



**HIGHPEAK**  
E N E R G Y

**HighPeak Energy**

May 15, 2023



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## FORWARD-LOOKING STATEMENTS

The information in this presentation and in any oral statements made in connection herewith contains forward-looking statements that involve risks and uncertainties. When used in or in connection with this document, the words “believes,” “plans,” “expects,” “anticipates,” “forecasts,” “intends,” “projects,” “continue,” “may,” “will,” “could,” “should,” “future,” “potential,” “estimate” or the negative of such terms and similar expressions as they relate to HighPeak Energy, Inc. (“HighPeak Energy” or the “Company”) are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. For example, the Company's review of strategic alternatives is currently in its preliminary stages and may not result in a sale of the Company, a recommendation that a transaction occur or result in a completed transaction, and any transaction that occurs may not increase shareholder value, in each case as a result of such risks and uncertainties.

These risks and uncertainties include, among other things, the results of the strategic review being undertaken by the Company's Board and the interest of prospective counterparties, the Company's ability to realize the results contemplated by the 2023 and 2024 guidance contained herein, volatility of commodity prices, political instability or armed conflict in crude oil or natural gas producing regions such as the ongoing war between Russia and Ukraine, OPEC+ policy decisions, inflationary pressures on costs of oilfield goods, services and personnel, product supply and demand, the impact of a widespread outbreak of an illness, such as the coronavirus disease 2019 (“COVID-19”) pandemic, on global and U.S. economic activity, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, the integration of acquisitions, including the Alamo acquisitions and the Hannathon acquisition, litigation, the costs and results of drilling and operations, availability of equipment, services, resources and personnel required to perform the Company's drilling and operating activities, access to and availability of transportation, processing, fractionation, refining and storage facilities, HighPeak Energy's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to any credit facility and derivative contracts entered into by HighPeak Energy, if any, and purchasers of HighPeak Energy's oil, NGL and gas production, uncertainties about estimates of reserves, identification of drilling locations and the ability to add proved reserves in the future, the assumptions underlying forecasts, including forecasts of production, expenses, cash flow from sales of oil and gas and tax rates, quality of technical data, environmental and weather risks, including the possible impacts of climate change, cybersecurity risks and acts of war or terrorism. These and other risks are described in the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission (the “SEC”) on March 6, 2023 (the “Annual Report”), and in its other filings with the SEC. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See “Risk Factors,” “Business,” “Management's Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk” in the Registration Statement for a description of various factors that could materially affect the ability of HighPeak Energy to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

## RESERVE INFORMATION

Reserve engineering is a process of estimating the recovery of underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. Reserves estimates included herein may not be indicative of the level of reserves or PV-10 value of oil and natural gas production in the future, as they are based on prices significantly higher than current commodity prices. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact HighPeak's strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Estimated Ultimate Recoveries, or “EURs,” refers to estimates of the sum of total gross remaining reserves per well as of a given date and cumulative production prior to such given date for developed wells. “Resource” refers to gross volumes of hydrocarbons without giving effect to recovery efficiency or the economic viability of production. Neither EURs nor resource constitute or represent reserves as defined by the SEC and neither is intended to be representative of anticipated future well results or aggregate production volumes. Each such metric is inherently more uncertain than proved reserve estimates prepared in accordance with SEC guidelines.

## USE OF PROJECTIONS

The financial, operational, industry and market projections, estimates and targets in this presentation (including production, operating expenses, capital expenditures, EBITDAX and Asset FCF in future periods) are based on assumptions that are inherently subject to significant uncertainties and contingencies, many of which are beyond the Company's control. The assumptions and estimates underlying the projected, expected or target results are inherently uncertain and are subject to a wide variety of significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the financial, operational, industry and market projections, estimates and targets, including assumptions, risks and uncertainties described in "Cautionary Note Regarding Forward-Looking Statements" above. These projections are speculative by their nature and, accordingly, are subject to significant risk of not being actually realized by the Company. Projected results of the Company for Q4'23, FY2023, Q4'24 and FY2024 are particularly speculative and subject to change. Actual results may vary materially from the current projections, including for reasons beyond the Company's control. The projections are based on current expectations and available information as of the date of this release. The Company undertakes no duty to publicly update these projections except as required by law.

In particular, you should be aware that, unless otherwise indicated, projections shown herein are based on management's "flat" commodity price parameters rather than SEC pricing guidelines or current NYMEX forward pricing. The flat prices used in preparing the projections contained herein were \$80 per Bbl of oil and \$4 per MMBtu of natural gas, as compared to prices of \$93.67 per Bbl for oil and \$6.358 per MMBtu that would have been used if using SEC reserve pricing guidelines. HighPeak believes that the use of flat pricing provides useful information as the flat prices reflect what management believes to be reasonable assumptions as to future commodity prices over the productive lives of its properties. However, HighPeak cautions you that the flat pricing used in preparing its projections is not necessarily a projection of future oil and natural gas prices, and should be carefully considered in addition to, and not as a substitute for, other commodity price assumptions held by third parties.

## USE OF NON-GAAP FINANCIAL MEASURES

This presentation may include non-GAAP financial measures, including EBITDAX and adjusted EBITDAX, unlevered asset free cash flow, operating margin and unhedged cash operating margin, unhedged EBITDAX margin, and PV-10. HighPeak believes these non-GAAP measures are useful because they allow HighPeak to more effectively evaluate its operating performance and compare the results of its operations from period to period and against its peers without regard to financing methods, capital structure or tax status. HighPeak does not consider these non-GAAP measures in isolation or as alternatives to similar financial measures determined in accordance with GAAP. HighPeak's computations of these non-GAAP financial measures may not be comparable to other similarly titled measures of other companies.

HighPeak defines EBITDAX as net income before interest expense, income taxes, depreciation, depletion and amortization, exploration and other expenses, impairment and abandonment expenses, non-cash gains or losses on derivatives, stock-based compensation, gain on exchange of debt, gains and losses from the sale of assets, transaction costs and nonrecurring workforce reduction severance payments. HighPeak defines Adjusted EBITDAX as EBITDAX excluding cash G&A expenses. HighPeak's management believes EBITDAX is useful as it allows them to more effectively evaluate HighPeak's operating performance and compare the results of its operations from period to period and against its peers without regard to financing methods or capital structure. HighPeak excludes the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within the industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. HighPeak also presented EBITDAX on an "annualized" basis, which represents EBITDAX for a fiscal quarter annualized for a 12-month period as if EBITDAX for each fiscal quarter in such period was equal to the quarter specified. HighPeak defines cash operating margin as realized price less lease operating expenses, gathering, processing and transportation expenses and production taxes, on a per-Boe basis. HighPeak defines cash margin as realized price less lease operating expense, gathering, processing and transportation expenses, cash general and administrative expenses and production taxes, on a per-Boe basis. HighPeak defines unhedged as excluding the effects of derivatives and hedged as including the effects of derivatives. HighPeak defines Unlevered Asset Free Cash Flow as Adjusted EBITDAX less Capex. HighPeak defines PV-10 as the present value of estimated future net revenues to be generated from the production of proved reserves, without giving effect to non-property related expenses, discounted at 10% per year before income taxes. Unhedged EBITDAX margin, which we have provided as a supplement to—rather than in lieu of—EBITDAX margin including hedges, provides useful information regarding our results of operations and profitability by illustrating the operating results of our oil and natural gas properties without the benefit or detriment, as applicable, of our financial oil and natural gas hedges. By excluding our oil and natural gas hedges, we are able to convey actual operating results using realized market prices during the period, thereby providing analysts and investors with additional information they can use to evaluate the impacts of our hedging strategies over time. For reconciliations of each such non-GAAP measure as presented herein to its most comparable measure prepared in accordance with GAAP, see the Appendix to this presentation.

In the case of non-GAAP financial measures presented for future periods, HighPeak advises that it is unable to provide reconciliations of such measures without unreasonable efforts. Accordingly, such measures should be considered in light of the fact that no GAAP measure of performance or liquidity is available as a point of comparison to such non-GAAP measures.

## INDUSTRY AND MARKET DATA

This presentation has been prepared by HighPeak and may include market data and other statistical information from sources believed by HighPeak to be reliable, including independent industry publications, governmental publications or other published independent sources. Some data is also based on HighPeak's good faith estimates, which are derived from its review of internal sources as well as the independent sources described above. Although HighPeak believes these sources are reliable, they have not independently verified the information and cannot guarantee its accuracy and completeness.

## DRILLING LOCATIONS

The Company has estimated its drilling locations based on well spacing assumptions and upon the evaluation of its drilling results and those of other operators in its area, combined with its interpretation of available geologic and engineering data. The drilling locations actually drilled on the Company's properties will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities conducted on these identified locations may not be successful and may not result in additional proved reserves. Further, to the extent the drilling locations are associated with acreage that expires, the Company would lose its right to develop the related locations.

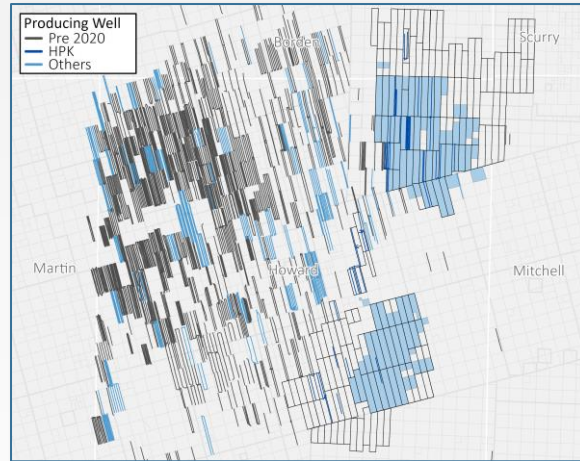


# HighPeak's Story

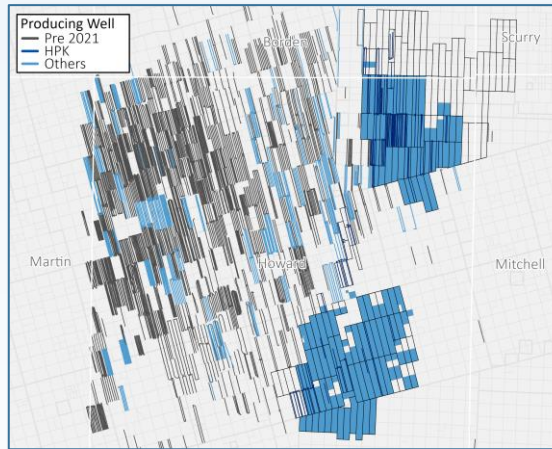
Delineation Phase Transitions Into Full-Scale Field Development and Bolt-On Acquisitions



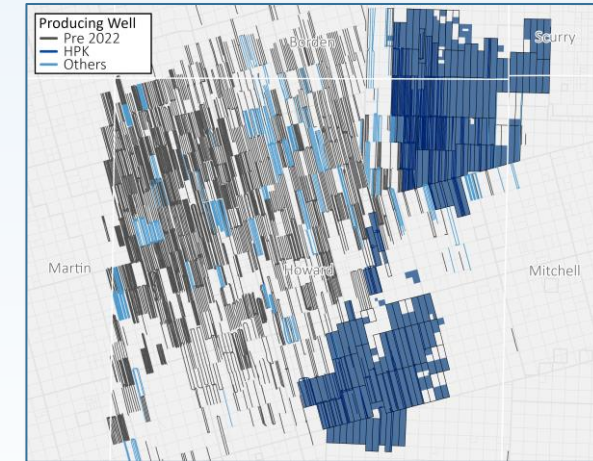
2020



2021



2022+



Acreage:	51,000
Benchs Delineated:	2
Gross Wells Drilled:	49
Gross Wells on Production (Hz):	30
Year-end Net Production (Boepd):	~3,300

Acreage:	63,000
Benchs Delineated:	3
Gross Wells Drilled:	105
Gross Wells on Production (Hz):	56
Year-end Net Production (Boepd):	~14,800

Acreage: <sup>(1)</sup>	~113,600
Benchs Delineated:	5-6
Gross Wells Drilled: <sup>(2)</sup>	240
Gross Wells on Production (Hz): <sup>(2)</sup>	198
Q1'23 Avg Net Production (Boepd):	~37,200

**Production from HighPeak's initial drilling program confirmed the geological model and long-term, multi-zone development potential**

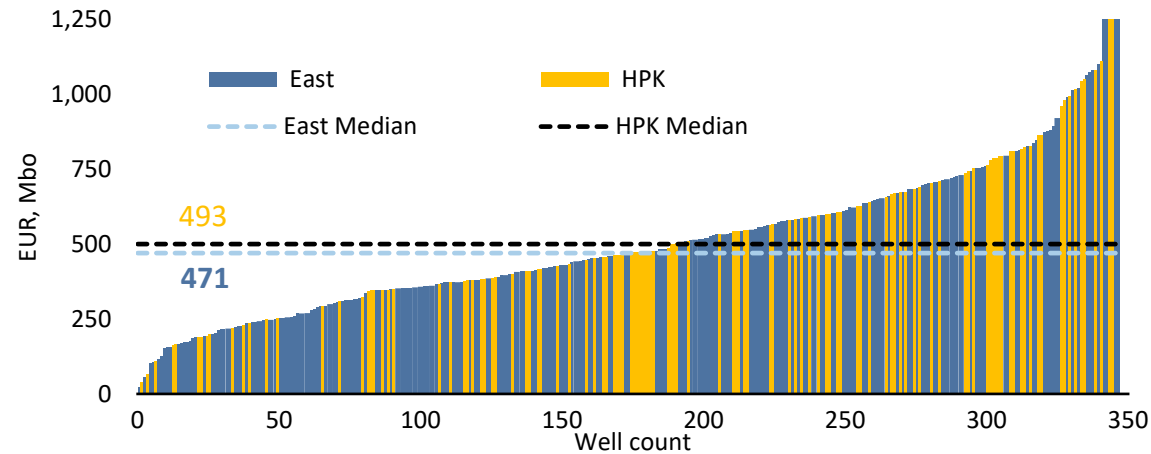
(1) Acreage as of 4/28/23.  
(2) As of 3/31/23; Includes wells in flowback.

# HighPeak Exhibiting Leading Results in Howard and South Borden Counties

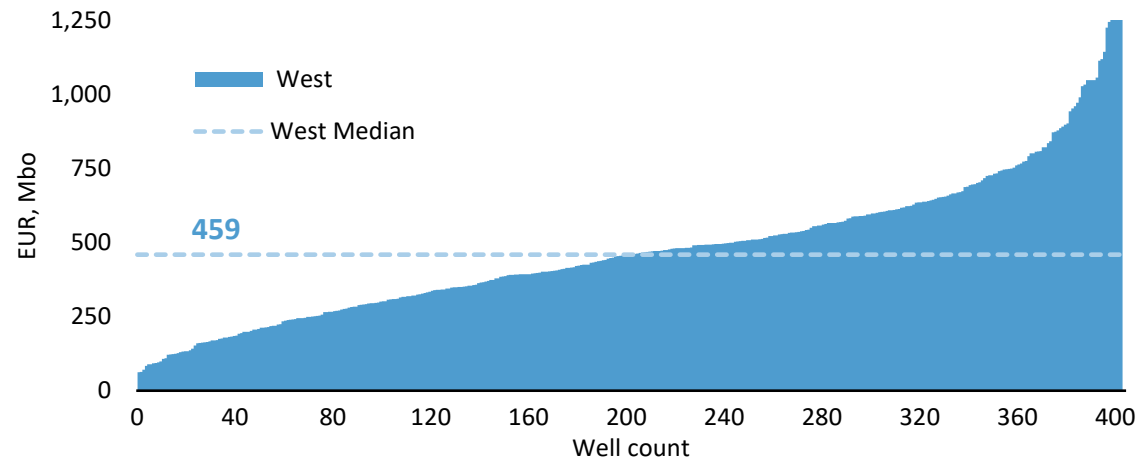
Oil EUR Distributions per Enverus Relative to HPK Results



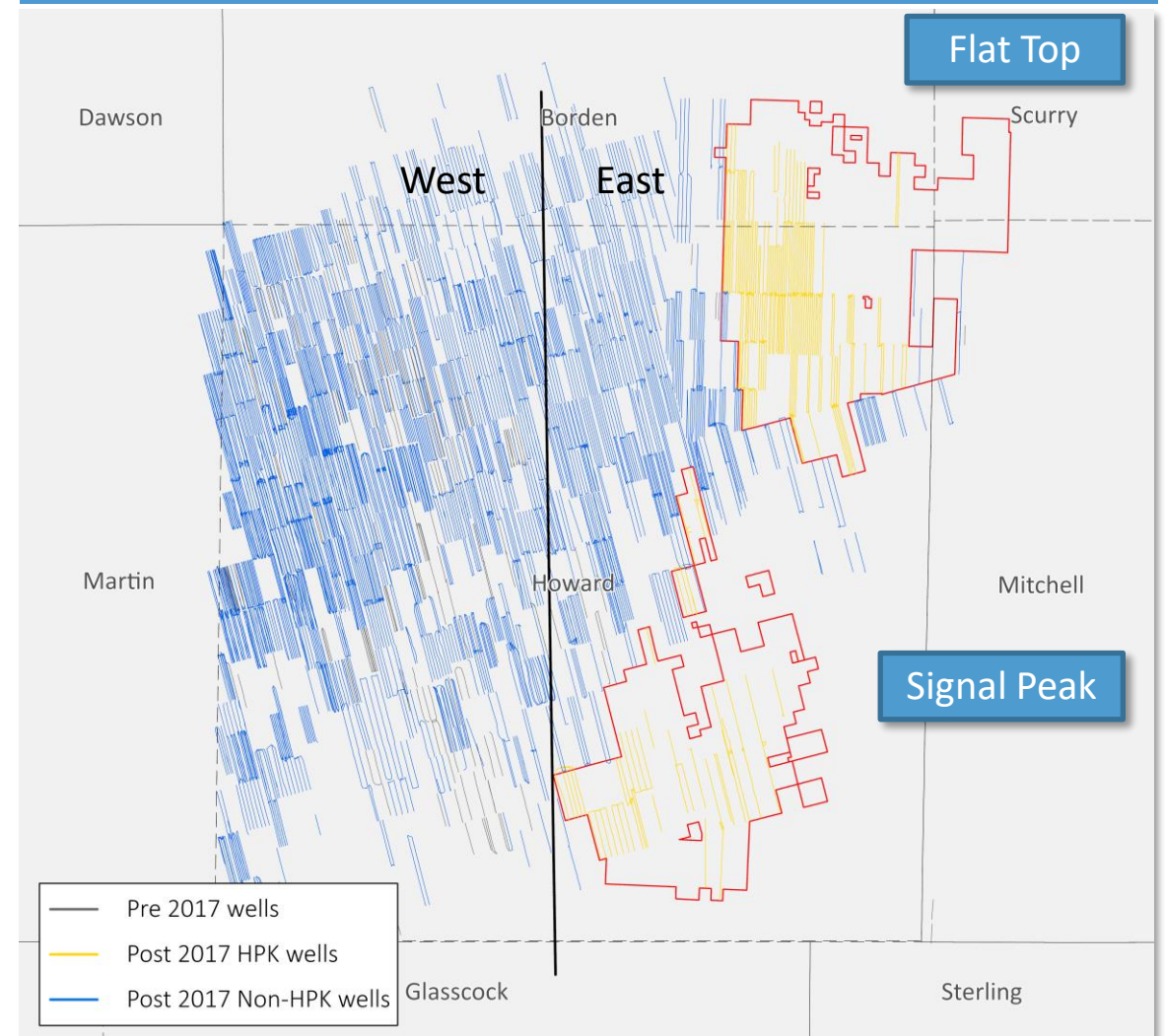
## East Howard & South Borden Oil EUR Distribution



## West Howard & South Borden Oil EUR Distribution



## Delineation and Laterals to Date



Source: Enverus, HPK based on reserves per HighPeak's year-end 2022 third party reserve report prepared by Cawley Gillespie & Associates ("CGA"). Assumes effective date of 01/01/23; based on SEC pricing – average oil (\$/bbl): \$93.67 and average gas (\$/MMBtu): \$6.358.

Note: Wells used for EUR distribution as of 1/1/20 spud date, lateral length >7,500', minimum 4 producing months.

# HighPeak Overview

Northern Midland Basin Pure-Play Capitalized For Oil-Weighted Value Creation



## Updated Development Plan

- Q1'23 production average **37.2 MBoe/d**
  - Increased 209% Year Over Year**
- 113,600 net acres (63.2k Flat Top, 50.4k Signal Peak)<sup>(1)</sup>
- 61% HBP, 98% operated, 12,000' average lateral length<sup>(1)</sup>
- ~2,500 gross locations remaining (89% average working interest)<sup>(1)</sup>
- Q1'23 unhedged cash operating margin of \$53.31/Boe<sup>(2)</sup>

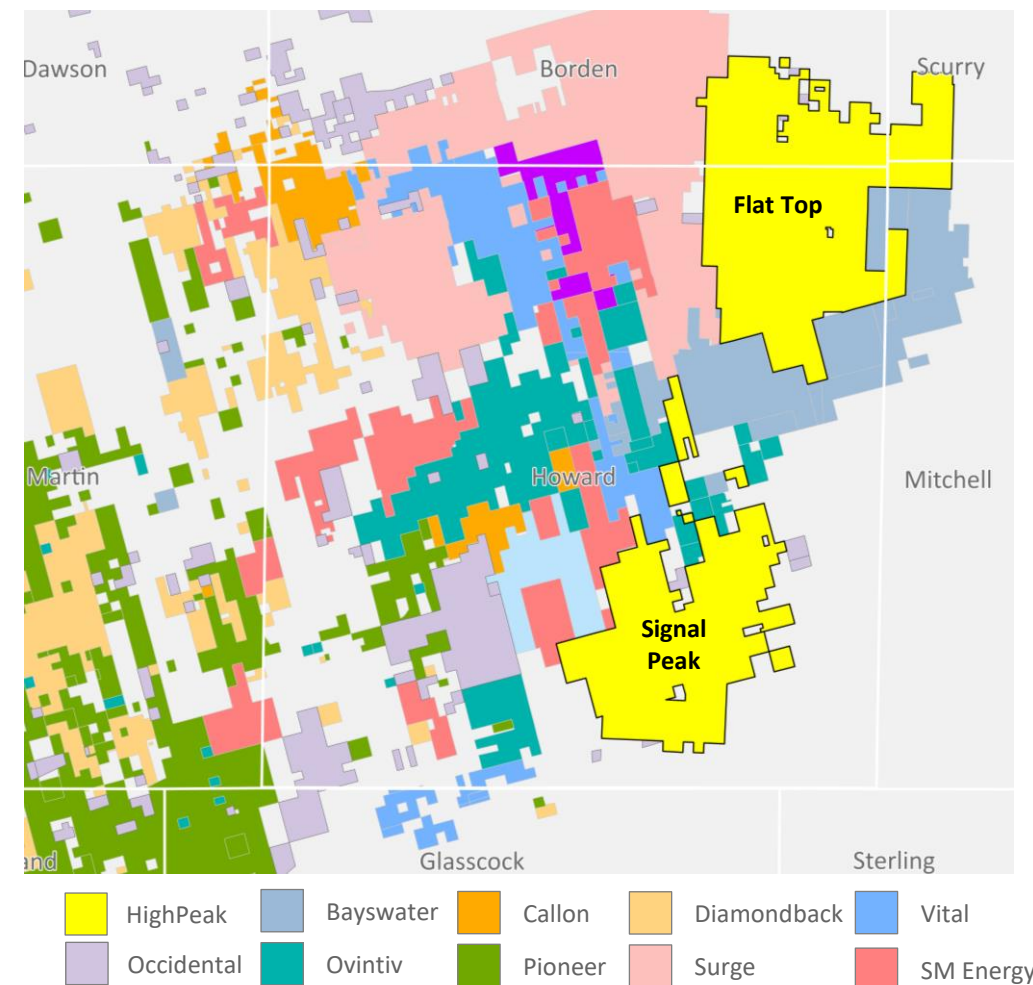
### Operating Statistics<sup>(2)</sup>

Gross/Net Wells In Progress as of 3/31/23	<b>64 / 61.3</b>
% Oil / % Liquids (Q1'23)	<b>85% / 94%</b>
2023E Exit Production (MBoe/d)	<b>~58</b>

### Financial Statistics (\$mm)<sup>(2)</sup>

3/31/23 Net Debt / Q1'23 LQA EBITDAX <sup>(5)</sup>	<b>1.2x</b>
Q1'23E LQA EBITDAX <sup>(3)</sup>	<b>~\$705</b>
Free Cash Flow Positive <sup>(4)</sup>	<b>H2'23</b>

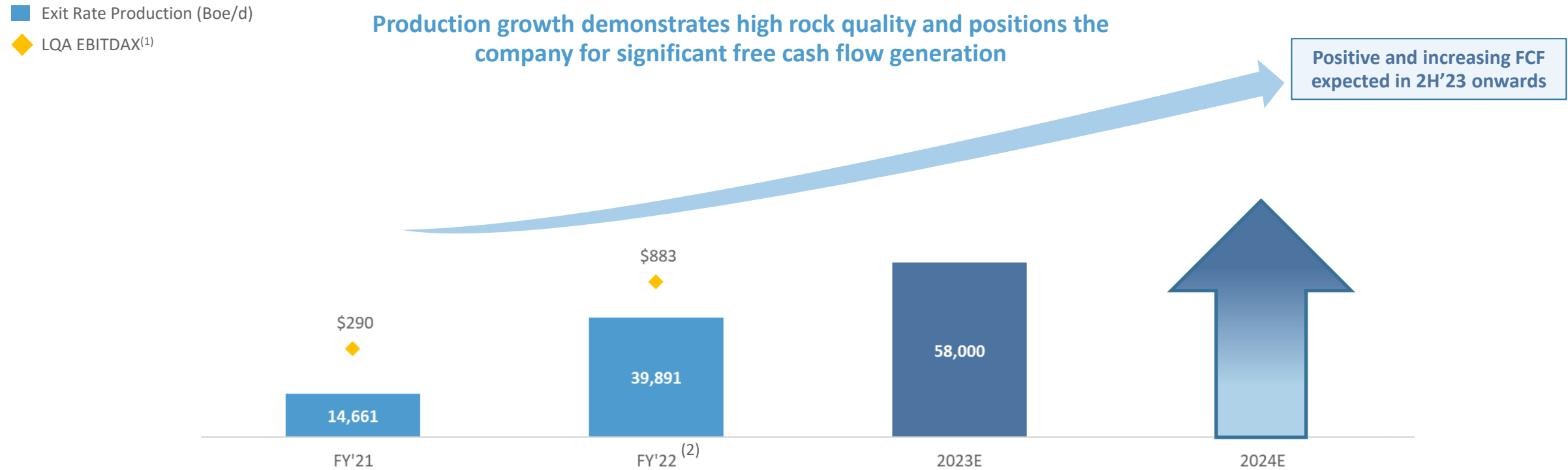
## Acreage Map



Note: Acreage map per Enverus and company data.  
(1) Net acreage as of 4/28/2023. HBP %, % operated, avg. WI %, locations and wells in progress as of 3/31/23.  
(2) All forward-looking metrics / estimates based on midpoint of updated company guidance released in May 2023.

(3) EBITDAX is a non-GAAP financial measure. See the Appendix for a reconciliation to the most comparable GAAP measure.  
(4) Free Cash Flow is a non-GAAP financial measure and defined as estimated EBITDAX less capex, interest expense and dividends.

Value Creation Over Time



	Significant value created through consistent, repeatable development results			
Avg. Rigs Running	~1	6	~3 (6 → 2)	Within Cash Flow
Gross Wells Drilled	44	123	80-90	
Gross Wells TIL	30	92	105-115	

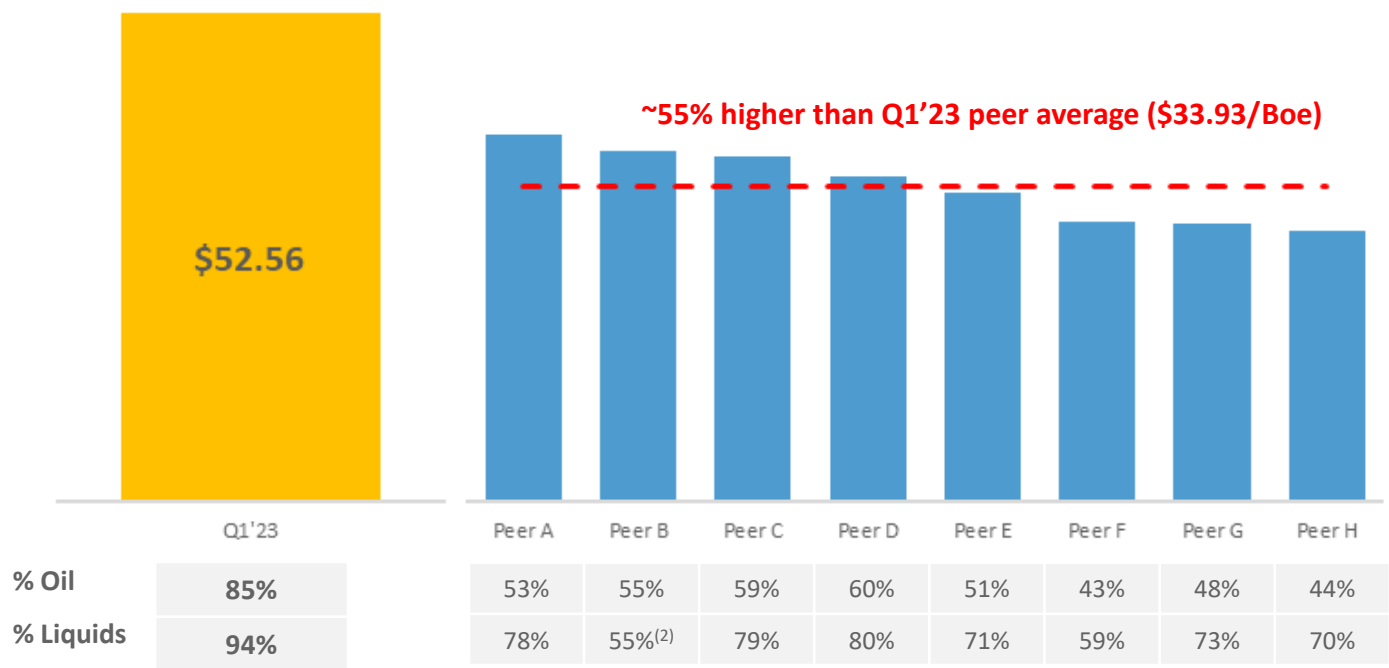
Note: All forward-looking metrics based on midpoint of updated company guidance released in May 2023.  
(1) EBITDAX is a non-GAAP financial measure. See the Appendix for a reconciliation to the most comparable GAAP measure.  
(2) Includes Hannathon acquisition.



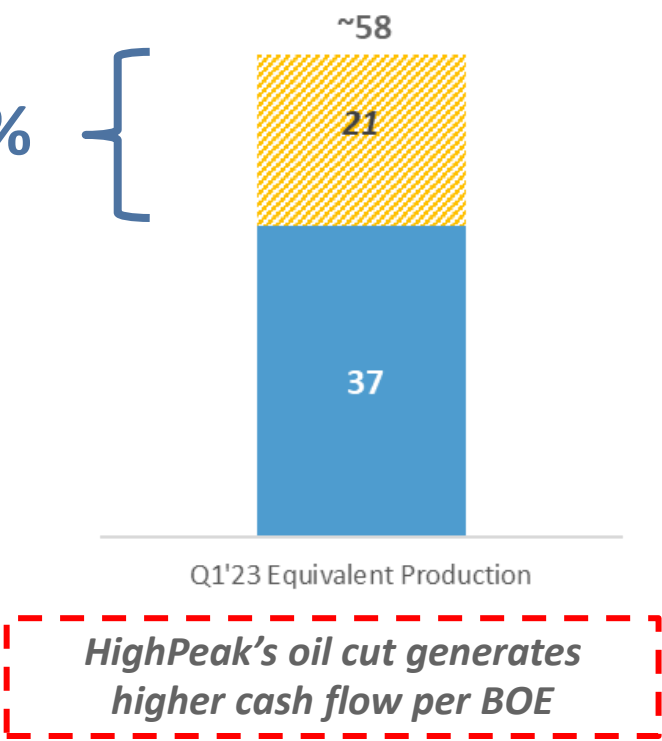
High oil cut, low-cost structure, and continued scaling of production lead to HPK's peer leading margins

- Q1 margins are **33% above** nearest peer
- HPK Q1'23 margin (\$52.56/Boe) is **~55% higher** vs. Q1'23 peer average

Unhedged EBITDAX Margins for the 3 Months Ended 3/31/23 (\$/Boe)<sup>(1)</sup>



Equivalent Economic MBOE/D



Source: Public filings.  
(1) Q1'23 unhedged EBITDAX and production figures as reported. EBITDAX calculation for peers reflects adjusted EBITDAX for the 3M ended period as calculated by respective companies. Peers include CPE, ESTE, FANG, MTDR, PR, PXD, SM, and VTLE.  
(2) Peer B reports production on a 2-stream basis

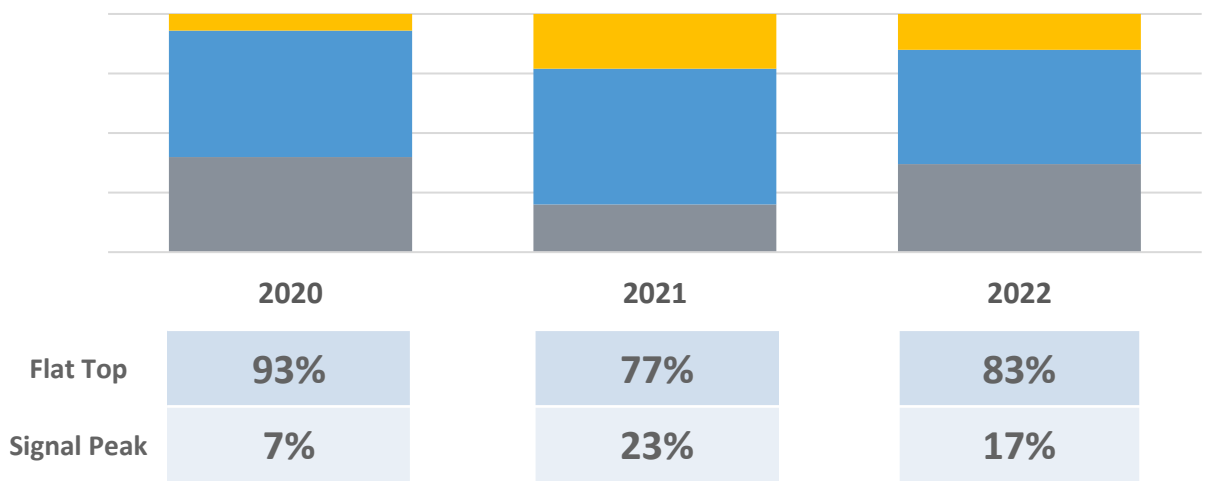


- Continue to demonstrate consistent well results as we have expanded development across the acreage position and formations
- 2022 wells have outpaced 2021’s improvements over 2020

## Development by Zone

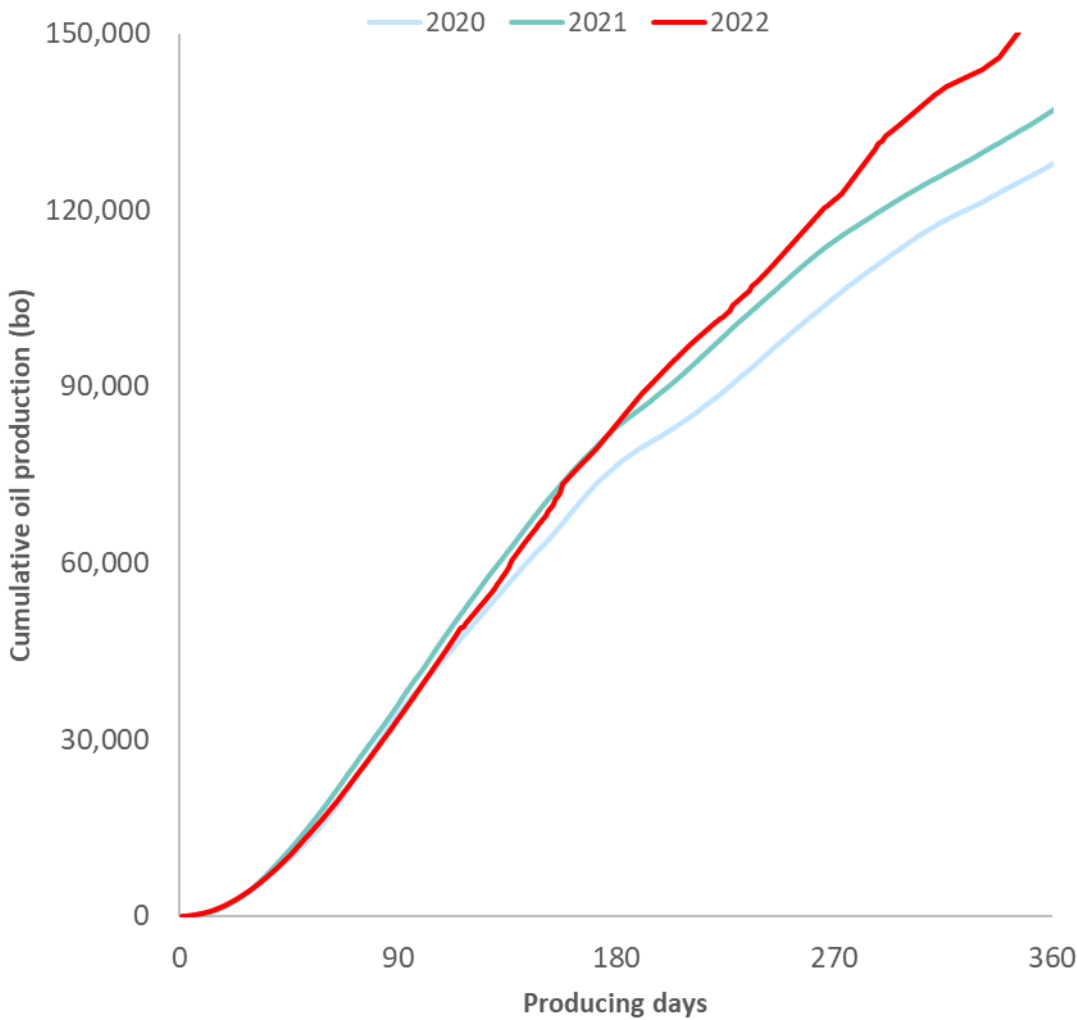
(% of Net TIL Lateral Ft.)

■ LS ■ WCA ■ WCD



Source: Company provided.

## Improving Well Performance Year Over Year

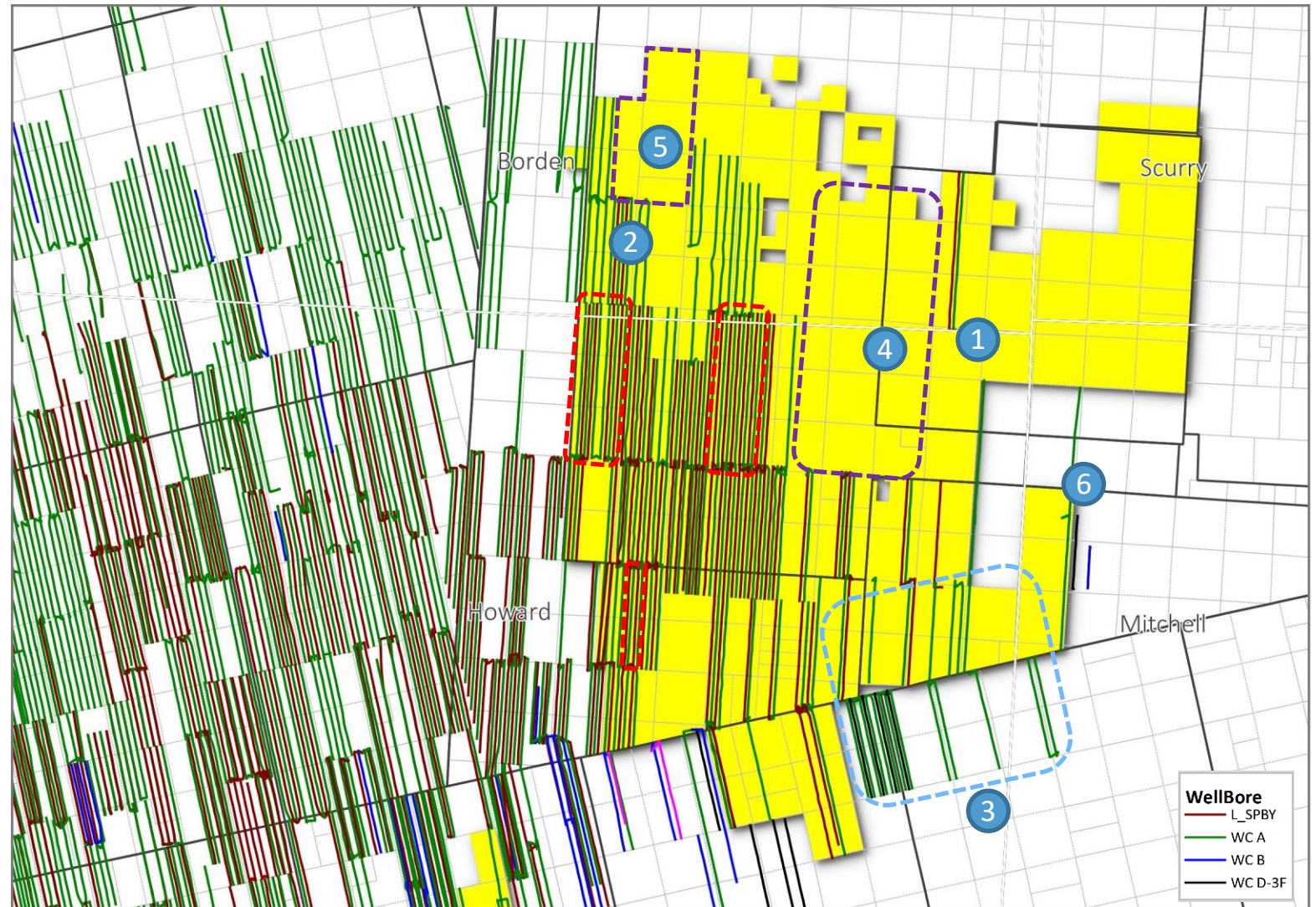


## Summary

Q1'23 activity  
areas

### ■ Key Pads/Areas

- ① – Conrad pad  
– Extended LS/WCA ~4 miles northeast of development area
- ② – Griffin 48-37 B pad  
– LS wells producing similar to WCA
- ③ – Southeast Flat Top  
– Demonstrated well performance similar to core Flat Top area
- ④ – WCA/LS co-development planned based on strong offset performance
- ⑤ – WCA/LS co-development planned based on strong offset performance
- ⑥ – Offset operator 2 well WCA pad; confirms potential further east into Mitchell County





## Summary

### ■ Lower Spraberry / Wolfcamp A

1-2 Delineation in advance of development

3-4 Initial development pads

### Lower Spraberry / Wolfcamp A – Phase 1 Development

### ■ Wolfcamp D – 3F

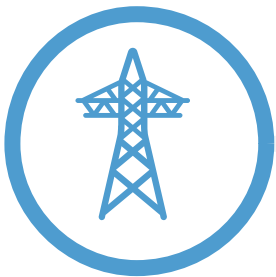
5-8 Testing additional stacked bench  
– Wells in various stages of completion or initial flowback

### ■ Infrastructure

- 3 SWD wells in operation
- Plan to drill 1-2 additional wells in 2023
- Constructing 20" water gathering system
- Build out of main electrical system



Power



**Efficient**

Running 1-2 rigs on electric power, dual fuel frac crew

**Clean**

10MW solar farm in progress

**Scalable**

Expandable substation is operational

Facilities



**Quality**

Newly built VRU, VRT & instrument air

**Expandable**

Large scale, expandable CTBs & production corridors minimizes surface impact

**On Pipe**

> 75% oil / 100% gas minimizes trucking

Fluid



**Recycling**

Can supply 100% of the stimulation fluid for 2 frac crews at Flat Top, currently expanding recycle capabilities at Signal Peak

**Infrastructure**

Pipeline connected horizontal SWDs with high-volume, low-pressure injection

Sand



**Environmental**

Local sand mine (less than 20-mile round trip) currently supplying 2 frac crews, reducing trucking miles

**Energy Savings**

Using wet sand eliminates natural gas burned in drying process

Continuing our efficiency and environmental stewardship



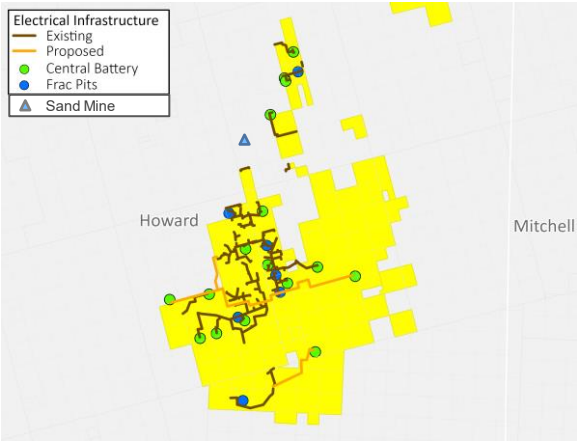
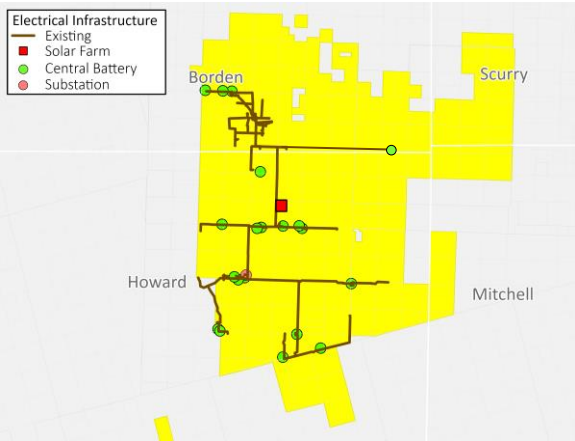
□ Central Tank Battery configuration –

- Large
- Scalable
- Efficient
- Low emissions

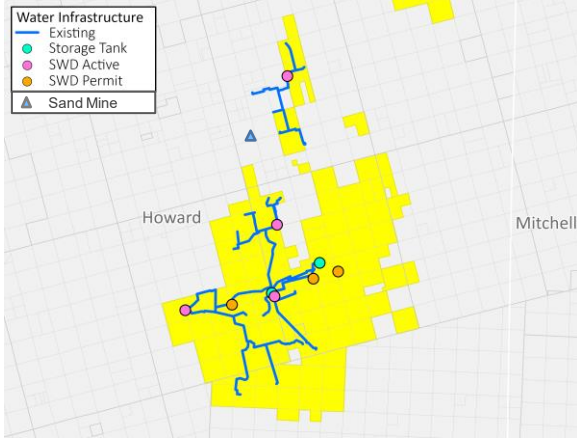
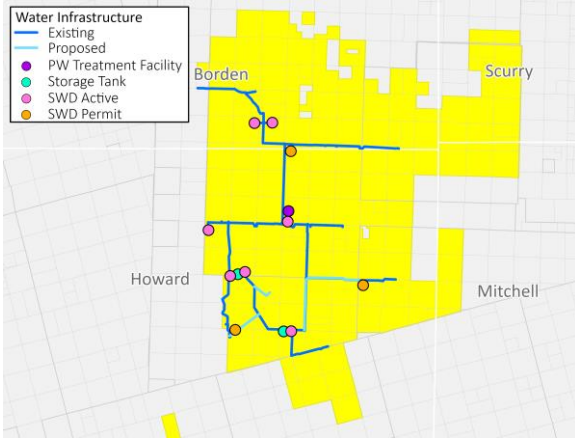
All electrical, SWD and recycle systems in place for full development



Electrical Infrastructure



Water Infrastructure



# Substantial Inventory<sup>(1)</sup>

Results Driven By Excellent Reservoir Performance Across Multiple Targets



**~ 2,500**  
**Total Gross Locations**

## Inventory Details

- Approximately 1,300 delineated primary locations from current producing intervals
- **>14 years** of anticipated primary at 4-rig cadence; **~58 rig-years** of primary
- Approximately 1,200 additional upside locations; **~51 rig-years** of upside
- Conservative 6 wells/section spacing<sup>(2)</sup>
- ~12,000 ft avg. lateral length

## Rock & Fluid Properties

- High TOC (up to 9%)
- Thermally mature (oil window)
- 34 – 38 API crude with high BTU gas



## Remaining Inventory (Gross Locations)

	Flat Top		Signal Peak		Total		
	Primary	Upside	Primary	Upside	Primary	Upside	All
Middle Spraberry	-	150	-	111	-	261	261
Jo Mill	-	174	-	111	-	285	285
Lower Spraberry	182	-	138	-	320	-	320
Wolfcamp A	198	-	144	-	342	-	342
Wolfcamp B	59	240	98	24	157	264	421
Wolfcamp C	-	-	-	165	-	165	165
Wolfcamp C (Hutto)	-	-	-	169	-	169	169
Wolfcamp D (3-Fingers)	47	45	238	-	285	45	330
Wolfcamp D (Base)	-	-	191	19	191	19	210
TOTAL	486	609	809	599	1,295	1,208	2,503

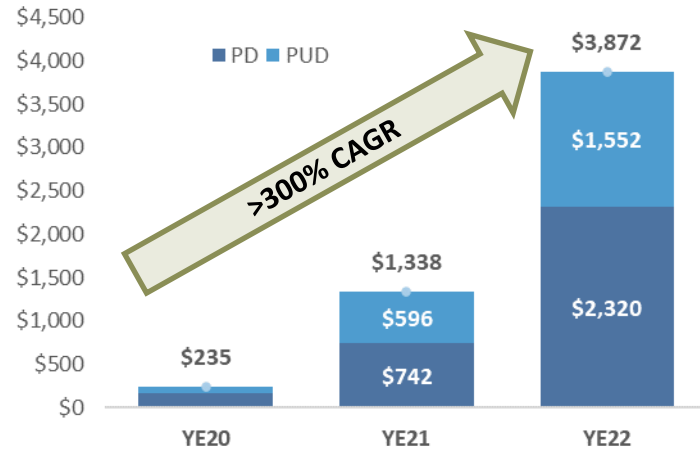
Note: Rig years based on illustrative 20 gross wells drilled per year/rig in Wolfcamp D, 24/year in all others.  
(1) As of December 31, 2022.  
(2) Assumes 1-mile-wide drilling units.

# Year-End Proved Reserves Summary <sup>(1)(2)</sup>

2022 SEC Pricing - \$93.67/Bbl & \$6.358/MMBtu

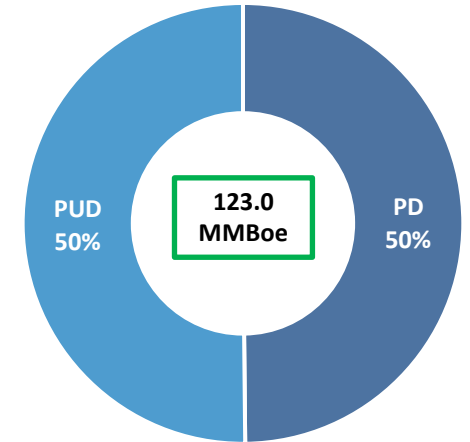


PV10 (\$mm)

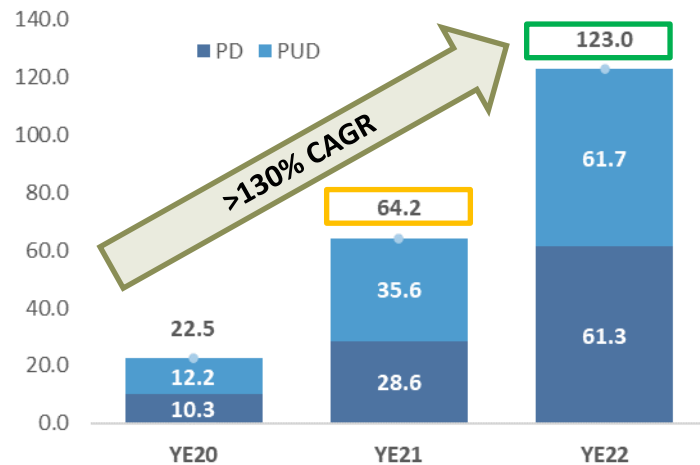


- >300% PV10 CAGR
- >130% Net Reserves CAGR
- Proved Reserves: 80% oil, 92% liquids
- 2022 Replacement Ratio<sup>(3)</sup>
  - Drill Bit: 546%
  - Drill Bit + Acquisitions: 757%

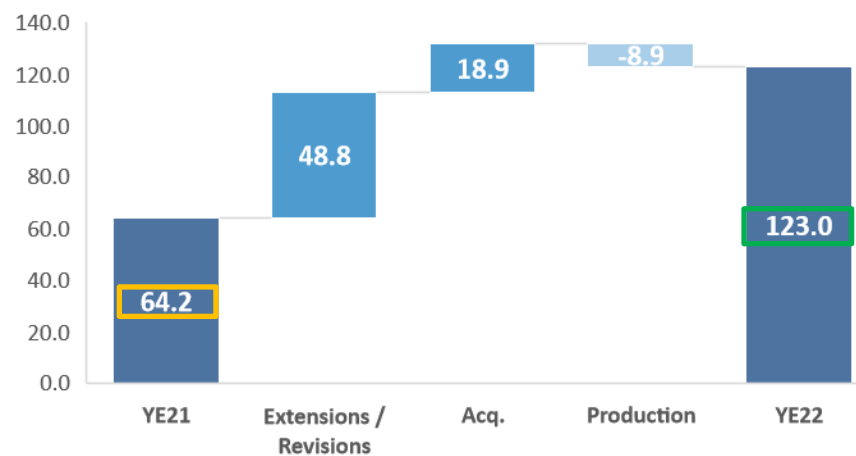
YE22 Proved Reserves by Category



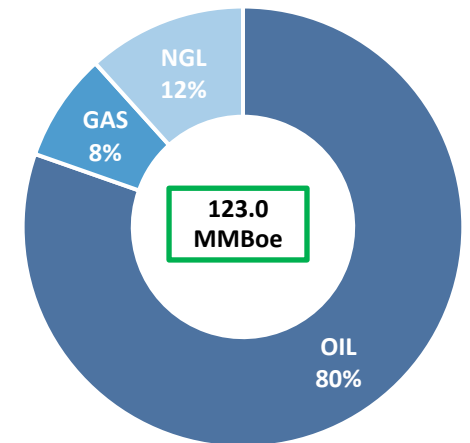
Net Reserves (MMBoe)



Proved Reserves (MMBoe)



YE22 Proved Reserves Mix



(1) Reserves per HighPeak's year-end 2020/2021/2022 third party reserve reports prepared by Cawley Gillespie & Associates ("CGA").

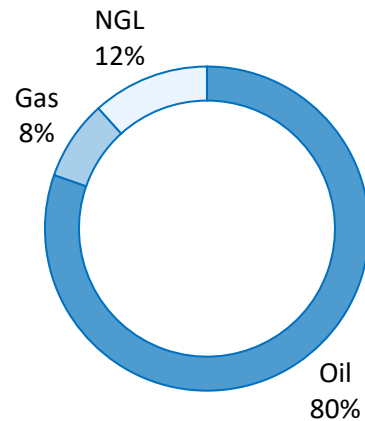
(2) SEC pricing (oil, \$/Bbl / gas, \$/MMBtu) each report: 2020: \$39.57/\$1.985, 2021: \$66.56/\$3.598, 2022: \$93.67/\$6.358.

(3) Drill Bit Replacement Ratio is defined as reserves from Extensions plus Revisions divided by Production; Drill Bit + Acquisitions Replacement Ratio is defined as reserves from Extensions plus Revisions plus Acquisitions divided by Production.

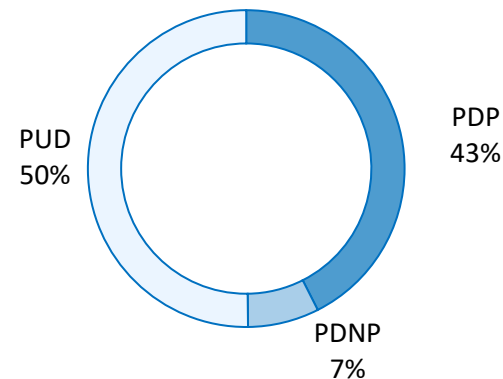
## Year-End 2022 Proved Reserves

Reserve Category	Net Proved Reserves			% of Total Proved	% Liquids	PV-10 (\$MM)
	Oil (MBbl)	Gas (MMcf)	NGL (MBbl)	Total (MBoe)		
Proved Developed Producing (PDP)	40,428	29,028	7,042	52,308	43%	\$1,947
Proved Developed Non-Producing (PDNP)	7,417	3,641	927	8,950	7%	\$373
<b>Total Proved Developed Reserves</b>	<b>47,845</b>	<b>32,669</b>	<b>7,968</b>	<b>61,259</b>	<b>50%</b>	<b>\$2,320</b>
Proved Undeveloped (PUD)	50,971	25,968	6,401	61,699	50%	\$1,552
<b>Total Proved Reserves</b>	<b>98,816</b>	<b>58,638</b>	<b>14,369</b>	<b>122,958</b>	<b>100%</b>	<b>\$3,872</b>

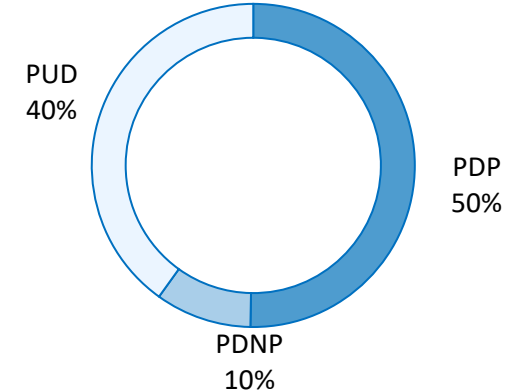
Proved Net Reserves by Commodity



Proved Net Reserves by Category



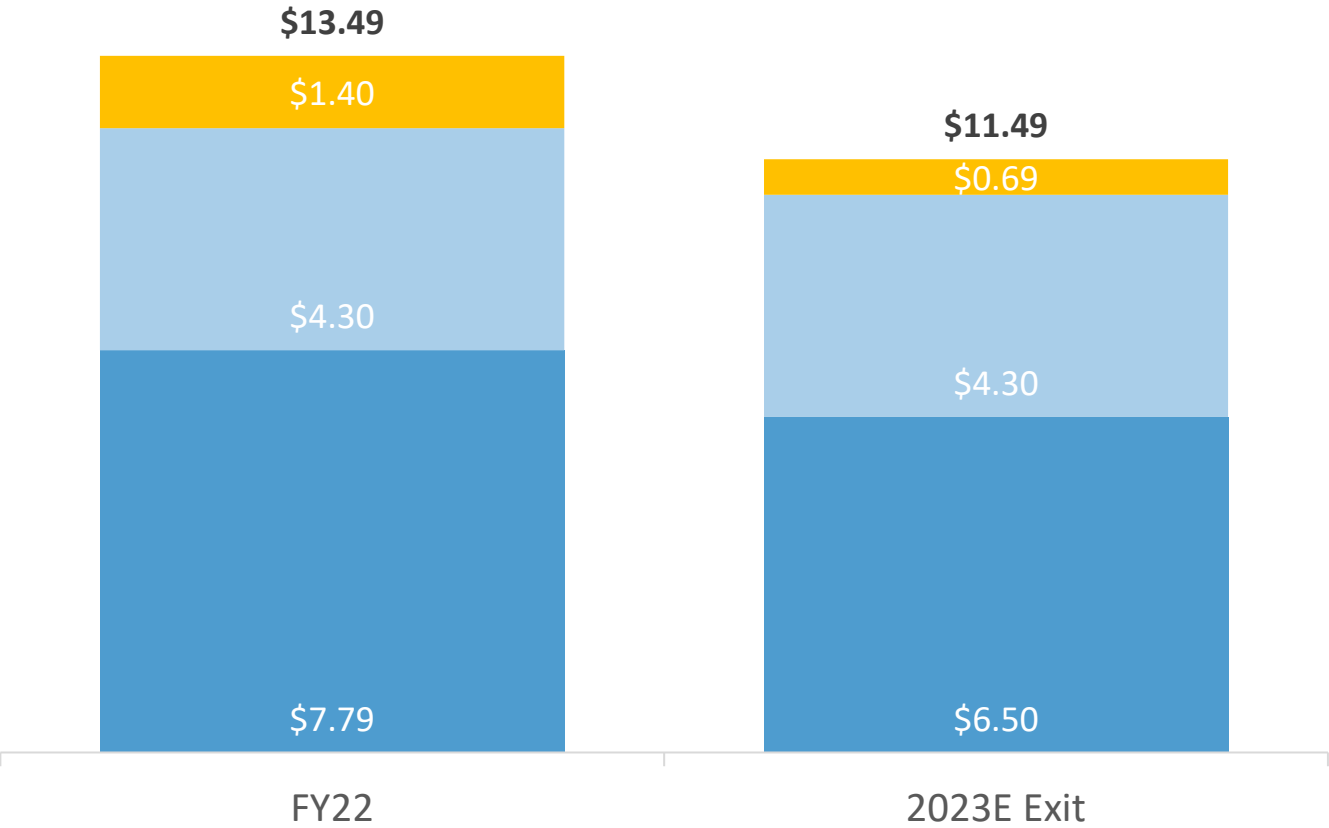
Proved PV-10 by Category



(1) Reserves per HighPeak's year-end 2022 third party reserve report prepared by Cawley Gillespie & Associates ("CGA"). Assumes effective date of 01/01/23; based on SEC pricing – average oil (\$/bbl): \$93.67 and average gas (\$/MMBtu): \$6.358.



■ LOE   ■ Production Taxes   ■ G&A



## Continued Optimization Gains:

- A** Continued generator removal and solar farm integration
- B** Volume dilution of fixed costs
- C** Infrastructure buildout in Signal Peak and Borden County

Note: All forward-looking metrics based on company estimate for 2023E exit using flat \$80 WTI / \$4 HH price deck.

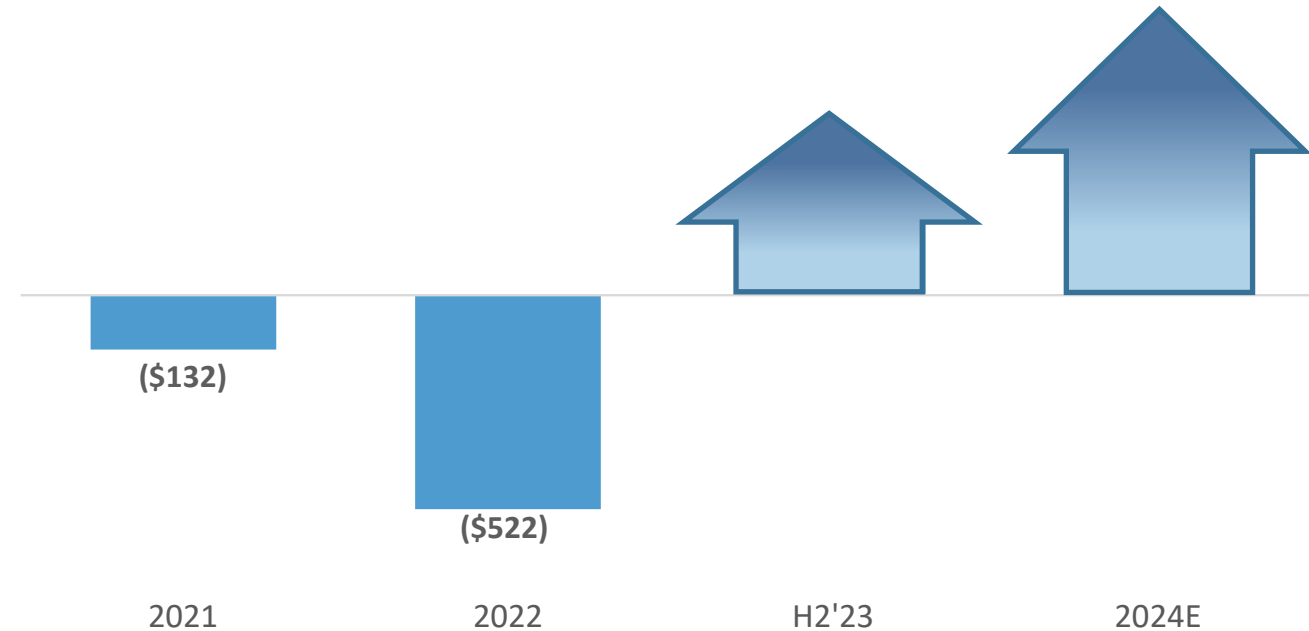
Production (MBoe/d)	2023
Average production rate	45 – 51
Exit production rate	55 – 61

Capex (\$mm)	2023
Gross Operated Wells TIL	105 – 115
Capital Expenditures D,C,E&F	\$900 - \$975
Capital Expenditures, Infra/Land/Other	\$50 - \$60
Total Capital Expenditures	\$950 - \$1,035
Average Rigs	~3 (6 → 2)
Average Frac Crews	~2 (3 → 2)

Unit Measures (\$/Boe)	2023
Lease Operating Expenses	\$6.50 - \$7.50
General & Administrative	\$0.75 - \$1.00

## Est. FCF Inflection Point in 2023 – Entering FCF Growth Mode Thereafter

(\$ in millions)




**Expected to begin delivering free cash flow in 2H'23 under 2-rig program**  
**Expected to run 2024 program within cash flow**


## Current Debt Overview


- \$475MM in aggregate senior unsecured notes
  - \$225MM February 2024 notes, 10.0% coupon. Pre-payable at par, offering significant flexibility
  - \$250MM November 2024 notes, 10.625% coupon, callable at par in November 2023
- Current borrowing base of \$700MM with \$575MM elected commitments


## Current Capitalization (\$MM)

	As of 3/31/2023
Cash and cash equivalents	\$48
Revolving credit facility	420
10.000% senior notes due 2024	225
10.625% senior notes due 2024	250
<b>Total debt</b>	<b>\$895</b>
<i>Net debt<sup>(1)</sup></i>	<i>\$847</i>
Market capitalization as of 3/31/23	2,603
<b>Enterprise value</b>	<b>\$3,450</b>
Borrowing base <sup>(2)</sup>	\$700
Liquidity <sup>(3)</sup>	326
<b>Operating statistics:</b>	
Q1'23 LQA EBITDAX	\$705
<b>Credit statistics:</b>	
Total debt / Q1'23 LQA EBITDAX	1.3x
Net debt / Q1'23 LQA EBITDAX	1.2x

- 
- Operational Scale**
- 113,600 net acres in two highly contiguous blocks in the Midland Basin
  - First quarter year over year production growth of > 200%

- 
- Inventory Quality and Depth**
- Primary delineated inventory of 1,300 gross locations
  - 2,500 total gross locations identified

- 
- Peer Leading Margins**
- Peer leading margins and cost structure among public companies in the Permian Basin
  - Highly oil-weighted inventory with 85% of production being oil and 94% liquids during Q1'23

- 
- Sustainable Free Cash Flow Generation**
- Entering projected free cash flow growth
  - Long term leverage target of < 1.0x Net Debt/EBITDAX

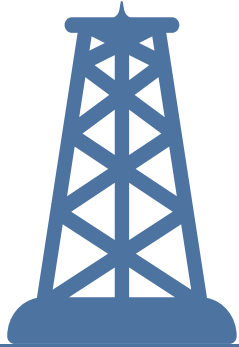




# HIGHPEAK ENERGY, INC.

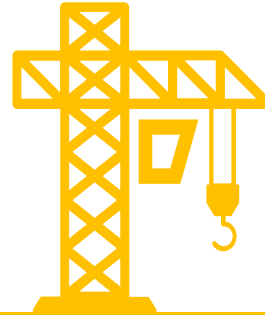
Appendix





## Rig Released Wells

	1Q23	
	Gross	Net
OP	25	24.7
Nonop	0	0.0
Total	25	24.7
SWD	1	1.0



## In Progress<sup>(1)</sup>

	As of 03/31/2023	
	Gross	Net
OP	62	60.2
Nonop	1	0.1
Total	63	60.3
SWD	1	1.0



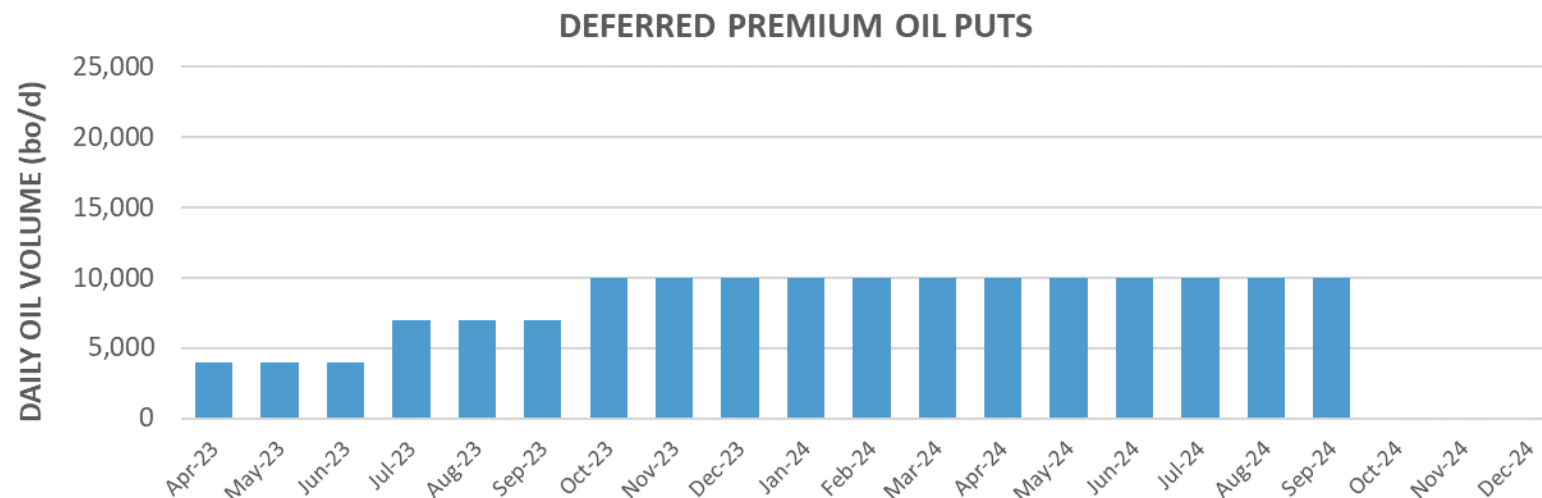
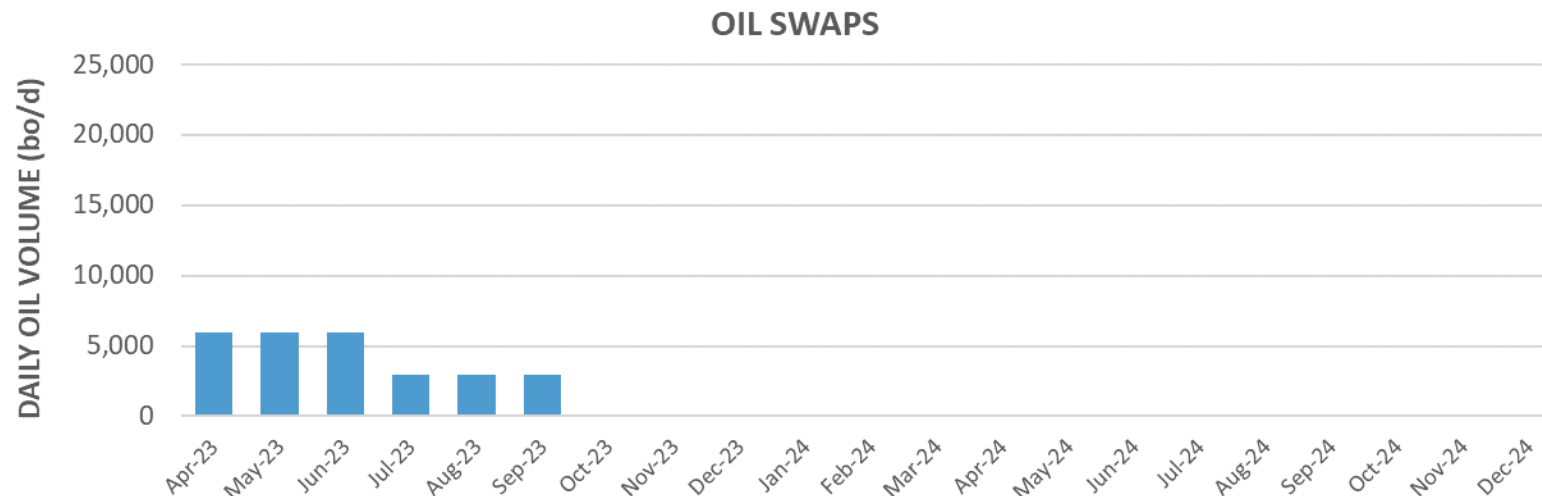
## Turned in Line

	1Q23	
	Gross	Net
OP	26	25.5
Nonop	6	0.3
Total	32	25.8

(1) In Progress includes 15 gross (14.9 net) wells drilling as of March 31, 2023.

## Summary

- Average oil volumes of ~4,492 Bo/d hedged from Q2'23 – Q3'23 using swaps at an average price of \$69.32/bbl
- Average oil volumes of ~7,011 Bo/d hedged from Q2'23 – Q4'23 using puts at an average price of \$58.43/bbl
- Average oil volumes of ~7,486 Bo/d hedged for 2024 using puts at an average price of \$53.83/bbl
  - Deferred premium cost of \$5/bbl on all puts



	OIL SWAPS		OIL PUTS	
	VOL (Mbbbl)	Price	VOL (Mbbbl)	Price
2023/Q2	546	\$67.81	364	\$61.05
2023/Q3	276	\$72.30	644	\$60.46
2023/Q4			920	\$55.97
<b>2023</b>	<b>822</b>	<b>\$69.32</b>	<b>1,928</b>	<b>\$58.43</b>
2024/Q1			910	\$53.83
2024/Q2			910	\$53.83
2024/Q3			920	\$53.83
2024/Q4				
<b>2024</b>			<b>2,740</b>	<b>\$53.83</b>

SEASONED LEADERSHIP TEAM WITH HIGHLY RELEVANT EXPERIENCE



Jack Hightower  
Chairman & CEO

BLUESTEM | ENERGY



Michael L. Hollis  
President & Director



Rodney L. Woodard  
Chief Operating Officer



Steven W. Tholen  
Chief Financial Officer



Alan R. Huffman  
Chief Technical Officer

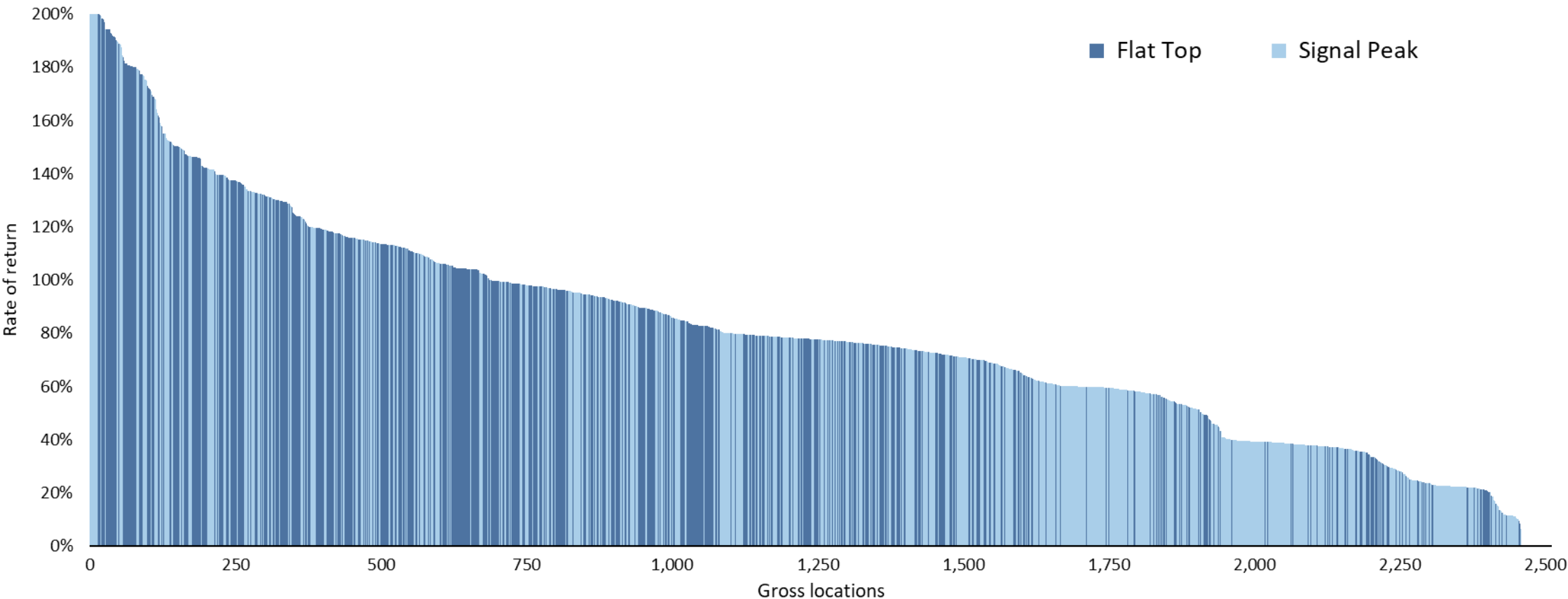


David F. DeLaO  
VP, Drilling





Remaining Locations



(# of wells)	Well IRR					Total
	>20%	>40%	>60%	>80%	>100%	
Flat Top	1,067	993	928	811	567	1,095
Signal Peak	1,354	1,153	904	587	353	1,408
Total	2,421	2,146	1,832	1,398	920	2,503

Source: Company year-end '22 SEC database evaluated at \$85/oil & \$4 gas

# HighPeak's Position Poised For Optimal Development

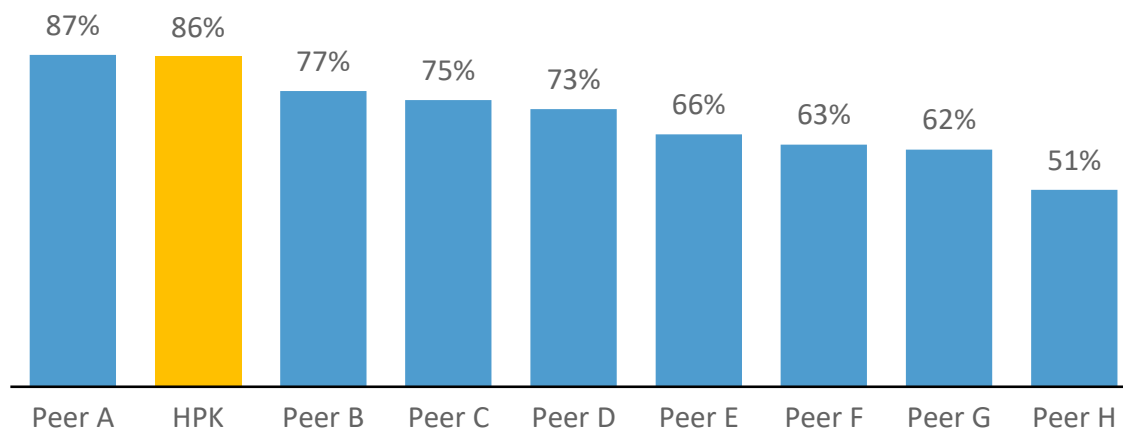
Optimal Acreage To Maximize Deep Inventory Development



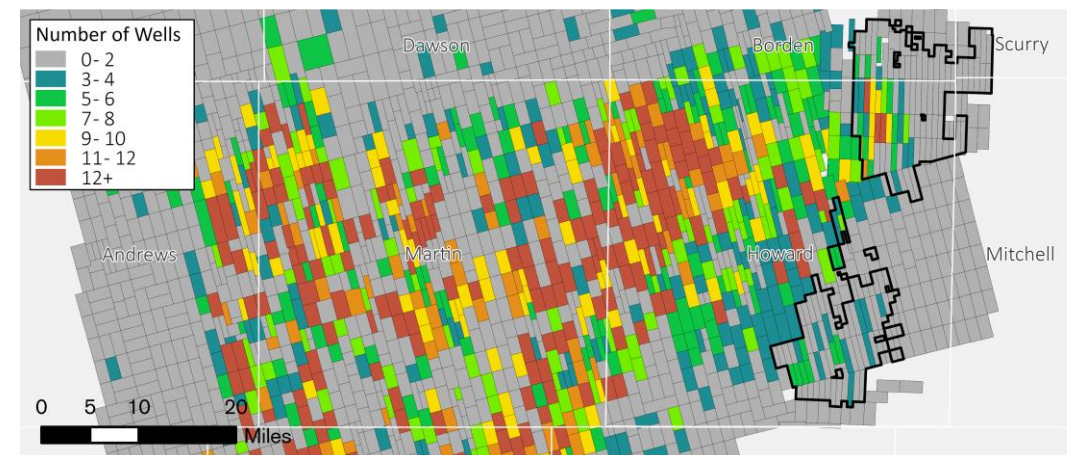
## HighPeak Poised for Optimal Development on Proven Inventory

- ~88% of HPK acreage has 6 or less wells/DSU making it one of the least densely populated acreage of any mid-cap Permian public
- One of the smallest parent child risks relative to HighPeak's Permian basin peers
- Clean fairways allow for optimized full-scale pad development on delineated acreage
- Contiguous acreage with optimal lateral design to maximize capital efficiency

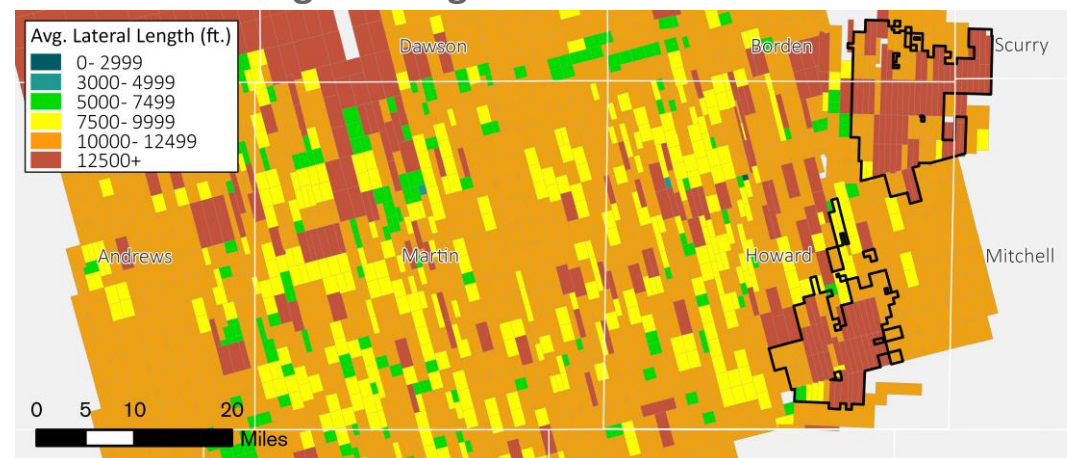
## Non-child as percent of overall remaining net locations<sup>(1)</sup>



## DSU well density Northern Midland<sup>(2)</sup>



## DSU lateral length configuration Northern Midland



Source: Enverus.  
(1) Based on May 2022 Permian Play Fundamentals report. Peers include CPE, ESTE, FANG, MTDR, PR, PXD, SM, and VTLE (LPI).  
(2) Well density normalized for a 1-mile wide DSU.

Production	Q1 2023
Total sales volumes (MBoe)	3,350.0
Total daily sales volumes (MBoe/d)	37.22
Oil percentage	85%
Liquids percentage	94%
Realized Pricing	
Oil per Bbl	\$76.07
NGL per Bbl	\$27.04
Gas per Mcf	\$2.21
Total per Boe (excluding derivatives)	\$66.80
<i>Total per Boe (including derivatives)</i>	<i>\$66.15</i>
Costs (per Boe)	
LOE	\$8.57
Workover expenses	\$1.26
Production & Ad Valorem taxes	\$3.67
G&A (Cash)	\$0.75
Total cash costs	\$14.25
Cash margin (excluding derivatives)	\$52.56
<i>Cash margin (including derivatives)</i>	<i>\$51.90</i>

Earnings	Q1 2023
Net Income (\$MM)	\$50.3
<i>GAAP Earnings (per diluted share)</i>	<i>\$0.39</i>
EBITDAX (\$MM)	\$173.9
<i>EBITDAX (per diluted share)</i>	<i>\$1.34</i>
Other	
Capex (\$MM) <sup>(1)</sup>	\$379.1
Rig Released <sup>(2)</sup> / Turn in Line	26 / 32

(1) Excludes acquisition capex.  
 (2) Rig Released includes 1 SWD.

## Reconciliation of Net Income to EBITDAX

(in thousands)	Quarter Ended		
	31-Dec-21	31-Dec-22	31-Mar-23
Net income	\$ 37,025	\$ 67,899	\$ 50,257
Interest expense	1,331	21,468	26,972
Income tax expense (benefit)	12,224	20,004	14,507
Depletion, depreciation and amortization	21,464	83,211	81,131
Accretion of discount	51	125	118
Exploration and abandonment expense	407	466	2,164
Stock based compensation	3,782	4,142	4,054
Derivative-related noncash activity	(3,935)	23,565	(5,314)
Other	40	(13)	(30)
Est. Hannathon EBITDAX contribution			
<b>EBITDAX</b>	<b>\$ 72,389</b>	<b>\$ 220,867</b>	<b>\$ 173,859</b>
Cash G&A	3,843	6,637	2,502
<b>Adjusted EBITDAX</b>	<b>\$ 76,232</b>	<b>\$ 227,504</b>	<b>\$ 176,361</b>

## Unhedged Cash Operating Margin Reconciliation

(in thousands)	Qtr. Ended
	31-Mar-23
Oil, NGL and natural gas sales (including deducts)	\$ 223,794
Less: Lease operating expenses	(28,720)
Less: Workover expenses	(4,222)
Less: Production & ad valorem taxes	(12,297)
Less: Cash G&A	(2,502)
<b>Cash Margin</b>	<b>\$ 176,053</b>
Divided by: Production (Mboe)	3,350.0
<b>Cash Margin per Boe, excluding effects of derivatives</b>	<b>\$52.56</b>
<b>Cash Margin</b>	<b>\$ 176,053</b>
Cash G&A	2,502
Divided by: Production (Mboe)	3,350.0
<b>Cash Operating Margin per Boe, before cash G&amp;A and excluding effects of derivatives</b>	<b>\$53.31</b>

## Reconciliation of Proved Reserves PV-10 to Standardized Measure

(in thousands)	As of 12/31/20	As of 12/31/21	As of 12/31/22
<b>Reserves PV-10</b>	<b>\$235,490</b>	<b>\$1,338,193</b>	<b>\$3,872,045</b>
Present value of future income taxes/abandonment costs	(\$13,298)	(\$219,384)	(\$455,537)
<b>Standardized measure</b>	<b>\$222,192</b>	<b>\$1,118,809</b>	<b>\$3,416,508</b>