Investor Presentation

November 2024

Forward Looking Statements & Non-GAAP Financial Measures

This presentation contains "forward-looking statements" within the meaning of Section 27A of the Securities Act, Section 21E of the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as "may," "will," "should," "could," "would," "expects," "plans," "anticipates," "intends," "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that we expect or anticipate will or may occur in the future, including the expected impact of the war in Ukraine and the Israel–Hamas war on our business, our industry and the global economy, estimated future production and net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), share repurchases, business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control. Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this presentation are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in Item 1A. "Risk Factors" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Gulfport's Annual Report on Form 10-K for the year ended December 31, 2023, Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Gulfport's Quarterly Reports on Form 10-Q and all forward-looking statements speak only as of the date of this presentation.

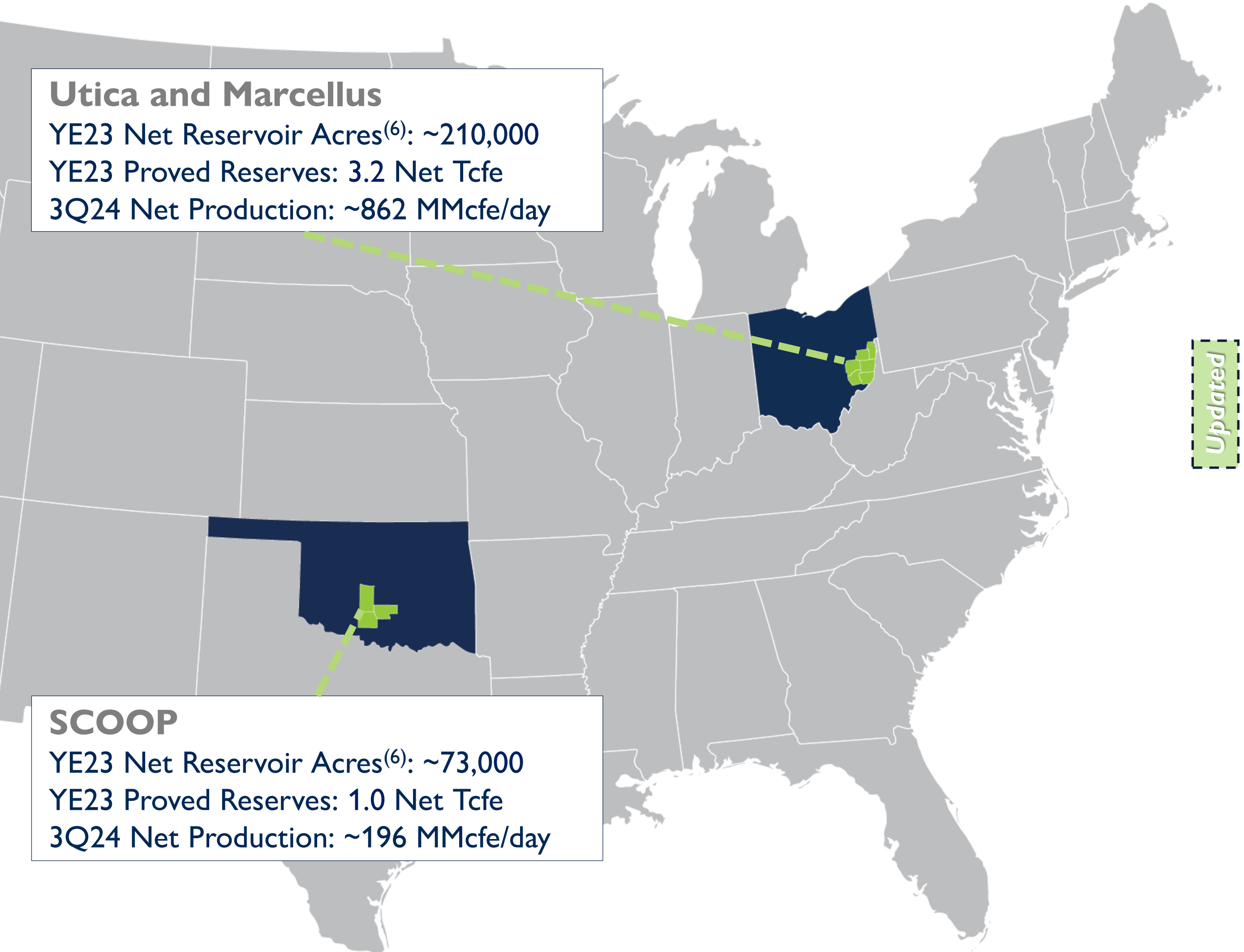
Gulfport's proved reserves and adjusted proved reserves are those quantities of natural gas, oil, and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, 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.

Gulfport's estimate of its total proved reserves is based on reports prepared by Netherland, Sewell Associates, Inc., independent petroleum engineers, and internal estimates. Factors affecting ultimate recovery include the scope of Gulfport's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Estimates may change significantly as development of Gulfport's natural gas, oil and natural gas liquids assets provide additional data. Gulfport's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Gulfport's management uses certain non-GAAP financial measures for planning, forecasting and evaluating business and financial performance, and believes that they are useful tools to assess Gulfport's operating results. Although these are not measures of performance calculated in accordance with generally accepted accounting principles (GAAP), management believes that these financial measures are useful to an investor in evaluating Gulfport because (i) analysts utilize these metrics when evaluating company performance and have requested this information as of a recent practicable date, (ii) these metrics are widely used to evaluate a company's operating performance, and (iii) we want to provide updated information to investors. Investors should not view these metrics as a substitute for measures of performance that are calculated in accordance with GAAP. In addition, because all companies do not calculate these measures identically, these measures may not be comparable to similarly titled measures of other companies. These non-GAAP financial measures include adjusted EBITDA, adjusted free cash flow, recurring general and administrative expense and present value of estimated future net revenue A reconciliation of each financial measure to its most directly comparable GAAP financial measure is included as part of this presentation. These non-GAAP measure should be considered in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

The information in this presentation is not a prospectus or offering document and does not constitute an offer, invitation or recommendation to subscribe for, retain or purchase any securities in Gulfport Energy Operating Corporation (the "Issuer"), Gulfport or any of their respective subsidiaries or affiliates. Gulfport has prepared a preliminary offering memorandum for the proposed offering to which the information in this presentation relates and the securities described in this presentation are being offered in reliance on exemptions from the registration requirements of the Securities Act of 1933, as amended (the "Act") only to persons reasonably believed to be qualified institutional buyers under Rule 144A or outside the United States to non-U.S. persons under Regulation S promulgated under the Act. These exemptions apply to offers and sales of securities that do not involve a public offering. The securities have not been and will not be registered under the Act or under any state securities laws. Before you invest, you should read the detailed information in the preliminary offering memorandum, and the documents incorporated by reference therein, for more complete information about the Issuer and Gulfport. The preliminary offering memorandum, including the documents incorporated by reference, modifies and supersedes in its entirety any information in this presentation or which has otherwise been previously provided. You should rely solely on the information contained in the preliminary offering memorandum, including the documents incorporated by reference, to make an investment decision. This presentation, and the information contained herein, will not form the basis of any contract or commitment.

Gulfport Energy Overview



Utica and Marcellus
YE23 Net Reservoir Acres[6]: ~210,000
YE23 Proved Reserves: 3.2 Net Tcfe
3Q24 Net Production: ~862 MMcfe/day

SCOOP
YE23 Net Reservoir Acres[6]: ~73,000
YE23 Proved Reserves: 1.0 Net Tcfe
3Q24 Net Production: ~196 MMcfe/day

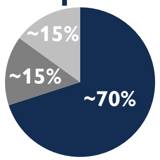
Key Highlights

Updated

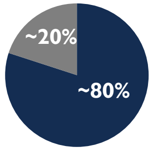
NYSE:	**GPOR**
Market Cap[1]:	**$2.5 Billion**
Enterprise Value ('EV')[2]:	**$3.3 Billion**
EV / 2025 EBITDA[2,7]:	**3.9x**
Liquidity[3]:	**~$910 Million**
Leverage[4]:	**0.97x**
D&C Capital:	$325 – $335 Million
Maintenance Leasehold Capital:	$50 – $60 Million
2024E Total Base Capital:	**$375 - $395 Million**
2024E Total Net Production:	**1,055 – 1,070 MMcfe/day**
~92% Natural Gas	
Top-decile adjusted free cash flow yield[5] relative to natural gas peers	
Remaining Inventory:	**~500 gross operated**
>12 years of net inventory at attractive rates of return	

2024E Activity

2024E Capital Program



2024E Production Mix



1. Market capitalization calculated as of 10/28/24 at a price of $142.86 per share using shares outstanding from the Company's 3Q2024 10-Q filing.
2. Enterprise value calculated as of 10/28/24 at a price of $142.86 per share using shares outstanding, long-term debt, preferred stock and cash and cash equivalents from the Company's 3Q2024 financial statements. The impact of the conversion of the 43,745 outstanding preferred shares would increase common shares outstanding by ~3.1 million common shares and increase the EV / 2025 Adjusted EBITDA multiple by 0.5x to 4.4x.
3. As of 9/30/24 and calculated as $3.2 million cash plus $906.2 million borrowing base availability, which takes into effect $30.0 million of borrowings on revolver and $63.8 million of letters of credit.
4. As of 9/30/24 using net debt to LTM Adjusted EBITDA. Net debt and Adjusted EBITDA are non-GAAP measures. Net debt is defined as total long-term debt minus cash and cash equivalents.
5. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Adjusted free cash flow excludes discretionary acreage acquisitions and common stock repurchases. Adjusted free cash flow yield is calculated using adjusted free cash flow divided by market capitalization using shares outstanding from the Company's 3Q2024 10-Q filing.
6. Appalachia acreage includes ~193,000 Utica and ~17,000 Marcellus net reservoir acres. SCOOP acreage includes ~41,000 Woodford and ~32,000 Springer net reservoir acres.
7. EBITDA estimate sourced from Factset as of 10/28/24.

Focused Strategy and Compelling Valuation

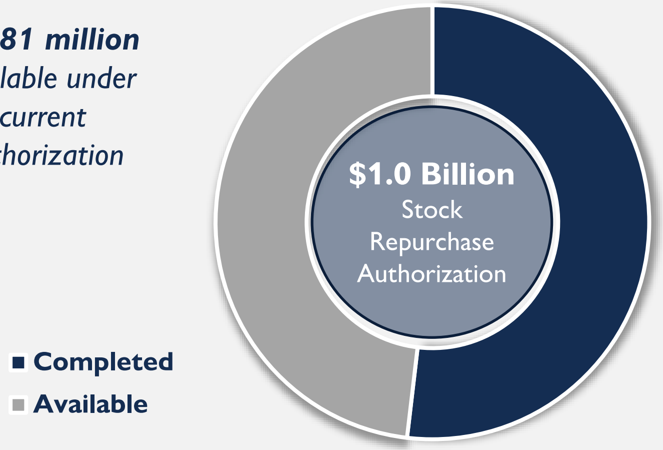
High Quality Asset Base Natural Gas Weighted with Liquids Opportunities	• Multi-basin portfolio provides diversification and capital allocation optionality • Capture value accretion through liquids-rich development in the Utica, Marcellus and SCOOP • Low breakeven inventory supports sustainable returns and adjusted free cash flow[(1)] generation
Improve Margins and **Free Cash Flow Generation**	• Focus on continuously improving cycle times and reducing operating costs • Top decile adjusted free cash flow[(1)] yield and positive adjusted free cash flow[(1)] across wide range of commodity prices
Enhance Shareholder Value through Disciplined Capital Allocation	• Return capital to shareholders through repurchase of undervalued common stock • Reinvest in strategic acquisition opportunities that provide operating synergies, quality resource depth and optionality to our near-term development activities
Maintain **Strong Balance Sheet**	• Maintain financial strength and flexibility to execute strategic and operating plans in volatile commodity environment • Hedging program reduces commodity risk and future cash flow volatility
Committed to **ESG Excellence**	• Safety of employees, contractors and communities is our highest priority • Committed to operating in an environmentally responsible and sustainable manner • Provide community support through giving and volunteering in our operating areas

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.

Delivering Value For Shareholders

Common Stock Repurchase Program

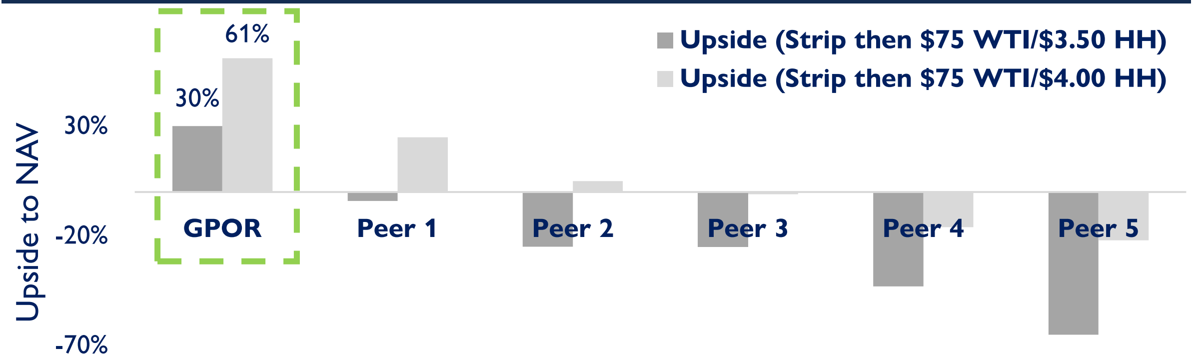
~$481 million
Available under current authorization



~$519 million
Repurchased as of October 28, 2024, retiring ~5.2 million shares

Recently expanded by 54% to $1.0 billion

NAV Valuation Upside to Current Share Price[2]



Common Stock Repurchases

- Recently expanded common stock repurchase program authorizes purchases up to $1.0 billion of Gulfport outstanding shares
  - As of October 28, 2024, repurchased ~$518.7 million at an average price of $100.17 per share
- Total reduction of ~5.2 million shares, reducing common stock outstanding by approximately 18% since the initial authorization date in March 2022
- Expect to allocate substantially all FY2024 adjusted free cash flow[1], excluding discretionary acreage acquisitions, towards common stock repurchases
- Looking ahead to 2025, Gulfport forecasts significant adjusted free cash flow[1] generation and plans to continue to opportunistically repurchase common shares to deliver significant value for shareholders

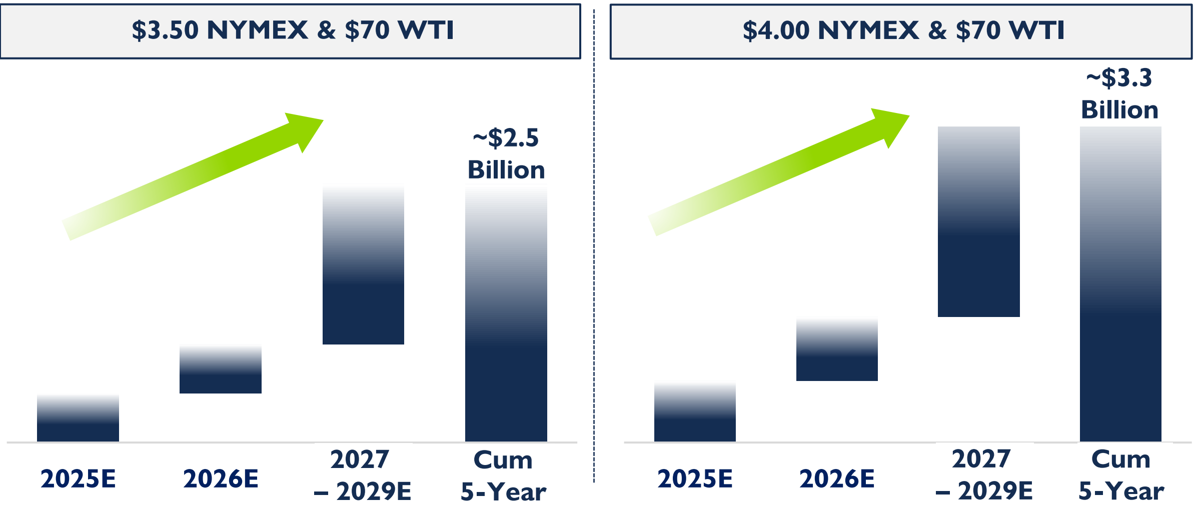
Discretionary Acreage Acquisitions

- Planning discretionary acreage acquisitions of ~$45 million during 2024
- Since 2023, the Company will have added ~4.5 years of high-margin, liquids-rich inventory through delineation and discretionary acreage acquisition efforts by year end 2024

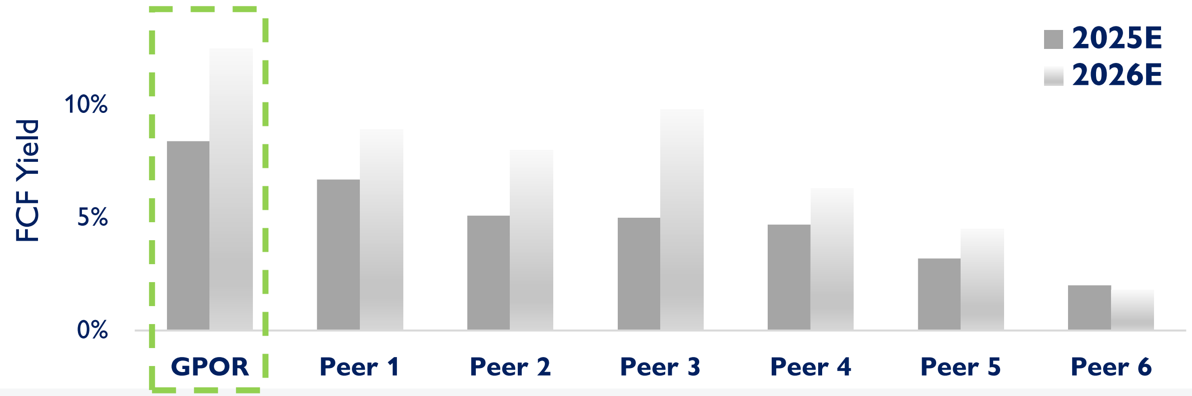
1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.
2. Sourced from Enverus Intelligence 2Q2024 Gas NAV Compass. All mentions of NAV are on a post-tax basis. Utilized strip prices as of 8/27/24 and share prices as of 10/25/24. Peers include AR, CNX, CRK, EQT, & RRC.

Adjusted Free Cash Flow Generation Potential

2025E – 2029E Adjusted Free Cash Flow[1,2,3] Illustration ($MM)



Adjusted Free Cash Flow Yield[4,5]



Key Highlights

- Sustainable free cash generation underpinned by high-quality assets
- Meaningful adjusted free cash flow profile **generating ~90% - 135% of market capitalization[6]** over the next five years
- Delivering highest free cash flow yield among natural gas peers
- The focus on maintenance leasehold and land spend, in combination with our discretionary acreage acquisitions, have bolstered our future drilling programs and we anticipate lower maintenance land spend going forward

	Base Assumptions	Upside Potential
Net Production:	Low single digit growth of 0% – 5%	*Improving base decline, reduced cycle times and potential uplift from managed pressure programs*
Cash Costs:	$1.25 – $1.40 / Mcfe	*Reducing per unit cash costs which includes LOE, GP&T, taxes other than income and G&A*
Updated Total Capital:	**$325 – $335 Million D&C ~$45 Million Land**	*Continued operational efficiencies, cost reductions and lower maintenance land spend*
Differentials:	Natural Gas: $0.20 - $0.35 off NYMEX Oil: $5.50 - $6.50 off WTI NGL: 35% - 40% of WTI	*Optimizing marketing strategy to improve sales points reached and realizations*
Commodity Prices:	Flat price scenarios	*Commodity price improvements*

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.
2. Based upon flat price cases and base assumptions per year. Includes current hedge position as of October 28, 2024.
3. No payment of cash income taxes assumed in illustration. Company does not currently anticipate paying significant cash income taxes over next five years (*estimating <5% of cumulative 5-year adjusted free cash flow*).
4. Sourced from J.P. Morgan E&P Valuation Analysis utilizing J.P. Morgan estimates & Bloomberg Finance L.P.; Strip pricing as of 10/22/24 ($67.25/$65.77 per bbl for WTI and $3.07/$3.52 per Mcf for NYMEX gas in 2025-26); Share prices as of 10/21/24. Peers include AR, CNX, CTRA, EQT, NFG, & RRC.
5. FCF Yield is calculated using estimated free cash flow divided by current market capitalization.
6. Market capitalization calculated as of 10/28/24 at a price of $142.86 per share using shares outstanding from the Company's 3Q2024 10-Q filing.

Gulfport ENERGY

Third Quarter 2024 Results

	3Q2024	YTD 2024	*Full Year 2024 Guidance*
Total Net Production	1,057.2 MMcfe/day	1,053.7 MMcfe/day	*1,055 – 1,070 MMcfe/day*
Incurred Capital Expenditures[1]	$82.5 Million	$329.0 Million	*Total Base Capital[5]: $375 - $395 Million*
Per Unit Operating Cost[2]	$1.18 per Mcfe	$1.16 per Mcfe	*$1.15 – $1.23 per Mcfe*
Adjusted Free Cash Flow[3]	$72.6 Million	$131.6 Million	*Return substantially all adjusted free cash flow[3], excluding discretionary acreage acquisitions, towards common stock repurchases*
Common Stock Repurchases	$49.9 Million	$104.4 Million	
Discretionary Acreage Acquisitions	$19.8 Million	$38.8 Million	*~$45 Million*
Current Leverage (Net Debt[4] to Adjusted EBITDA[3])	0.97x		*Maintain financial strength*

Key Highlights

- Turned-in-line 7 gross Utica wells and 3 gross SCOOP wells, delivering total net production of 1,057.2 MMcfe/day
- Increased total net oil production by 68% over 2Q2024
- Incurred capital expenditures of $82.5 million, below analyst consensus expectations
- Completed opportunistic discretionary acreage acquisitions of $38.8 million YTD 2024, with plans to allocate ~$45 million
- Generated $72.6 million of adjusted free cash flow[3]
- Reduced D&C capital expenditures to $325 million – $335 million, a decrease of 4% based upon the midpoint of the previously issued guidance range
- Repurchased 5.2 million[6] shares of common stock at a weighted-average share price of $100.17, totaling ~$518.7 million
- Expanded common stock repurchase authorization by 54% percent to $1.0 billion
- Extended the weighted average maturity of the Company's long-term senior notes by 3.2 years

1. Excludes $0.8 million and $3.7 million of non-D&C capital for 3Q2024 and YTD 2024, respectively, and excludes targeted discretionary acreage acquisitions of $19.8 million and $38.8 million for 3Q2024 and YTD2024, respectively.
2. Includes LOE, GP&T and taxes other than income.
3. Adjusted EBITDA and adjusted free cash flow are non-GAAP financial measures; see supplemental slides. Adjusted free cash flow excludes discretionary acreage acquisitions and common stock repurchases.
4. As of 9/30/24 using net debt to LTM Adjusted EBITDA. Net debt and Adjusted EBITDA are non-GAAP measures. Net debt is defined as total long-term debt minus cash and cash equivalents.
5. Includes D&C capital of $325 million - $335 million and maintenance leasehold and land capital of $50 million - $60 million.
6. As of October 28, 2024.

Gulfport ENERGY

Full Year 2024 Guidance

Reaffirmed

Total Net Production

1,055 – 1,070 MMcfe/day

Focusing on liquids-rich development, improving margins and supporting expected free cash flow generation

Updated

Incurred Base Capital

$375 – $395 Million

Operational efficiencies reduce future maintenance capital requirements on comparable drilling programs

Reaffirmed

Discretionary Acreage Acquisitions

~$45 Million

Allocating ~$45 million toward accretive acreage that extends high-quality resource depth and provides optionality for near term development

Reaffirmed

Per Unit Operating Cost

$1.15 – $1.23 per Mcfe

Continuous optimization of per unit operating expenses, including LOE, taxes other than income and midstream costs

Resilient Adjusted Free Cash Flow Generation and Yield(1)

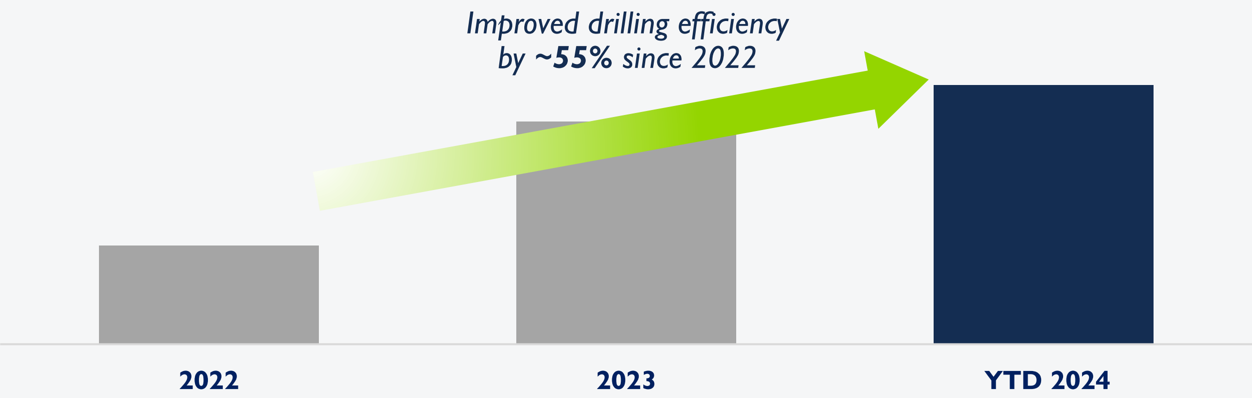
Compelling valuation for shareholders with top-decile yield relative to peers and continued free cash flow generation in volatile commodity market

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Adjusted free cash flow yield is calculated using adjusted free cash flow and dividing by current market capitalization.

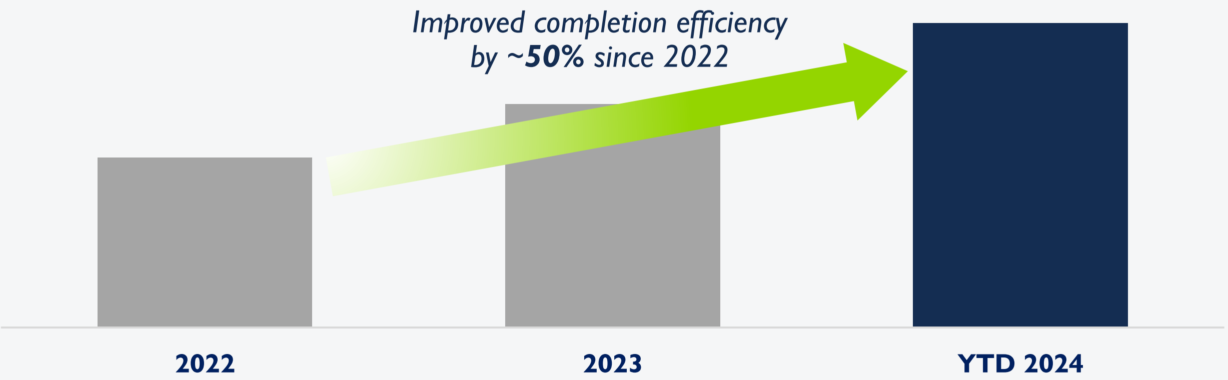
Significant Improvement in Operational Efficiencies

Ohio Drilling and Completion Efficiencies

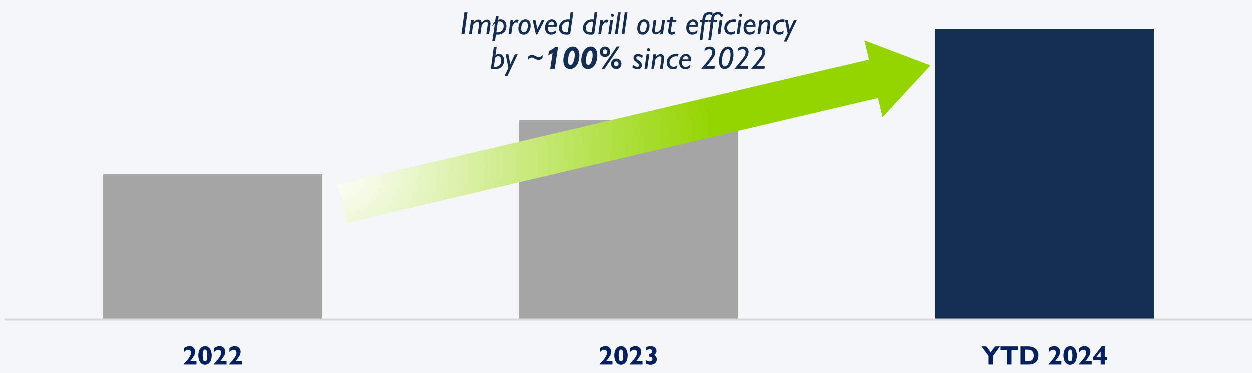
Average Total Footage per Day



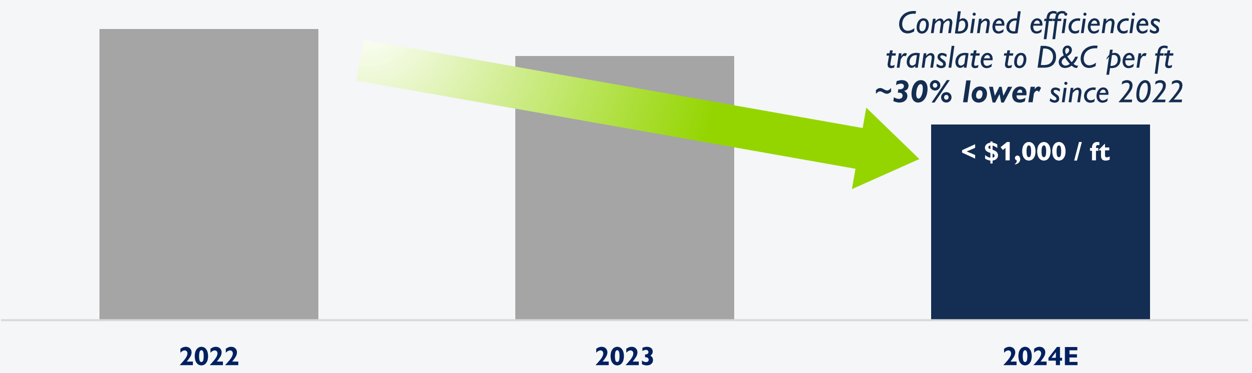
Average Frac Pumping Hours



Average Plugs Drilled per Day



Utica Dry Gas D&C Cost Per 1,000 ft



2024 Capital Program and Production Outlook

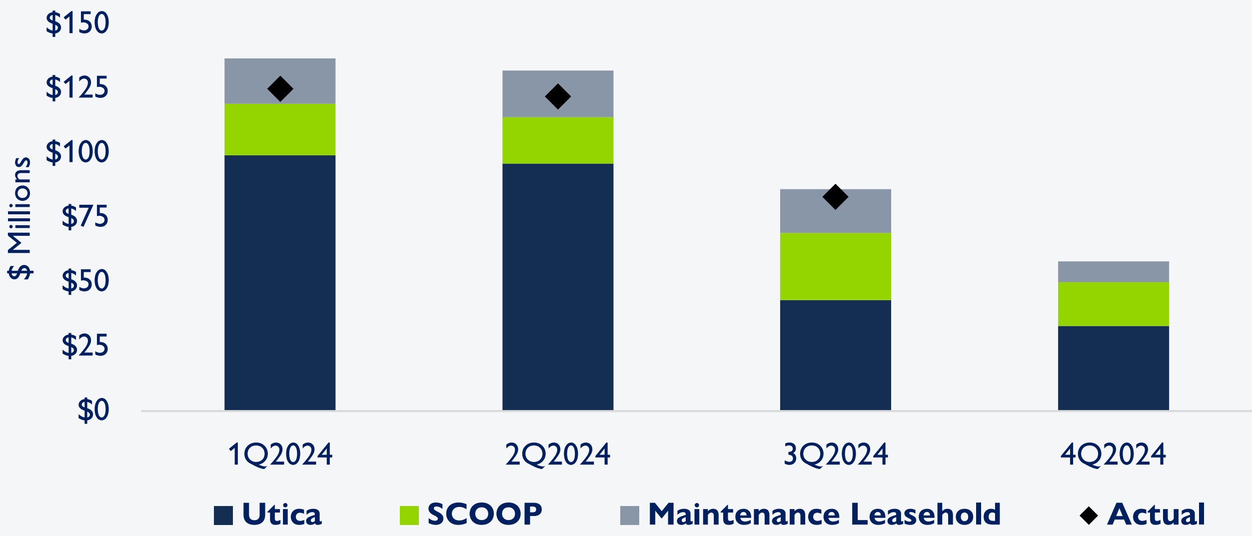
Capital Program

- Continuing to benefit from operating momentum and capital efficiencies
- Reducing drilling and completion capital expenditures to $325 million – $335 million, a decrease of 4% based upon midpoint of prior guidance
- Efficiency gains reduce future maintenance capital requirements
- Planning discretionary acreage acquisitions of ~$45 million, of which $38.8 million was invested through 3Q2024

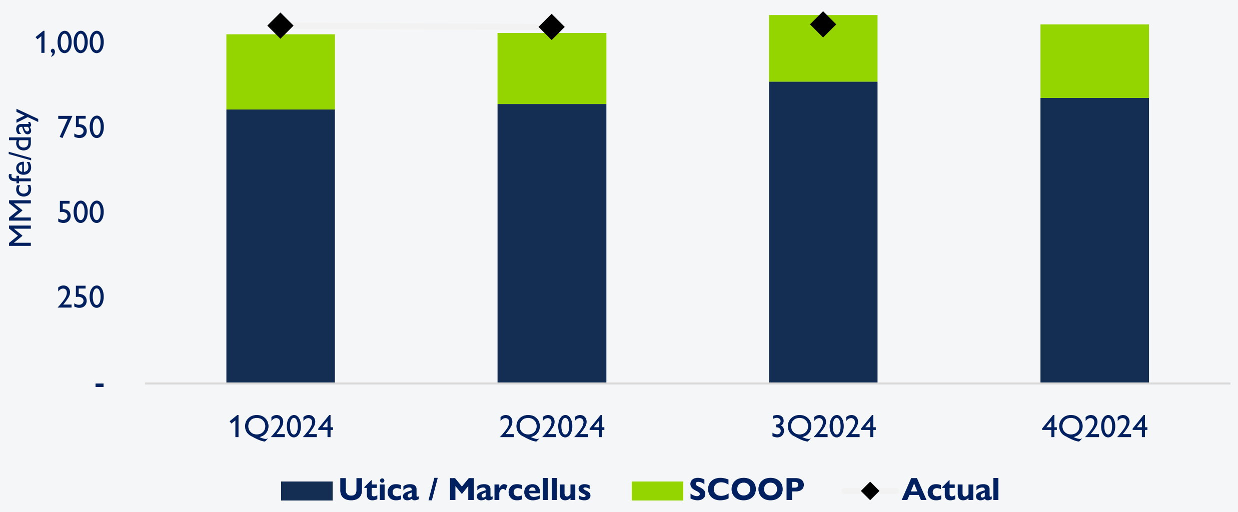
Production

- Reaffirming full year 2024 production guidance of 1,055 – 1,070 MMcfe/day
- Increasing total net oil production, up 68% Q-o-Q, and forecasted to continue grow in fourth quarter of 2024 and FY 2025
- Improving base decline providing support for production profile
- Plan to continue focusing on liquids-rich development in 2025, improving margins and supporting free cash flow generation

Total Capital Expenditures[1]



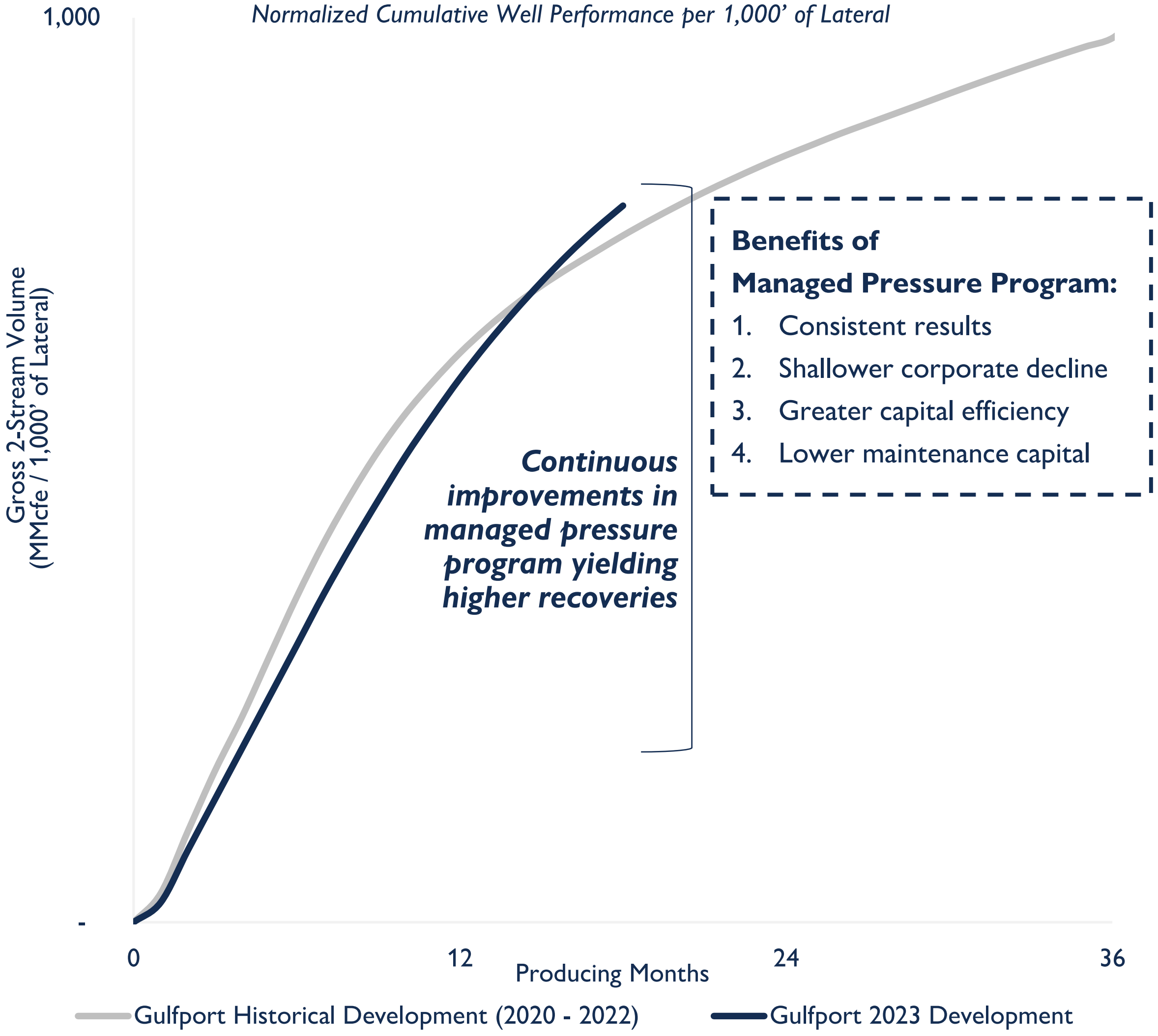
Total Net Production



1. Excludes discretionary acreage acquisitions during 2024.

Managed Pressure Program Yielding Higher Recoveries

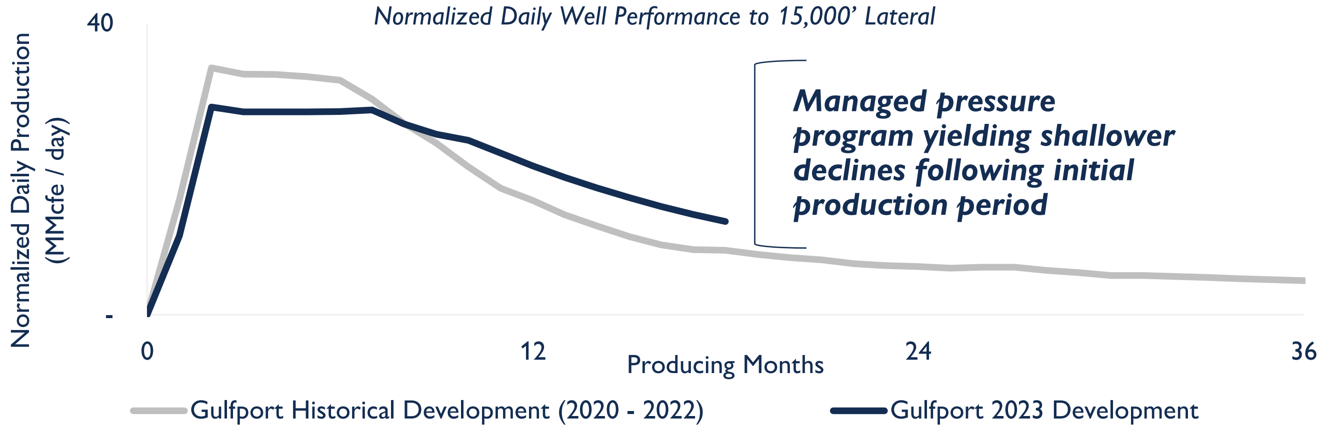
Gulfport Utica Dry Gas Well Performance(1)



Key Highlights

- Enhances productivity by maintaining stimulated reservoir conductivity
- Lowers initial well costs by decreasing facility builds
- Reduces lease operating expense with standardized facility designs
- Minimizes risk of productivity impact via proppant flowback
- Reduces well downtime and operating maintenance experienced on higher rate production by limiting equipment damage from erosion
- Prolongs formation pressure above the bubblepoint, delivering lower gas-to-oil ratios in liquids wells

Gulfport Utica Dry Gas Well Performance(1)



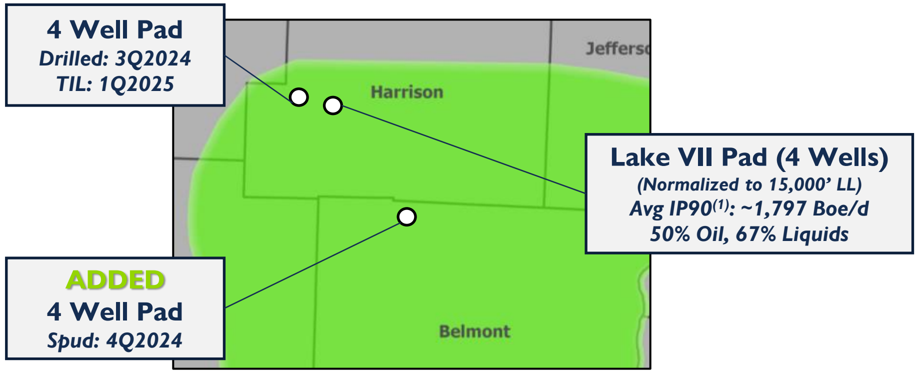
1. Includes wells turned-to-sales within each calendar year with at least twelve months of production history.

Recent Condensate Performance Providing Strong Results

Key Highlights

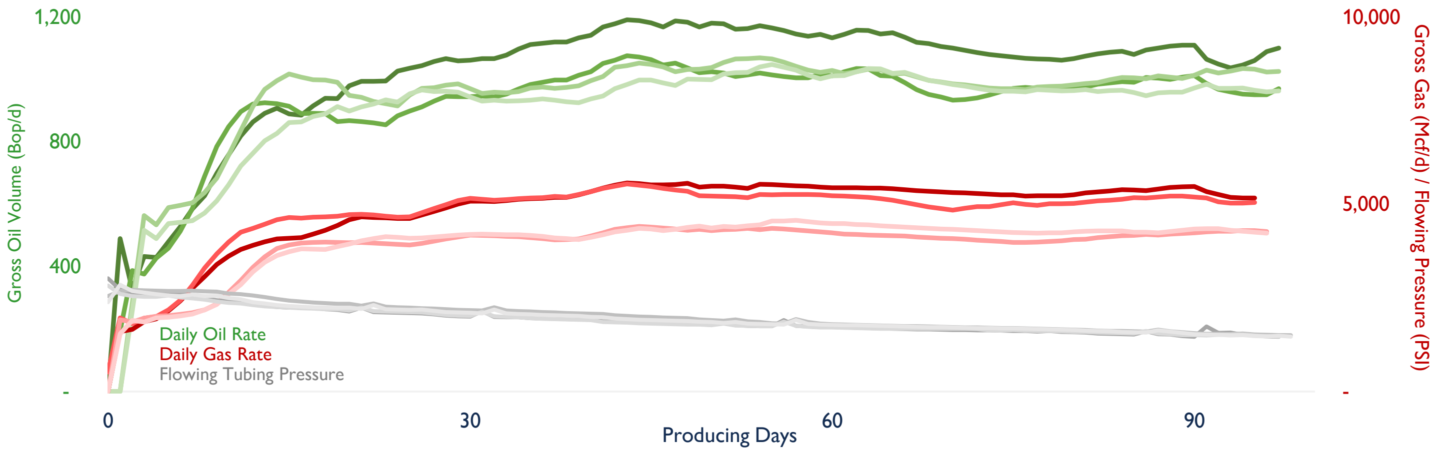
- Exhibits attractive liquids production rates with minimal pressure drawdown during initial 90-day period
- Testing increased production rates to determine optimal production profile aimed at maximizing long term well performance
- Analysis indicates similar initial productive capacity as nearby offsets
- Forecasting >50% of Appalachia turn-in-lines in 2025 will be liquids-weighted due premium economics

Over 2 years[4] of liquids-rich Utica inventory added via discretionary acre acquisitions and ~2 years[4] of liquids-rich Marcellus inventory added via delineation activities



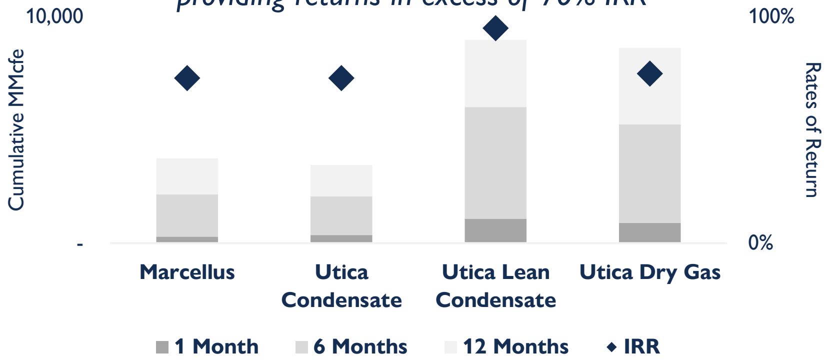
Recent Condensate Well Performance

Lake VII Pad Daily Production History

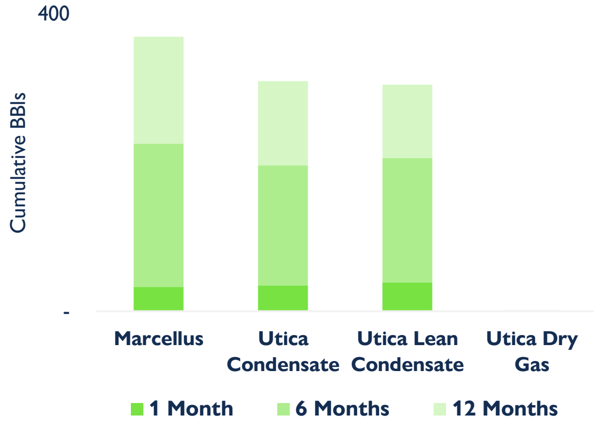


Cumulative MMcfe Production[2,3]

Utica dry gas, Utica liquids and Marcellus providing returns in excess of 70% IRR



Cumulative Liquids Production[2]



1. Production rate normalized to 15,000 ft lateral and assumes ethane rejection, per Gulfport's gathering contracts. Avg IP90 in full ethane recovery totals 2,011 Boe/d, 44% oil and 75% liquids. Actual average lateral length on the Lake VII pad is ~17,300'.
2. Representing average cumulative production by type curve area. Utica Lean Condensate assumes oil yield of < 50 Bbl / Mcf. Production data normalized to 15,000 ft lateral.
3. Based on flat $3.50 / Mcf natural gas and $70 / Bbl oil. Average internal rates of return of actual engineered locations for each defined development area over the next five years of development.
4. Based on assumed development cadence of approximately 20 to 25 wells per year.

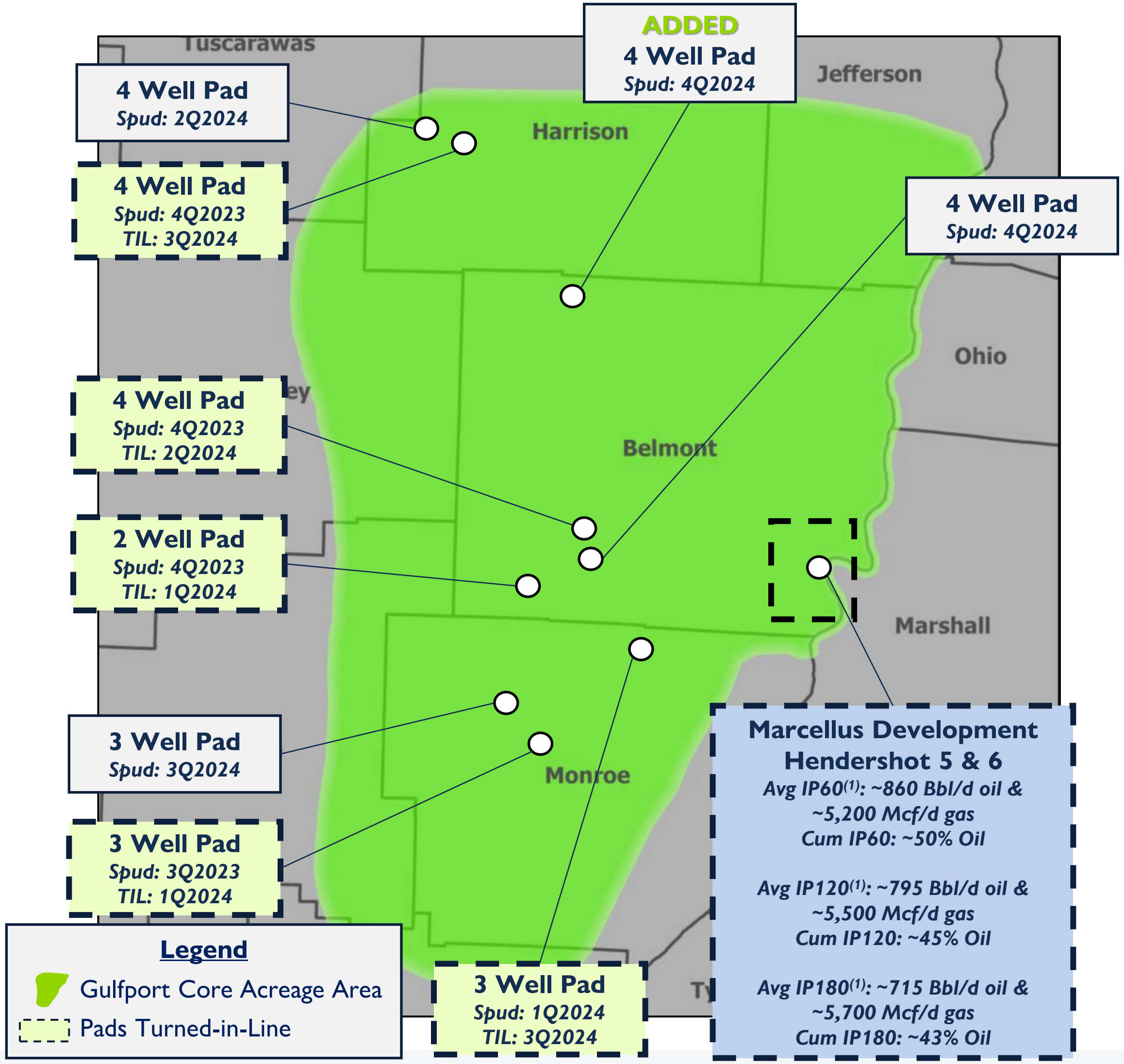
Utica and Marcellus Development Plan

Utica Key Highlights

- Extended Utica inventory by over 1.5 years through discretionary acreage acquisitions in the liquids-rich area of the play during 2023
  - Prioritized for near term development
  - Planning to allocate incremental ~$45 million in discretionary acreage acquisitions during 2024
- Current development program includes high return, liquids-rich development
  - Encouraged by recent Company results and industry development in the Utica liquids window
- Continue to optimize well performance and implement a managed pressure program, yielding consistent EUR's per well
- Turned-to-sales 16 gross Utica wells during 2024

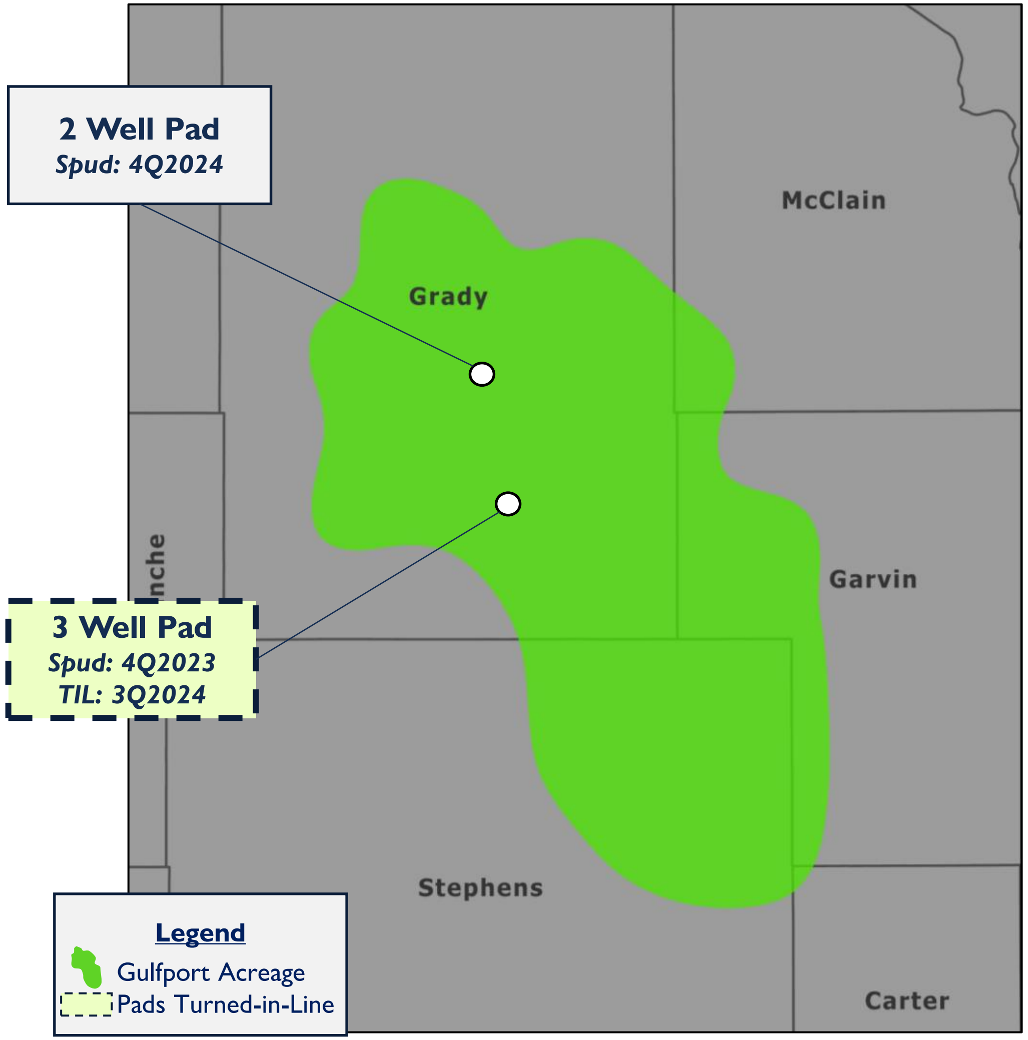
Marcellus Key Highlights

- Marcellus development is within our Utica footprint and captures value enhancement through stacked pay synergies and liquids optionality
  - Hendershot development delineated **50 – 60** nearby locations
  - Totals **~2 years**[2] of drillable inventory
- Plan to begin drilling 4-well Marcellus pad in Belmont County early 2025



1. Rates provided are gross two-stream and normalized to 15,000 ft lateral.
2. Based on assumed development cadence of approximately 20 to 25 wells per year.

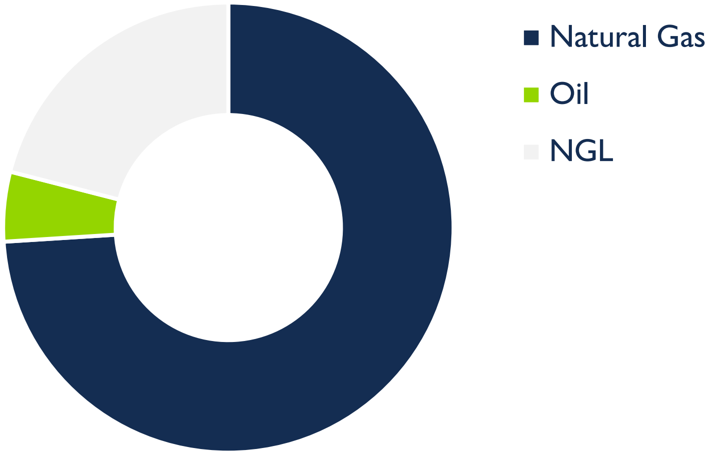
SCOOP Development Plan



Key Highlights

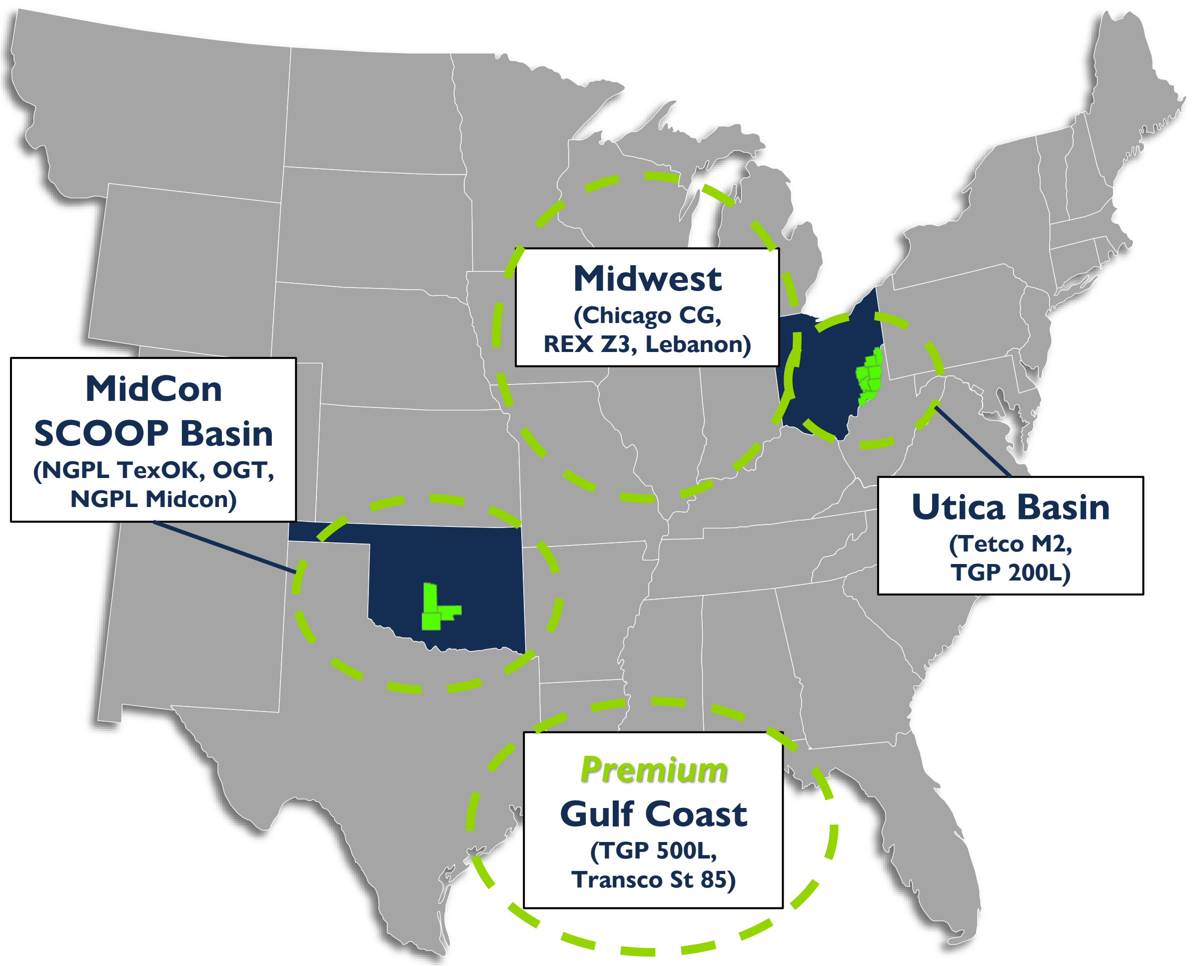
- Targeting high return, liquids-rich development in the SCOOP
- Optimized unit development and well designs yielding strong recoveries
- Expanding learnings and efficiency gains from Utica development to our SCOOP development program
- Recently added SCOOP drilling rig and spud two-well pad in October 2024
- Plan to drill 5 gross wells and turned-to-sales 3 gross wells during 2024

SCOOP 3Q2024 Production Mix



Advantaged Firm Portfolio Provides Access to Diverse Markets

- Diversified and right-sized takeaway capacity
  - 625,000 MMBtu/d[1] of firm takeaway from the Utica
  - 200,000 MMBtu/d[1] of firm takeaway from the SCOOP
- Strategic connectivity from wellhead provides access to premium basin egress pipelines and netback enhancement
- Premium Gulf Coast transportation allows delivery to growing LNG demand center and industrial corridor at NYMEX-plus pricing
- Proactively hedge in-basin exposure to secure pricing



Regional Exposure[1]		Bal 2024E[2]
Midwest	450,000 MMBtu/d firm takeaway	30% - 40%
Gulf Coast	175,000 MMBtu/d firm takeaway	10% - 15%
MidCon	200,000 MMBtu/d firm takeaway	15% - 20%
In-Basin Exposure		30% – 40%

1. Primary reservation volume only. Excludes zero-leg and secondary-leg reservation volume. Assumes run-rate gross reservation volume on a MMBtu/d basis.
2. Percentages represent approximate gross production exposure to basin regions.

Strong Capital Structure and Financial Profile

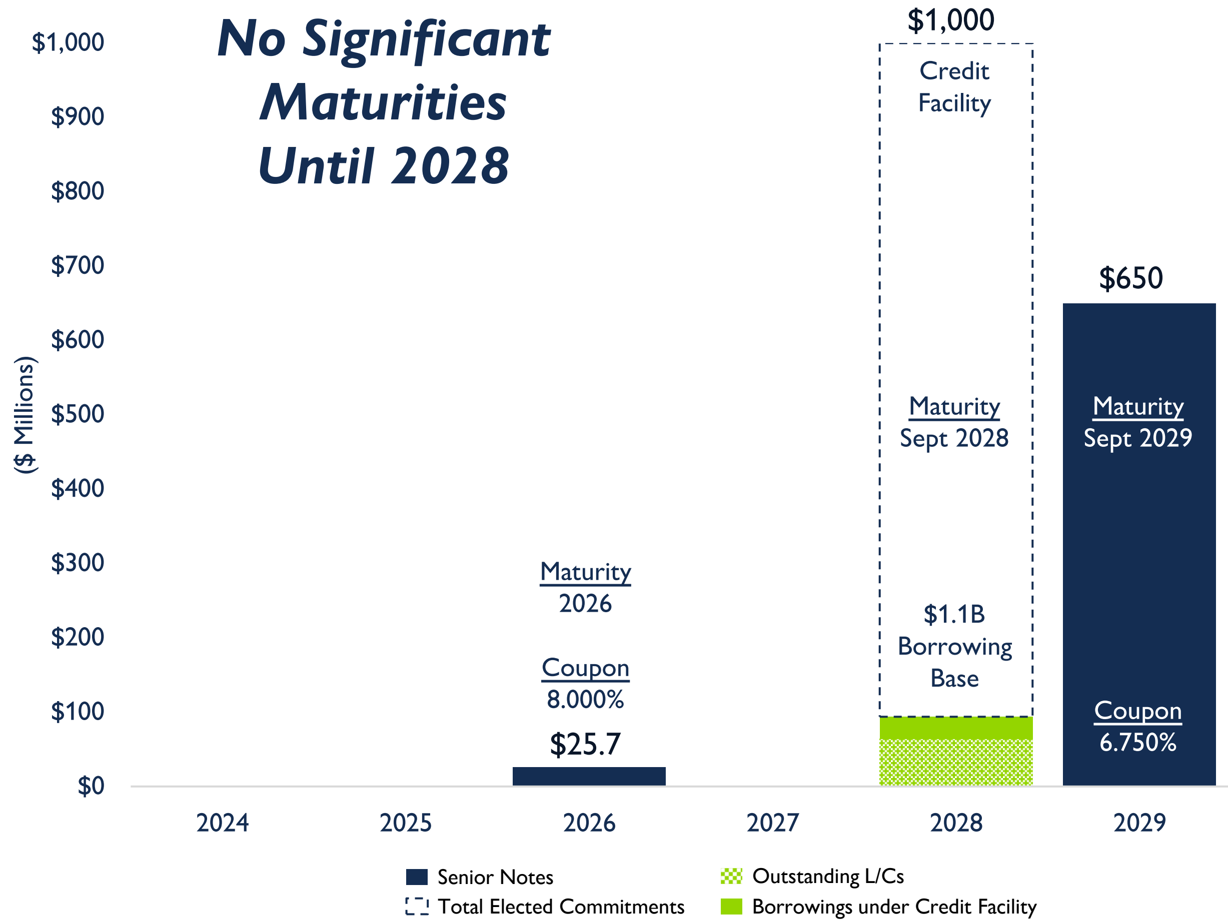
Third Quarter 2024 Overview

Cash and Liquidity	• $3.2 million of cash equivalents • ~$910 million of liquidity(1)
Debt	• $30.0 million borrowings under credit facility • $25.7 million of senior notes due 2026 • $650 million of senior notes due 2029 • Leverage of 0.97x(2)

Preferred Equity	• Preferred stock: 43.8 thousand shares
	  • Dividend: 10% Cash / 15% Payment-in-Kind
	  • Convertible to ~3.1 million common shares

Common Equity	• Common stock: 18.1 million shares • Authorized common stock repurchase of up to $1.0 billion • Repurchased ~$504.0 million as of September 30, 2024

As of September 30, 2024



1. Liquidity as of 9/30/2024 and calculated as $3.2 million cash plus $906.2 million borrowing base availability, which takes into effect $30.0 million of borrowings on revolver and $63.8 million of letters of credit.
2. As of 9/30/2024 using net debt to TTM Adjusted EBITDA. Net debt is a non-GAAP measure. It is defined as total long-term debt minus cash and cash equivalents.

Focused on Continuous Improvement and ESG Excellence

Environmental

- **Achieved overall "A" rating for Appalachia assets from MiQ for second consecutive year**
- Lowered Scope 1 methane intensity rate[1] by 36% over the last 3 years
- Conducted Company's first climate risk assessment and integrated climate-related risk into Enterprise Risk Management (ERM) program
- Reused or recycled ~75% of our water generated from production and flowback
- Progressed in multi-year program to convert natural-gas driven pneumatic devices to air in the SCOOP

For additional information please refer to Gulfport's Corporate Sustainability Report

www.gulfportenergy.com/sustainability

Improved Methane Intensity Rate

36% since 2021

Reduced Combined Total Recordable Incident Rate

53% since 2021

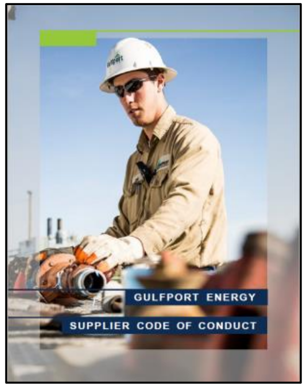
Social

- Reduced combined total recordable incident rate by 53% in 2023 compared to 2021
- Increased diversity in the workplace with 43% of employees identifying as gender or ethnically diverse
- Partnered with organizations that support Gulfport's key focus areas: education, health and human services, environmental stewardship and military and veterans
- Paid over $360 million in royalties to local landowners and working interest owners in 2023

Governance

- Experienced 7-member board including, 5 independent directors
- Appointed two gender diverse directors, resulting in 60% diversity of independent directors
- Separated role of Chairman and CEO while retaining Lead Independent Director role
- Increased short-term compensation incentive ESG metrics to a 30% weighting

Vendor Code of Conduct can be found on Gulfport's website



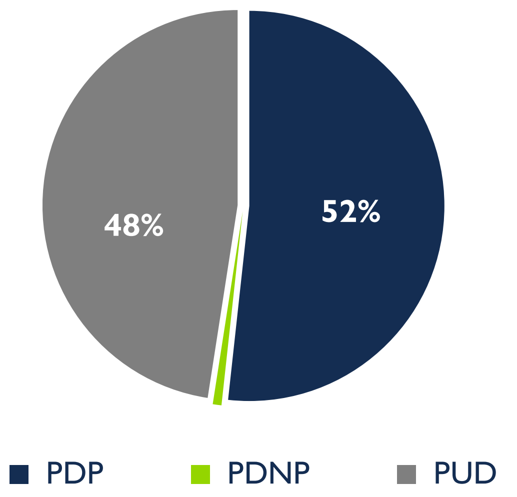
Note: More details on our ESG initiatives can be found on the Gulfport website: www.gulfportenergy.com
1. Based on EPA required Subpart W reporting.

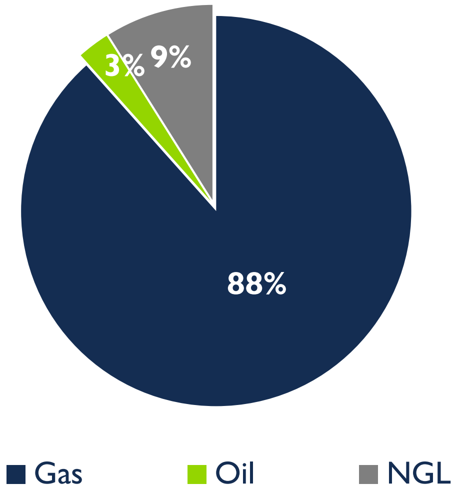
Appendix

2023 Proved Reserve Summary

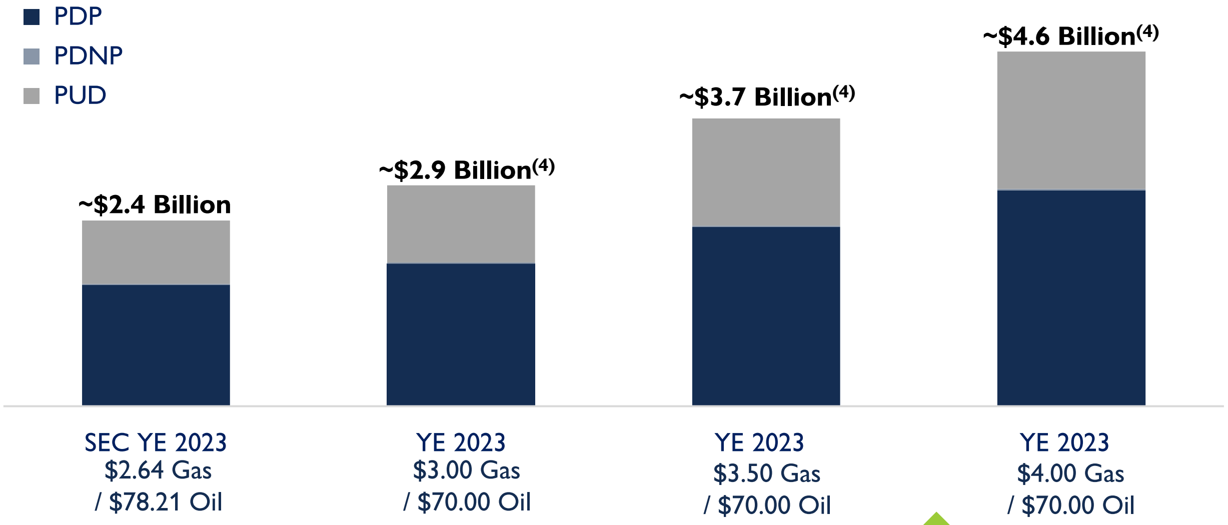
Net Reserves as of December 31, 2023[1]					
	Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)	SEC PV-10[3] ($MM)
Proved Developed Producing	1,969	6	30	2,188	$1,574
Proved Developed Non-Producing	10	0	1	15	16
Proved Undeveloped[2]	1,746	12	32	2,011	819
Total Proved Reserves	3,725	19	63	4,214	$2,409

Proved Reserve Components





SEC Year End Proved Reserves PV-10[3,4]



1. Per Company NSAI reserve report for year ending 12/31/23.
2. Proved undeveloped reserves, under SEC reserve reporting guidelines, only includes wells scheduled to be drilled within the next five years.
3. PV-10 is a non-GAAP measure; see supplemental slides.
4. Flat price cases at stated price scenarios.

Gulfport ENERGY

Full Year 2024 Guidance

	FY 2024E Guidance PREVIOUS		FY 2024E Guidance UPDATED	
Production				
Average Net Daily Gas Equivalent – MMcfe/day	1,055	1,070	1,055	1,070
% Gas	~92%		~92%	
Realizations (before hedges)[1]				
Natural Gas (Differential to NYMEX) - $/Mcf	($0.20)	($0.35)	($0.20)	($0.35)
NGL (% of WTI)	35%	40%	35%	40%
Oil (Differential to NYMEX WTI) - $/Bbl	($4.75)	($5.75)	*($5.50)*	*($6.50)*
Expenses				
Lease Operating Expense - $/Mcfe	$0.17	$0.19	$0.17	$0.19
Taxes Other Than Income - $/Mcfe	$0.08	$0.10	$0.08	$0.10
GP&T - $/Mcfe	$0.90	$0.94	$0.90	$0.94
Recurring Cash G&A[2] - $/Mcfe	$0.11	$0.13	$0.11	$0.13

Incurred Capital Expenditures – $ millions	FY 2024E Guidance PREVIOUS		FY 2024E Guidance UPDATED	
D&C	$330	$360	*$325*	*$335*
Maintenance Leasehold and Land	$50	$60	$50	$60
Total Base Capital Expenditures	$380	$420	*$375*	*$395*
Discretionary Acreage Acquisitions	~$45		~$45	

Based on the capital efficiency gains, currently forecast 2025 capital to be in line with updated 2024 guidance. The 2025 capital program will continue to focus on liquids-rich development, supporting robust expected adjusted free cash flow generation.

2024E Adjusted Free Cash Flow Generation[3]

- Continued adjusted free cash flow[3] generation in volatile commodity market
- Planning discretionary acreage acquisitions of ~$45 million, allocated toward accretive acreage opportunities
- Plans to allocate substantially all adjusted free cash flow[3], excluding discretionary acreage acquisitions, towards common stock repurchases

Note: Guidance for the year ending 12/31/24 is based on multiple assumptions and certain analyses made by the Company based on its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward-looking statements.

1. Based upon current forward pricing at October 18, 2024 and basis marks.
2. Recurring cash G&A is a non-GAAP financial measures; see supplemental slides.
3. Adjusted free cash flow is a non-GAAP financial measures; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.

Development Plan Overview

Utica

2023 Operated Activity

	Well Count	Lateral Length
Spud	18 gross (15.9 net)	~17,700'
Drilled	20 gross (18.2 net)	~15,700'
Turned-to-Sales	20 gross (18.2 net)	~14,300'

2024 Operated Activity

	Well Count	Lateral Length
Spud	~20 gross (~19.7 net)	~15,200'
Drilled	~18 gross (~17.5 net)	~16,100'
Turned-to-Sales	~16 gross (~15.4 net)	~17,900'

Marcellus

2023 Operated Activity

	Well Count	Lateral Length
Spud	2 gross (2.0 net)	~11,900'
Drilled	2 gross (2.0 net)	~11,900'
Turned-to-Sales	2 gross (2.0 net)	~11,900'

SCOOP

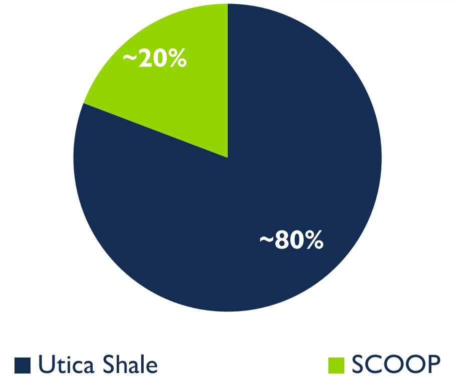
2023 Operated Activity

	Well Count	Lateral Length
Spud	5 gross (3.2 net)	~11,800'
Drilled	2 gross (1.7 net)	~8,600'
Turned-to-Sales	2 gross (1.7 net)	~8,600'

2024 Operated Activity

	Well Count	Lateral Length
Spud	~2 gross (~1.8 net)	~15,100'
Drilled	~5 gross (~4.1 net)	~13,500'
Turned-to-Sales	~3 gross (~2.3 net)	~12,400'

2024E Operated D&C Capital



Hedged Production

Hedge Book[1]

	Natural Gas							Oil					Propane	
	Swaps		Collars			Calls Sold		Swaps		Collars			Swaps	
	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Put $/MMBtu	Avg. Call $/MMBtu	Volume MMBtu/d	Avg. Call $/MMBtu	Volume Bbl/d	Avg. Price $/Bbl	Volume Bbl/d	Avg. Put $/Bbl	Avg. Call $/Bbl	Volume Bbl/d	Avg. Price $/Bbl
4Q 2024	400,000	$3.77	225,000	$3.36	$5.14	202,000	$3.33	500	$77.50	1,000	$62.00	$80.00	2,500	$30.25
1Q 2025	250,000	$3.82	220,000	$3.37	$4.23	200,000	$5.76	2,000	$74.50	-	-	-	2,000	$30.09
2Q 2025	250,000	$3.82	220,000	$3.37	$4.23	200,000	$5.76	2,000	$74.50	-	-	-	2,000	$30.09
3Q 2025	250,000	$3.82	220,000	$3.37	$4.23	200,000	$5.76	2,000	$74.50	-	-	-	2,000	$30.09
4Q 2025	250,000	$3.82	220,000	$3.37	$4.23	173,478	$5.93	2,000	$74.50	-	-	-	2,000	$30.09
FY 2025	250,000	$3.82	220,000	$3.37	$4.23	193,315	$5.80	2,000	$74.50	-	-	-	2,000	$30.09
1Q 2026	160,000	$3.59	70,000	$3.31	$4.06	-	-	-	-	-	-	-	-	-
2Q 2026	160,000	$3.59	70,000	$3.31	$4.06	-	-	-	-	-	-	-	-	-
3Q 2026	160,000	$3.59	70,000	$3.31	$4.06	-	-	-	-	-	-	-	-	-
4Q 2026	160,000	$3.59	70,000	$3.31	$4.06	-	-	-	-	-	-	-	-	-
FY 2026	160,000	$3.59	70,000	$3.31	$4.06	-	-	-	-	-	-	-	-	-

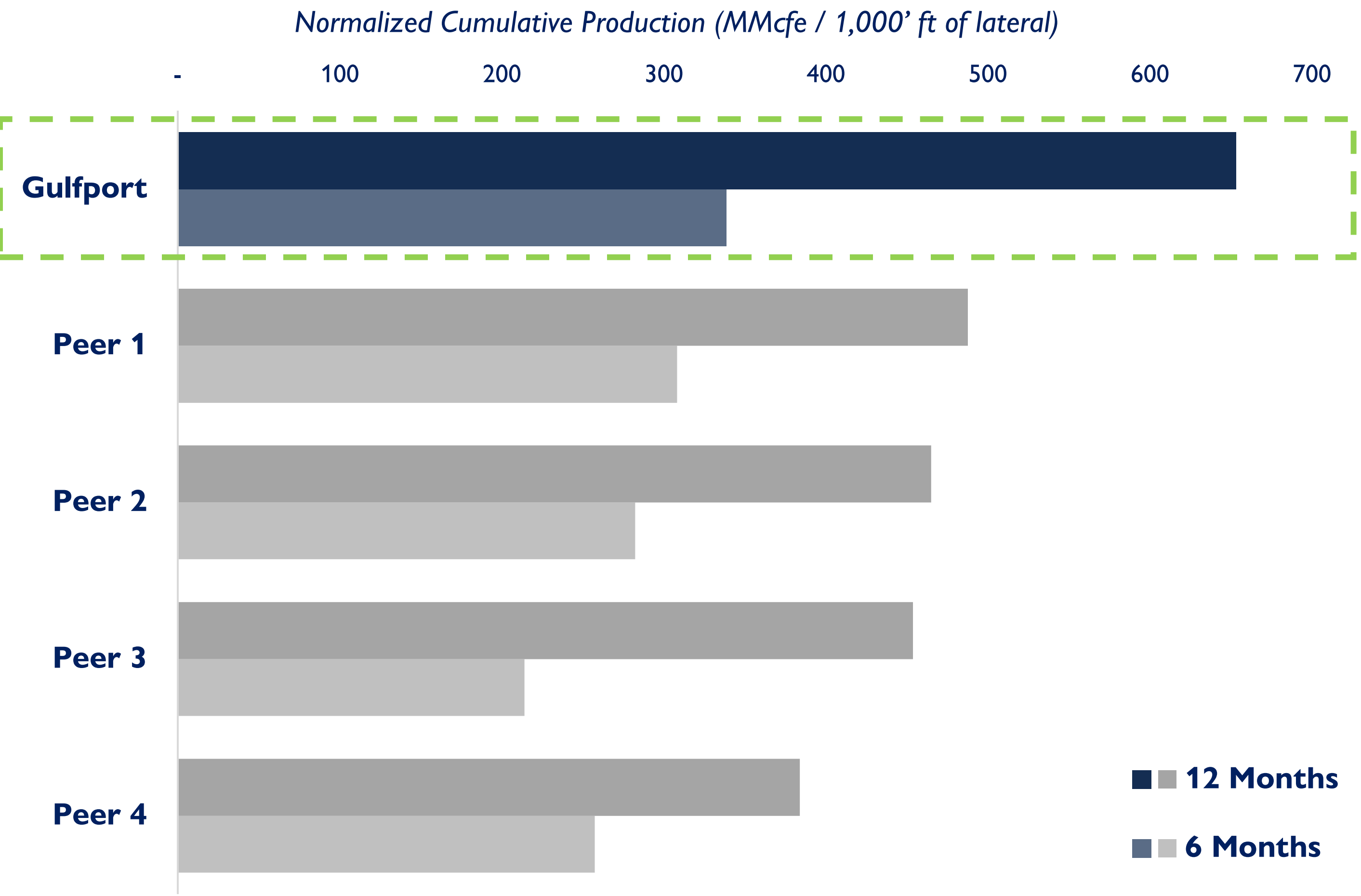
The Company also has:

Rex Zone 3 basis swaps of ~150 BBtu/d at ($0.15) for 4Q2024, ~110 BBtu/d at ($0.20) for 2025 and ~40 BBtu/d at ($0.19) for 2026
Tetco M2 basis swaps of ~230 BBtu/d at ($0.94) for 4Q2024, ~230 BBtu/d at ($0.96) for 2025 and ~130 BBtu/d at ($0.98) for 2026
NGPL TXOK basis swaps of ~70 BBtu/d at ($0.31) for 4Q2024 and ~40 BBtu/d at ($0.29) for 2025
TGP 500 basis swaps of ~10 BBtu/d at +$0.31 for 2025 and ~10 BBtu/d at +$0.54 for 2026
Transco Station 85 basis swaps of ~5 BBtu/d at +$0.38 for 2025 and ~5 BBtu/d at +$0.52 for 2026

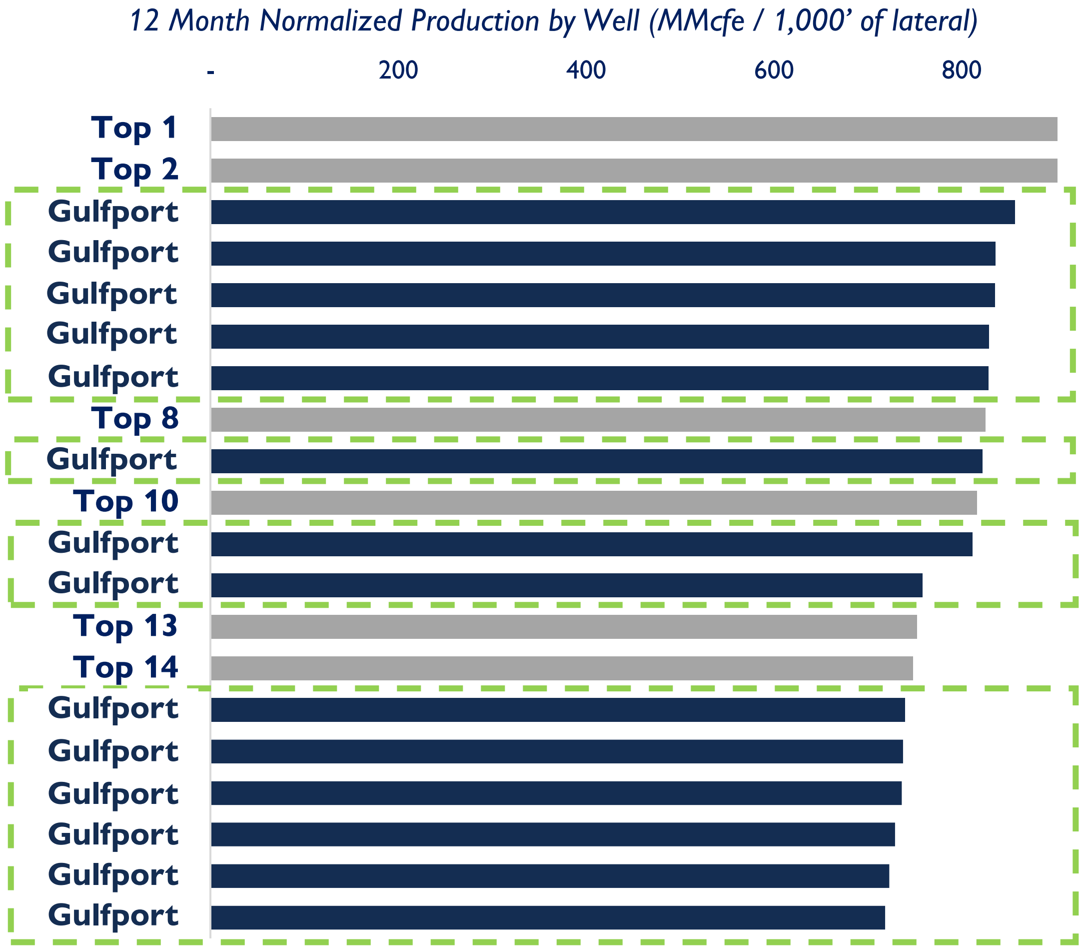
1. As of 10/28/2024.

Recent Utica Well Performance

Gulfport Utica Well Productivity Outperforming Peers[1]



Top 20 Performing Utica Wells[1]

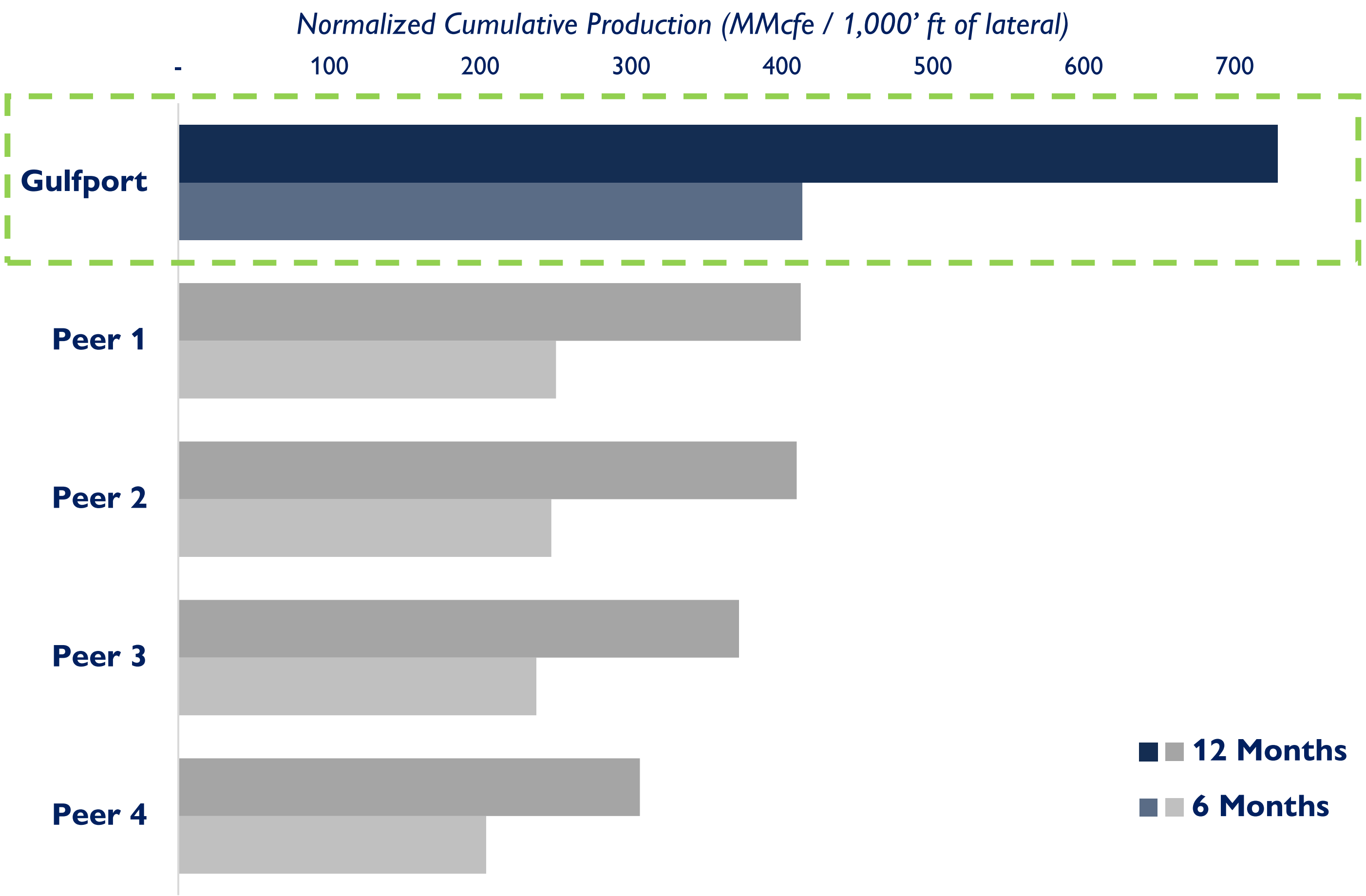


Note: Gulfport well data is sourced internally. All peer data sourced from Enverus. Includes all wells with equal or greater than 7,000' lengths brought online since 2021 with at least twelve months of production data available. Peers include Ascent Resources, Encino Energy, EQT and Expand Energy.

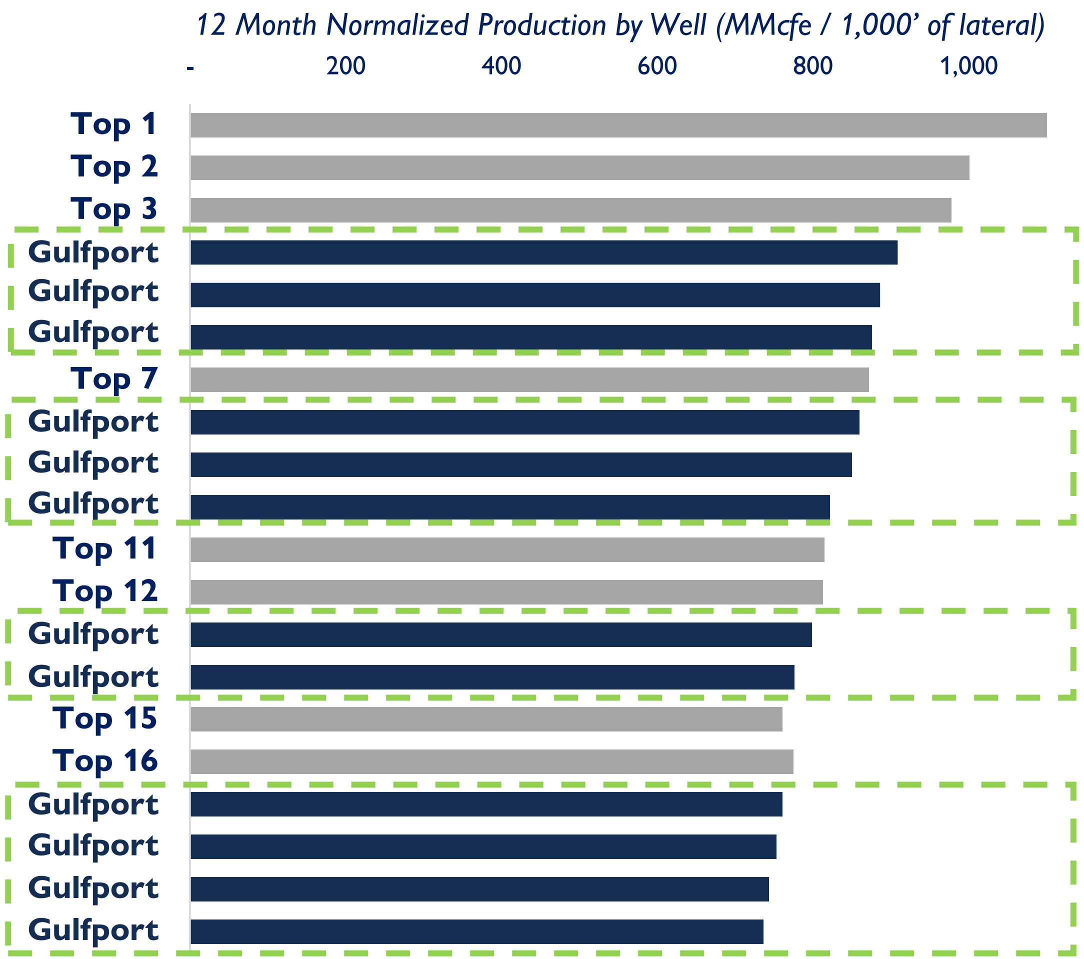
1. Data is two-stream equivalents. Mcfe is equal to one thousand cubic feet of natural gas equivalent, with one barrel of oil being equivalent to 20,000 cubic feet of natural gas.

Recent SCOOP Well Performance

Gulfport Oklahoma Well Productivity Outperforming Peers[(1)]



Top 20 Performing SCOOP / STACK Wells[(1)]



Note: Gulfport well data is sourced internally. All peer data sourced from Enverus. Includes all wells with equal or greater than 7,000' lengths brought online since 2021 with at least twelve months of production data available. Peers include Continental Resources, Devon Energy, Marathon Oil and Ovintiv.

1. Data is two-stream equivalents. Mcfe is equal to one thousand cubic feet of natural gas equivalent, with one barrel of oil being equivalent to 20,000 cubic feet of natural gas.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure equal to net (loss) income, the most directly comparable GAAP financial measure, plus interest expense, deferred income tax expense (benefit), depreciation, depletion and amortization, impairment and accretion, net non-cash derivative loss (gain), non-recurring general and administrative expenses comprised of expenses related to the continued administration of our prior Chapter 11 filing, stock-based compensation, loss on debt extinguishment, restructuring costs and other items which include items related to our Chapter 11 filing and other non-material expenses.

Below is a reconciliation of net (loss) income (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands)
(Unaudited)

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
Net (loss) income (GAAP)	$ (13,967)	$ 608,444	$ 11,856	$ 1,225,185
Adjustments:				
Interest expense	15,866	14,919	46,027	42,402
Deferred income tax (benefit) expense	(3,833)	(554,741)	3,433	(554,741)
DD&A, impairment and accretion	113,895	80,144	273,593	240,864
Non-cash derivative loss (gain)	46,911	9,644	166,454	(412,319)
Non-recurring general and administrative expenses	33	700	1,561	2,435
Stock-based compensation expenses	2,664	2,360	8,410	6,138
Restructuring costs	—	—	—	4,762
Loss on debt extinguishment	13,388	—	13,388	—
Other, net[1,2]	3,133	(1,438)	3,530	(20,492)
Adjusted EBITDA (Non-GAAP)	$ 178,090	$ 160,032	$ 528,252	$ 534,234

1. For the three and nine months ended September 30, 2024, "Other, net" included approximately $3.0 million related to changes in the Company's legal reserves for certain litigation and regulatory proceedings.
2. For the nine months ended September 30, 2023, "Other, net" included a $17.8 million receipt of funds related to our interim claim distribution from our Chapter 11 Plan of Reorganization and a $1 million administrative payment to Rover as part of the executed settlement. For more discussion, refer to Note 1 of our consolidated financial statements included in our Quarterly Report on Form 10-Q for the nine months ended September 30, 2024. Additionally, "Other, net" included a $5.0 million recoupment of previously placed collateral for certain firm transportation commitments during our Chapter 11 filing.

Adjusted Free Cash Flow

Adjusted free cash flow is a non-GAAP measure defined as adjusted EBITDA plus certain non-cash items that are included in net cash provided by (used in) operating activities but excluded from adjusted EBITDA less interest expense, capitalized expenses incurred and capital expenditures incurred, excluding discretionary acreage acquisitions. Gulfport includes ranges of expectations for adjusted free cash flow for 2024. We are unable, however, to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. Accordingly, Gulfport is relying on the exception provided by Item 10(e)(1)(i)(B) of Regulation S-K to exclude such reconciliation. Items excluded in net cash provided by operating activities to arrive at adjusted free cash flow include interest expense, income taxes, capitalized expenses as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Below is a reconciliation of net cash provided by operating activities (the most comparable GAAP measure) to free cash flow. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands) (Unaudited)	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
Net cash provided by operating activity (GAAP)	$ 189,698	$ 156,274	$ 501,185	$ 567,680
Adjustments:				
Interest expense	15,866	14,919	46,027	42,402
Non-recurring general and administrative expenses	33	700	1,561	2,435
Restructuring costs	—	—	—	4,762
Other, net[1,2]	2,231	(2,482)	726	(25,507)
Changes in operating assets and liabilities, net				
Accounts receivable - oil, natural gas, and natural gas liquids sales	(5,415)	14,627	(33,548)	(171,673)
Accounts receivable - joint interest and other	(6,936)	(5,519)	(7,947)	(9,114)
Accounts payable and accrued liabilities	(15,900)	(17,175)	21,117	123,657
Prepaid expenses	(1,499)	(1,329)	(850)	(356)
Other assets	12	17	(19)	(52)
Total changes in operating assets and liabilities	$ (29,738)	$ (9,379)	$ (21,247)	$ (57,538)
Adjusted EBITDA (Non-GAAP)	$ 178,090	$ 160,032	$ 528,252	$ 534,234
Interest expense	(15,866)	(14,919)	(46,027)	(42,402)
Capitalized expenses incurred[3]	(6,413)	(5,611)	(17,991)	(16,117)
Capital expenditures incurred, excluding discretionary acreage acquisitions[4,5,6]	(83,254)	(90,584)	(332,633)	(362,298)
Adjusted free cash flow (Non-GAAP)	$ 72,557	$ 48,918	$ 131,601	$ 113,417

1. For the three and nine months ended September 30, 2024, "Other, net" included approximately $3.0 million related to changes in the Company's legal reserves for certain litigation and regulatory proceedings.
2. For the nine months ended September 30, 2023, "Other, net" included a $17.8 million receipt of funds related to our interim claim distribution from our Chapter 11 Plan of Reorganization and a $1 million administrative payment to Rover as part of the executed settlement. For more discussion, refer to Note 1 of our consolidated financial statements included in our Quarterly Report on Form 10-Q for the nine months ended September 30, 2024. Additionally, "Other, net" included a $5.0 million recoupment of previously placed collateral for certain firm transportation commitments during our Chapter 11 filing.
3. Includes cash capitalized general and administrative expense and incurred capitalized interest expenses.
4. Incurred capital expenditures and cash capital expenditures may vary from period to period due to the cash payment cycle.
5. For the three months ended September 30, 2024, includes $0.8 million of non-D&C capital and excludes targeted discretionary acreage acquisitions of $19.8 million. For the nine months ended September 30, 2024, includes $3.7 million of non-D&C capital and excludes targeted discretionary acreage acquisitions of $38.8 million. The Company has guided to an anticipated total of approximately $45 million of discretionary acreage acquisitions in 2024.
6. For the three months ended September 30, 2023, includes $0.7 million of non-D&C capital and excludes targeted discretionary acreage acquisitions of $19.4 million. For the nine months ended September 30, 2023, includes $1.7 million of non-D&C capital and excludes targeted discretionary acreage acquisitions of $24.9 million.

Recurring General and Administrative (G&A) Expense

Recurring general and administrative expense is a non-GAAP financial measure equal to general and administrative expense (GAAP) plus capitalized general and administrative expense, less non-recurring general and administrative expenses comprised of expenses related to the continued administration of our prior Chapter 11 filing. Gulfport includes a recurring cash general and administrative expense estimate for 2024. We are unable, however, to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. Accordingly, Gulfport is relying on the exception provided by Item 10(e)(1)(i) (B) of Regulation S-K to exclude such reconciliation. Items excluded in general and administrative expense to arrive at recurring general and administrative expense include capitalized expenses as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Below is a reconciliation of general and administrative expense (the most comparable GAAP measure) to recurring general and administrative expense. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands)
(Unaudited)

	Three Months September 30, 2024			Three Months Ended September 30, 2023		
	Cash	Non-Cash	Total	Cash	Non-Cash	Total
General and administrative expense (GAAP)	$ 7,815	$ 2,664	$ 10,479	$ 7,534	$ 2,360	$ 9,894
Capitalized general and administrative expense	5,183	1,312	6,495	4,496	1,162	5,658
Non-recurring general and administrative expense	(33)	—	(33)	(700)	—	(700)
Recurring General and Administrative Expense (Non-GAAP)	$ 12,965	$ 3,976	$ 16,941	$ 11,330	$ 3,522	$ 14,852

(In thousands)
(Unaudited)

	Nine Months September 30, 2024			Nine Months Ended September 30, 2023		
	Cash	Non-Cash	Total	Cash	Non-Cash	Total
General and administrative expense (GAAP)	$ 22,019	$ 8,410	$ 30,429	$ 21,100	$ 6,138	$ 27,238
Capitalized general and administrative expense	14,388	4,142	18,530	13,163	3,023	$ 16,186
Non-recurring general and administrative expense	(1,561)	—	(1,561)	(2,435)	—	$ (2,435)
Recurring General and Administrative Expense (Non-GAAP)	$ 34,846	$ 12,552	$ 47,398	$ 31,828	$ 9,161	$ 40,989

Present value of estimated future net revenue (PV-10)

PV – 10 is a non-GAAP measure derived from standardized measure of discounted future new cash flows (GAAP). Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented below. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

(In thousands)
(Unaudited)

	December 31, 2023			December 31, 2022		
	Proved Developed	Proved Undeveloped	Total Proved	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$2,535	$2,235	$4,769	$10,712	$7,951	$18,663
Present value of estimated future net revenue (PV-10)	$1,590	$819	$2,409	$5,803	$3,721	$9,524
Standardized measure			$2,383			$8,279

Note: Reserves as of December 31, 2023 utilized prices of $78.21/Bbl of oil, $31.42/Bbl for NGLs and $2.64/MMBtu of natural gas. Reserves as of December 31, 2022 utilized prices of $94.14/Bbl of oil, $47.86/Bbl for NGLs and $6.36/MMBtu of natural gas. Prices are determined in accordance with the SEC requirement to use the unweighted arithmetic average of the first day-of-the-month price for the preceding twelve months without giving effect to derivative transactions.

Thank You.

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