CALLON
PETROLEUM

THIRD QUARTER EARNINGS PRESENTATION

November 2022

FOCUSED ON CAPITAL DISCIPLINE & CREATING SHAREHOLDER VALUE

Important Disclosures

Cautionary Statement Regarding Forward-Looking Information

This presentation contains 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 include all statements regarding wells anticipated to be drilled and placed on production; inventory and delineation; future levels of development activity and associated production, capital expenditures, cash flow expectations, and margins; the Company's guidance for income statement expenditures and capital expenditures; estimated realizations; estimated reserve quantities and the present value thereof; future income and returns; future debt levels and leverage and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "plans," "may," "will," "should," "could," and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices; changes in the supply of and demand for oil and natural gas, including as a result of actions by, or disputes among members of OPEC and other oil and natural gas producing countries with respect to production levels or other matters related to the price of oil; general economic conditions or the COVID-19 pandemic and various governmental actions taken to mitigate its impact; our ability to drill and complete wells; operational, regulatory and environment risks; the cost and availability of equipment and labor; our ability to finance our development activities at expected costs or at expected times or at all; rising interest rates and inflation; our inability to realize the benefits of recent transactions; currently unknown risks and liabilities relating to the newly acquired assets and operations; adverse actions by third parties involved with the transactions; risks that are not yet known or material to us; and other risks more fully discussed in our filings with the SEC, including our most recent Annual Reports on Form 10-K and subsequent Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov. Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Non-GAAP Financial Measures

This presentation refers to non-GAAP financial measures such as "adjusted free cash flow," "adjusted EBITDA," "adjusted EBITDA per boe," "adjusted G&A," "adjusted discretionary cash flow" and "net debt". These measures, detailed below, are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our filings with the U.S. Securities and Exchange Commission (the "SEC") and posted on our website.

Adjusted free cash flow is a supplemental non-GAAP measure that is defined by the Company as adjusted EBITDA less operational capital expenditures (accrual), capitalized cash interest, capitalized cash G&A (which excludes capitalized expense related to share-based awards), and cash interest expense, net. We believe adjusted free cash flow provides useful information to investors because it is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Adjusted free cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities, or as a measure of liquidity, or as an alternative to net income (loss).

Callon calculates adjusted EBITDA as net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of evaluated oil and gas properties, non-cash share-based compensation expense, merger, integration and transaction expense, (gain) loss on extinguishment of debt, and certain other expenses. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, the Company believes that adjusted EBITDA provides useful information to investors because it provides additional information with respect to our performance or ability to meet our future debt service, capital expenditures and working capital requirements. Because adjusted EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDA presented in this presentation may not be comparable to similarly titled measures of other companies.

Net debt is a supplemental non-GAAP measure that is defined by the Company as total debt excluding unamortized premiums, discount, and deferred loan costs, less cash and cash equivalents. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt. This metric is sometimes presented as a ratio with Adjusted EBITDA for the preceding 12 months in order to provide investors with another means of evaluating the Company's ability to service its existing debt obligations as well as any future increase in the amount of such obligations. The Company refers to this as its leverage ratio.

The Company is unable to reconcile the projected adjusted free cash flow (non-GAAP), adjusted discretionary cash flow (non-GAAP), adjusted G&A, net debt and adjusted EBITDA (non-GAAP) metrics included in this release to projected net cash provided by operating activities (GAAP), G&A, total debt and net income (loss) (GAAP), respectively, because components of the calculations are inherently unpredictable, such as changes to current assets and liabilities, the timing of capital expenditures, movements in oil and gas pricing, unknown future events, and estimating future certain GAAP measures. The inability to project certain components of the calculation would significantly affect the accuracy of the reconciliation.

Focused on Capital Discipline and Creating Shareholder Value

Top-Tier
Permian Basin & Eagle Ford Shale Portfolio

Committed
to ESG Excellence

Delineated
~15 Years of High-Return Drilling Inventory

Disciplined
Capital Spending Program

Increasing
Margins + Operational Improvements

Top-Tier Acreage Position + Strong Margins = Peer Leading Free Cash Flow Yield

Disciplined Strategy Delivers Results

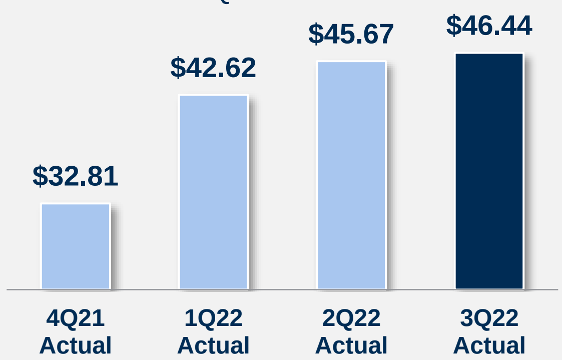
CAP

Delivering on Commitments
3Q 2022 Highlights

Production Volumes	**107**	MBoe/d (62% oil)
YTD Reinvestment Percentage[1]	**61%**	% of cash flow after changes in WC
Operational Capital[2] ($MM)	**$255**	Within Guidance

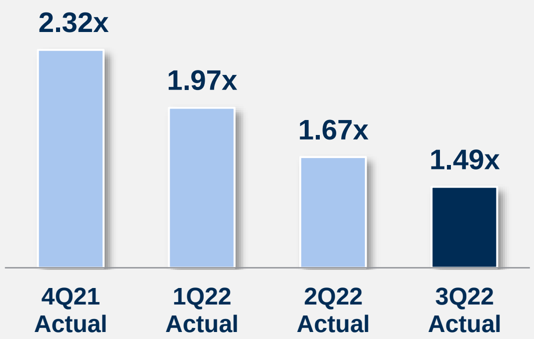
Adjusted EBITDA
per Boe[3]

42%
increase from 4Q21



Leverage Ratio
Net Debt / LTM Adj. EBITDA[3]

1.00x - 1.25x
by year-end 2022



Improved D&C Efficiencies and Well Productivity

Delivered 3Q Sequential Oil Production Growth of 8%

Contracted Firm Natural Gas Transportation to Gulf Coast

Reduced 3Q Total Debt Level to <$2.4 Billion

Refinanced Senior Notes[4] and Extended RBL Maturity Date[4]

2022 Accomplishments

1. Reinvestment percentage is calculated by dividing operational capital expenditures by adjusted discretionary cash flow minus capitalized interest minus capitalized G&A
2. Operational capital expenditures includes drilling, completions, facilities, and equipment, but excludes land and seismic
3. Adjusted EBITDA per Boe & net debt are non-GAAP financial measures, please see the Appendix for the reconciliation
4. On June 9th, Callon issued $600 million of senior unsecured notes. The proceeds, along with borrowings under the credit facility, were used to redeem $460.2 million of 6.125% Senior Notes due 2024 and $319.7 million of 9.0% Second Lien Senior Secured Notes due in 2025. On October 19th, Callon amended and restated its credit facility, extending the maturity to October 2027

Strong Execution Advances Our Goals

3Q 2022 *By the Numbers*

Total Production	**107.3** (MBoe/d)
Oil Production	**66.4** (MBbls/d)
LOE	**$76** ($MM)
Production and Ad Valorem Tax	**6.0%** (% of total oil, natural gas, and NGL revenue)
GP&T	**$28** ($MM)
Operational Capital[1]	**$255** ($MM)
Adjusted EBITDA[2]	**$459** ($MM)
Adjusted Free Cash Flow[2]	**$148** ($MM)

Third Quarter *Accomplishments*

OPERATIONAL

Efficient Execution of Completions
>11 stages per day in Howard County

Delivered Sequential Production Growth
Grew total daily production by 7%

Tested New Formations
Tested Austin Chalk and Middle Spraberry formations

Improved Midland Basin Well Productivity
Realized 28% increase in productivity vs 2019-2021

FINANCIAL

Ninth Sequential Increase in Adj. EBITDA per Boe
Increased to $46.44 per Boe

Disciplined Reinvestment Rate
Year-to-date only 61% of cash flow reinvested[3]

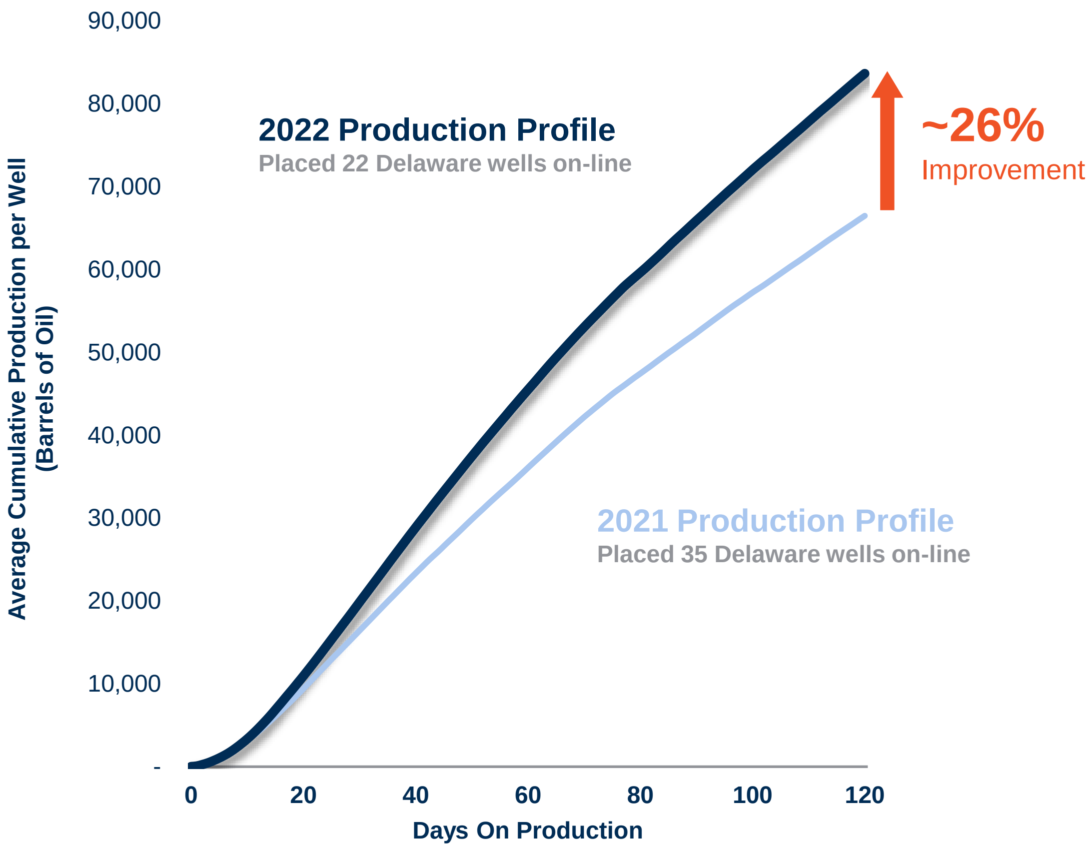
Amended Revolving Credit Facility
Extended the maturity of the credit facility to 2027

Further Debt Reduction
Reduced outstanding debt by approximately $330 million during the first nine months of 2022

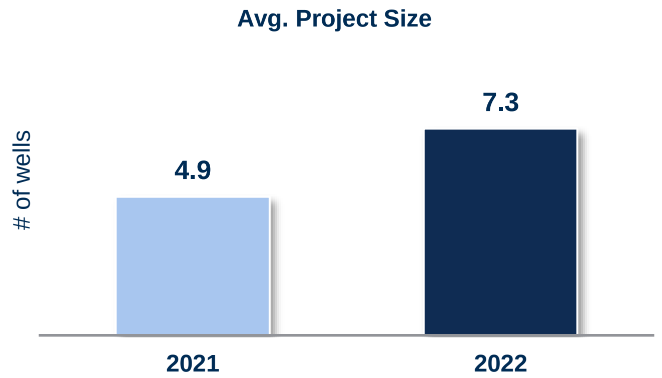
1. Operational capital includes drilling, completions, facilities, and equipment, but excludes land and seismic
2. Adjusted EBITDA and Adjusted Free Cash Flow are non-GAAP measures. Please see Appendix for reconciliation
3. Reinvestment percentage is calculated by dividing operational capital expenditures by adjusted discretionary cash flow minus capitalized interest minus capitalized G&A

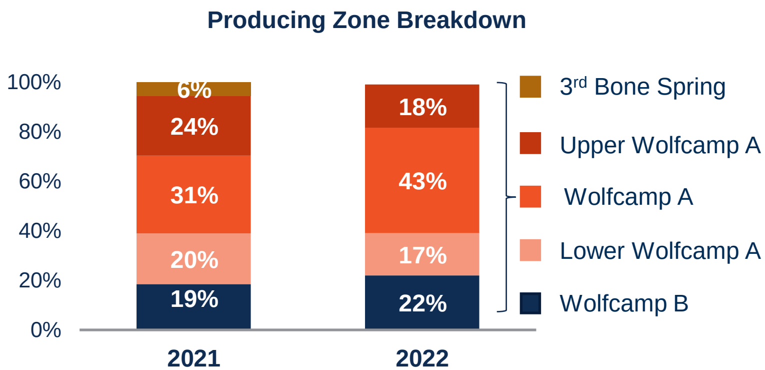
Delaware Basin: *Optimizing* Production Profiles

Delaware Basin Well Production Profile[1]



Scaled Development of Multi-Zone Resource Base[2]

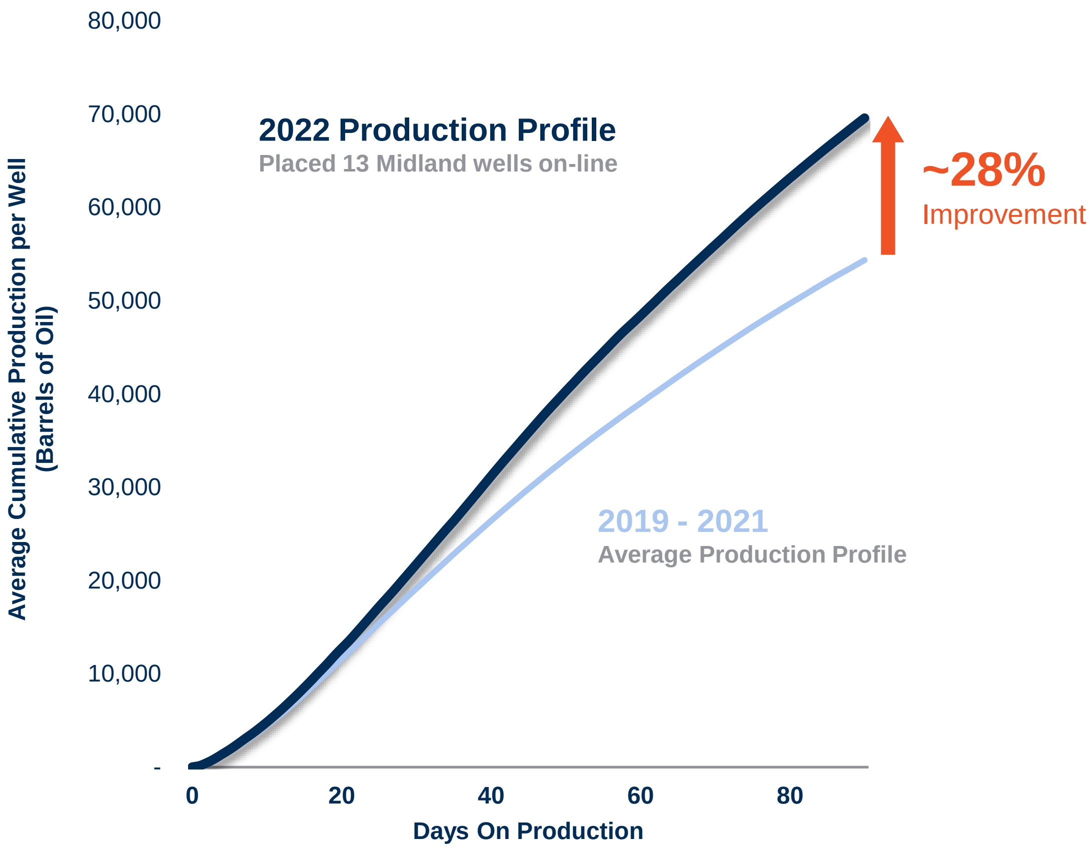




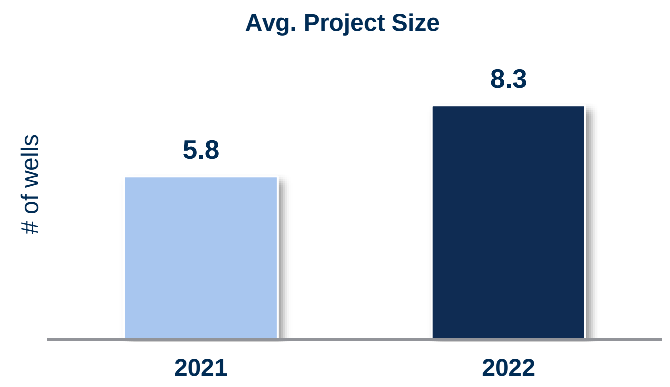
1. Represents wells placed on-line during 2021 and 2022 with 120 days of production history
2. Reflects all of 2021's development activity and the first nine months of 2022

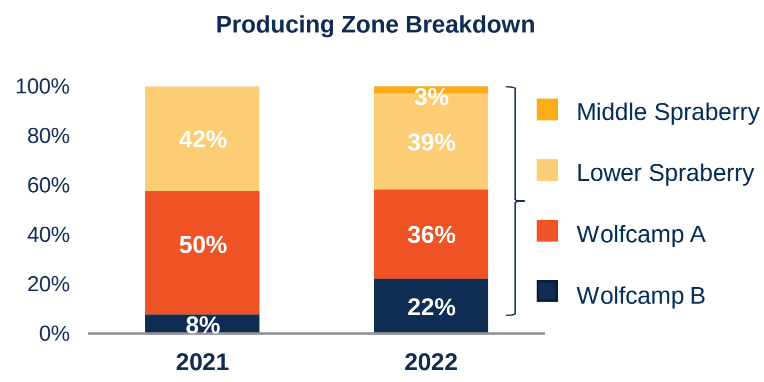
Midland Basin: *Optimizing* Production Profiles

Midland Basin Well Production Profile[1]



Scaled Development of Multi-Zone Resource Base[2]



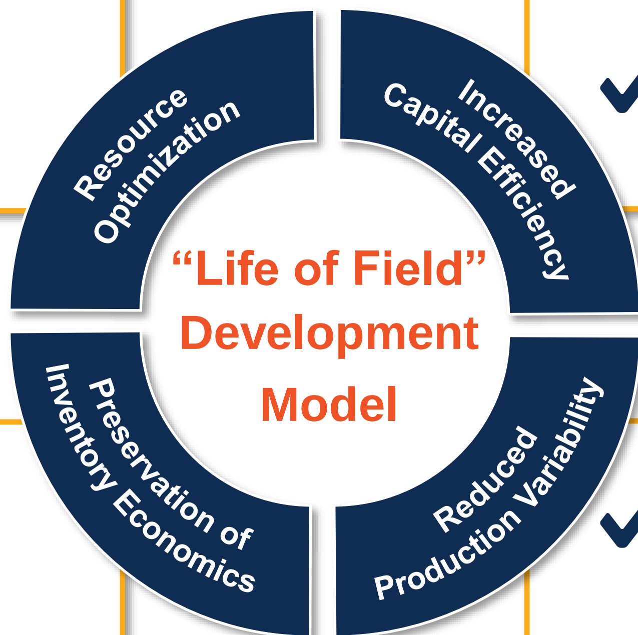


1. Represents wells placed on-line during 2021 and 2022 with 120 days of production history
2. Reflects all of 2021's development activity and the first nine months of 2022

Efficient Development Philosophy

- Optimizes value of reservoir system
- Increases average future well productivity

- Increases efficiencies through scaled development model
- More consistent capital efficiency profile over time



- Concurrent development of locations that meet economic thresholds
- Mitigates degradation impacts from a "high-grading" model of development

- Reduces impact of offset completions and the need to shut-in production
- Lowers the number of potential child wells

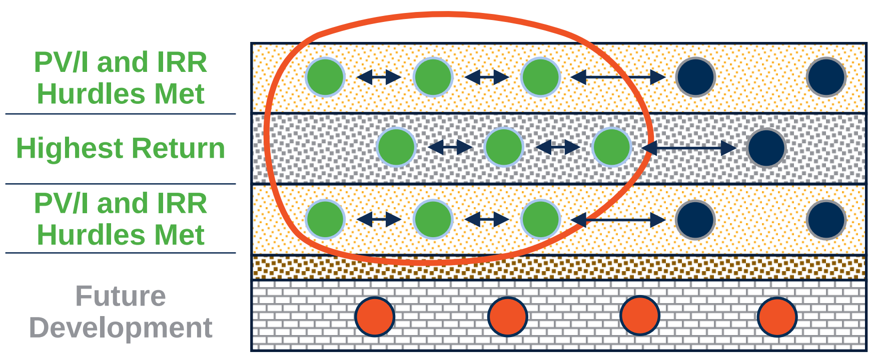
"Life of Field" Development vs Alternative

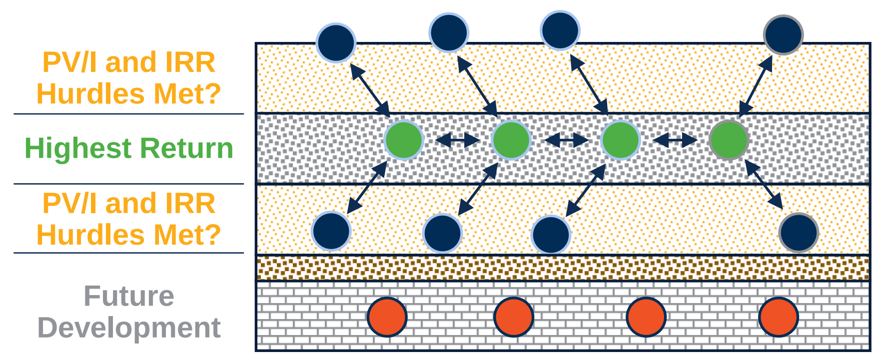
"Life of Field" Development

Scaled, co-development of multiple zones that meet strict economic thresholds, resulting in the optimization of economic resource capture within a reservoir system that is characterized by zones that interact with each other

Alternative: High-Grading of Zones

- ✗ Meaningful decline in capital efficiency over time and loss of economic inventory
- ✗ Increasingly complex parent and child interactions in "four dimensions"
- ✗ More exposure to offsetting frac impacts (both horizontal and vertical adjacent activity)



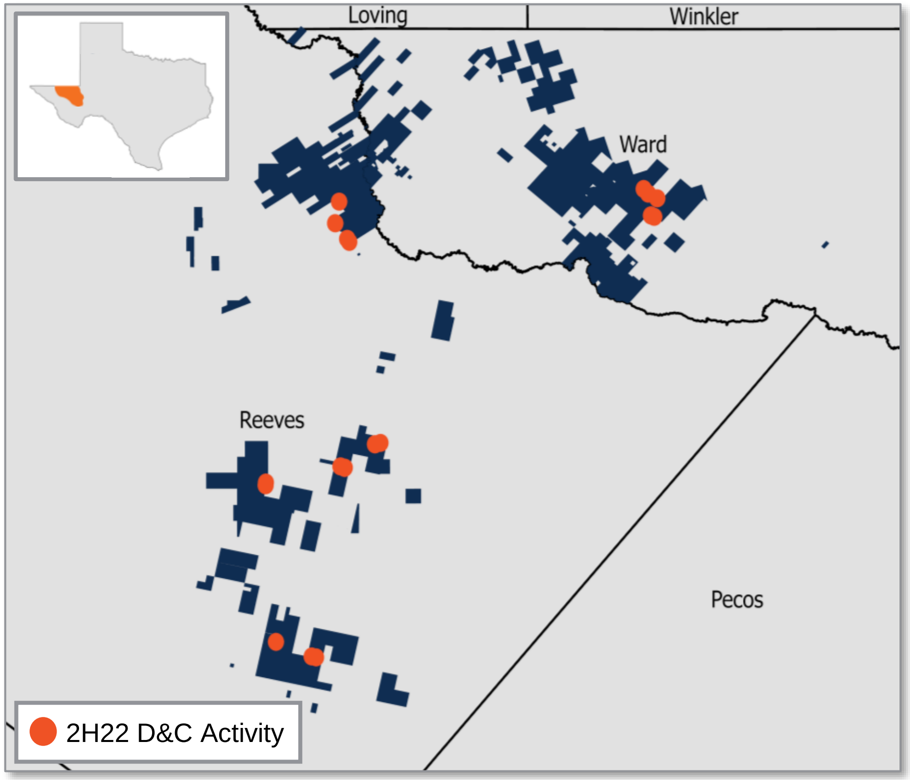


Parent wells | Child wells | Future Development

Note: PV/I is defined as present value of cash inflows divided by initial capital investment

Second Half Development
Delaware Basin

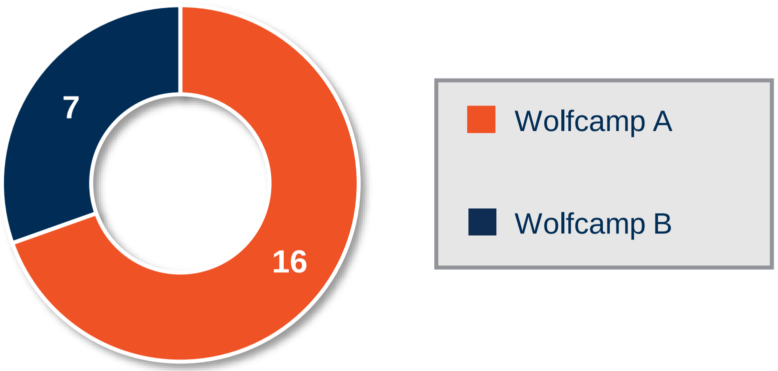
Delaware Basin Acreage Position



Second Half of 2022 Development Plan

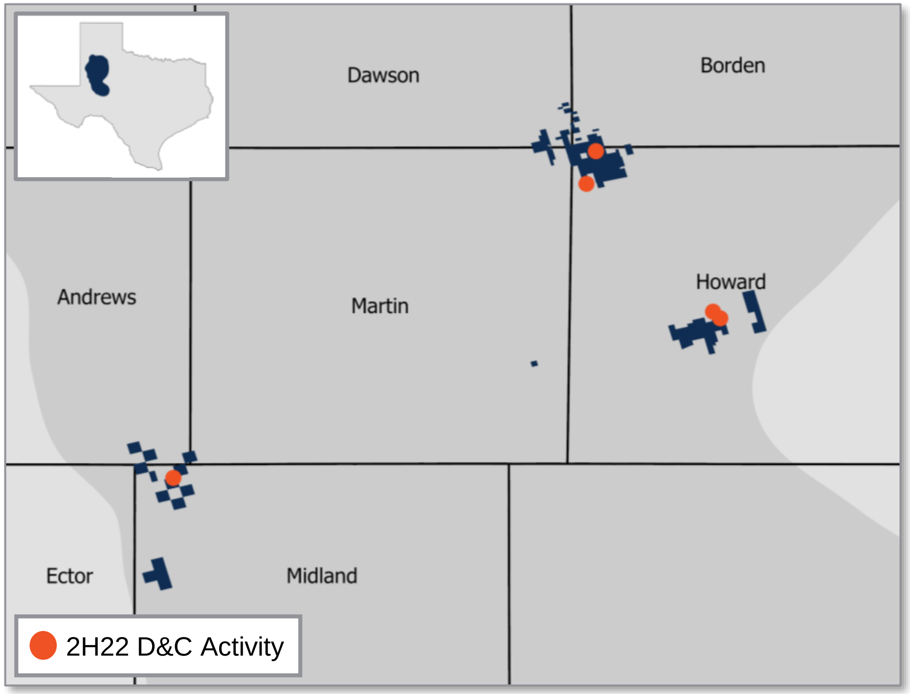
- Utilizing advanced seismic methods to identify and avoid geohazards
- Continuing trend of larger pad developments, reducing parent and child interactions
- Placed on-line 10 gross wells in 3Q22 and targeting another 13 gross wells in 4Q22

Delaware Basin Second Half Formation Targets



Second Half Development
Midland Basin

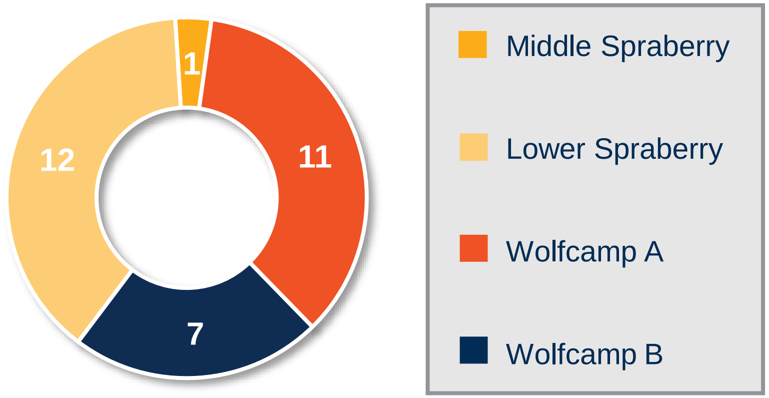
Midland Basin Acreage Position



Second Half of 2022 Development Plan

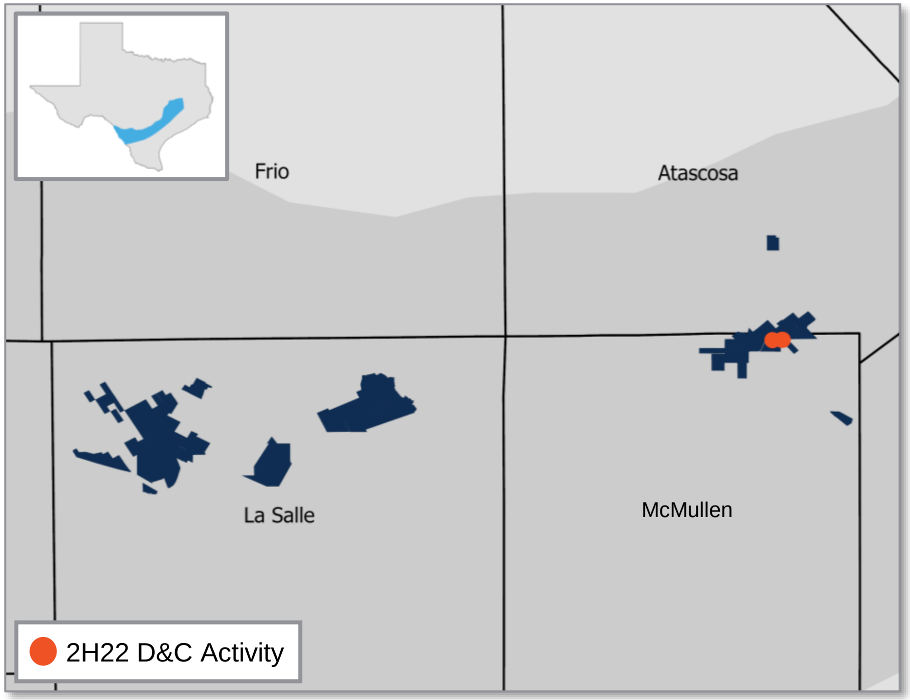
- Midland Basin represents ~50% of new wells in the second half of 2022
- Development consists of projects of 4 - 11 wells on Howard & Midland County acreage
- Multi-bench development
  - Targeting development in four separate zones
- Placed on-line 22 gross wells in 3Q22 and targeting another 9 gross wells in 4Q22

Midland Basin Second Half Formation Targets



Second Half Development
Eagle Ford Shale

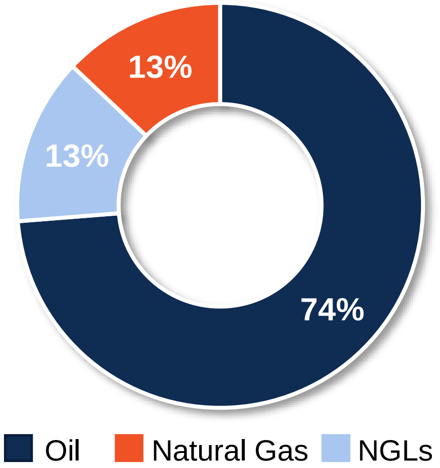
Eagle Ford Shale Acreage Position



Second Half of 2022 Development Plan

- Eagle Ford represents ~20% of new wells in the second half of 2022
- All development focused on McMullen County acreage
- Placed on-line 11 gross wells in 3Q22
- Flowing back initial Austin Chalk well

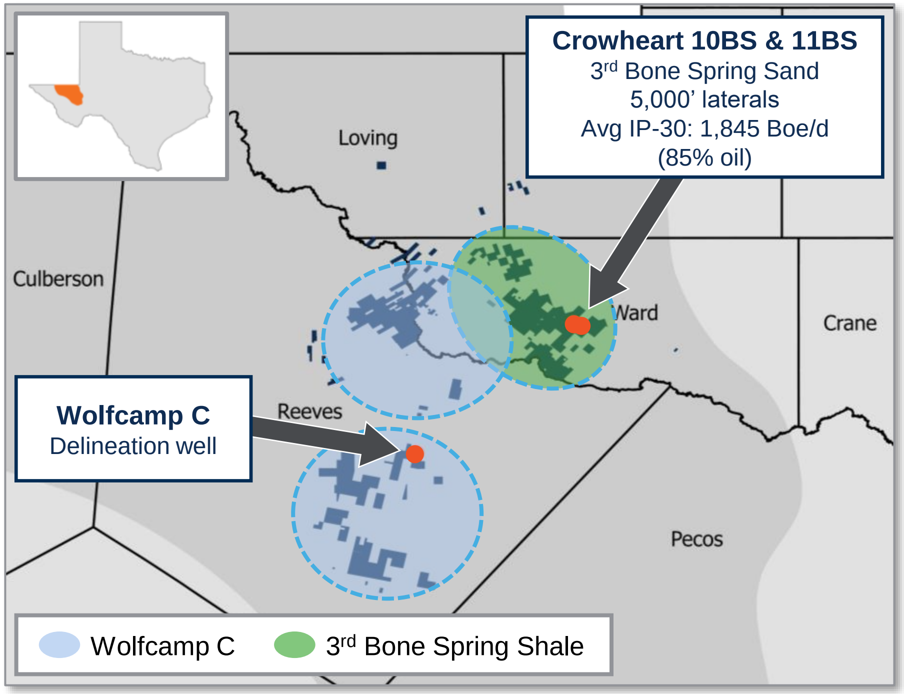
Eagle Ford Production Profile[1]



1. Represents the first nine months of production in 2022

Organic Inventory Expansion

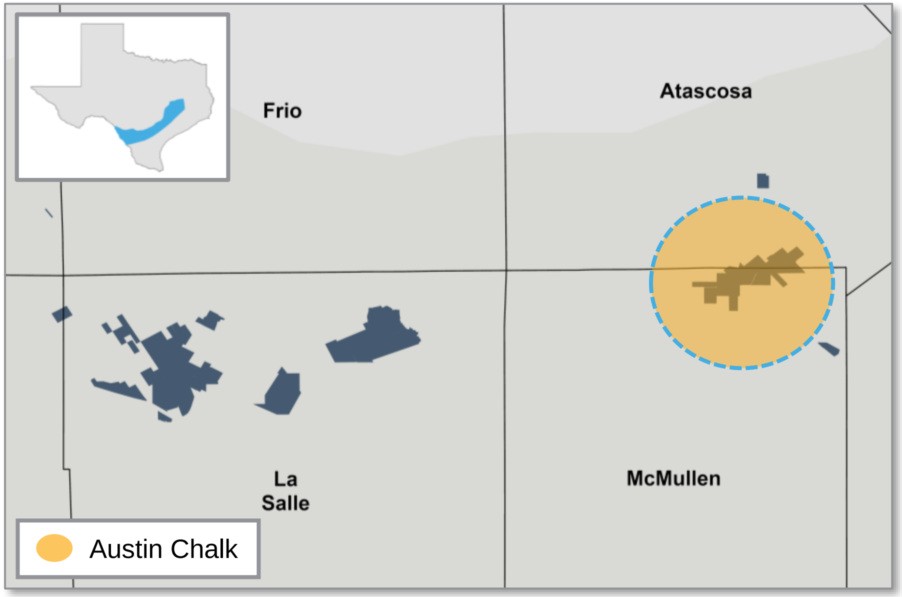
2022 Delineation: Delaware



Delaware Inventory Upside Potential

- Multiple prospective zones in the Delaware with emerging potential in both shallower and deeper formations
- Potential to de-risk ~150 locations with additional 3rd Bone Spring Shale and Wolfcamp C wells
- Planning to test deep Wolfcamp C well in 2023

2022 Delineation: Eagle Ford



Eagle Ford Inventory Upside Potential

- Over 50 prospective Austin Chalk locations in initial target area
- Completed first delineation well in the second half of 2022

Rationale for Conversion to Successful Efforts Method of Accounting

Increased Transparency

- Financial statements will be more reflective of our operating decision-making process

Improved Comparability

- Majority of peer group utilizes the successful efforts method
- Increased peer comparability when analyzing operating results, capital spending, and efficiency ratios

Preferred by Investors

- Investor community preferred method of accounting
- More conservative accounting method as less items are capitalized

Better Indicative Value

- Eliminates proved property impairments based on historical prices
- Impairment evaluations follow changes in current market conditions

Conversion to Successful Efforts Method

Summary of Expected Impacts

	Full Cost	Successful Efforts	Financial Impact
Exploration Expense	Costs associated with exploration are capitalized	Costs associated with exploration activities are expensed	**New** income statement line item
G&A Expense	Capitalize portions of costs associated with acquisitions, exploration and development	Do not expect to capitalize G&A costs	**Increase** in expensed G&A costs
DD&A	Calculated on a cost pool level (i.e. country)	Calculated at a lower level (i.e. field or property)	**Increase** in depletion expense[3]
Interest Expense	Capitalized interest is based on project under development and unproved properties	Do not expect to capitalize interest	**Increase** in expensed interest costs
Proved Property Impairment Testing	Quarterly ceiling test assesment[1]	Assess annually or when impairment indicators exist[2]	Timing of impairments will be based on current market indicators

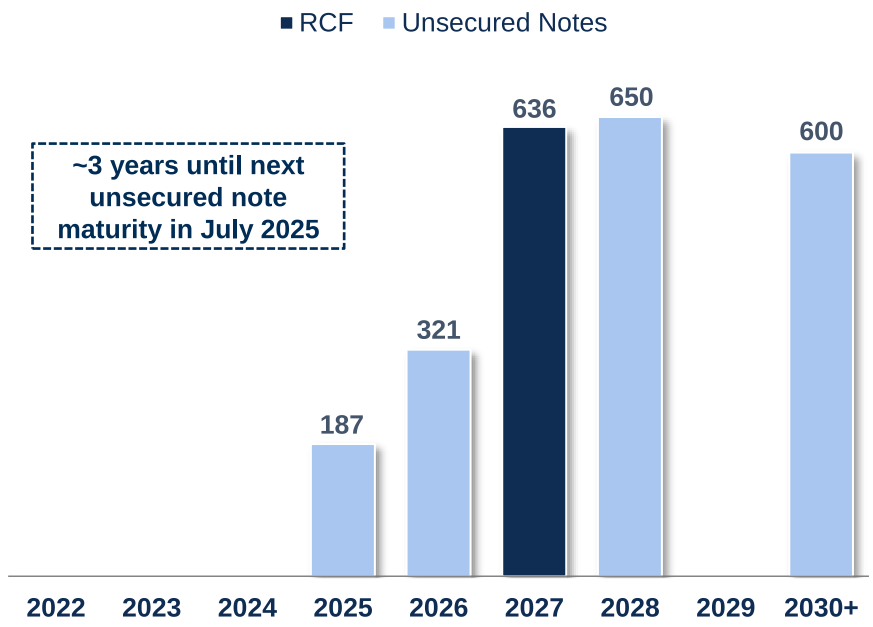
1. Calculation is performed by comparing total capitalized costs to discounted future net cash flows using 12-month average historical pricing
2. Assessment involves a comparison of capitalized costs to undiscounted future net cash flows. If capitalized costs are higher, calculate FV of assets and record impairment for the difference
3. Expect depletion expense to increase as prior impairments are lower under successful efforts, which increases the depletable base

Proactively Addressed Near-Term Maturities

Completing Steps Toward Shareholder Return Program

- [x] Retired 2nd Lien Notes
- [x] Retired Unsecured Notes Due in 2024
- [x] Extended Credit Facility Maturity
- [ ] Reduce Debt to $2 bln and Leverage to 1x
- [ ] Announce Shareholder Return Program

Debt Maturities[1] (in $MM)



Positive Ratings Momentum

B2 / Moody's
One Notch Upgrade on Unsecured Rating to B3

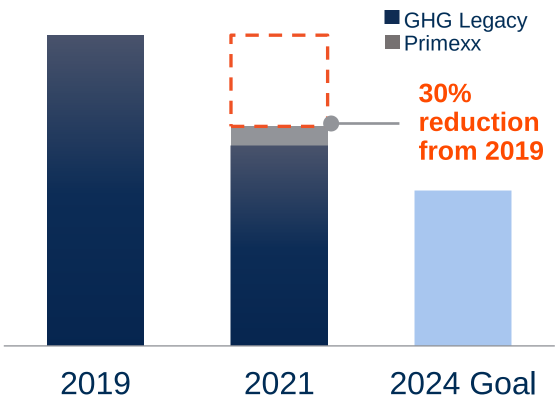
B / S&P
One Notch Upgrade on Issuer Rating to B and Unsecured Rating to B+

B / Fitch
One Notch Upgrade on Unsecured Rating to B+

1. As of September 30th, 2022 and pro forma for recent amended RBL credit agreement

Shaping Our Future: *Aggressively* Reducing Emissions

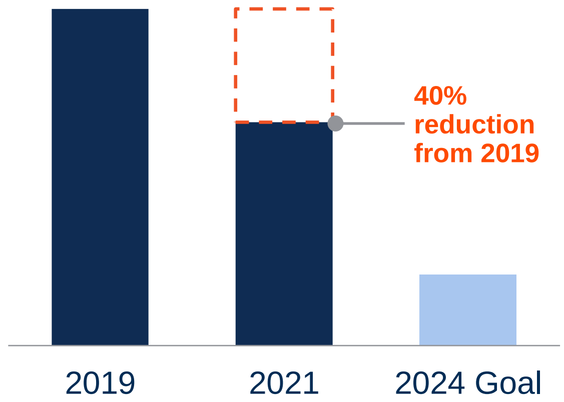
Scope 1 GHG Intensity[1]



50% reduction

ACCELERATED GOAL
50% reduction in GHG intensity by 2024, targeting the high end of previous guidance and accelerating the achievement timeline by one year

Methane Emissions[2]



CH_4

<0.2% reduction

NEW GOAL
Reduce methane emissions to less than 0.2% by 2024

Flaring

Routine flaring 0%

ACCELERATED GOAL
End routine flaring by the end of 2022, an acceleration of three years vs previous goal

<1% All flaring

ACCELERATED GOAL
Reduce all flaring to less than 1% by 2024

Targeting achievements 1+ years ahead of peer group

2021 Sustainability Report available at www.callon.com

1. Scope 1 GHG emissions intensity calculated as metric tons CO2e/thousand equivalent barrels produced. "GHG Legacy" refers to 2021 Callon standalone, excludes assets acquired in the Delaware Basin from Primexx Resource Development, LLC and BPP Acquisition, LLC (the "Primexx Acquisition"). Emissions are reported in accordance with EPA regulations.
2. Calculated as methane emissions as a percentage of gas produced

Maintaining Capital *Discipline*

Fourth Quarter Outlook
Guidance and Financial Estimates

Total Production
105-108
MBoe/d
(63% oil / 82% liquids)

3Q22: 107 MBoe/d

Operational CapEx
$180-$195
million

3Q22: $255MM

Adj. Free Cash Flow Generation
>$200 million[1]

2022 YTD: $457MM

Full Year Outlook
2022 Guidance

Total Production
103-105
MBoe/d
(62.5% oil / 82% liquids)

2021: 96 MBoe/d

Operational CapEx
$830-$845
million

2021: $509MM[2]

Capital Reinvestment Rate
~55%
Operating CF[3]

2021: 59%

1. Based on strip pricing as of November 1, 2022
2. Not pro forma for Primexx
3. Based on actual price realizations through October 31, 2022 and forward strip pricing as of November 1, 2022 for the balance of 2022

2022 Guidance

	Prior	Updated	COMMENTARY
Total production (MBoe/d)	**102 - 105**	**103 - 105**	Increased bottom end of range
Oil	**63.0%**	**62.5%**	
NGL	**19.0%**	**19.5%**	
Gas	**18.0%**	**18.0%**	
Income statement expenses **($MM, except where noted)**			
LOE, including workovers	**$275 - $295**	**$275 - $295**	Tracking high end (fuel and power costs)
Gathering, processing, and transportation	**$80 - $90**	**$90 - $100**	Contract price increases tied to CPI
Production taxes, including ad valorem (% of total oil, natural gas, and NGL revenues)	**6.0%**	**6.0%**	
Adjusted G&A: cash component[1]	**$50 - $60**	**$50 - $55**	
Adjusted G&A: non-cash component[2]	**$5 - $15**	**$5 - $15**	
Cash interest expense, net	**$55 - $60**	**$70 - $75**	Increased floating interest rate assumption
Estimated effective income tax rate	**22%**	**22%**	
Capital expenditures **($MM, accrual basis)**			
Total operational capital[3]	**$790 - $810**	**$830 - $845**	Includes addition of sixth drilling rig
Cash capitalized interest	**$95 - $105**	**$95 - $105**	
Cash capitalized G&A	**$35 - $40**	**$40 - $45**	
Gross Operated Wells Placed on Production	**113 - 117**	**113 - 117**	

1. Excludes the change in fair value and amortization of share-based incentive awards
2. Amortization of equity-settled, share based incentive awards
3. Includes facilities, equipment, seismic, land, and other items, excludes capitalized expenses

APPENDIX

Oil Hedges

	4Q22	1Q23	2Q23	3Q23	4Q23	FY 2023	FY 2024
NYMEX WTI (Bbls, $/Bbl)							
Swaps							
Total Volumes	1,748,000	675,000	682,500	184,000	-	1,541,500	
Total Daily Volumes	19,000	7,500	7,500	2,000	-	4,223	
Avg. Swap Price	$65.89	$79.18	$79.18	$85.00	-	$79.87	
Collars							
Total Volumes	1,104,000	810,000	819,000	368,000	368,000	2,365,000	
Total Daily Volumes	12,000	9,000	9,000	4,000	4,000	6,479	
Avg. Short Call Strike	$70.16	$91.93	$91.93	$80.14	$80.14	$88.26	
Avg. Long Put Strike	$60.00	$73.22	$73.22	$70.00	$70.00	$72.22	
Three-Way Collars							
Total Volumes	-	450,000	455,000	460,000	460,000	1,825,000	
Total Daily Volumes	-	5,000	5,000	5,000	5,000	5,000	
Avg. Short Call Strike	-	$90.00	$90.00	$90.00	$90.00	$90.00	
Avg. Long Put Strike	-	$70.00	$70.00	$70.00	$70.00	$70.00	
Avg. Short Put Strike	-	$50.00	$50.00	$50.00	$50.00	$50.00	
Total WTI Volume Hedged (Bbls)	2,852,000	1,935,000	1,956,500	1,012,000	828,000	5,731,500	
Average WTI Ceiling Strike ($/Bbl)	$67.54	$87.03	$87.03	$85.50	$85.62	$86.56	
Average WTI Floor Strike ($/Bbl)	$63.61	$74.55	$74.55	$72.73	$70.00	$73.57	
NYMEX WTI (Bbls, $/Bbl)							
Swaptions							
Total Volumes	–	–	–	–	–	–	1,830,000
Total Daily Volumes	–	–	–	–	–	–	5,000
Avg. Swap Price	–	–	–	–	–	–	$80.30
MIDLAND-CUSHING DIFFERENTIAL (Bbls, $/Bbl)							
Swaps							
Total Volumes	598,000	–	–	–	–	–	
Total Daily Volumes	6,500	–	–	–	–	–	
Avg. Swap Price	$0.50	–	–	–	–	–	

1. Callon hedge portfolio as of October 28th, 2022

Natural Gas Hedges

	4Q22	1Q23	2Q23	3Q23	4Q23	FY 2023
NYMEX HENRY HUB (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	1,550,000	–	–	–	–	–
Total Daily Volumes	16,848	–	–	–	–	–
Avg. Swap Price	$3.62	–	–	–	–	–
Collars						
Total Volumes	3,670,000	4,500,000	910,000	920,000	310,000	6,640,000
Total Daily Volumes	39,891	50,000	10,000	10,000	3,370	18,192
Avg. Short Call Strike	$6.91	$7.49	$4.75	$4.75	$4.75	$6.60
Avg. Long Put Strike	$4.67	$4.95	$3.50	$3.50	$3.50	$4.48
Total NY MEX Volume Hedged (MMBtu)	5,220,000	4,500,000	910,000	920,000	310,000	6,640,000
Average NY MEX Ceiling Strike ($/MMBtu)	$5.93	$7.49	$4.75	$4.75	$4.75	$6.60
Average NY MEX Floor Strike ($/MMBtu)	$4.36	$4.95	$3.50	$3.50	$3.50	$4.48
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	1,220,000	1,800,000	1,820,000	1,840,000	620,000	6,080,000
Total Daily Volumes	13,261	20,000	20,000	20,000	6,739	16,658
Avg. Swap Price	($0.75)	($0.75)	($0.75)	($0.75)	($0.75)	($0.75)

1. Callon hedge portfolio as of October 28th, 2022

Non-GAAP Adjusted EBITDA[1]

($000s)	FY 2021	4Q 21	1Q 22	2Q 22	3Q 22
Net income	**$365,151**	**$285,351**	**$39,737**	**$348,009**	**$549,603**
(Gain) loss on derivative contracts	522,300	10,145	358,300	81,648	(134,850)
Loss on commodity derivative settlements, net	(423,306)	(149,938)	(133,476)	(184,558)	(105,006)
Non-cash expense (benefit) related to share-based awards	12.923	939	4,166	(3,210)	99
Merger, integration, transaction and other	21,944	12,343	(13)	1,051	2,861
Income tax (benefit) expense	180	(837)	484	3,009	3,515
Interest expense, net	102,012	25,226	21,558	20,691	19,468
Depreciation, depletion and amortization	356,556	112,551	102,979	109,409	122,833
Loss on extinguishment of debt	41,040	43,460	-	42,417	-
Adjusted EBITDA	**$998,800**	**$339,240**	**$393,735**	**$418,466**	**$458,523**
Primexx EBITDA[2]	$170,923				
Total Production (MBoe)	34,894	10,338	9,239	9,162	9,873
Net Income per BOE	**$10.46**	**$27.60**	**$4.30**	**$37.98**	**$55.67**
Adjusted EBITDA per BOE	**$28.62**	**$32.81**	**$42.62**	**$45.67**	**$46.44**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures
2. Represents EBITDA from January 1st through September 30th, 2021 prior to closing on transaction on October 1st

Non-GAAP Adjusted EBITDA, Adjusted Free Cash Flow and Adjusted Discretionary Cash Flow[1]

($000s)	4Q 21	1Q 22	2Q 22	3Q 22
Net cash provided by operating activities	**$366,310**	**$281,270**	**$372,325**	**$475,275**
Changes in working capital and other	(67,390)	123,805	25,096	(75,748)
Change in accrued hedge settlements	6,781	(31,951)	1,839	40,590
Cash interest expense, net	22,268	19,842	19,206	18,406
Merger, integration and transaction	11,271	769	-	-
Adjusted EBITDA	**$339,240**	**$393,735**	**$418,466**	**$458,523**
Less: Operational capital expenditures (accrual)	159,786	157,378	237,812	254,662
Less: Capitalized cash interest	22,591	23,506	24,416	25,964
Less: Cash interest expense, net	22,268	19,842	19,206	18,406
Less: Capitalized cash G&A	11,035	9,703	11,432	11,053
Adjusted Free Cash Flow	**$123,560**	**$183,306**	**$125,600**	**$148,438**

($000s)	4Q 21	1Q 22	2Q 22	3Q 22
Net cash provided by operating activities	**$366,310**	**$281,270**	**$372,325**	**$475,275**
Changes in working capital	(67,594)	126,997	23,342	(76,994)
Merger, integration and transaction	11,271	769	-	-
Adjusted Discretionary Cash Flow	**$309,987**	**$409,036**	**$395,667**	**$398,281**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures.

Non-GAAP Net Debt Reconciliation[1]

($ millions)	12/31/21	3/31/22	6/30/22	9/30/22
Total debt	$2,694	$2,623	$2,516	$2,373
Unamortized premiums, discount, and deferred loan costs, net	29	27	21	21
Adjusted total debt	**$2,723**	**$2,650**	**$2,537**	**$2,394**
Less: Cash and cash equivalents	10	4	6	4
Net Debt	**$2,713**	**$2,646**	**$2,531**	**$2,390**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures