# HighPeak Energy

Investor Presentation

May 2023

# Disclaimer

**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 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, 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.

# Disclaimer (Cont'd)

**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, 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. 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.

# Updated Development Plan Accelerates Transition to Free Cash Flow

HIGHPEAK ENERGY

## Updated Development Plan

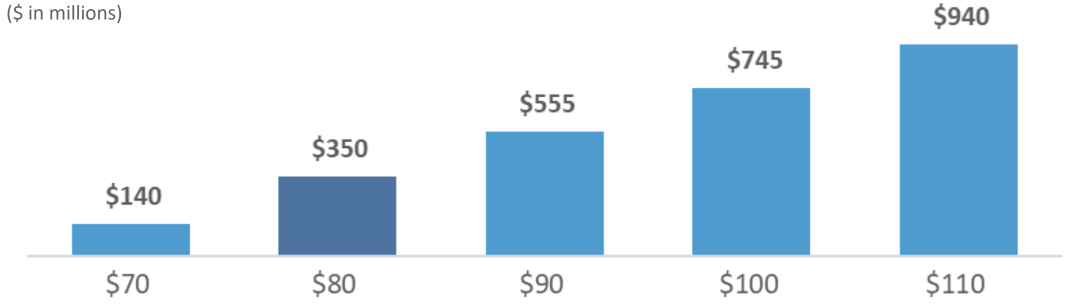
**2023**

- **Intentionally moderated development plan to accelerate free cash flow inflection point while delivering significant production growth**
  - Reducing rig count to 2 rigs starting in June through the remainder of 2023
  - Reduced completion crews from 4 to 2 in early second quarter

**2024**

- **2024 development program projected to generate significant production growth and meaningful free cash flow**
  - Increase to 4 rig/2 frac crew program in January 2024

### Illustrative 2024E FCF at Various WTI Oil Prices(1)




## 2023 & 2024 Outlook

| Production (MBoe/d) | 2023 | 2024 |
|---|---|---|
| Average production rate | 45 - 51 | 60 - 66 |
| Exit production Rate | 55 - 61 | 68 - 76 |

**YoY Est. Avg. Production Growth >30%**

| Capex ($mm) | 2023 | 2024 |
|---|---|---|
| Gross Operated Wells TIL | 105 – 115 | 105 – 110 |
| Capital Expenditures D,C,E&F | $900 - $975 | $850 - $900 |
| Capital Expenditures, Infra/Land/Other | $50 - $60 | $20 - $30 |
| Total Capital Expenditures | $950 - $1,035 | $870 - $930 |
| Average Rigs | ~3 (6 → 2) | 4 |
| Average Frac Crews | ~2 (3 → 2) | 2 |

| Unit Measures ($/Boe) | 2023 | 2024 |
|---|---|---|
| Lease Operating Expenses | $6.50 - $7.50 | $5.75 - $6.75 |
| General & Administrative | $0.75 - $1.00 | $0.60 - $0.80 |

(1) Free Cash Flow is a non-GAAP financial measure and defined as estimated EBITDAX less Capex, interest expense & dividends at various oil prices combined with gas price of $4/Mcf.

# HighPeak Overview

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

## Key Highlights

- 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)[1]
- 61% HBP, 98% operated, 12,000’ average lateral length[1]
- ~2,500 gross locations remaining (89% average working interest)[1]
- Q1’23 unhedged cash operating margin of $53.31/Boe[2]

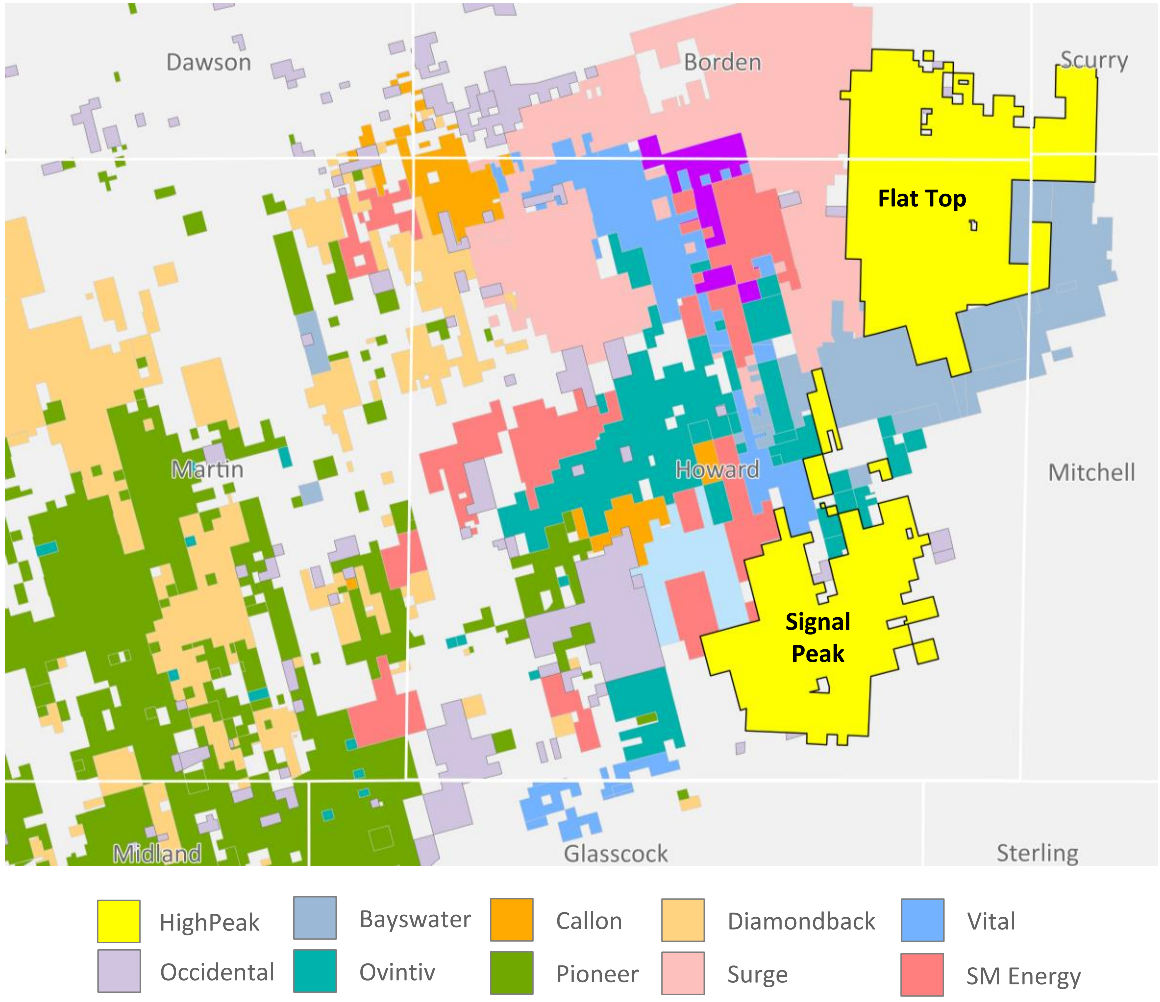
## Operating Statistics[3]

| | |
|---|---|
| Gross/Net Wells in Progress as of 3/31/23 | **64 / 61.3** |
| % Oil / % Liquids (Q1’23) | **85% / 94%** |
| 2023E Exit Production (MBoe/d) | **58** |
| 2024E Exit Production (MBoe/d) | **72** |

## Financial Statistics ($mm)[3]

| | |
|---|---|
| Q4‘23E LQA EBITDAX[4] | **$1,200** |
| Q4‘24E LQA EBITDAX[4] | **$1,550** |
| 2024E Free Cash Flow[5] | **$350** |
| Q1’23 Net Debt / Q1’23 LQA EBITDAX | **1.2x** |

## Acreage Position and Select Offset Operators

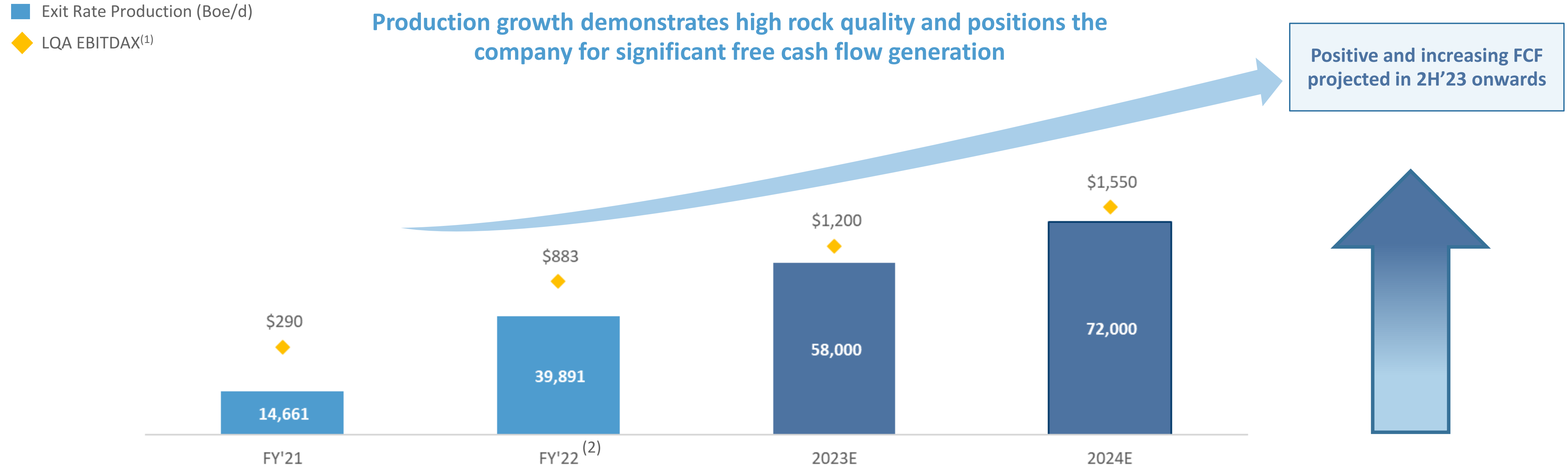



Note: Acreage map per Enverus and company data. Cash flows calculated using flat $80 WTI / $4 HH price deck.
(1) Net acreage as of 4/28/23. HBP %, % operated, avg. WI %, locations and wells in progress as of 3/31/23.
(2) Unhedged cash operating margin is a non-GAAP financial measure. See the Appendix for a reconciliation to the most comparable GAAP measure.
(3) All forward-looking metrics based on midpoint of updated company guidance.
(4) EBITDAX is a non-GAAP financial measure. See the Appendix for a reconciliation to the most comparable GAAP measure.
(5) Free Cash Flow is a non-GAAP financial measure and defined as estimated EBITDAX less Capex, interest expense & dividends.

# Differentiated Growth Story Now Shifting to FCF Harvest

HIGHPEAK ENERGY

## Value Creation Over Time




**Significant value created through consistent, repeatable development results**

| | | | | | |
|---|---|---|---|---|---|
| Avg. Rigs Running | ~1 | 6 | ~3 (6 → 2) | 4 | |
| Gross Wells Drilled | 44 | 123 | 80-90 | 110-115 | |
| Gross Wells TIL | 30 | 92 | 105-115 | 105-110 | |

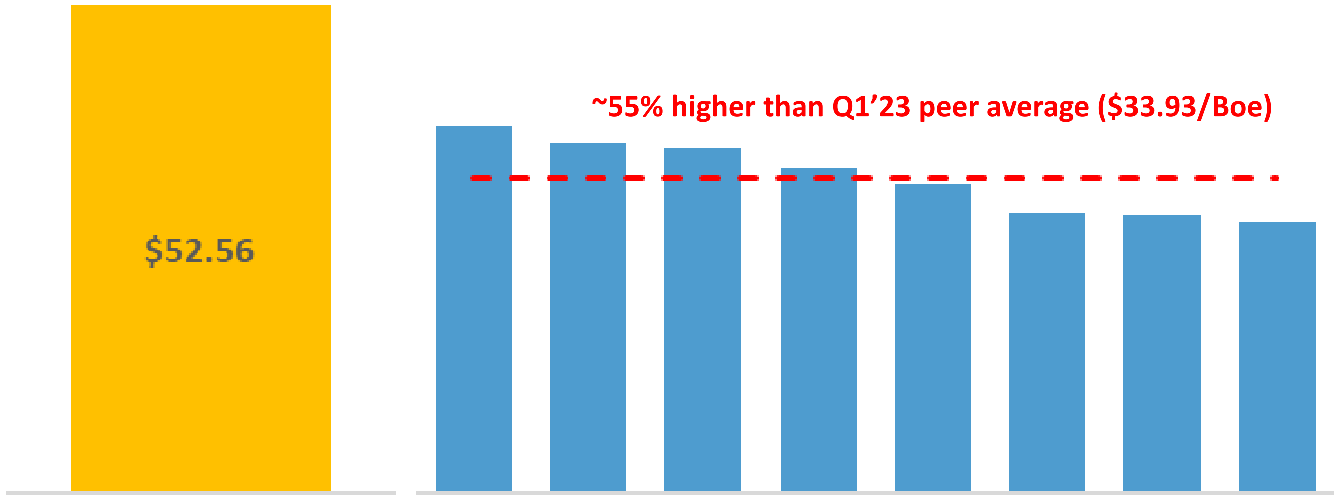
Note: All forward-looking metrics based on midpoint of updated company guidance. Cash flows calculated using flat $80 WTI / $4 HH price deck.
(1) EBITDAX is a non-GAAP financial measure.
(2) Includes Hannathon acquisition.

# HighPeak's Margins Continue to Outpace Peers

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

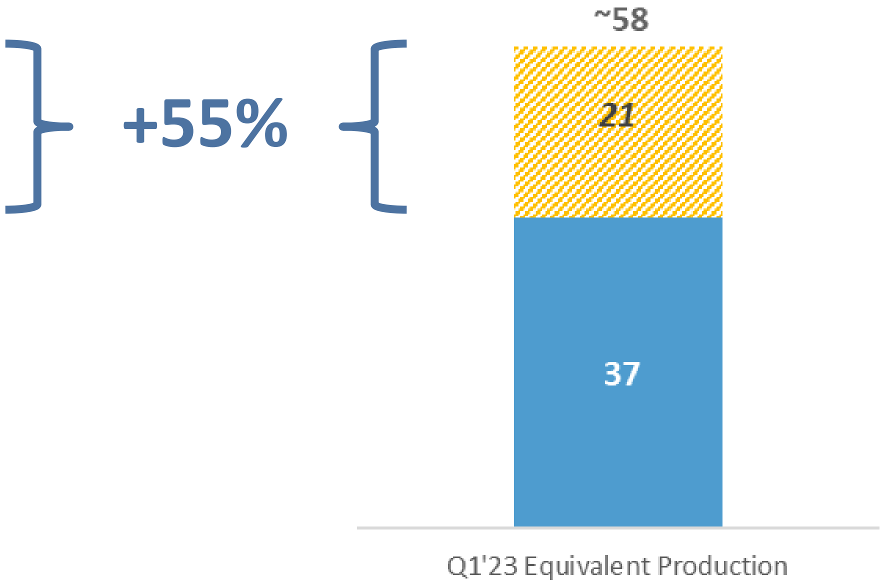
- Q1 margins are **33% above** nearest peer
- HPK Q1'23 margin ($52.56/Boe) is **~55% higher** vs. Q1'23 peer average

## Unhedged EBITDAX Margins for the 3 Months Ended 3/31/23 ($/Boe)(1)




| | Q1'23 | Peer A | Peer B | Peer C | Peer D | Peer E | Peer F | Peer G | Peer H |
|---|---|---|---|---|---|---|---|---|---|
| % Oil | 85% | 53% | 55% | 59% | 60% | 51% | 43% | 48% | 44% |
| % Liquids | 94% | 78% | 55%(2) | 79% | 80% | 71% | 59% | 73% | 70% |

## Equivalent Economic MBOE/D



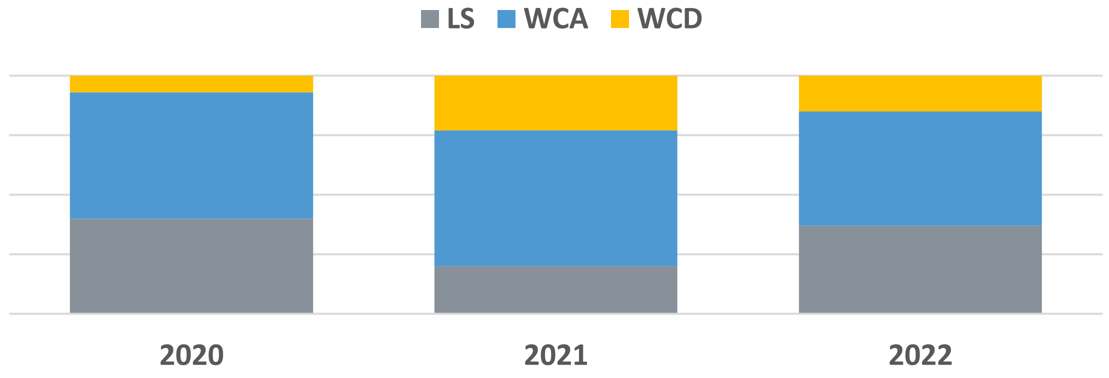

*HighPeak's oil cut generates higher cash flow per BOE*

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

# Enhancing Well Results Across Multiple Benches

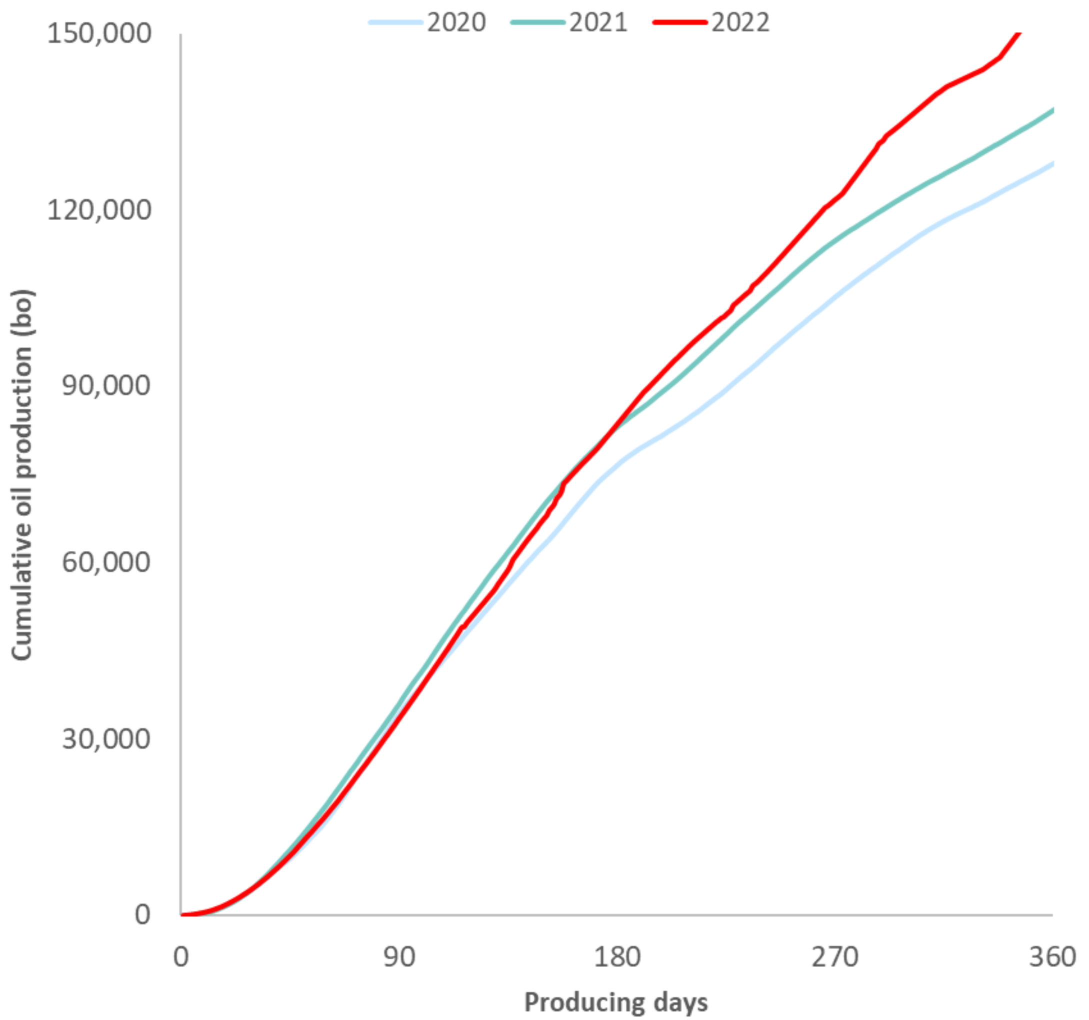
- Continue to demonstrate consistent well results as we have expanded development across the acreage position and formations
- 2022 wells have outpaced 2021's improvements over 2020

## Development by Zone
(% of Net TIL Lateral Ft.)




| | 2020 | 2021 | 2022 |
|---|---|---|---|
| Flat Top | 93% | 77% | 83% |
| Signal Peak | 7% | 23% | 17% |

## Improving Well Performance Year Over Year




Source: Company provided.

## Summary

Q1'23 activity areas

- Key Pads/Areas

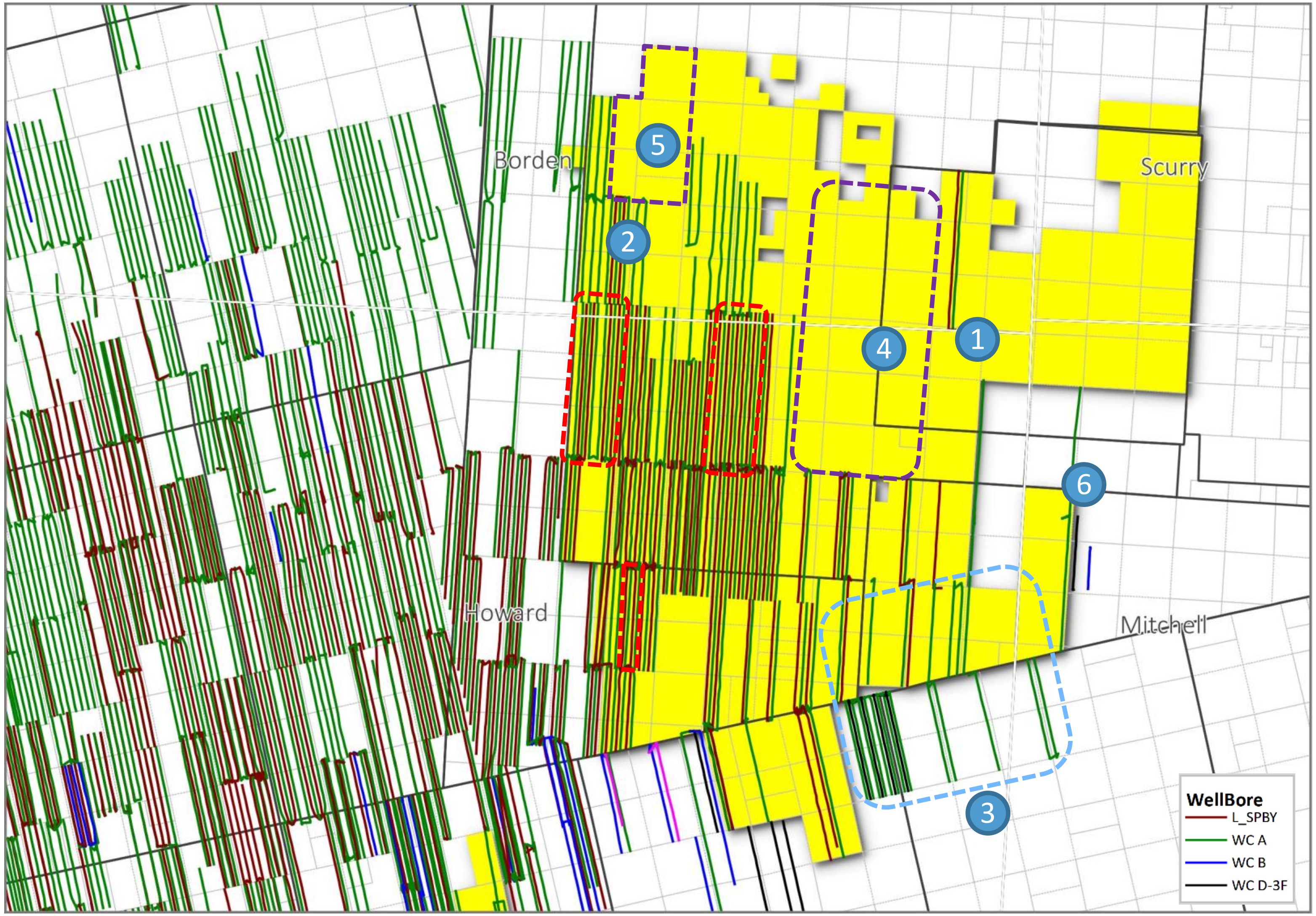
1 – Conrad pad
  – Extended LS/WCA ~4 miles northeast of development area

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, 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



# Operations – Signal Peak

## 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

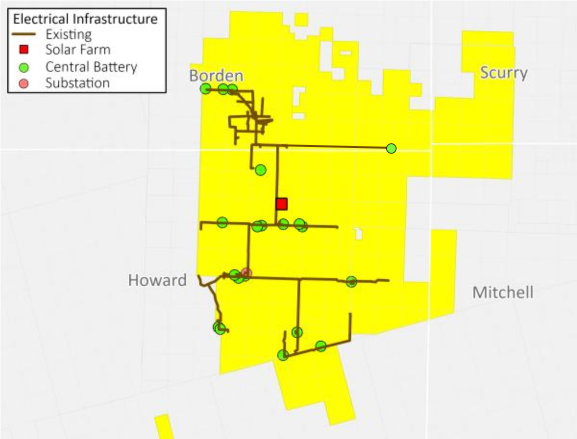
**Continuing our efficiency and environmental stewardship**

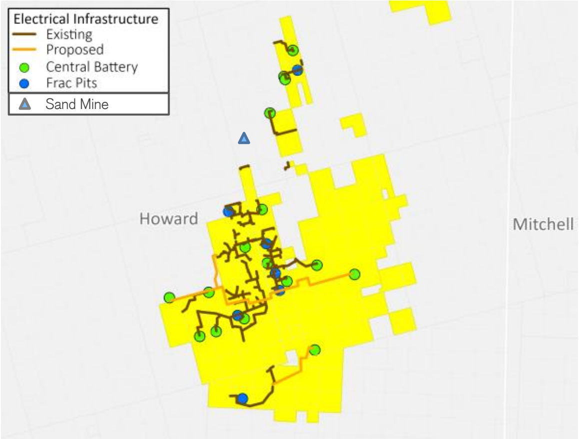
# Asset Ready for Full Development

- Central Tank Battery configuration –
  - Large
  - Scalable
  - Efficient
  - Low emissions

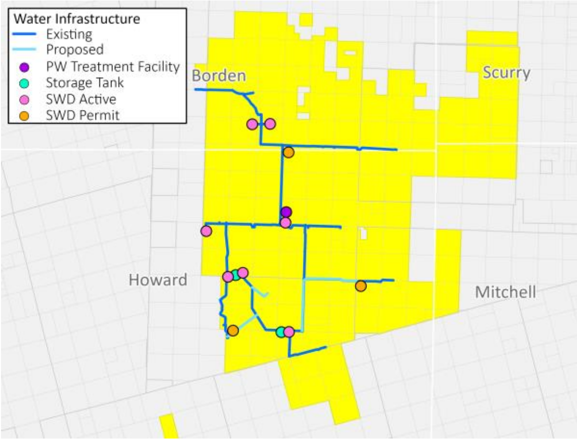
**All electrical, SWD and recycle systems in place for full development**

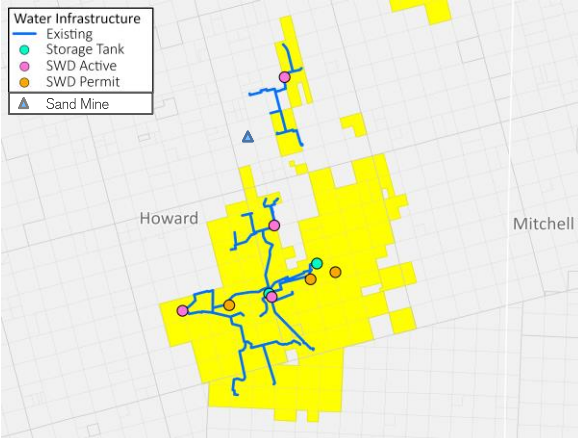
## Electrical Infrastructure




## Water Infrastructure

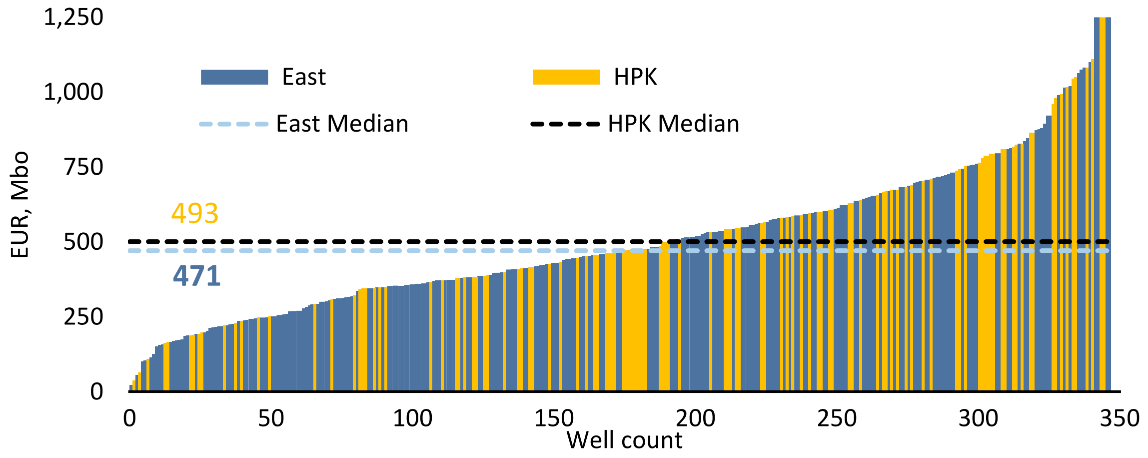


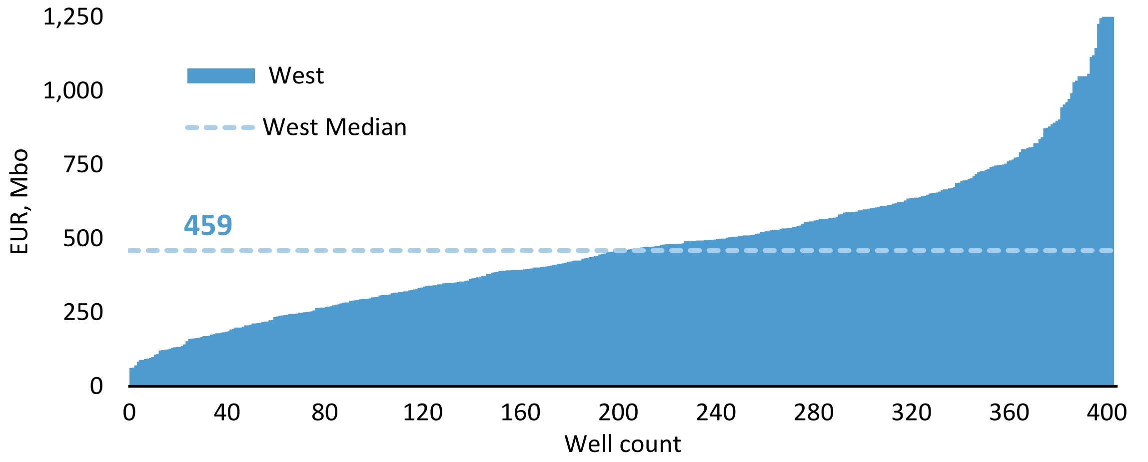
# HighPeak Exhibiting Leading Results in Howard and South Borden Counties

Oil EUR Distributions per Enverus Relative to HPK Results

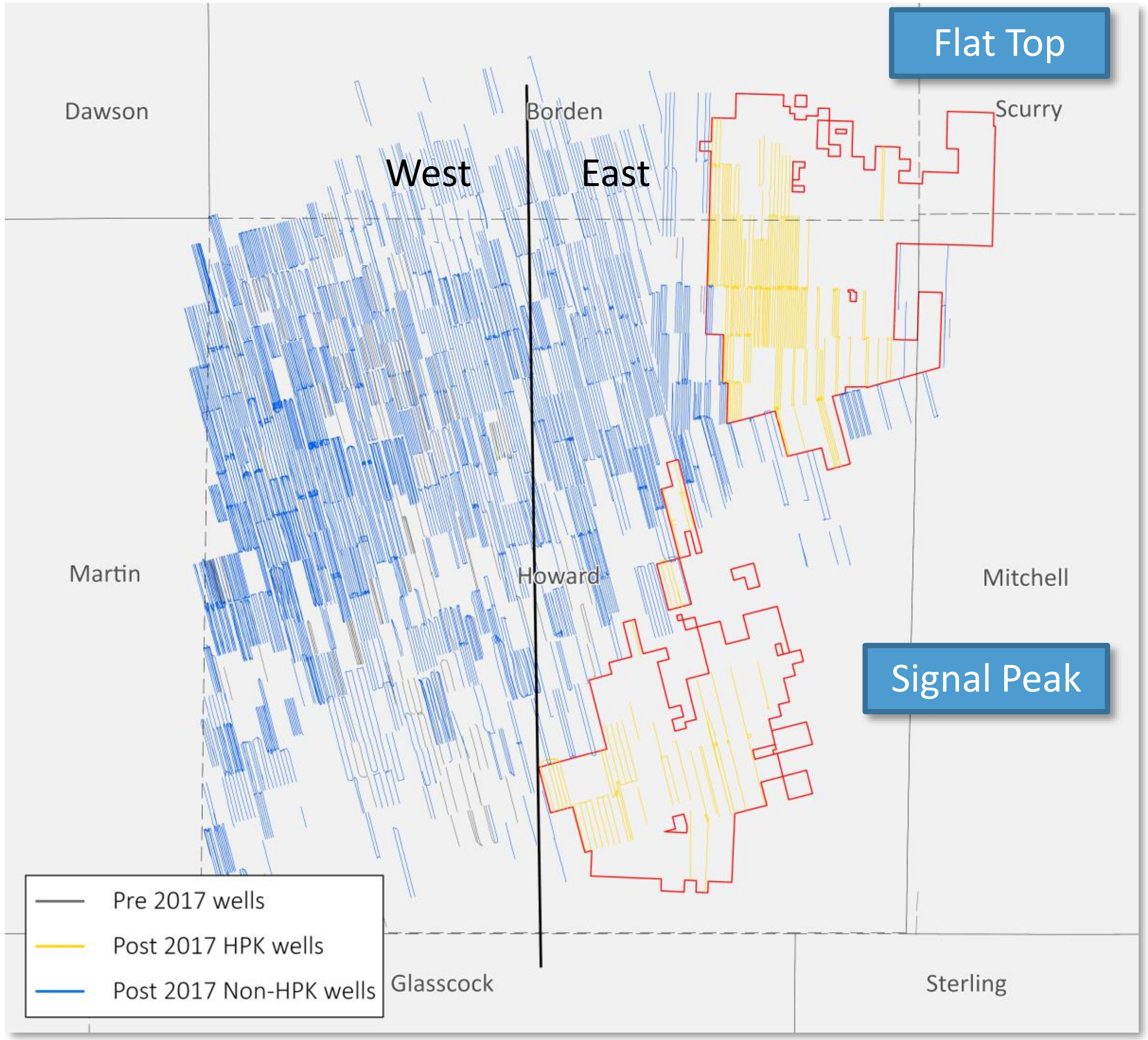
## East Howard & South Borden Oil EUR Distribution




## 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 Checks All the Boxes

| | |
|---|---|
| **Operational Scale** | ▪ 113,600 net acres in two highly contiguous blocks in the Midland Basin<br>▪ First quarter year over year production growth of > 200% |
| **Inventory Quality and Depth** | ▪ 2,500 total gross locations; primary delineated inventory of 1,300 gross locations<br>▪ > 14-year primary inventory life at 4-rig cadence |
| **Peer Leading Margins** | ▪ Peer leading margins and cost structure among public companies in the Permian Basin<br>▪ 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<br>▪ 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(1)

| | 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.

# Substantial Inventory[1]

Results Driven By Excellent Reservoir Performance Across Multiple Targets

HIGHPEAK ENERGY

**~ 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[2]
- ~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)

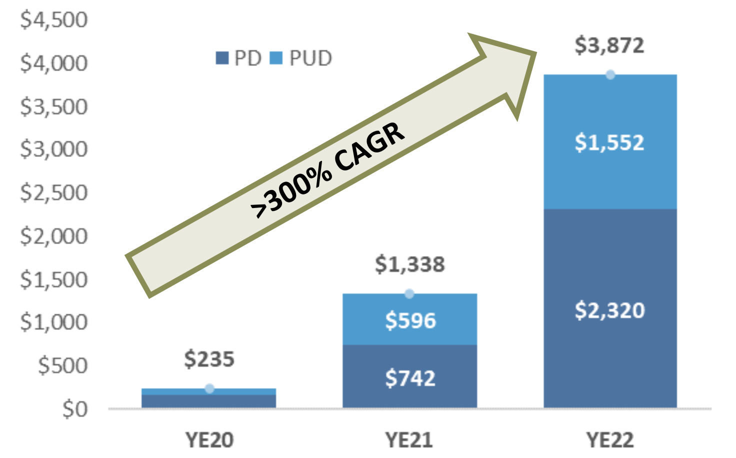
| | Flat Top | | Signal Peak | | Total | | |
|---|---|---|---|---|---|---|---|
| | Primary | Upside | Primary | Upside | Primary | Upside | All |
| **Middle Spraberry** | - | 150 | - | 111 | - | **261** | **261** |
| **Jo Mill** | - | 174 | - | 111 | - | **285** | **285** |
| **Lower Spraberry** | 182 | - | 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 (1)(2)

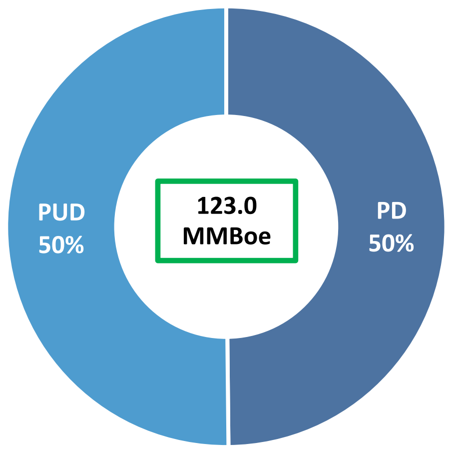
2022 SEC Pricing - $93.67/Bbl & $6.358/MMBtu

**PV10 ($mm)**

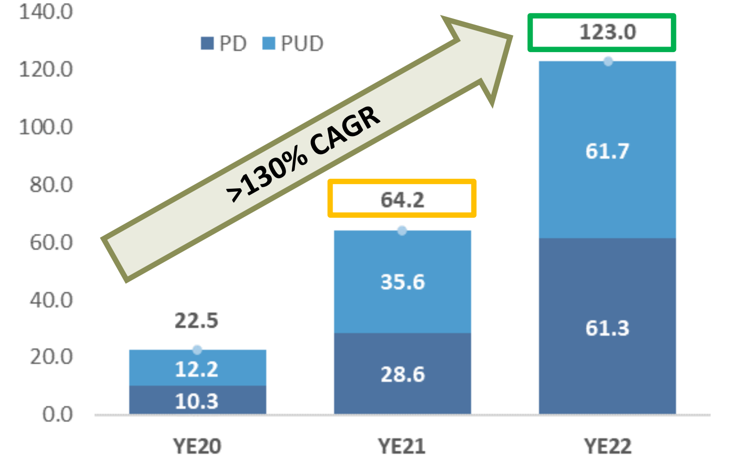



- Multi-year drilling program has driven significant reserves additions and PV10 growth
- 2022 Replacement Ratio(3)
  - Drill Bit: 546%
  - Drill Bit + Acquisitions: 757%

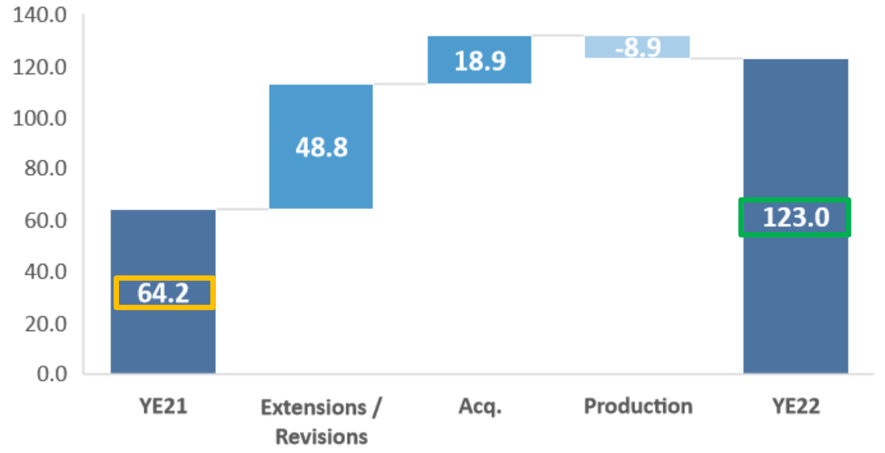
**YE22 Proved Reserves by Category**



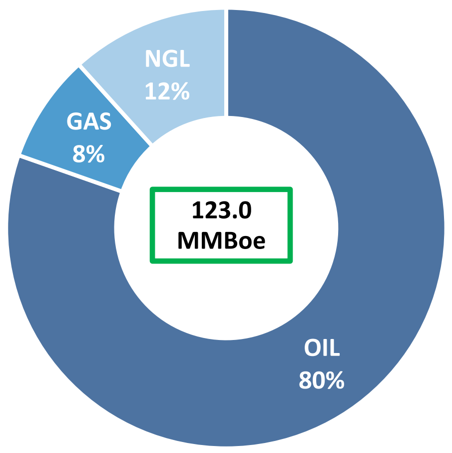

**Net Reserves (MMBoe)**




**Proved Reserves (MMBoe)**




**YE22 Proved Reserves Mix**



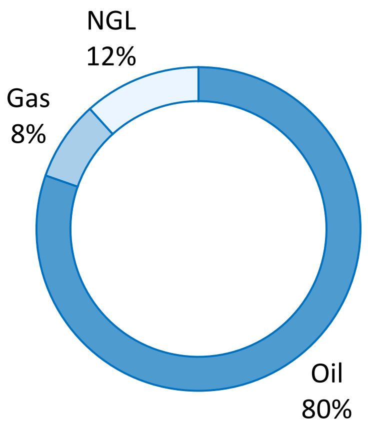

(1) Reserves per HighPeak's year-end 2020/2021/2022 third party reserve reports prepared by Cawley Gillespie & Associates ("CGA").
(2) SEC pricing (oil, $/Bbl / gas, $/MMBtu) each report: 2020: $39.57/$1.985, 2021: $66.56/$3.598, 2022: $93.67/$6.358.
(3) Drill Bit Replacement Ratio is defined as reserves 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.

## SEC Pricing: Year-End 2022 Proved Reserves(1)

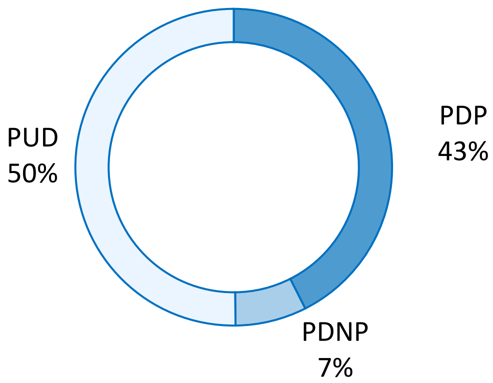
### Year-End 2022 Proved Reserves

| Reserve Category | Net Proved Reserves: Oil (MBbl) | Gas (MMcf) | NGL (MBbl) | Total (MBoe) | % of Total Proved | % Liquids | PV-10 ($MM) |
|---|---|---|---|---|---|---|---|
| Proved Developed Producing (PDP) | 40,428 | 29,028 | 7,042 | 52,308 | 43% | 91% | $1,947 |
| Proved Developed Non-Producing (PDNP) | 7,417 | 3,641 | 927 | 8,950 | 7% | 93% | $373 |
| **Total Proved Developed Reserves** | **47,845** | **32,669** | **7,968** | **61,259** | **50%** | **91%** | **$2,320** |
| Proved Undeveloped (PUD) | 50,971 | 25,968 | 6,401 | 61,699 | 50% | 93% | $1,552 |
| **Total Proved Reserves** | **98,816** | **58,638** | **14,369** | **122,958** | **100%** | **92%** | **$3,872** |

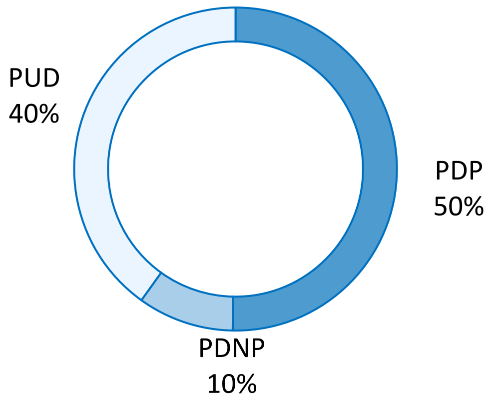
**Proved Net Reserves by Commodity**




**Proved Net Reserves by Category**

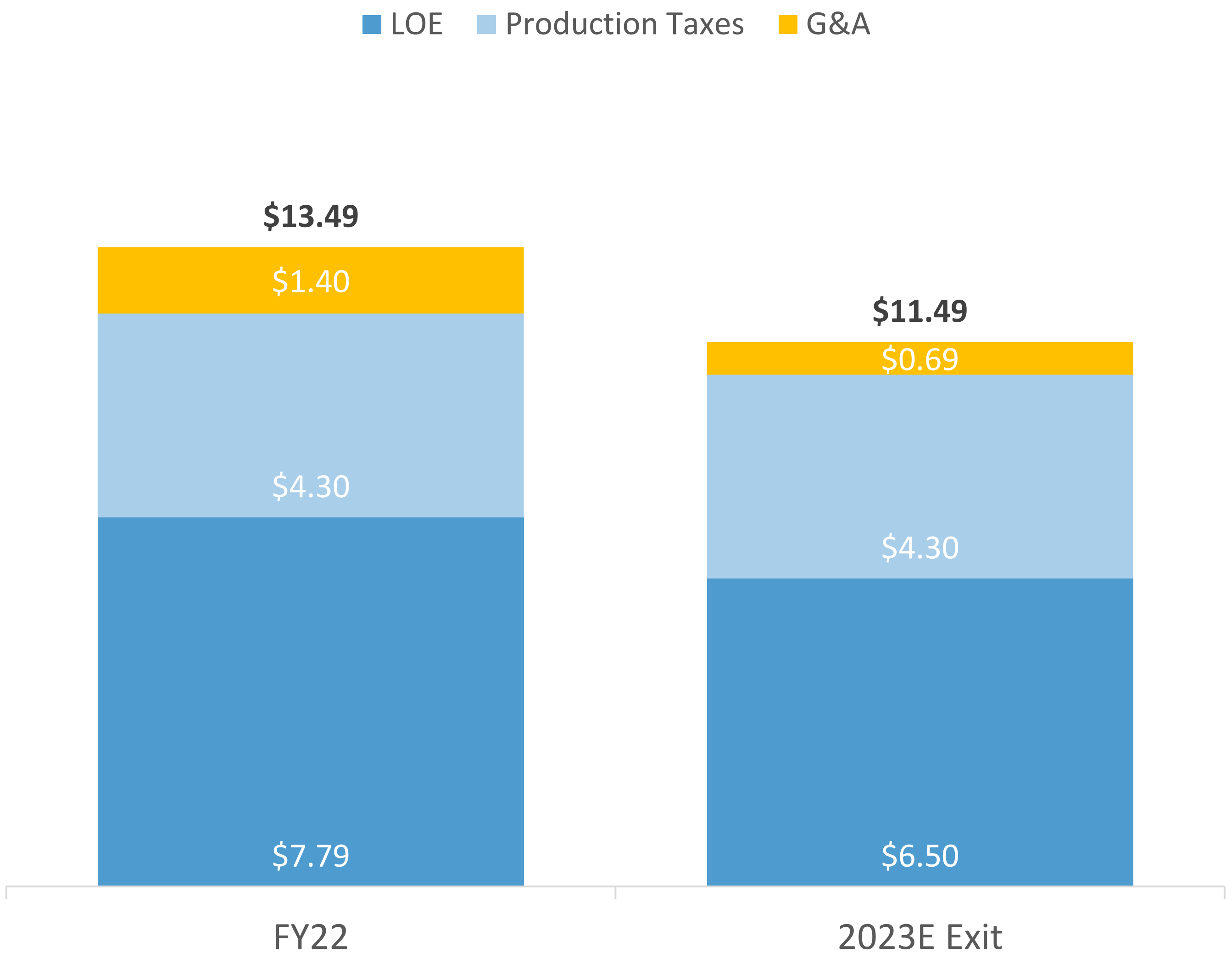



**Proved PV-10 by Category**




(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.

# Improving Costs Per BOE




## 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

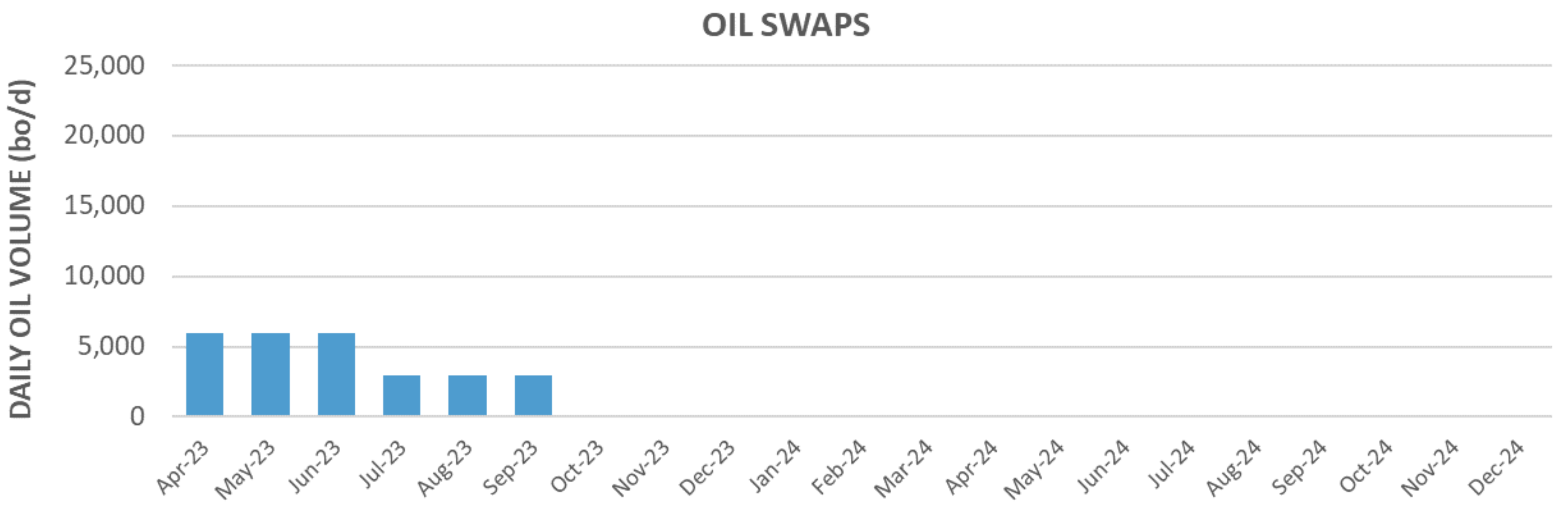
Note: All forward-looking metrics based on company estimate for 2023E Exit. Cash flows calculated using flat $80 WTI / $4 HH price deck.

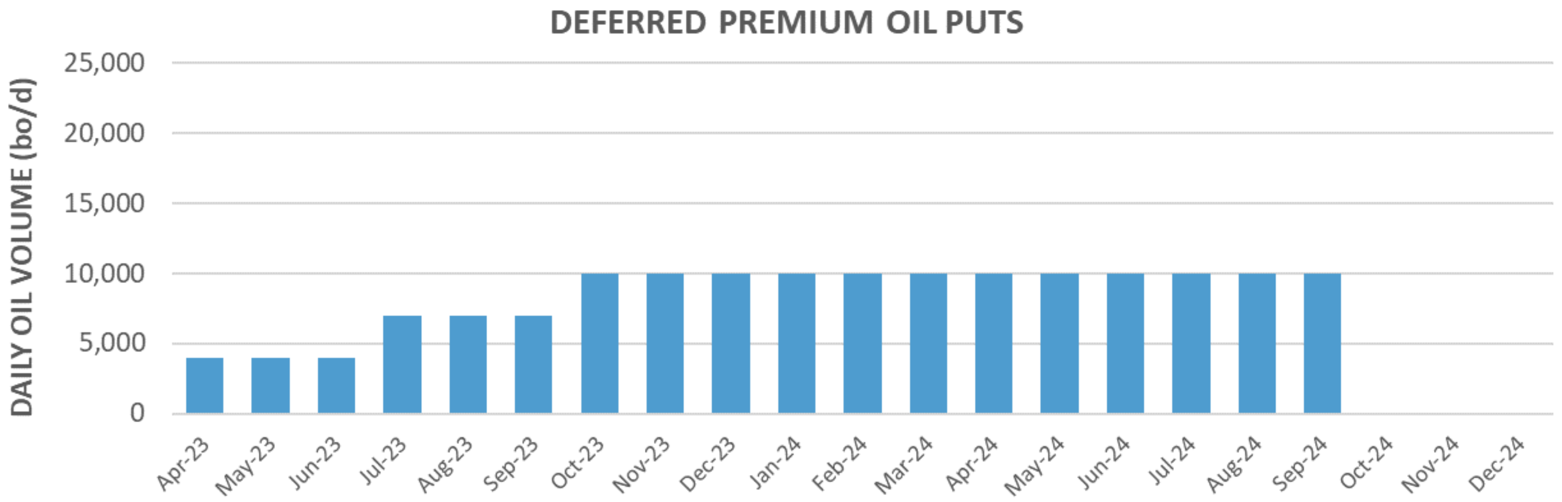
## Hedges[1]

### 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 (Mbbl) | Price | VOL (Mbbl) | Price |
| 2023/Q2 | 546 | $67.81 | 364 | $61.05 |
| 2023/Q3 | 276 | $72.30 | 644 | $60.46 |
| 2023/Q4 | | | 920 | $55.97 |
| **2023** | **822** | **$69.32** | **1,928** | **$58.43** |
| 2024/Q1 | | | 910 | $53.83 |
| 2024/Q2 | | | 910 | $53.83 |
| 2024/Q3 | | | 920 | $53.83 |
| 2024/Q4 | | | | |
| **2024** | | | **2,740** | **$53.83** |




Includes all hedges through 5/10/23.

# Q1 2023 Summary

| 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 |
| *Total per Boe (including derivatives)* | *$66.15* |
| **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 |
| *Cash margin (including derivatives)* | $51.90 |

| Earnings | Q1 2023 |
|---|---|
| Net Income ($MM) | $50.3 |
| *GAAP Earnings (per diluted share)* | *$0.39* |
| EBITDAX ($MM) | $173.9 |
| *EBITDAX (per diluted share)* | *$1.34* |
| **Other** | |
| Capex ($MM)[(1)] | $379.1 |
| Rig Released[(2)] / Turn in Line | 26 / 32 |

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

# Non-GAAP Reconciliation

## 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 | | | |
| **EBITDAX** | **$ 72,389** | **$ 220,867** | **$ 173,859** |
| Cash G&A | 3,843 | 6,637 | 2,502 |
| **Adjusted EBITDAX** | **$ 76,232** | **$ 227,504** | **$ 176,361** |

## 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) |
| **Cash Margin** | **$ 176,053** |
| Divided by: Production (Mboe) | 3,350.0 |
| **Cash Margin per Boe, excluding effects of derivatives** | **$52.56** |
| | |
| **Cash Margin** | **$ 176,053** |
| Cash G&A | 2,502 |
| Divided by: Production (Mboe) | 3,350.0 |
| **Cash Operating Margin per Boe, before cash G&A and excluding effects of derivatives** | **$53.31** |

## 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 |
|---|---|---|---|
| **Reserves PV-10** | **$235,490** | **$1,338,193** | **$3,872,045** |
| Present value of future income taxes/abandonment costs | ($13,298) | ($219,384) | ($455,537) |
| **Standardized measure** | **$222,192** | **$1,118,809** | **$3,416,508** |