SM|ENERGY

2022 Results and 2023 Operating Plan

FEBRUARY 22, 2023

DISCLAIMERS

Forward-looking statements

This presentation contains forward-looking statements within the meaning of securities laws. The words “demonstrate,” “estimate,” “expect,” "goal," "generate," “plan,” “target,” “believes,” “objectives,” “priorities,” and similar expressions are intended to identify forward-looking statements. Forward-looking statements in this release include, among other things, certain projections for the full year and first quarter of 2023 regarding guidance for capital expenditures, production, percent of oil, operating costs, general and administrative expenses, exploration expenses, and DD&A; total expected inventory, inventory estimates by operating area, and total inventory expected average rate of return; the Company’s 2023 strategic objectives including delivering increased return of capital to stockholders, operational execution, and replacing/building top-tier inventory; the portion of capital expenditures to be allocated to drilling and completion costs and to each of our operating areas; the number of wells expected to be drilled and completed in each of our operating areas; components of 2023 completion design and expected PDP decline rates; percentage of expected future production that is hedged; expected average lateral length per well; expected South Texas transportation costs; expected number of Austin Chalk locations; timing of expected payout for certain new wells; and plan to process ethane for 2023. These statements involve known and unknown risks, which may cause SM Energy's actual results to differ materially from results expressed or implied by the forward-looking statements. Future results may be impacted by the risks discussed in the Risk Factors section of SM Energy's most recent Annual Report on Form 10-K, as such risk factors may be updated from time to time in the Company's other periodic reports filed with the Securities and Exchange Commission, specifically the 2022 Form 10-K. The forward-looking statements contained herein speak as of the date of this release. Although SM Energy may from time to time voluntarily update its prior forward-looking statements, it disclaims any commitment to do so, except as required by securities laws.

Non-GAAP financial measures & metrics

This presentation references non-GAAP financial measures and metrics. Please see the “Non-GAAP Reconciliations and Disclosures” section of the Appendix, which includes definitions of non-GAAP measures and metrics used in this presentation and reconciliations of non-GAAP measures to the most directly comparable GAAP measure.

Reserves disclosure

The SEC requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil, natural gas and natural gas liquids (NGLs), that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions (using the trailing 12-month average first-day-of-the-month prices), operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, the Company currently does not disclose probable or possible reserves in its SEC filings.

Proved reserves attributable to the Company as of December 31, 2022, are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $93.67 per Bbl of oil, $6.36 per MMBtu of natural gas, and $42.52 per Bbl of NGLs. At least 80% of the PV-10 of the Company’s estimate of its total proved reserves at December 31, 2022, was audited by Ryder Scott Company, L.P.

PREMIER OPERATOR OF TOP-TIER ASSETS

2022 RESULTS SIGNIFICANTLY EXCEEDED PLAN GOALS

2022 Plan Goals & Results

Generate increased Adjusted free cash flow[1]

$849 million
Adjusted free cash flow[1]
(2.2x YE21)

20%
Yield to YE market cap[1]

Reduce leverage ratio[1] to ~1.0x, Net debt[1] to ~$1B

0.59x
Met leverage ratio[1] target in 2Q

$1.1 billion
Net debt[1][2]

$77 million[2]
Return of capital program initiated in September

Demonstrate measurable ESG stewardship

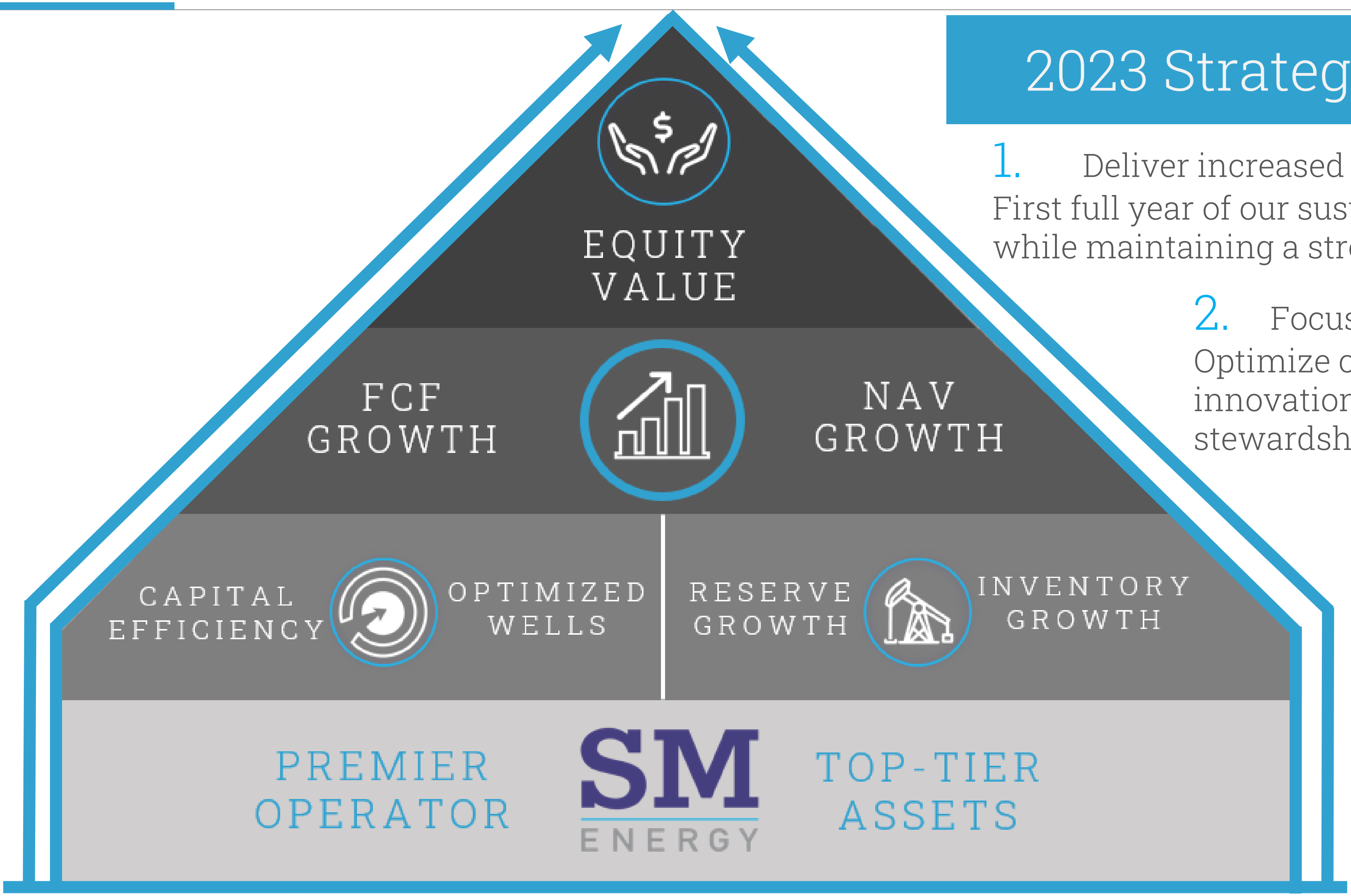
Exceeded internal targets

- Methane Intensity <0.04 mT CH4/MBOE
- Scope 1 + 2 GHG Intensity down ~40% since base year 2019
- De minimis routine flaring & non-routine flaring <1%

(1) Indicates a non-GAAP measure or metric. Please refer to the "Non-GAAP Reconciliations and Disclosures" section in the Appendix.
(2) Net debt at December 31, 2022, and Return of capital for the full year ended December 31, 2022.

PREMIER OPERATOR OF TOP-TIER ASSETS

VALUE CREATION



2023 Strategic Objectives

1. Deliver increased return of capital to stockholders: First full year of our sustainable capital return program while maintaining a strong balance sheet

2. Focus on operational execution: Optimize capital efficiency, demonstrate innovation, and maintain focus on ESG stewardship

3. Continue to replace/build top-tier inventory: Repeat track record of inventory replacement and growth, applying our differential strength in geosciences and development optimization

SUSTAINABLE AND REPEATABLE

BUSINESS MODEL

SUSTAINABLE

Sustainable

- Premier Operator of Top Tier Assets
- Return of Capital
- Strong Balance Sheet

SM ENERGY

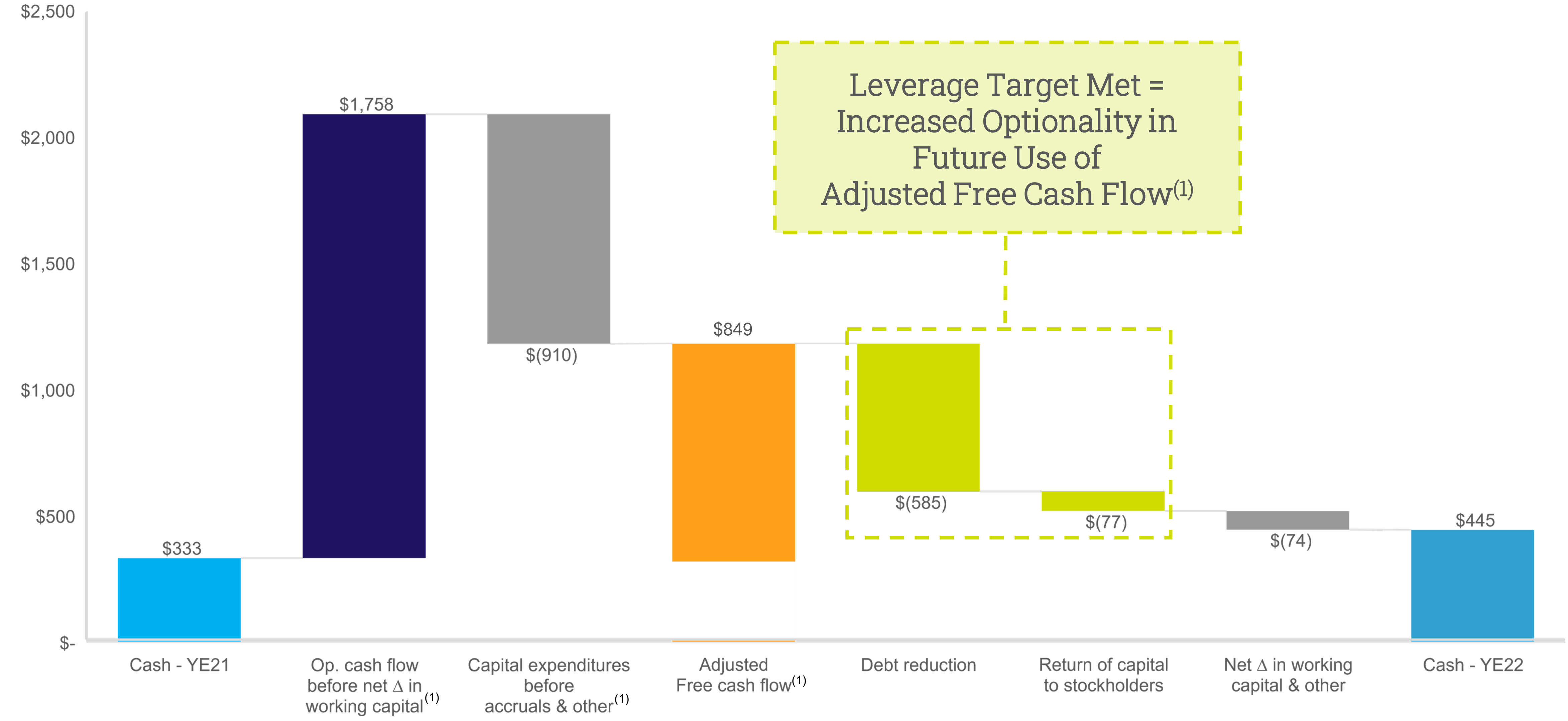
Repeatable

- World Class Technical Team
- Organically Add Inventory
- Strategic Inventory Capture and Growth

REPEATABLE

RECORD 2022 FCF[1] AT $849MM | 20% YIELD TO YE MARKET CAP[1]

2022 DEBT REDUCTION PIVOTS TO 2023 RETURN OF CAPITAL



Note | Amounts shown in millions. Amounts may not recalculate due to rounding.
(1) Indicates a non-GAAP measure or metric. Please refer to the “Non-GAAP Reconciliations and Disclosures” section in the Appendix.

Plan Overview & Guidance

2023 PLAN GUIDANCE(1)

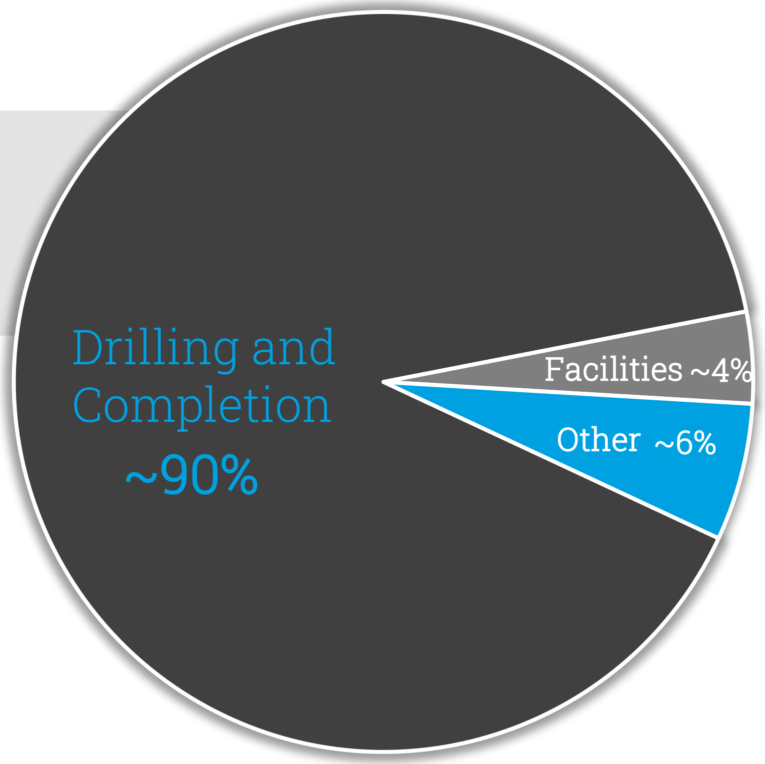
OPTIMIZING FREE CASH FLOW OVER A MULTI-YEAR PLAN

2023

Capital Expenditures(2)
~$1.1 billion

~60% Midland Basin

~40% South Texas



Key Metrics

Key Metrics	Guidance FY 2023
Capital Expenditures(2) ($B)	$1.1
Total Production (MMBoe)	52.5 – 54.5
Total Production (MBoe/d)	144 – 150
Oil percentage	~43%
LOE (per Boe)	$5.75 – $6.00
Transportation (per Boe)	~$2.50
Production & Ad Valorem taxes(3) (per Boe)	$2.90 – $3.00
G&A(4) ($MM)	~$120
Exploration Expense ($MM)	~$45
DD&A (per Boe)	$12 – $13

Key Assumption $80 oil | $3 gas | $34 NGL's

Q1 2023 Guidance

- Production: 12.9 – 13.1 MMBoe (143 – 146 MBoe/d), at 42 – 43% oil
- Capital expenditures(2): $320 – $330 million
- Activity:
  Drill: ~22 net wells (~12 South Texas, ~10 Midland Basin)
  Complete: ~25 net wells (~15 South Texas, ~10 Midland Basin)

(1) As of February 22, 2023.
(2) Capital expenditures before change in capital expenditure accruals and other; excludes acquisitions.
(3) Production & Ad Valorem taxes estimated at ~4.7% of pre-hedge revenue and ~$0.80/Boe, respectively.
(4) Includes $15 – $20 million non-cash compensation.

BALANCE SHEET

LEVERAGE OBJECTIVES MET

As of December 31, 2022:

Net debt-to-Adjusted EBITDAX[1]

0.59x

- Liquidity $1.7 billion
- Cash balance $445 million
- Net Debt[1] $1.1 billion[2]

~$551 million

total debt reduction during 2022

Three credit rating agency upgrades in 2022[3]:

Fitch ↑ BB- Outlook: Stable

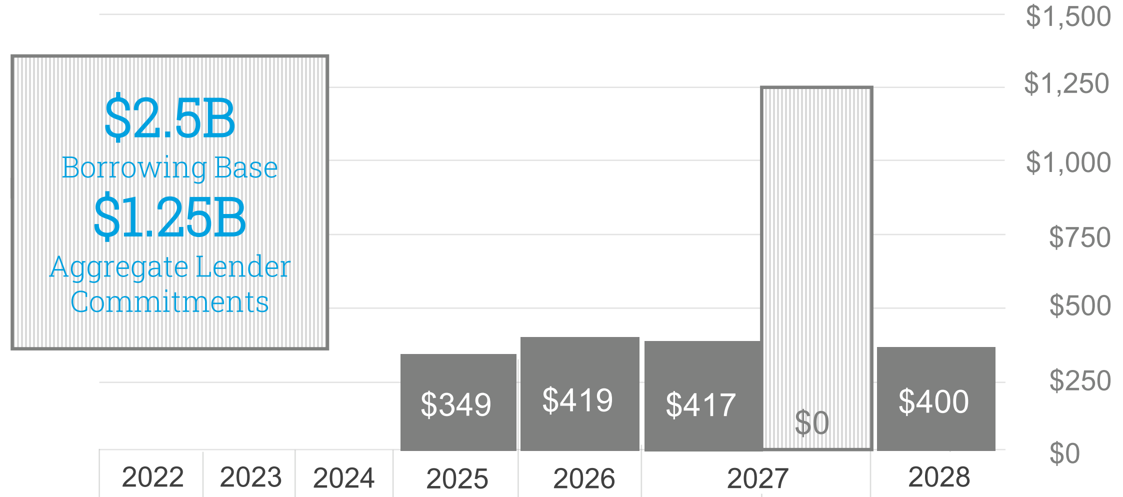
Moody's ↑ B2 Outlook: Positive

S&P ↑ BB- Outlook: Positive

As of December 31, 2022:

Debt Maturities

in millions



	2022	2023	2024	2025	2026	2027	2028
Coupon				5.625%	6.750%	6.625%	6.500%
Initial Call Date				6/2020	9/2021	1/2022	7/2024
Initial Call Price				102.81%	103.38%	104.97%	103.25%
Maturity Date				6/2025	9/2026	1/2027	7/2028

Revolving Credit Facility   Unsecured Senior Notes

(1) Indicates a non-GAAP measure or metric. Please refer to the "Non-GAAP Reconciliations and Disclosures" section in the Appendix.
(2) After return of capital paid to stockholders of ~$77 million.
(3) Ratings indicated are senior unsecured debt ratings.

HEDGING SUMMARY

HEDGE VOLUMES LOWER – ALIGNED WITH LOWER LEVERAGE

~25%

of total expected 2023 production hedged(1)

2023 Hedge Program

Oil

- ~6,800 MBbls(2), or slightly less than 30% of expected 2023 oil production, is hedged to contract prices in the Midland Basin at a weighted-average price of $74.10/Bbl (weighted-average of collar ceilings and swaps)
- ~5,400 MBbls of expected 2023 Midland Basin oil production is hedged to the local price point at a positive $0.94/Bbl basis

Natural gas

- ~36,500 BBtu(3), or slightly less than 30% of expected 2023 natural gas production, is hedged
- ~5,100 BBtu is hedged to HSC at a weighted-average price of $4.10/MMBtu, and ~12,300 BBtu of HSC basis is hedged with a weighted-average price of $(0.01)/MMBtu
- 900 BBtu is hedged to Waha at a weighted-average price of $3.98/MMBtu, and we have ~9,100 Bbtu of Waha basis is hedged with a weighted-average price of $(1.23)/MMBtu

As of February 15, 2023

(1) Percent of 2023 production hedged assumes mid-point of guidance and 43% oil.
(2) Hedges include oil swaps and collars to WTI and Brent; excludes basis swaps and roll differential hedges.
(3) Hedges include natural gas swaps and collars to Henry Hub, HSC, and Waha; excludes basis swaps. Percent hedged based on dry gas volumes.

YEAR-END 2022 PROVED RESERVES

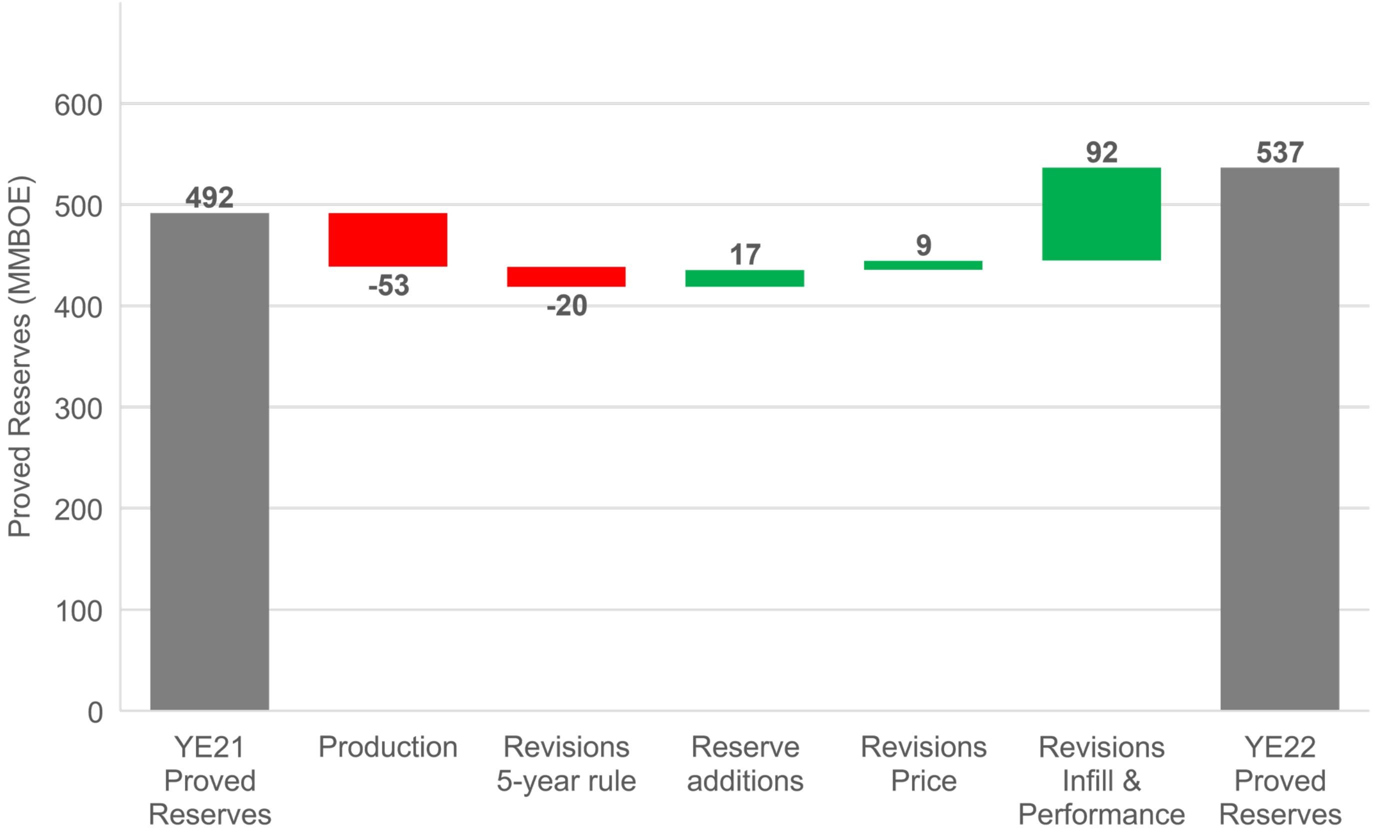
PROVED RESERVES UP 9% COMPARED TO PRIOR YEAR

Proved Reserves 537 MMBoe

Pre-tax PV-10(1) $12B

Reserves life index (proved reserves / 2022 production) 10 years

Production Replacement(2) 205%



59% Proved Developed

38% oil | 44% natural gas | 18% NGLs

Note | Calculated in accordance with SEC Pricing at $93.67 per barrel of oil NYMEX, $6.36 per MMBtu of natural gas at Henry Hub and $42.52 per barrel of natural gas liquids ("NGLs") at Mt. Belvieu.

(1) Indicates a non-GAAP measure or metric. Please refer to the "Non-GAAP Reconciliations and Disclosures" section in the Appendix.
(2) Calculated as reserve additions plus infills/performance revisions divided by 2022 production.

YEAR-END 2022 INVENTORY

ORGANICALLY REPLACING AND MAINTAINING HIGHLY ECONOMIC INVENTORY

Total Company expected economic inventory(1)

10–13+ years

Total Company inventory expected average return(1)

>60%

Individually Modeled – Not Just Sticks On a Map!

- Organically maintaining inventory
- Nearly **80%** of inventory is classified as 3P reserves → having economic and geologic certainty
- Organic inventory potential will be realized in future years through further testing and delineation

(1) Based on flat \$65/Bbl oil, \$3.25/MMBtu gas, and \$29/Bbl NGL's; inventory life assumes range of 80 – 100 completions per year.

Regional Update

MIDLAND BASIN

FOCUSED ON EXECUTION, WELL PERFORMANCE AND CAPITAL EFFICIENCY

2023 OPERATING PLAN

2023 PLAN DETAILS

- 2023 net wells planned: drill 40 – 45; complete ~50
- ~11,135’ expected average lateral feet per well, including 15 wells at ≥15,000 ft lateral length(1)
- ~33% Boe PDP decline expected (YE22 - YE23)

BEST IN CLASS WELL PERFORMANCE

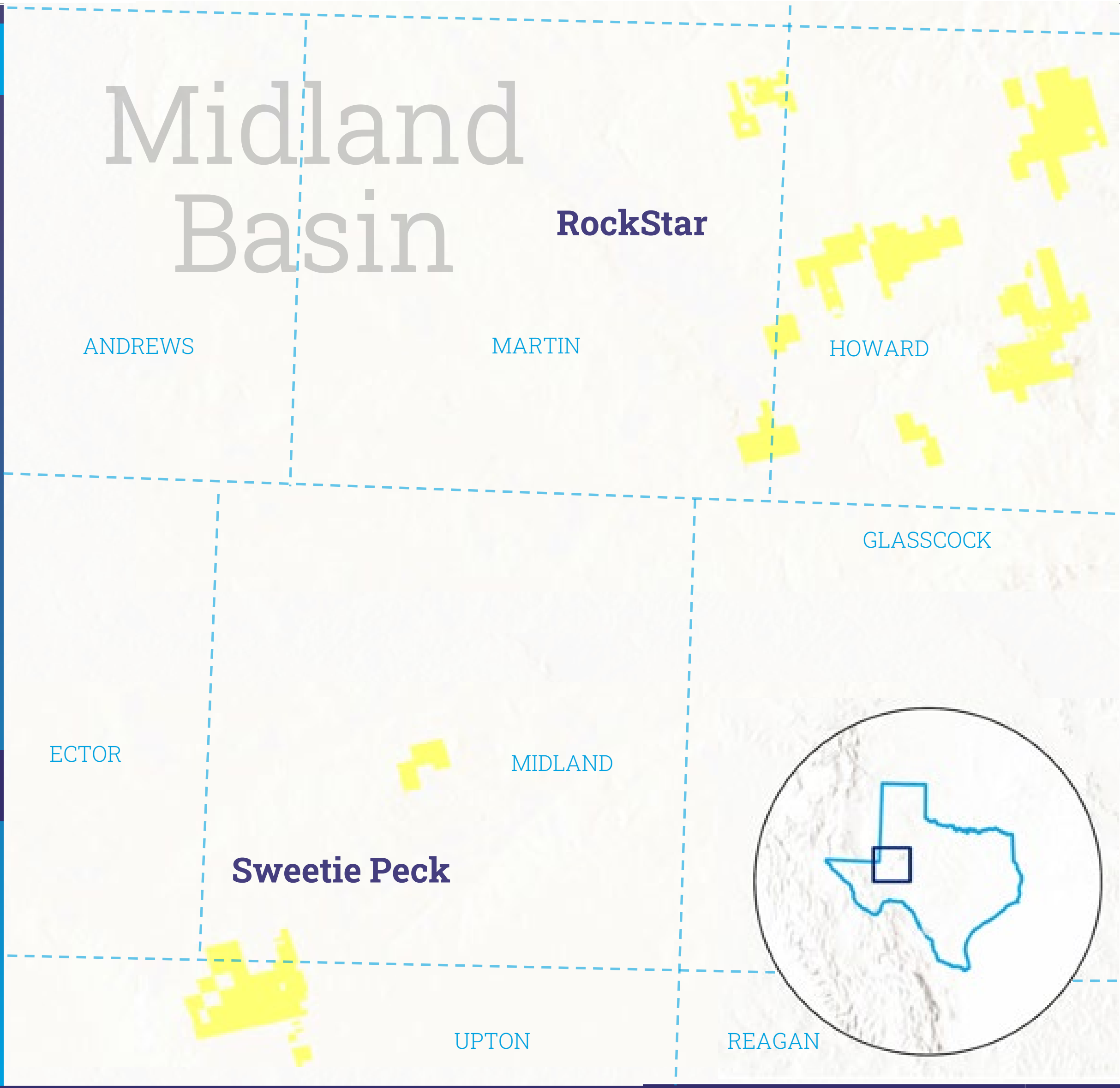
- Continue to optimize completion design and employ simul-frac
- Average of 6 – 8 well pad groups enable increased simul-frac/efficiency
- Continue to test 8 producing intervals
- 2023 completion designs expected to utilize average fluid loading of 64 Bbls/ft and 2,800 lbs/ft sand

OPERATING DETAILS(2)

Rigs Running: 3

Completion Crews: 1

~82,000 NET ACRES



(1) Based on operated wells expected to be completed in 2023.
(2) 2023 expected average.

INVENTORY UPSIDE ON EXISTING ACREAGE – UP TO 8 PRODUCING INTERVALS

Midland Basin Inventory Upside

6,500'	LEONARD
7,100'	MIDDLE SPRABERRY
7,700'	JO MILL
7,800'	LOWER SPRABERRY
8,200'	DEAN
8,400'	WOLFCAMP A
8,600'	WOLFCAMP B
9,500'	WOLFCAMP D

LEONARD

- First test ~ 800 days on production, 288 MBoe produced to date from 9,900' lateral
- Six Leonard tests planned for 1H23

DEAN

- Among best portfolio returns to date. Smails Dean well, fully bounded, averaged 30-day peak IP rate of 3,850 Boe/d at 91% oil (effective lateral of 13,737')
- 14 wells completed to date averaged 30-day peak IP rate of 1,440 Boe/d at 89% oil (average effective lateral 11,373')
- Incorporating into optimization/co-development plan

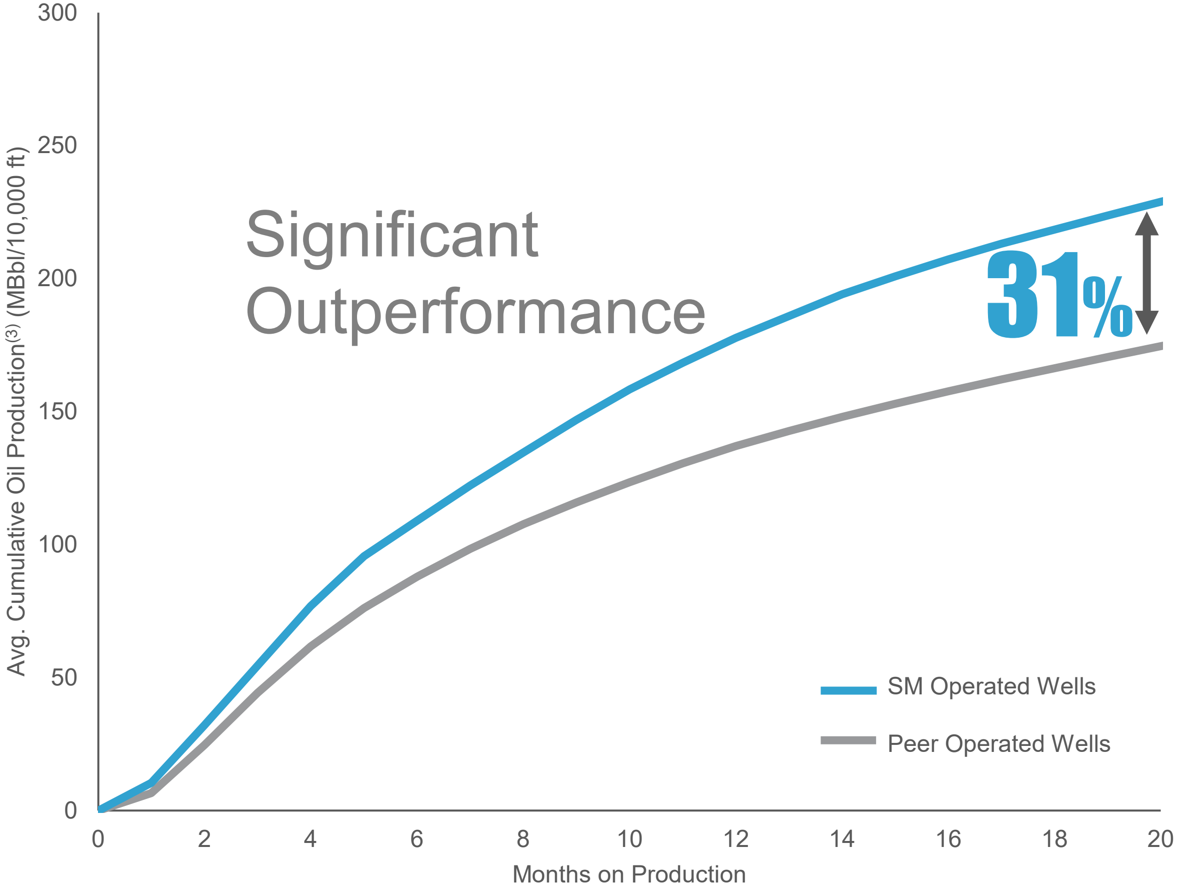
WOLFCAMP D

- Initial test well (2019) averaged 30-day peak IP rate of ~1,400 Boe/d with 80% oil (effective lateral 7,920')
- May 2022 test well averaged 30-day peak IP rate of ~1,900 Boe/d with 79% oil (effective lateral 10,166')
- Two additional Wolfcamp D wells online in 4Q22
- Seven additional Wolfcamp D wells planned in 2023

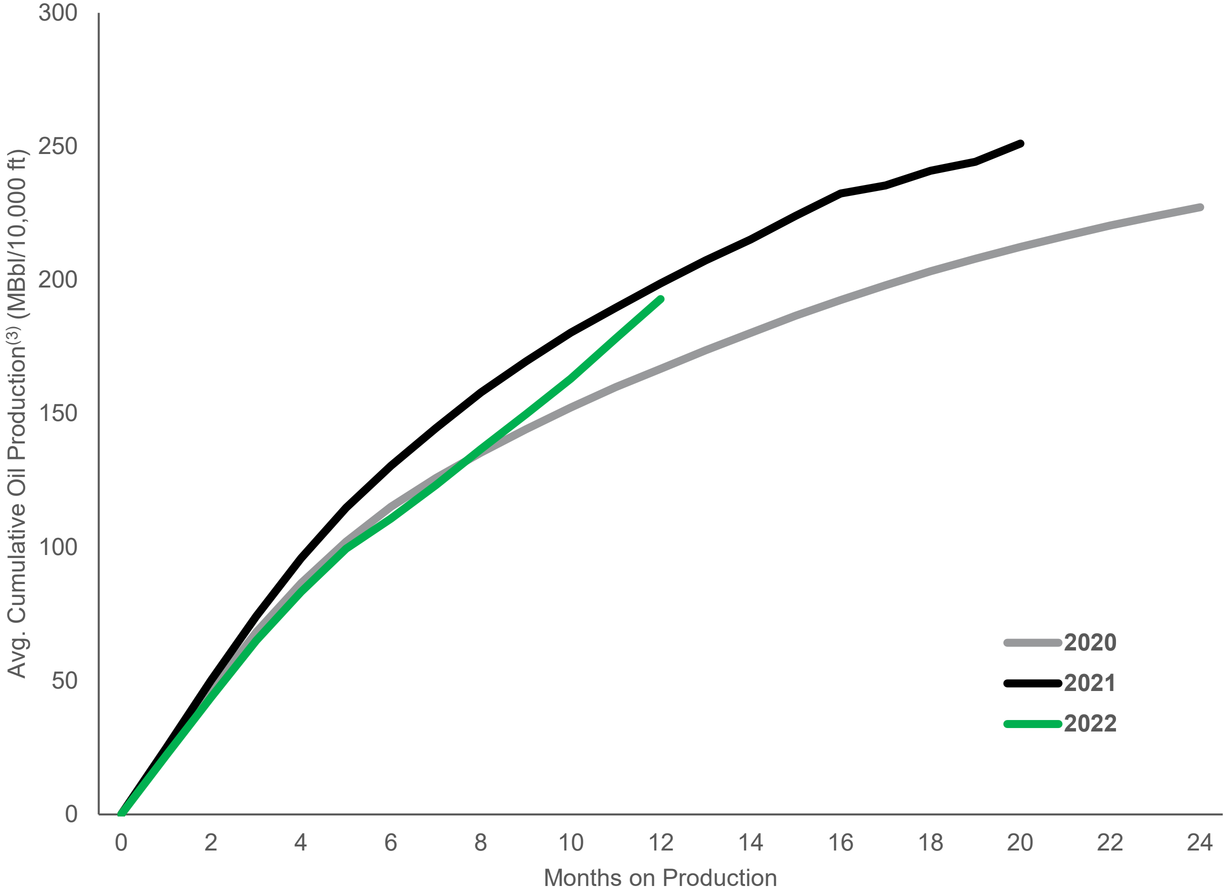
MIDLAND BASIN – PRODUCTION OUTPERFORMANCE

SM OUTPERFORMS PEERS & CONTINUES OPTIMIZATION

SM Wells v. Peers(1) Howard County



SM 2020-2022 Wells(2)



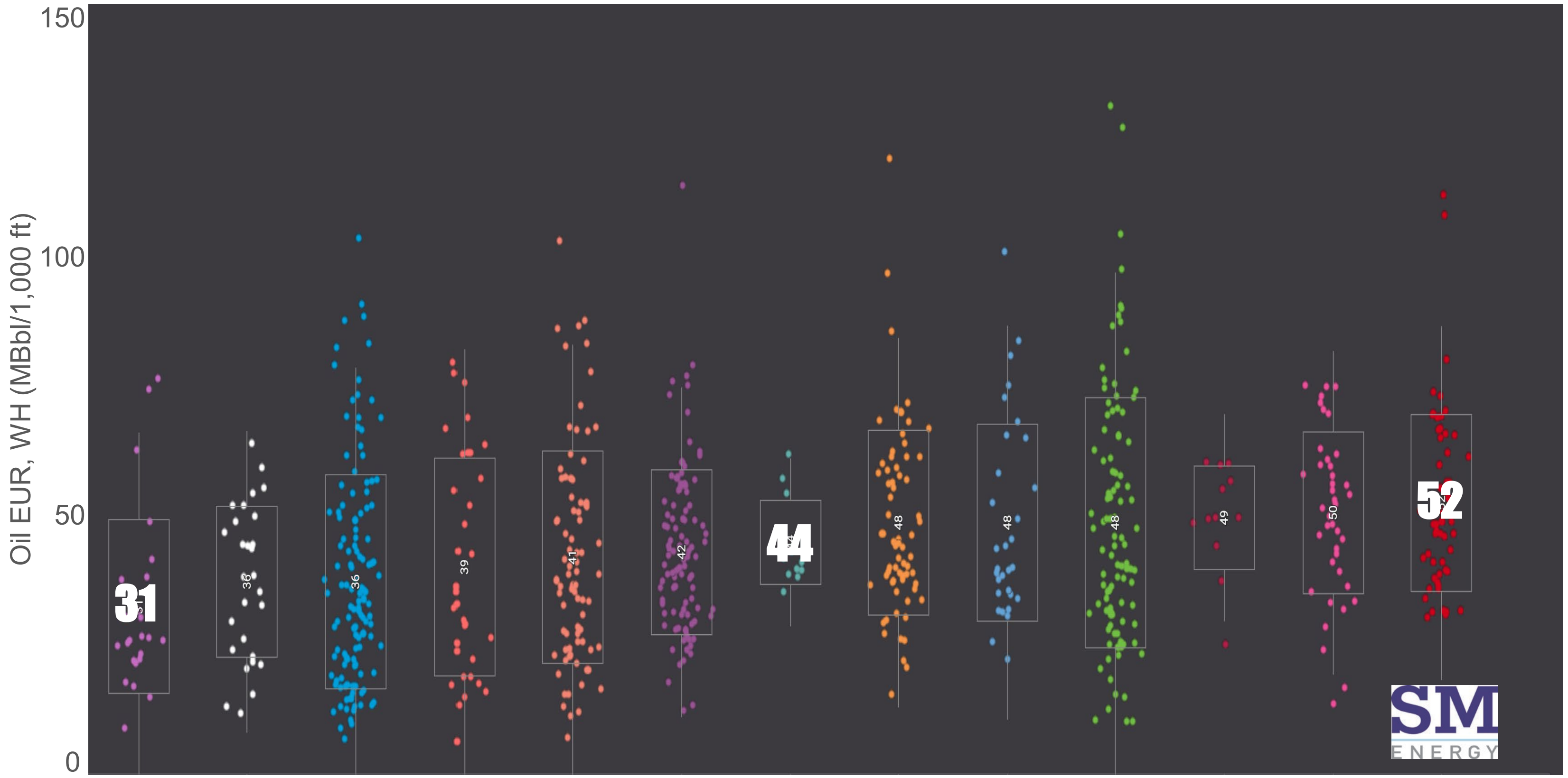
(1) Enverus data as of January 26, 2023 | Horizontal wells completed in Howard County January 2021 through November 2022 | Peers include operators with 10 or more completions: Bayswater, Birch, Callon, Chevron, Crownquest, Diamondback, Endeavor, Highpeak, Murchison, Occidental, Ovintiv, Pioneer, SOGC, Surge and Vital.

(2) Includes all SM operated wells completed in 2020-2022.
(3) Lateral length normalized to 10,000 ft.

MIDLAND BASIN – EUR OUTPERFORMANCE

TECHNICAL EXPERTISE YIELDS EXCEPTIONAL RETURNS

SM Operated Wells v. Peers
Howard County



Third-party Evaluation indicates SM ENERGY Best EUR Performance

(1) Enverus Intelligent Research data | Wells completed in Howard County from January 2021 through November 2022 | Peers include operators with 10 or more completions: Bayswater, Birch, Callon, Crownquest, Diamondback, Endeavor, Highpeak, Murchison, Occidental, Ovintiv, Surge and Vital.

SOUTH TEXAS

FOCUSED ON EXECUTION AND RETURNS ENHANCEMENT

2023 OPERATING PLAN

2023 PLAN DETAILS

- 2023 net wells planned: drill 40 – 45; complete ~40
- ~9,770' expected average lateral feet per well(1)
- ~37% Boe PDP decline expected (YE22 - YE23)

ENHANCING INVENTORY VALUE

MARKETING UPDATE

- Natural gas transportation costs expected to decrease an additional ~$0.35/Mcf in mid 2023

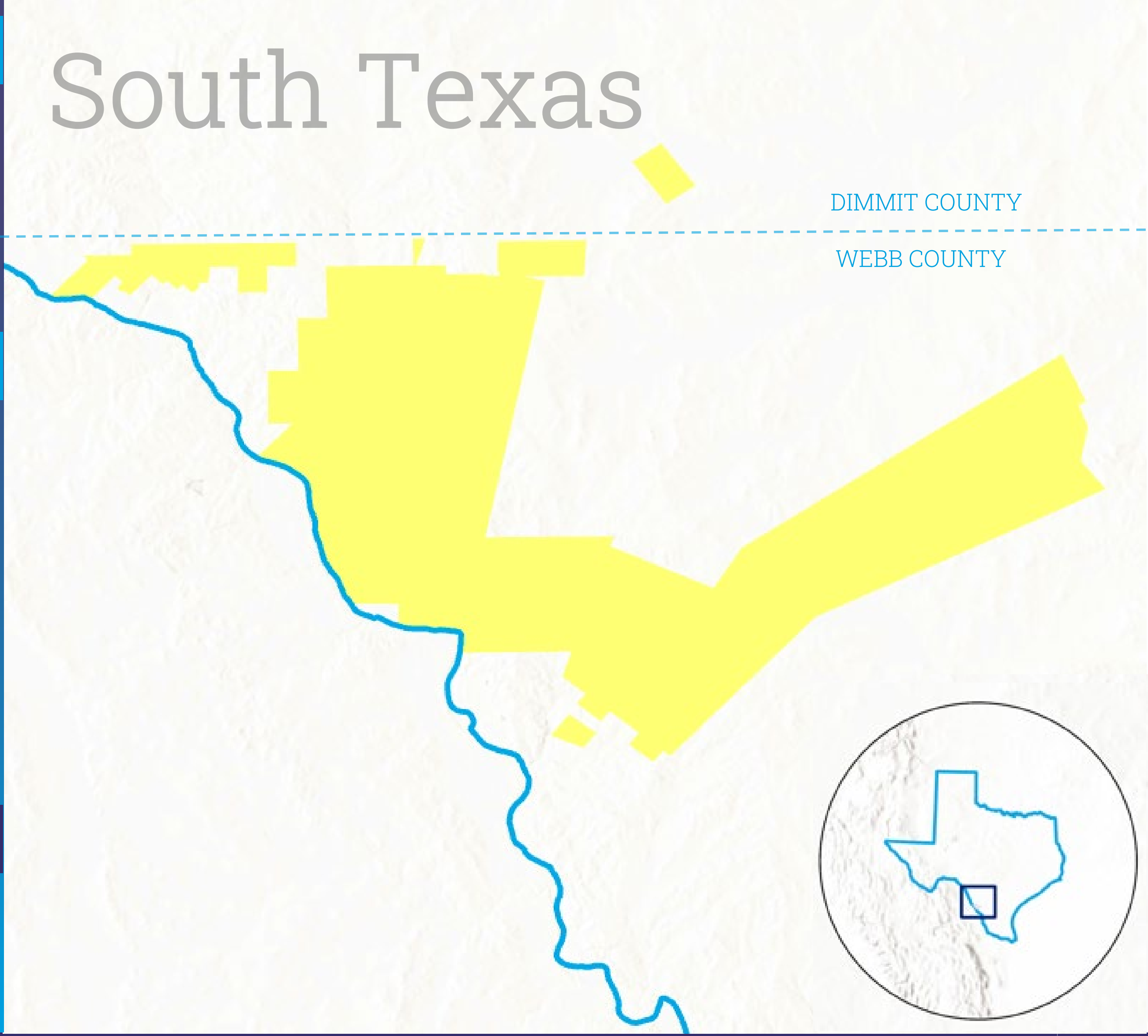
AUSTIN CHALK SUCCESS

- 2022 wells: expected payout averages ~13 months(2) (43% Oil | 72% Liquids)(3)
- Delineation & development program of 68 wells producing to date has indicated Austin Chalk inventory over a broad area

OPERATING DETAILS(4)

Rigs Running: Completion Crews:

~155,000 NET ACRES



(1) Based on operated wells expected to be completed in 2023.

(2) Based on Strip Pricing at 12/30/22 | $79/Bbl oil, $4/MMBtu gas, and $30/Bbl NGL's | Includes 30 gross wells that have reached peak IP30 during 2022, excluding three wells that do not expect to payout.

(3) Includes 33 gross wells that have reached peak IP30 during 2022, including three joint-development wells.

(4) 2023 expected average.

SOUTH TEXAS: AUSTIN CHALK SUCCESS CONTINUES

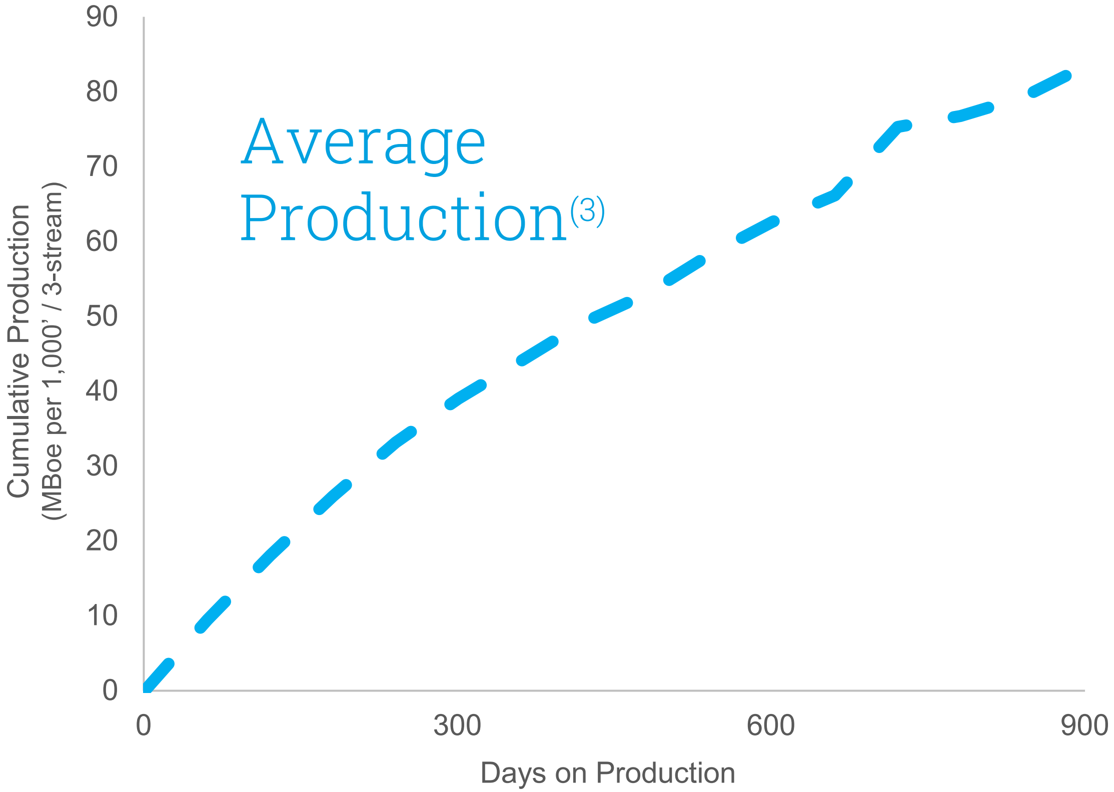
AUSTIN CHALK SUPPORTS RAPID GROWTH IN OIL/LIQUIDS PRODUCTION

New Wells that Reached IP30(1)

WELLS	14
AVG. BOE/D	~2,500
OIL | LIQUIDS %	30 | 64

Austin Chalk Wells Currently Producing

68 Wells Producing ~50-90% Liquids(2)



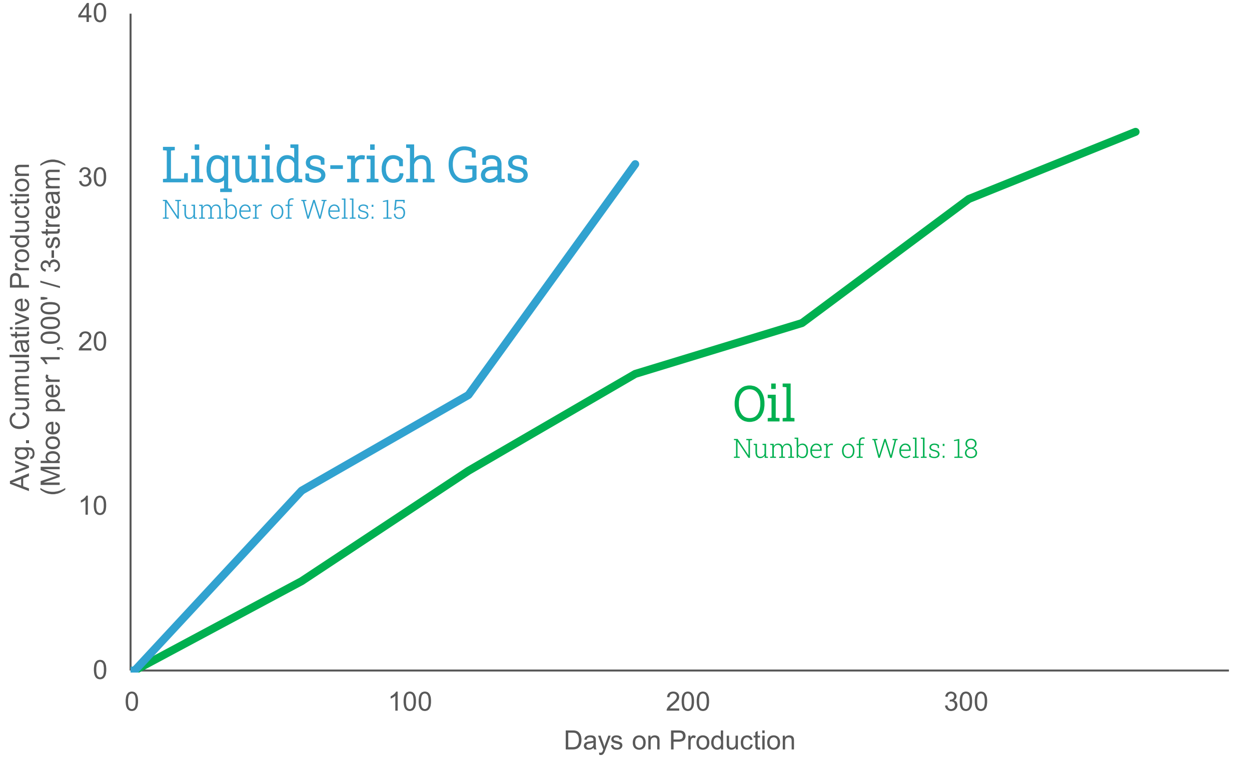
(1) New wells that have reached IP30 since October 1, 2022.
(2) Includes oil and NGLs based on peak IP30.
(3) Includes 68 gross wells that have reached peak IP30, including three joint-development wells. On average, wells have been producing for approximately 1 ¼ years.

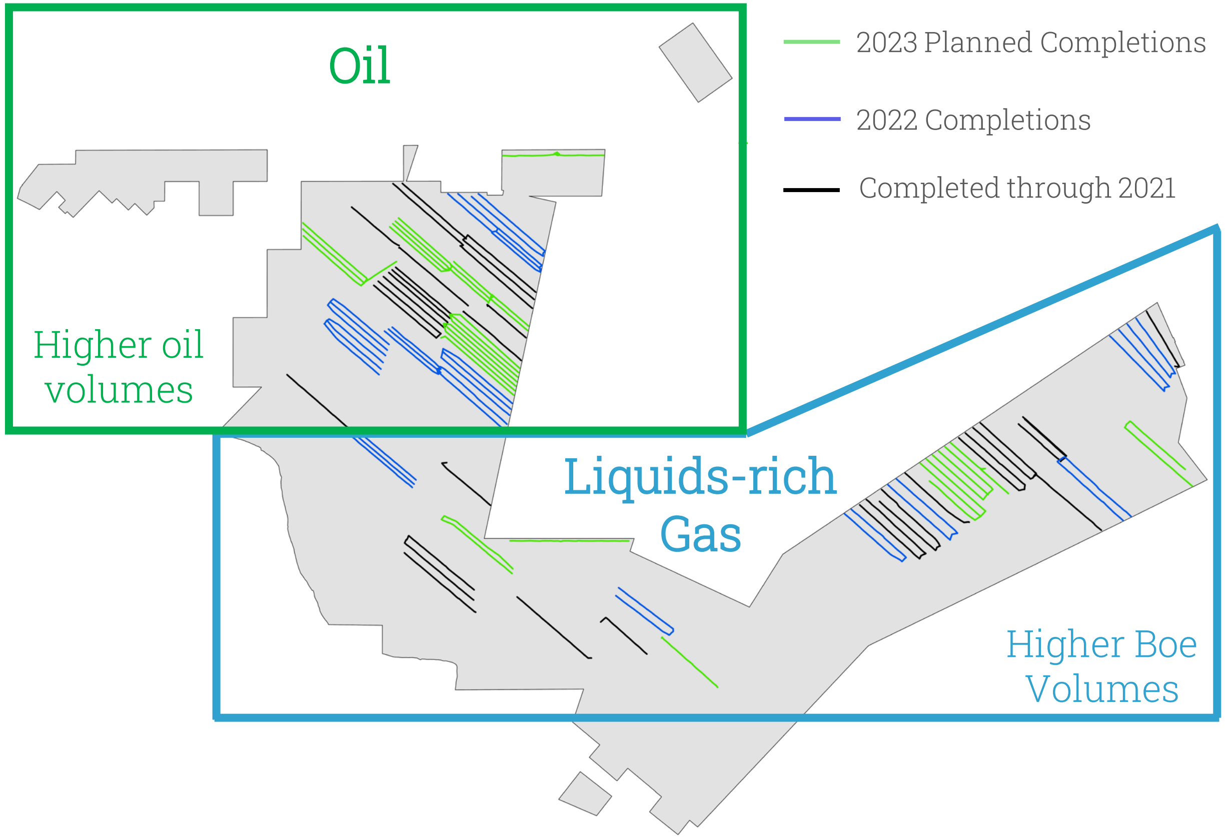
SOUTH TEXAS: AUSTIN CHALK SUCCESS CONTINUES

PRODUCTION CURVES VARY BY COMMODITY MIX

COMPARISON OF OIL & LIQUIDS-RICH GAS AREAS(1)

2022 Austin Chalk Wells(1)



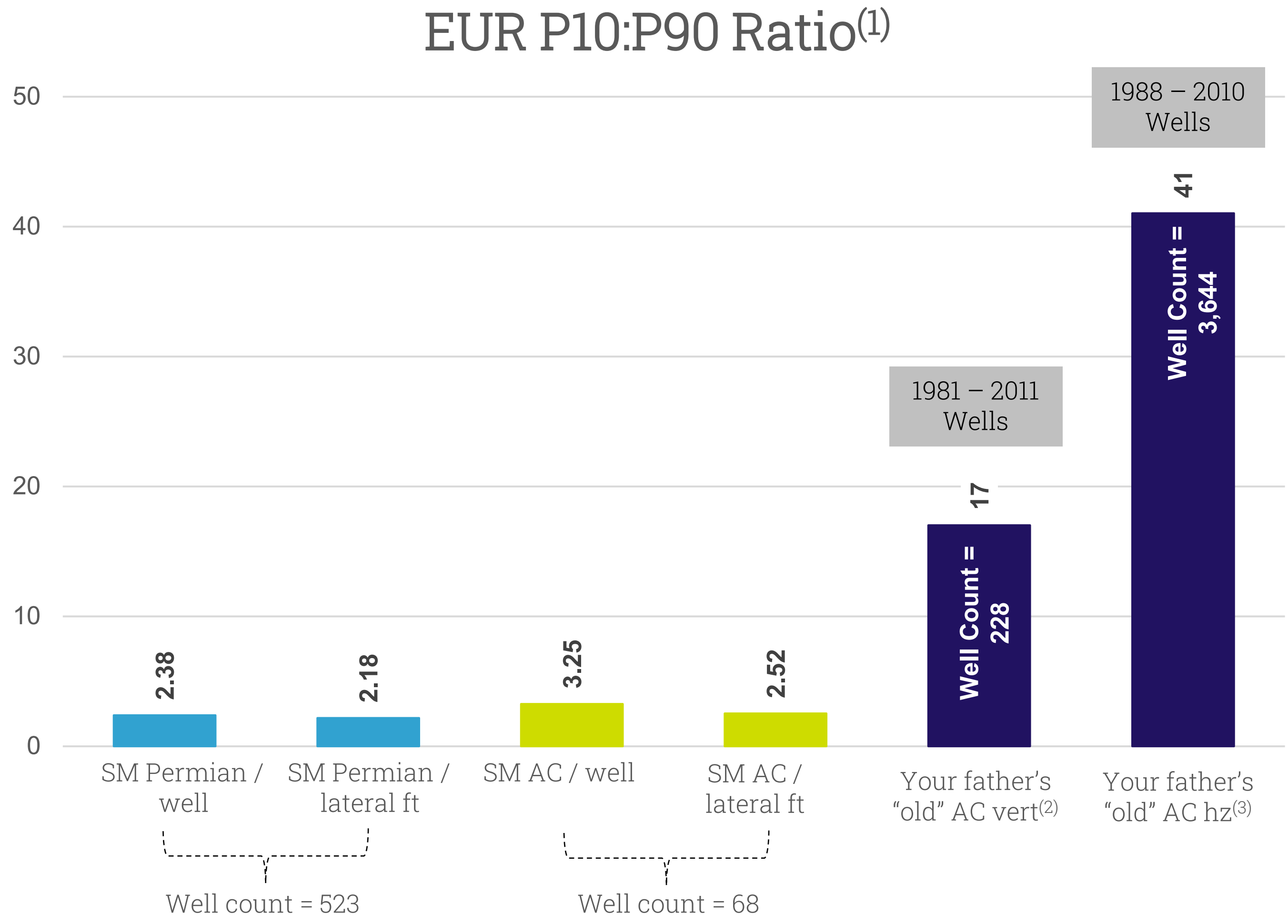


(1) All SM operated wells reaching peak IP30 in the Austin Chalk in 2022.

SOUTH TEXAS

CONFIDENCE IN THE AUSTIN CHALK: REPEATABLE & PREDICTABLE

Not Your "Old" Austin Chalk: Austin Chalk P10:P90 is Indicative of an Outstanding Resource Play



(1) P10:P90 ratio based on EUR data.

(2) Based on production data from 228 Austin Chalk vertical wells completed between 1981 and 2011 primarily located in east Texas.

(3) Based on production data from 3,644 Austin Chalk horizontal wells completed between 1988 and 2010 primarily located in east Texas.

SUSTAINABLE AND REPEATABLE

BUSINESS MODEL

SUSTAINABLE

Sustainable

- Premier Operator of Top Tier Assets
- Return of Capital
- Strong Balance Sheet

SM ENERGY

Repeatable

- World Class Technical Team
- Organically Add Inventory
- Strategic Inventory Capture and Growth

REPEATABLE

Appendix

2022 PROVED RESERVES

PROVED RESERVES AT YEAR-END WERE 537 MMBOE, UP 9% COMPARED WITH PRIOR YEAR

Proved Reserves by Region

YE 2021 (MMBoe)	251.6	240.4	492.0
YE 2022	**Midland Basin**	**South Texas**	**Total**
Oil (MMBbl)	153.1	52.7	205.8
Gas (Bcf)	625.1	777.8	1,402.9
NGL (MMBbl)	0.2	97.6	97.8
Total (MMBoe)	257.4	280.0	537.4
% Proved Developed	64%	55%	59%
Reserve Growth	2%	16%	9%

537
MMBoe

Proved Reserves

↑9%
year over year

SEC Pricing

	2022	2021	% change
Oil ($/Bbl)	$93.67	$66.56	41%
Gas ($/MMBtu)	$6.36	$3.60	77%
NGLs ($/Bbl)	$42.52	$36.60	16%

FOURTH QUARTER AND FULL YEAR 2022 PERFORMANCE

Key Metrics

	4Q22	2022
Production and Pricing		
Total Production (MMBoe)	13.1	53.0
Total Production (MBoe/d)	142.9	145.1
Oil percentage / Liquids	43% / 59%	45% / 60%
Pre-Hedge Realized Price ($/Boe)	$50.92	$63.18
Post-Hedge Realized Price[(1)] ($/Boe)	$42.12	$49.76
Costs (per Boe)		
LOE	$5.20	$5.03
Transportation	$2.86	$2.83
Production & Ad Valorem taxes	$3.40	$3.86
Total Production Expenses	$11.46	$11.72
Cash Production Margin (pre-hedge)[(1)]	**$39.46**	**$51.46**
G&A (Cash)	$2.20	$1.88
G&A (Non-Cash)	$0.30	$0.28
DD&A	$10.93	$11.40
Earnings		
GAAP Earnings (per diluted share)	$2.09	$8.96
Adjusted net income[(1)] (per diluted share)	$1.29	$7.29
Adjusted EBITDAX[(1)] ($MM)	$373.9	$1,918.3
Adjusted free cash flow ($MM)		
Net cash provided by operating activities (GAAP)	$288.4	$1,686.4
Net change in working capital	$58.8	$72.1
Net cash provided by operating activities before net change in working capital	$347.2	$1,758.5
Capital Expenditures and other (GAAP)	$288.1	$879.9
Increase (decrease) in capital expenditure accruals and other	($20.8)	$29.8
Capital expenditures before increase (decrease) in capital expenditure accruals and other	$267.3	$909.7
Adjusted free cash flow[(1)]	**$79.9**	**$848.7**
Return of Capital ($MM)		
Share repurchase	$37.0	$57.2
Dividends Paid	$18.4	$19.6
Return of Capital ($MM)	**$55.4**	**$76.8**

2022 Production

145.1 MBoe/d

2022 Adjusted EBITDAX[(1)]

$1.92 billion

2022 Adj. free cash flow[(1)]

$848.7 million

Adj. free cash flow[(1)] Yield to YE Market Capitalization

20%

(1) Indicates a non-GAAP measure or metric. Please refer to the “Non-GAAP Reconciliations and Disclosures” section in the Appendix.
(2) Amounts may not calculate due to rounding.

4Q 2022 REALIZATIONS BY REGION

TWO TOP-TIER AREAS OF OPERATION

Benchmark Pricing	
NYMEX WTI Oil ($/Bbl)	$ 82.64
NYMEX Henry Hub Gas ($/MMBtu)	$ 6.26
Hart Composite NGL ($/Bbl)	$ 33.03

	Midland Basin	South Texas	Total
Production Volumes			
Oil (MBbls)	4,416	1,289	5,705
Gas (MMcf)	15,928	16,174	32,102
NGL (MBbls)	12	2,076	2,088
Total (Mboe)	7,083	6,060	13,143
Revenue (in thousands)			
Oil	$366,937	$102,877	$469,814
Gas	$69,103	$75,848	$144,951
NGL	$389	$54,096	$54,485
Total	$436,429	$232,821	$669,250
Expenses (in thousands)			
LOE	$51,329	$17,036	$68,365
Ad Valorem	$8,784	$3,926	$12,710
Transportation	$325	$37,312	$37,637
Production Taxes	$22,358	$9,597	$31,955
Per Unit Metrics			
Realized Price | Oil Per Bbl	$83.09	$79.82	$82.35
% of Benchmark - WTI	101%	97%	100%
Realized Price | Gas per Mcf	$4.34	$4.69	$4.52
% of Benchmark - NYMEX Henry Hub	69%	75%	72%
Realized Price | NGL per Bbl	nm	$26.06	$26.10
% of Benchmark - HART	nm	79%	79%
Realized Price per Boe	$61.62	$38.42	$50.92
LOE per Boe	$7.25	$2.81	$5.20
Ad Valorem per Boe	$1.24	$0.65	$0.97
Transportation per Boe	$0.05	$6.16	$2.86
Production Tax per Boe	$3.16	$1.58	$2.43
Production Tax as % of Pre-hedge Revenue	5.1%	4.1%	4.8%
Cash Production Margin per Boe[1]	$49.92	$27.22	$39.46

Note: Amounts may not calculate due to rounding.
(1) Indicates a non-GAAP measure or metric. Please refer to the “Non-GAAP Reconciliations and Disclosures” section in the Appendix.

OIL, GAS, AND NGL DERIVATIVE POSITIONS(1)

BY QUARTER

Oil

Period	Oil Swaps Volume (MBbls)	Oil Swaps $/Bbl(2)	Oil Collars Volume (MBbls)	Oil Collars Ceiling $/Bbl(2)	Oil Collars Floor $/Bbl(2)	Midland - Cushing Oil Basis Swaps Volume (MBbls)	Midland - Cushing Oil Basis Swaps Price Differential $/Bbl(2)	MEH – WTI Oil Basis Swaps Volume (MBbls)	MEH – WTI Oil Basis Swaps Price Differential $/Bbl(2)	NYMEX WTI Roll Basis Swaps Volume (MBbls)	NYMEX WTI Roll Basis Swaps Price Differential $/Bbl(2)	ICE Brent Oil Swaps Volume (MBbls)	ICE Brent Oil Swaps Price Differential $/Bbl(2)
Q1 2023	294	$45.20	577	$74.02	$60.00	1,294	$0.99	390	$1.65	1,220	$0.60	900	$86.50
Q2 2023	333	$45.18	464	$81.53	$67.85	1,357	$0.99	431	$1.68	1,243	$0.62	910	$86.50
Q3 2023	607	$59.77	291	$93.05	$75.00	1,414	$0.88	361	$1.59	1,304	$0.64	920	$86.50
Q4 2023	546	$60.00	-	-	-	1,294	$0.88	296	$1.53	1,201	$0.62	920	$86.50
Q1 2024	-	-	-	-	-	743	$1.17	200	$1.85	461	$0.42	910	$85.50
Q2 2024	-	-	293	$85.13	$75.00	709	$1.17	222	$1.84	536	$0.42	-	-
Q3 2024	-	-	308	$81.38	$75.00	735	$1.17	238	$1.85	593	$0.42	-	-
Q4 2024	-	-	318	$78.20	$75.00	774	$1.17	217	$1.85	598	$0.42	-	-

Gas

Period	NYMEX Henry Hub Gas Swaps Volume (BBtu)	NYMEX Henry Hub Gas Swaps $/MMBtu(2)	IF Waha Gas Swaps Volume (BBtu)	IF Waha Gas Swaps $/MMBtu(2)	IF Waha Gas Basis Swaps Volume (BBtu)	IF Waha Gas Basis Swaps $/MMBtu(2)	IF HSC Gas Basis Swaps Volume (BBtu)	IF HSC Gas Basis Swaps $/MMBtu(2)	NYMEX Henry Hub Gas Collars Volume (BBtu)	NYMEX Henry Hub Gas Collars Ceiling $/MMBtu(2)	NYMEX Henry Hub Gas Collars Floor $/MMBtu(2)	IF HSC Gas Collars Volume (BBtu)	IF HSC Gas Collars Ceiling $/MMBtu(2)	IF HSC Gas Collars Floor $/MMBtu(2)
Q1 2023	-	-	900	$3.98	1,816	$(0.81)	6,737	$0.19	7,919	$9.75	$3.84	900	$7.75	$3.38
Q2 2023	1,420	$5.05	-	-	2,462	$(1.93)	1,774	$(0.25)	5,181	$4.68	$3.83	1,345	$5.00	$4.25
Q3 2023	1,470	$5.11	-	-	2,442	$(1.05)	1,813	$(0.25)	6,194	$4.62	$3.75	1,389	$4.95	$4.25
Q4 2023	-	-	-	-	2,337	$(1.01)	2,008	$(0.25)	8,362	$5.70	$3.90	1,451	$5.55	$4.25
Q1 2024	-	-	-	-	5,089	$(0.61)	-	-	6,195	$8.91	$3.77	-	-	-
Q2 2024	-	-	-	-	5,285	$(1.09)	-	-	4,432	$4.00	$3.69	-	-	-
Q3 2024	-	-	-	-	5,344	$(0.99)	-	-	4,612	$4.21	$3.68	-	-	-
Q4 2024	-	-	-	-	5,240	$(0.73)	-	-	4,218	$5.27	$3.65	-	-	-
Q1 2025	-	-	-	-	5,102	$(0.46)	-	-	-	-	-	-	-	-
Q2 2025	-	-	-	-	5,236	$(0.78)	-	-	-	-	-	-	-	-
Q3 2025	-	-	-	-	5,117	$(0.72)	-	-	-	-	-	-	-	-
Q4 2025	-	-	-	-	5,046	$(0.66)	-	-	-	-	-	-	-	-

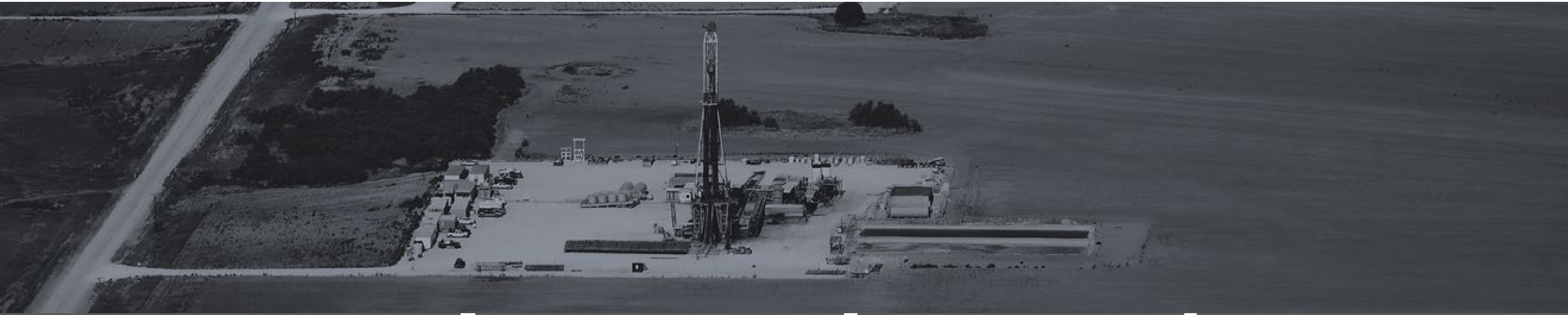
NGLs

Period	Propane Swaps Volume (MBbls)	Propane Swaps $/Bbl2)
Q1 2023	-	-
Q2 2023	123	$36.12
Q3 2023	122	$36.12
Q4 2023	127	$36.12

(1) Includes derivative contracts for settlement at any time during the first quarter of 2023 and later periods, entered into through February 15, 2023.
(2) Weighted-average contract price.

ACTIVITY BY REGION

WELLS DRILLED, FLOWING COMPLETIONS, AND DUC COUNT



	Wells Drilled[1]				Flowing Completions[1]				DUC Count[2][3]	
	4Q22		2022		4Q22		2022		As of December 31, 2022	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin										
RockStar	6	4	37	33	10	8	35	30	29	26
Sweetie Peck	13	9	26	17	6	2	9	6	20	14
Midland Basin total	19	13	63	50	16	10	44	36	49	40
South Texas										
Austin Chalk	11	12	34	34	9	9	36	36	15	15
Eagle Ford	2	1	7	6	2	2	7	7	14	13
South Texas total	13	13	41	40	11	11	43	43	29	28
Total[1][4]	32	26	104	90	27	21	87	79	78	69

(1) Wells drilled and flowing completions exclude 1 drilled and completed well that was subsequently abandoned, outside of our core areas of operation.
(2) The South Texas drilled but not completed well count includes 9 gross / 9 net wells, 8 of which are in the Eagle Ford shales, that are not included in our five-year development plan at December 31, 2022.
(3) Amounts may not calculate due to rounding.
(4) In 2022, and excluded from the table above, we drilled a science well to study and monitor Austin Chalk reservoir activity during and after development. We do not intend to complete this well.

LEASEHOLD SUMMARY

NO LEASEHOLD ON FEDERAL LANDS IN THE MIDLAND BASIN OR SOUTH TEXAS

Net Acres[1]

Midland Basin	
Sweetie Peck[2]	18,500
RockStar	63,500
Midland Basin total	82,000
South Texas	154,800
Rocky Mountain Other	10,300
Other Areas / Exploration	25,500
Total	**272,600**

MIDLAND BASIN NET ACRES

~82,000

SOUTH TEXAS NET ACRES

~155,000

As of December 31, 2022

(1) Includes developed and undeveloped oil and natural gas leasehold, fee properties, and mineral servitudes held as of December 31, 2022.
(2) Sweetie Peck acreage includes ~1,500 net drill-to-earn acreage.

NGL REALIZATIONS

2023 PLAN ASSUMES ETHANE PROCESSING ALL YEAR

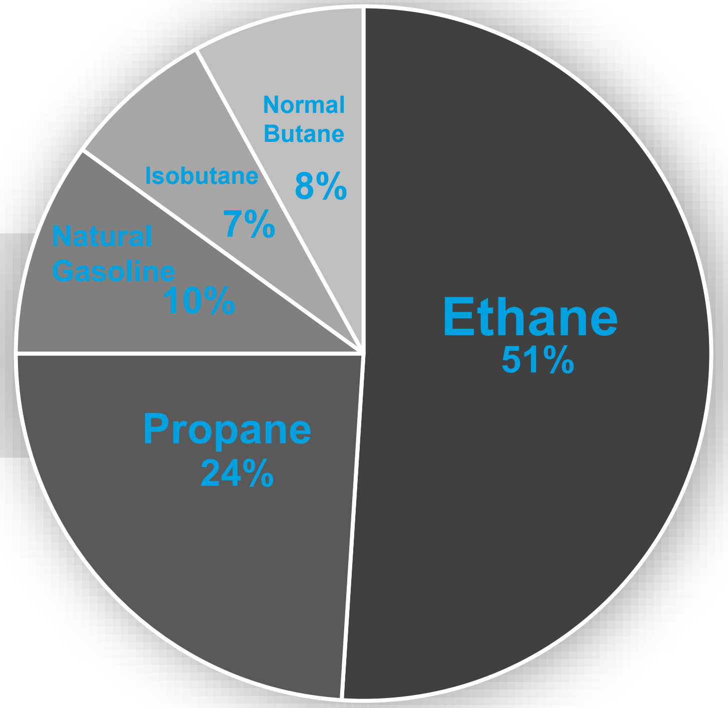
NGL price realizations tied to Mont Belvieu, fee-based contracts

- Differential reflects NGL composite barrel product mix as well as transportation and fractionation fees
- 2022 realizations reflect the processing of ethane for the year

Realizations by Quarter

	4Q 2021	1Q 2022[1]	2Q 2022	3Q 2022	4Q 2022
Mont Belvieu Benchmark Price ($/Bbl)	$44.21	$48.36	$50.05	$42.47	$33.03
SM NGL Realization ($/Bbl)	$39.63	$38.56	$42.08	$36.36	$26.10
% Differential to Mont Belvieu	**90%**	**80%**	**84%**	**86%**	**79%**

SM Energy NGL Composition[1]



(1) The Company elected to reject ethane for the full year 2021, began processing ethane during the first quarter of 2022, and processed ethane for the full year 2022. The Company plans to process ethane for the full year 2023.

Fourth Quarter & Full Year 2022

Non-GAAP Reconciliations and Disclosures

DEFINITIONS OF NON-GAAP MEASURES AND METRICS AS CALCULATED BY THE COMPANY

To supplement the presentation of its financial results prepared in accordance with U.S. generally accepted accounting principles (GAAP), the Company provides certain non-GAAP measures and metrics, which are used by management and the investment community to assess the Company's financial condition, results of operations, and cash flows, as well as compare performance from period to period and across the Company's peer group. The Company believes these measures and metrics are widely used by the investment community, including investors, research analysts and others, to evaluate and compare recurring financial results among upstream oil and gas companies in making investment decisions or recommendations. These measures and metrics, as presented, may have differing calculations among companies and investment professionals and may not be directly comparable to the same measures and metrics provided by others. A non-GAAP measure should not be considered in isolation or as a substitute for the most directly comparable GAAP measure or any other measure of a company's financial or operating performance presented in accordance with GAAP. A reconciliation of the Company's non-GAAP measures to the most directly comparable GAAP measure is presented below. These measures may not be comparable to similarly titled measures of other companies.

Adjusted EBITDAX: Adjusted EBITDAX is calculated as net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. Adjusted EBITDAX excludes certain items that the Company believes affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. The Company believes that Adjusted EBITDAX provides useful additional information to investors and analysts, as a performance measure, for analysis of the Company's ability to internally generate funds for exploration, development, acquisitions, and to service debt. The Company is also subject to financial covenants under the Company's Credit Agreement, a material source of liquidity for the Company, based on Adjusted EBITDAX ratios. Please reference the Company's 2022 Form 10-K for discussion of the Credit Agreement and its covenants.

Adjusted free cash flow or FCF: Adjusted free cash flow is calculated as net cash provided by operating activities before net change in working capital less capital expenditures before increase (decrease) in capital expenditure accruals and other. The Company uses this measure as representative of the cash from operations, in excess of capital expenditures that provides liquidity to fund discretionary obligations such as debt reduction, returning cash to stockholders or expanding the business.

Adjusted free cash flow yield to market capitalization: Adjusted free cash flow yield to market capitalization is calculated as Adjusted free cash flow (defined above) divided by market capitalization (share close price multiplied by outstanding common stock). The Company believes this metric provides useful information to management and investors as a measure of the Company's ability to internally fund its capital expenditures, to service or incur additional debt, and to measure management's success in creating stockholder value.

Adjusted net income (loss) and adjusted net income (loss) per diluted common share: Adjusted net income (loss) and adjusted net income (loss) per diluted common share excludes certain items that the Company believes affect the comparability of operating results, including items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. These items include non-cash and other adjustments, such as derivative gains and losses net of settlements, impairments, net (gain) loss on divestiture activity, gains and losses on extinguishment of debt, and accruals for non-recurring matters. The Company uses these measures to evaluate the comparability of the Company's ongoing operational results and trends and believes these measures provide useful information to investors for analysis of the Company's fundamental business on a recurring basis.

Cash production margin: Cash production margin is calculated as oil, gas, and NGL revenues (before the effects of commodity derivative settlements), less operating expenses (specifically, LOE, transportation, production taxes, and ad valorem taxes). This calculation excludes derivative settlements, G&A, exploration expense, and DD&A and is reflected on a per BOE basis using net equivalent production for the period presented. The Company believes this metric provides management and the investment community with an understanding of the Company's recurring operating margin before DD&A and G&A, which is helpful to compare period-to-period and across peers.

Net debt: Net debt is calculated as the total principal amount of outstanding senior unsecured notes plus amounts drawn on the revolving credit facility less cash and cash equivalents (also referred to as total funded debt). The Company uses net debt as a measure of financial position and believes this measure provides useful additional information to investors to evaluate the Company's capital structure and financial leverage.

Net debt-to-Adjusted EBITDAX: Net debt-to-Adjusted EBITDAX is calculated as Net Debt (defined above) divided by Adjusted EBITDAX (defined above) for the trailing twelve-month period (also referred to as leverage ratio). A variation of this calculation is a financial covenant under the Company's Credit Agreement. The Company and the investment community may use this metric in understanding the Company's ability to service its debt and identify trends in its leverage position. The Company reconciles the two non-GAAP measure components of this calculation.

Post-hedge: Post-hedge is calculated as the average realized price after the effects of commodity derivative settlements. The Company believes this metric is useful to management and the investment community to understand the effects of commodity derivative settlements on average realized price.

Pre-Tax PV-10: Pre-Tax PV-10 is the present value of estimated future revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This measure is presented because management believes it provides useful information to investors for analysis of the Company's fundamental business on a recurring basis.

Reinvestment rate: Reinvestment rate is calculated as capital expenditures before increase (decrease) in capital expenditure accruals and other divided by net cash provided by operating activities before net change in working capital. The Company believes this metric is useful to management and the investment community to understand the Company's ability to generate sustainable profitability and may be used to compare over periods of time across industry peers.

NON-GAAP RECONCILIATIONS

Adjusted EBITDAX[1]

(in thousands)

	Three Months Ended December 31, 2022	Twelve Months Ended December 31, 2022
Net income (GAAP)	**$ 258,463**	**$ 1,111,952**
Interest expense	22,638	120,346
Income tax expense	64,867	283,818
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	143,611	603,780
Exploration[2]	9,826	50,978
Impairment	1,002	7,468
Stock-based compensation expense	4,914	18,772
Net derivative (gain) loss	(11,168)	374,012
Derivative settlement loss	(115,620)	(710,700)
Net loss on extinguishment of debt	—	67,605
Other, net	(4,679)	(9,743)
Adjusted EBITDAX (non-GAAP)	**$ 373,854**	**$ 1,918,288**
Interest expense	(22,638)	(120,346)
Income tax expense	(64,867)	(283,818)
Exploration[2][3]	(8,851)	(36,810)
Amortization of debt discount and deferred financing costs	1,371	10,281
Deferred income taxes	66,061	269,057
Other, net	2,278	1,817
Net change in working capital	(58,833)	(72,063)
Net cash provided by operating activities (GAAP)	**$ 288,375**	**$ 1,686,406**

Adjusted Net Income[1]

(in thousands)

	Three Months Ended December 31, 2022	Twelve Months Ended December 31, 2022
Net income (GAAP)	**$ 258,463**	**$ 1,111,952**
Net derivative (gain) loss	(11,168)	374,012
Derivative settlement loss	(115,620)	(710,700)
Impairment	1,002	7,468
Net loss on extinguishment of debt	—	67,605
Other, net	(985)	(3,969)
Tax effect of adjustments[4]	27,509	57,632
Adjusted net income (non-GAAP)	**$ 159,201**	**$ 904,000**
Diluted net income per common share (GAAP)	**$ 2.09**	**$ 8.96**
Net derivative (gain) loss	(0.09)	3.01
Derivative settlement loss	(0.94)	(5.73)
Impairment	0.01	0.06
Net loss on extinguishment of debt	—	0.54
Other, net	(0.01)	(0.03)
Tax effect of adjustments[4]	0.22	0.46
Adjusted net income per diluted common share (non-GAAP)	**$ 1.29**	**$ 7.29**
Basic weighted-average common shares outstanding	122,485	122,351
Diluted weighted-average common shares outstanding	123,399	124,084

(1) Indicates a non-GAAP measure. See above "Definitions of non-GAAP measures and metrics as Calculated by the Company."
(2) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the consolidated statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the consolidated statements of operations for the component of stock-based compensation expense recorded to exploration expense.
(3) Amount is net of certain capital expenditures related to unsuccessful exploration efforts outside of our core areas of operations.
(4) The tax effect of adjustments is calculated using a tax rate of 21.7% for the three and twelve months ended December 31, 2022. This rate approximates the Company's statutory tax rate adjusted for ordinary permanent differences.

NON-GAAP RECONCILIATIONS

Adjusted Free Cash Flow[1]

(in thousands)

	Three Months Ended December 31, 2022	Twelve Months Ended December 31, 2022
Net cash provided by operating activities (GAAP)	**$ 288,375**	**$ 1,686,406**
Net change in working capital	58,833	72,063
Cash flow from operations before net change in working capital (non-GAAP)	**$ 347,208**	**$ 1,758,469**
Capital expenditures (GAAP)	**$ 288,088**	**$ 879,934**
Increase (decrease) in capital expenditure accruals and other	(20,801)	29,789
Capital expenditures before accruals and other (non-GAAP)	**$ 267,287**	**$ 909,723**
Adjusted free cash flow (non-GAAP)	**$ 79,921**	**$ 848,746**

Pre-tax PV-10[1]

(in millions)

	As of December 31, 2022	As of December 31, 2021
Standardized measure of discounted future net cash flows (GAAP)	**$ 9,962.1**	**$ 6,962.6**
Add: 10 percent annual discount, net of income taxes	7,551.5	4,844.9
Add: future undiscounted income taxes	3,888.3	2,130.3
Pre-tax undiscounted future net cash flows	21,401.9	13,937.8
Less: 10 percent annual discount without tax effect	(9,247.4)	(5,779.2)
Pre-tax PV-10 (non-GAAP)	**$ 12,154.5**	**$ 8,158.6**

Net Debt[1]

(in thousands)

	As of December 31, 2022
Principal amount of Senior Unsecured Notes[2]	$ 1,585,144
Revolving credit facility[2]	—
Total principal amount of debt (GAAP)	$ 1,585,144
Less: Cash and cash equivalents	444,998
Net Debt (non-GAAP)	**$ 1,140,146**

(1) Indicates a non-GAAP measure. See above "Definitions of non-GAAP measures and metrics as Calculated by the Company."
(2) Amounts are from Note 5 – Long-term Debt in Part II, Item 8 of the Company's Form 10-K as of December 31, 2022.

SM ENERGY CONTACTS

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