmcf/d
F	Gathering	~100 mmcf/d
G	Gathering	~100 mmcf/d
H	Gathering	~300 mmcf/d
I	Gathering	~400 mmcf/d
J	Transport/Term Sale	~700 mmcf/d
K	Transport/Term Sale	~100 mmcf/d
L	Transport/Term Sale	~150 mmcf/d
M	Transport/Term Sale	~300 mmcf/d

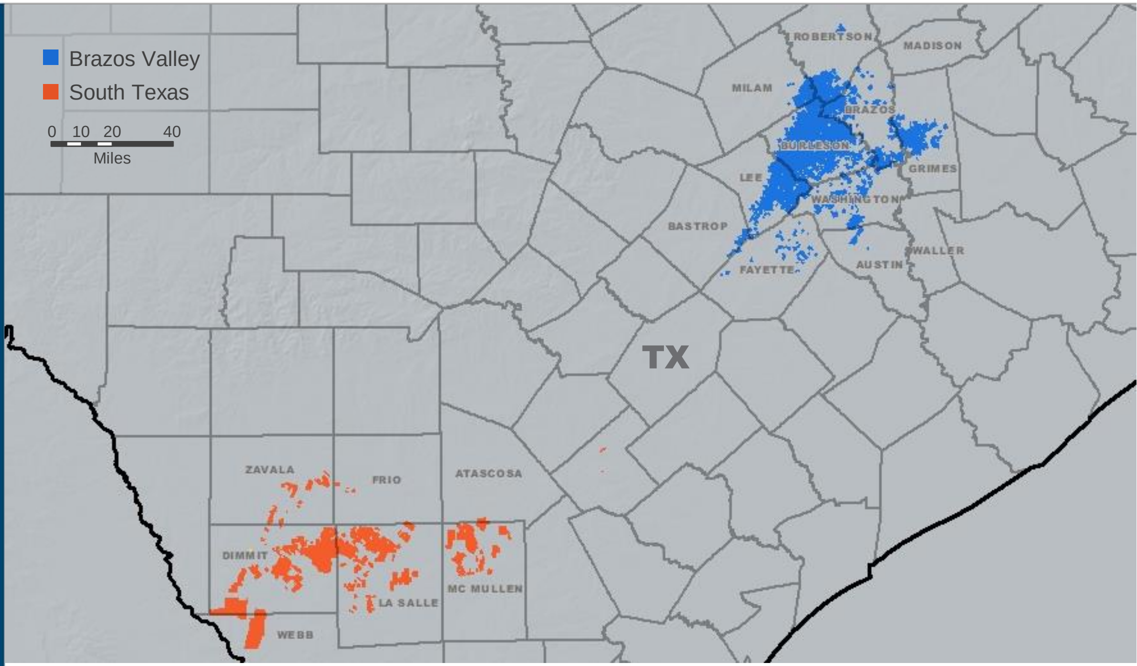


Eagle Ford: Superior Margins, Sustainable Free Cash Flow

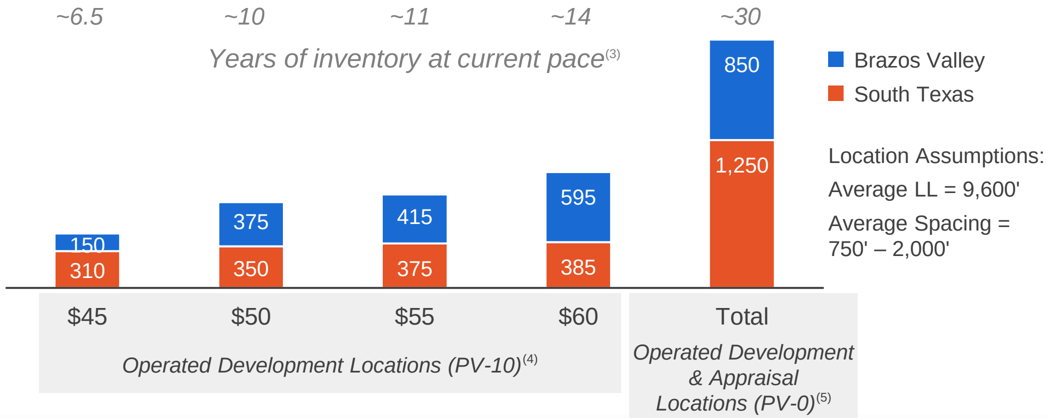
- ~14 years of drilling using 2 – 3 rigs
- 2022E BU EBITDAX[1,2] $1.55B – $1.66B
- Emerging Austin Chalk potential, ~10 wells in 2022 program
- Gas MVC shortfall projected to decline by 50% YoY

Asset Overview	3Q'22	4Q'22E	FY'22E
Net Production (mboe/d)	86	85 – 95	90 – 100
Average Rigs	4	~3	2 – 4
Wells Drilled	18	10 – 14	65 – 75
Wells TIL'd	21	14 – 20	40 – 50
Average LL (feet)			~10,500
Cost/Lateral Foot			$700 – $800
PDP Decline (5 year)			~15%
2022 TIL Decline (1 year)			~70%

Cost Assumptions (net)	3Q'22	4Q'22E	FY'22E
Differential to NYMEX ($/bbl)	$3.07		$1.75 – $2.25
LOE ($/boe)	$7.68		$6.50 – $6.75
GP&T ($/boe)	$11.46		$9.50 – $10.50
D&C Capital ($mm)	$172	$45 – $55	$375 – $415
Total Capital ($mm)	$194	$80 – $90	$450 – $500



Gross Inventory by Breakeven



Location Assumptions:

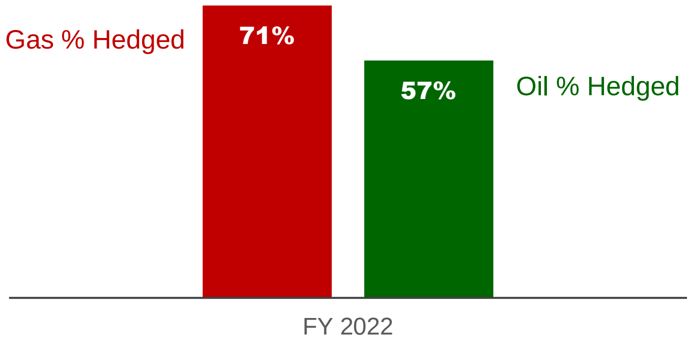
Average LL = 9,600'

Average Spacing = 750' – 2,000'

(1) BU level EBITDAX based on outlook as of 11/1/2022 and excludes hedges and corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 10/27/2022 for 2022 ($6.57 HHUB / $96 WTI)
(3) Assumes 70 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage. Only total counts include zones still in early evaluation or exploration wells.
Note: EBITDAX is a non-GAAP measures which is defined in the appendix

Hedging Program Reduces Risk, Protects Returns

As of 10/27/2022



DOWNSIDE PROTECTION LEVELS	4Q'22[1]	2023
Gas, $/mcf	$2.86	$3.19
Oil, $/bbl	$45.92	$64.54

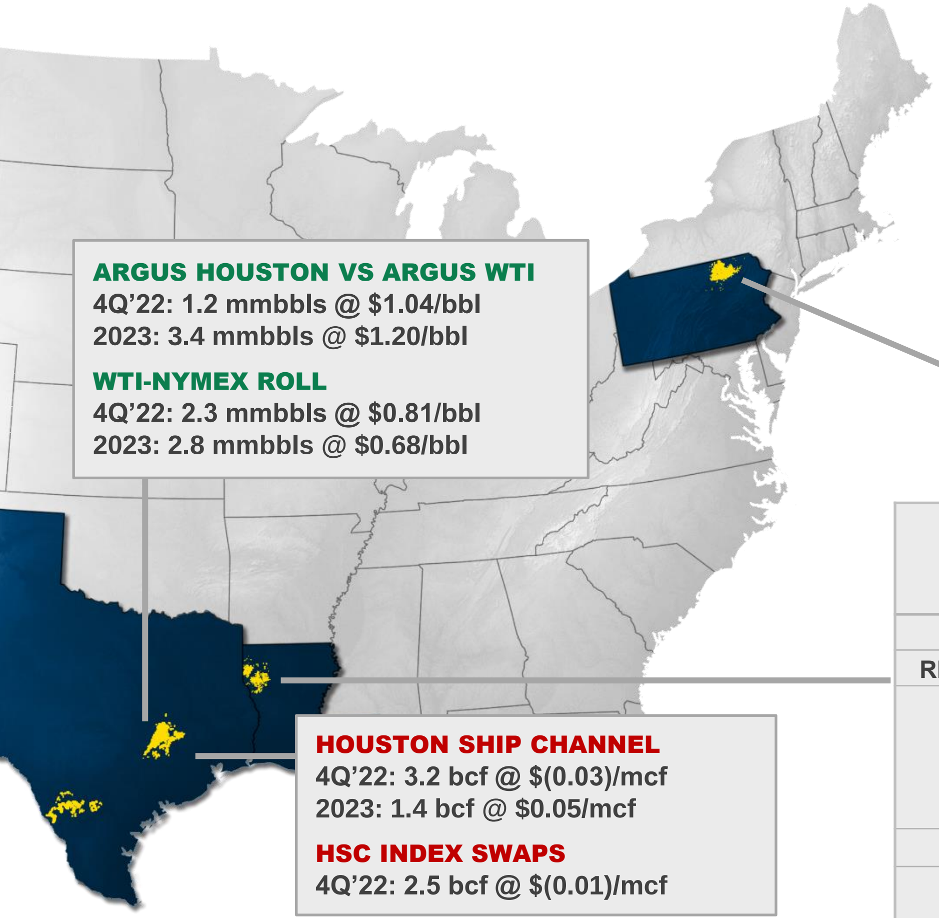
	NATURAL GAS													OIL				
	SWAPS		SWAPTIONS		COLLARS			THREE-WAY COLLARS				CALLS		SWAPS		COLLARS		
Date	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Put *$/mcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Call *$/mcf*	Volume *mmbbl*	Price *$/bbl*	Volume *mmbbl*	Bought Put *$/bbl*	Sold Call *$/bbl*
4Q 2022	117.3	2.60	–	–	120.1	3.12	4.27	6.4	2.41	2.90	3.43	–	–	2.6	45.92	–	–	–
RMDR '22	**117.3**	**2.60**	**–**	**–**	**120.1**	**3.12**	**4.27**	**6.4**	**2.41**	**2.90**	**3.43**	**–**	**–**	**2.6**	**45.92**	**–**	**–**	**–**
1Q 2023	114.3	2.64	1.8	2.88	59.3	3.54	6.66	0.9	2.50	3.40	3.79	18.0	3.29	1.9	47.17	0.7	76.09	91.21
2Q 2023	28.7	2.73	1.8	2.88	125.8	3.43	5.68	0.9	2.50	3.40	3.79	–	–	–	–	2.2	68.45	82.72
3Q 2023	27.2	2.75	1.8	2.88	126.7	3.43	5.68	0.9	2.50	3.40	3.79	–	–	–	–	1.9	69.12	82.23
4Q 2023	33.3	2.69	1.8	2.88	101.8	3.37	5.74	0.9	2.50	3.40	3.79	–	–	–	–	1.4	70.63	84.25
FY 2023	**203.5**	**2.67**	**7.3**	**2.88**	**413.5**	**3.43**	**5.83**	**3.7**	**2.50**	**3.40**	**3.79**	**18.0**	**3.29**	**1.9**	**47.17**	**6.2**	**69.99**	**83.86**
1Q 2024	44.5	2.77	–	–	16.4	3.97	6.08	–	–	–	–	–	–	–	–	–	–	–
2Q 2024	17.0	3.14	–	–	16.4	3.97	6.08	–	–	–	–	–	–	–	–	–	–	–
3Q 2024	16.8	3.16	–	–	16.6	3.97	6.08	–	–	–	–	–	–	–	–	–	–	–
4Q 2024	22.6	3.02	–	–	16.6	3.97	6.08	–	–	–	–	–	–	–	–	–	–	–
FY 2024	**100.9**	**2.95**	**–**	**–**	**65.9**	**3.97**	**6.08**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**

Note: Hedged volume and price reflect positions as of 10/27/2022
(1) RMDR 2022 includes 4Q'22

Hedged Financial Basis

As of 10/27/2022

- 17% of Marcellus and 56% of Haynesville basis hedged for the remainder of 2022
- Since 7/29/2022, CHK has added basis protection for:
  - 17.1 bcf of 4Q’22 gas at an average differential to NYMEX of $(0.52)
  - 155 bcf of 2023 gas at $(0.32)



	MARCELLUS						HAYNESVILLE				TRANSPORT SPREAD[1]	
	TETCO M3		TGP Z4 300L		LEIDY		CGT MAINLINE		TGT Z1		TETCO M3	
Date	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf
4Q 2022	9.1	0.90	2.8	(1.08)	19.1	(0.98)	70.9	(0.43)	9.8	(0.23)	9.9	0.77
RMDR ‘22	**9.1**	**0.90**	**2.8**	**(1.08)**	**19.1**	**(0.98)**	**70.9**	**(0.43)**	**9.8**	**(0.23)**	**9.9**	**0.77**
1Q 2023	17.3	1.49	6.0	(1.13)	22.6	(0.91)	57.2	(0.30)	8.6	(0.21)	6.8	0.76
2Q 2023	13.7	0.44	7.7	(1.33)	15.5	(1.17)	34.6	(0.33)	4.8	(0.29)	6.8	0.76
3Q 2023	13.8	0.44	7.8	(1.33)	15.6	(1.17)	35.0	(0.33)	4.8	(0.29)	6.9	0.76
4Q 2023	13.8	0.82	6.9	(1.18)	11.4	(1.10)	32.1	(0.30)	4.2	(0.26)	2.9	0.76
FY 2023	**58.6**	**0.84**	**28.4**	**(1.25)**	**65.0**	**(1.07)**	**158.8**	**(0.31)**	**22.4**	**(0.25)**	**23.4**	**0.76**
1Q 2024	3.6	1.25	4.1	(0.97)	7.7	(0.97)	26.2	(0.27)	6.6	(0.27)	–	–
2Q 2024	–	–	1.8	(1.16)	6.4	(1.03)	15.9	(0.29)	4.6	(0.32)	–	–
3Q 2024	–	–	1.8	(1.16)	6.4	(1.03)	16.1	(0.29)	4.6	(0.32)	–	–
4Q 2024	–	–	1.8	(1.16)	6.4	(1.03)	16.1	(0.29)	4.6	(0.32)	–	–
FY 2024	**3.6**	**1.25**	**9.6**	**(1.08)**	**27.0**	**(1.01)**	**74.3**	**(0.28)**	**20.3**	**(0.30)**	**–**	**–**

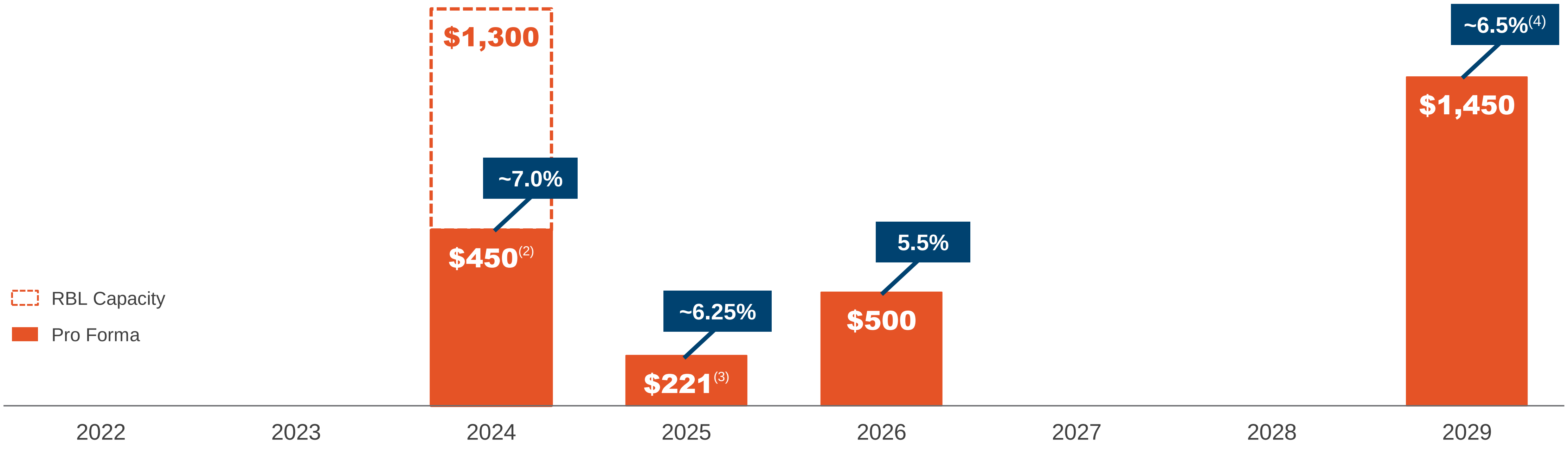
(1) TETCO M3 transport spread vs. TGP Z4 300L

Maturity Profile

Net debt-to-2023E EBITDAX ratio[(1)]

~0.4x

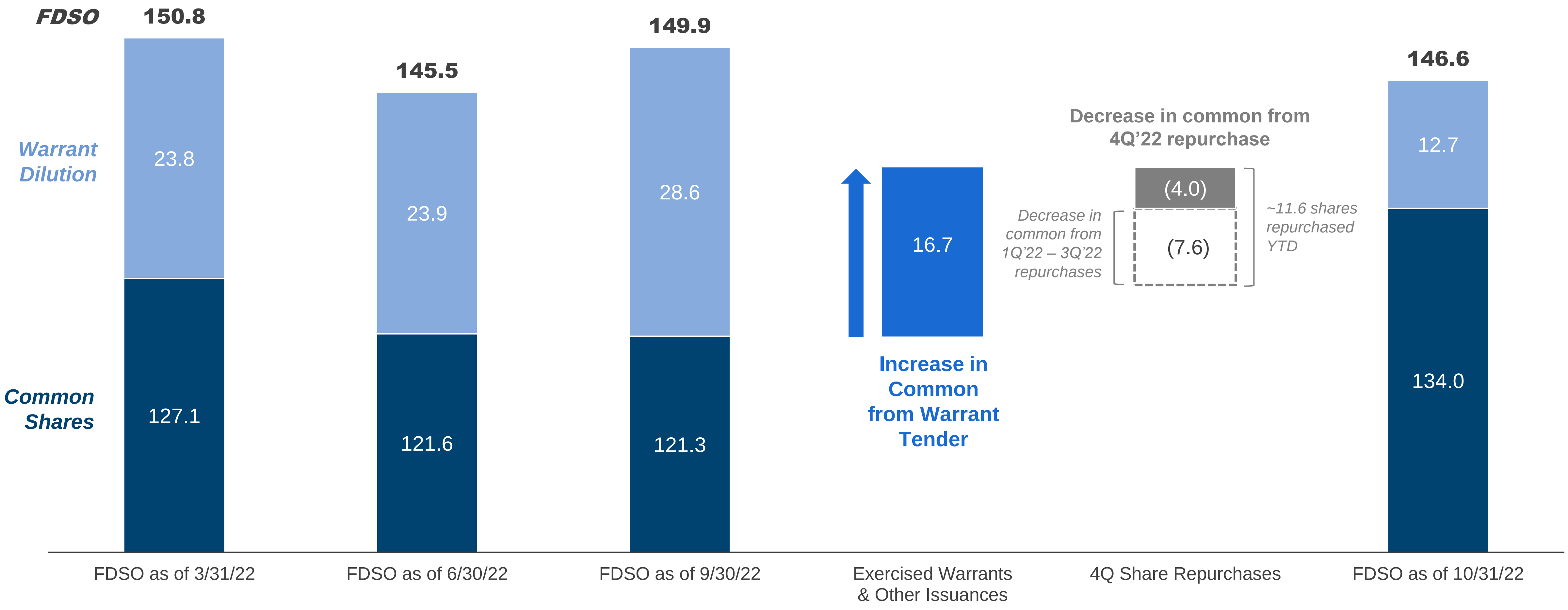
Preserving balance sheet strength



(1) A non-GAAP measure as defined in the appendix; 9/30/2022 net debt balance as a ratio to consensus 2023 EBITDAX as of 10/27/2022
(2) Revolver balance as of 9/30/2022
(3) Represents $221mm of CA-CIB and Natixis Tranche B
(4) $500mm at 5.875% and $950mm at 6.75%

Current Share Count

(Values shown in millions)



Note: Warrant dilution category includes shares held in reserve for general unsecured claims

Management's Outlook as of November 1, 2022

	2022 Projections
Total production:	
Oil – mbbls per day	51 – 56
NGL – mbbls per day	15 – 18
Natural gas – mmcf per day	3,600 – 3,680
Total daily rate – mmcfe per day	4,020 – 4,140
Estimated basis to NYMEX prices, based on 10/27/22 strip prices:	
Oil – $/bbl	***$1.75 – $2.25***
Natural gas – $/mcf	***($0.60) – ($0.70)***
NGL – realizations as a % of WTI	40% – 45%
Operating costs per mcfe of projected production:	
Production expense	$0.29 – $0.33
Gathering, processing and transportation expenses	$0.70 – $0.80
Oil – $/bbl	$2.80 – $3.00
Natural Gas – $/mcf	$0.75 – $0.85
Severance and ad valorem taxes	$0.16 – $0.18
General and administrative(1)	$0.08 – $0.11
Depreciation, depletion and amortization expense	$1.17 – $1.33
Marketing net margin and other ($ in millions)	$25 – $50
Interest expense ($ in millions)	***$150 – $160***
Cash taxes ($ in millions)	***$175 – $225***
Cash taxes (as a percent of income before income taxes)	6% – 9%
Adjusted EBITDAX, based on 10/27/22 strip prices ($ in millions)(2)	***$4,450 – $4,550***
Total capital expenditures ($ in millions)	$1,750 – $1,950
Marcellus D&C	$400 – $440
Haynesville D&C	$750 – $800
Eagle Ford D&C	$375 – $415
Powder River Basin D&C	$25
Non-D&C Field (workover, infrastructure and leasehold)	$115 – $165
Non-D&C Corporate (PP&E, G&G, capitalized interest and G&A)	$85 – $105

(1) Includes ~$0.01/mcfe of expenses associated with stock-based compensation, which are recorded in general and administrative expenses in Chesapeake's Condensed Consolidated Statement of Operations.
(2) Adjusted EBITDAX is a non-GAAP measure used by management to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The most directly comparable GAAP measure is net income (loss), but it is not possible, without unreasonable efforts, to identify the amount or significance of events or transactions that may be included in future GAAP net income (loss) but that management does not believe to be representative of underlying business performance. The company further believes that providing estimates of the amounts that would be required to reconcile forecasted adjusted EBITDAX to forecasted GAAP net income (loss) would imply a degree of precision that may be confusing or misleading to investors. Items excluded from net income (loss) to arrive at adjusted EBITDAX include interest expense, income taxes, depreciation, depletion and amortization expense, and exploration expense as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Reconciliation of Net Income (Loss) to Adjusted EBITDAX (unaudited)

($ in millions)	Successor Three Months Ended September 30, 2022	Successor Three Months Ended September 30, 2021
Net income (loss) (GAAP)	**$ 883**	**$ (345)**
Adjustments:		
Interest expense	52	17
Income tax expense (benefit)	74	(10)
Depreciation, depletion and amortization	440	228
Exploration	2	2
Unrealized (gains) losses on natural gas and oil derivatives	(199)	618
(Gains) losses on sales of assets	2	(3)
Other operating expense, net	6	6
Other	(4)	6
Adjusted EBITDAX (Non-GAAP)	**$ 1,256**	**$ 519**

Adjusted EBITDAX is not a measure of financial performance under GAAP, and should not be considered as an alternative to, or more meaningful than, net income (loss) prepared in accordance with GAAP. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The company believes this non-GAAP financial measure is a useful adjunct to cash flow provided by operating activities because: (i) Management uses adjusted EBITDAX to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies. (ii) Adjusted EBITDAX is more comparable to estimates provided by securities analysts. (iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss), our calculations of adjusted EBITDAX may not be comparable to similarly titled measures of other companies.

Reconciliations of Adjusted Free Cash Flow and Net Debt

ADJUSTED FREE CASH FLOW		
	Successor	
($ in millions)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021
Net cash provided by operating activities (GAAP)	**$ 1,313**	**$ 443**
Cash capital expenditures	(540)	(178)
Adjusted free cash flow (Non-GAAP)	**$ 773**	**$ 265**

NET DEBT	
	Successor
($ in millions)	September 30, 2022
Total debt (GAAP)	**$ 2,717**
Premiums and issuance costs on debt	(96)
Principal amount of debt	**2,621**
Cash and cash equivalents	(74)
Net debt (Non-GAAP)	**$ 2,547**