



# First Quarter 2026 Earnings Call Presentation

May 2026



## Disclaimer

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**Forward-Looking Statements.** This presentation contains “forward-looking statements” that express the Company’s opinions, expectations, beliefs, plans, objectives, assumptions or projections regarding future events or future results, in contrast with statements that reflect historical facts. All statements, other than statements of historical fact, included in this presentation regarding the Company’s strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management, future commodity prices, future production targets, leverage targets or debt repayment, hedging strategy, future capital spending plans, capital efficiency, our ability to make share repurchases, expected drilling and completions plans and projected well costs are forward-looking statements. When used in this presentation, words such as “may,” “assume,” “forecast,” “could,” “should,” “will,” “plan,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “target,” “outlook,” “guidance,” “budget” and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. Such statements are subject to a number of assumptions, risks and uncertainties, including those incident to the development, production, gathering and sale of natural gas, oil and NGLs, most of which are difficult to predict and many of which are beyond the control of the Company. These include, but are not limited to, our failure to realize, in full or at all, the anticipated benefits of capital raising transactions and acquisitions, including synergies; commodity price volatility; inflation; lack of availability and cost of drilling, completion and production equipment and services; supply chain disruption; project construction delays; environmental risks; drilling, completion and other operating risks; lack of availability or capacity of midstream gathering and transportation infrastructure; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital; the timing of development expenditures; the concentration of the Company’s operations in the Appalachian Basin; difficult and adverse conditions in the domestic and global capital and credit markets; impacts of geopolitical events and world health events, including trade wars; lack of transportation and storage capacity as a result of oversupply, government regulations or other factors; potential financial losses or earnings reductions resulting from the Company’s commodity price risk management program or any inability to manage its commodity risks; failure to realize expected value creation from property acquisitions and trades; weather related risks; competition in the oil and natural gas industry; loss of production and leasehold rights due to mechanical failure or depletion of wells and the Company’s inability to re-establish production; the Company’s ability to service its indebtedness; political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, armed conflicts, political instability and civil unrest, including instability in the Middle East, Venezuela and Mexico and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage; evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; risks related to the Company’s ability to expand its business, including through the recruitment and retention of qualified personnel; and the other risks described under the heading “Risk Factors” in the Company’s filings with the Securities and Exchange Commission (the “SEC”), including its most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

As a result, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements. Therefore, these forward-looking statements are not a guarantee of the Company’s performance, and you should not place undue reliance on such statements. All forward-looking statements, expressed or implied, included in this presentation are expressly qualified in their entirety by this cautionary statement. Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except to the extent that disclosure is required by law.

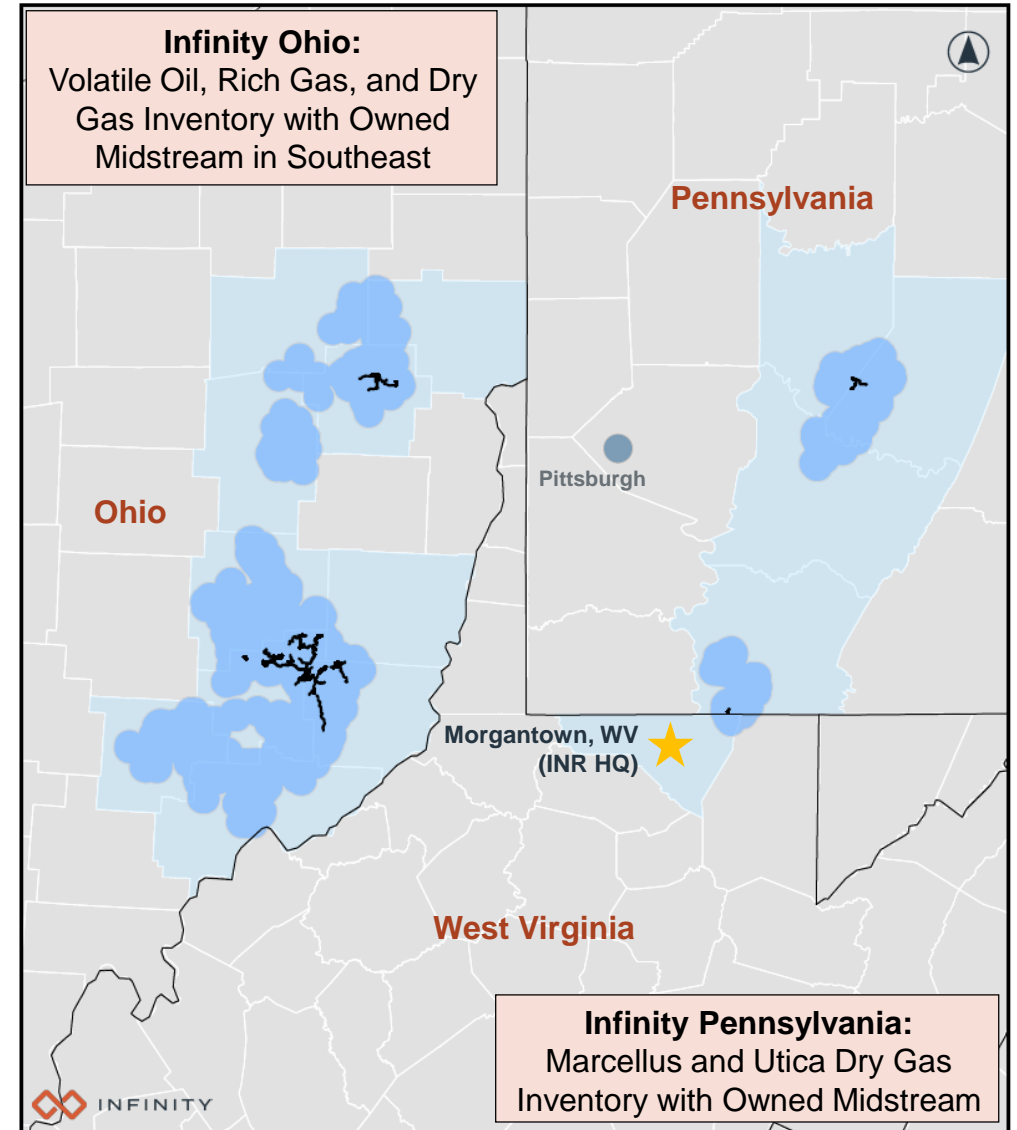
**Reserves.** The Company’s proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. Reserve engineering is a process of estimating underground accumulations of oil and natural gas 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 reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, the Company’s reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered. You should not assume that the present values referred to in this presentation represent the actual current market value of our oil, natural gas and NGL reserves. You are urged to consider closely the oil and natural gas disclosures in the Company’s filings with the SEC, including its most recent Annual Report on Form 10-K.

**Non-GAAP Measures.** This presentation includes certain non-GAAP financial measures, such as Adjusted EBITDAX, Adjusted EBITDAX Margin, PV-10, Capital Efficiency Ratio, F&D, DROI, Net Leverage and Net Debt. Because not all companies calculate non-GAAP financial measures identically (or at all), the non-GAAP financial measures included herein may not be comparable to other similarly titled measures used by other companies. Further, such non-GAAP financial information should not be considered as a substitute for the historical financial information prepared in accordance with GAAP included herein or provided in connection herewith. Please see the appendix of this presentation for definitions and reconciliations of such non-GAAP financial measures.



# High Growth, High Return Pure Play Appalachian Operator

- Pure Play Appalachian Operator**
  - ~175,000 net horizon acres balanced across Ohio and Pennsylvania
  - Greatest exposure to emerging **volatile oil window** in Ohio and **deep dry gas Utica window** in PA
- Fastest Growing Appalachian Operator across Oil and Gas**
  - Fastest growing public Appalachian producer
  - 88%** overall production growth in 1Q26 vs. 1Q25<sup>(1)</sup>
  - Added 48,000 net horizon acres in 1Q26**<sup>(1)</sup>
- Balanced, Top Tier Inventory Quality and Depth**
  - ~10 to 12 years of drilling inventory balanced across natural gas and oil weighted opportunities (2 rig pace)
  - Leading capital efficient Appalachian operator<sup>(2)</sup>
- Strong Operating Margins Support Balance Sheet Strength**
  - \$3.61 / Mcfe Adjusted EBITDAX margin** for 1Q26, bolstered by natural gas prices, liquids weighting and owned midstream<sup>(2)</sup>
  - ~1.2x net leverage** LQA with long term target <1.0x<sup>(2)</sup>
- Regionally Located Team with Vast Experience**
  - Deep Appalachian roots backed by seasoned board
  - Multi decade operating experience across Appalachia



1. Includes the impact of Antero and Chase acquisitions.

2. Capital efficiency, Adjusted EBITDAX margin and net leverage are non-GAAP measures. See appendix for additional details. Adjusted EBITDAX Margin for 1Q26 equals Adjusted EBITDAX of \$97.3 million divided by total production of 26,933 Mmcf.



# Continuing to Execute on Plan: First Quarter 2026 Results

	1Q26	1Q25
Total Production Volumes	299 MMcfe/d	159 MMcfe/d
Net Revenues	\$154.9 million	\$85.2 million
Operating Costs	\$32.4 million	\$20.1 million
Adjusted EBITDAX <sup>(1)</sup>	\$97.3 million	\$57.2 million
Incurred Development Capital Expenditures	\$110.7 million	\$81.6 million
Net Leverage <sup>(1)</sup> (Net Debt / LQA Adj. EBITDAX)	1.2x	0.0x

## Key Highlights

- **Added second rig in January and second frac fleet in March**
- **Spudded 7 wells totaling ~107,000 lateral feet**
  - 3 volatile oil wells in Ohio, 4 dry gas PA Marcellus wells
- **Stimulated 11 wells totaling ~162,000 lateral feet**
  - 8 volatile oil wells in Ohio and 3 rich gas wells in Ohio
- **TIL 4 oil weighted wells in Ohio during second half of first quarter**
  - 2 wells in Carroll County and 2 wells in Guernsey County
- Added ~5,500 net horizon acres during 1Q26, excluding Antero acquisition
- Midstream expansion continuing as planned in Pennsylvania and on acquired Ohio assets
  - Generated first revenues from 3<sup>rd</sup> party volumes in 1Q26
- Issued \$550 million of senior unsecured notes due 2031, \$350 million of convertible preferred stock and expanded credit facility to \$875 million
- \$929 million in liquidity with pro forma LQA net leverage of ~1.2x<sup>(1)</sup>

1. Adjusted EBITDAX and net leverage are non-GAAP measures. See appendix for additional details.



# Why Own Infinity Natural Resources

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**“A differentiated Appalachian E&P combining rare production growth with an integrated, high-margin operating platform.”**

## Balanced High-Quality Portfolio

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- \$3.4 Billion Economic Projects >2.0x DROI<sup>(1)</sup>
- Ohio Utica assets with exposure to oil-weighted, liquids-rich, and dry gas inventory
- Pennsylvania assets with exposure to stacked-pay Marcellus and Deep Utica inventory

## Expansive Midstream System

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- Upstream & Midstream integration in PA and acquired OH assets
- Control over gathering, processing, and marketing
- Structurally competitive cost advantages
- Lower breakevens through scale and integrated midstream

## Operational Flexibility

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- Capital flexibility to shift development across oil, liquids-rich, and dry gas in response to commodity price volatility
- Deep inventory enables cycle-driven capital allocation
- Enhances returns through commodity cycles

## Basin-Leading Profitability

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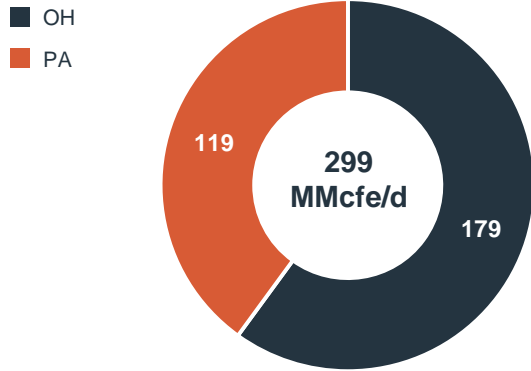
- Basin-leading Appalachian EBITDA margins per Mcfe
- Low F&D costs drive best-in-class capital efficiency
- High-margin resource base across the Utica and Marcellus

1. DROI is a non-GAAP measure. See appendix for additional details.

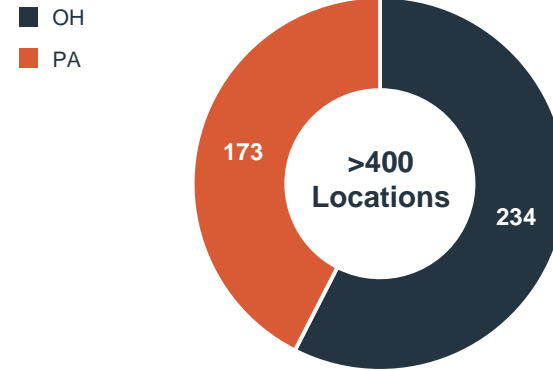


# Balanced, High Quality Portfolio

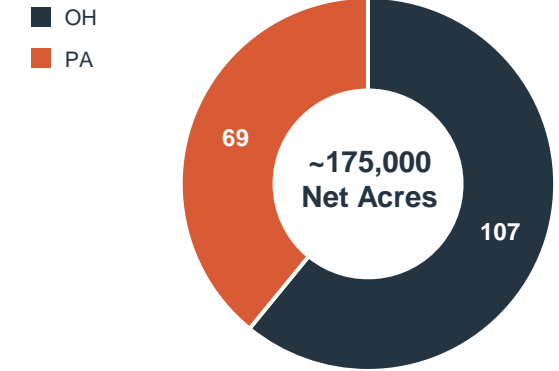
### 1Q26 Net Production (MMcfe/d)



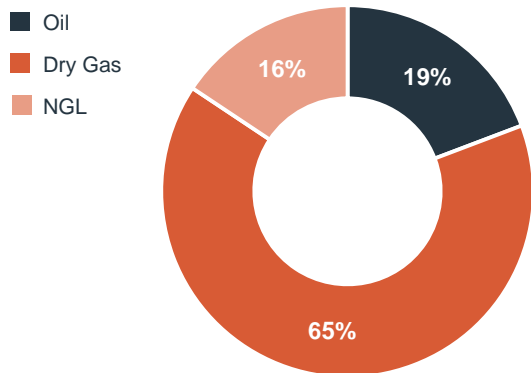
### Location Count by State<sup>(1)</sup>



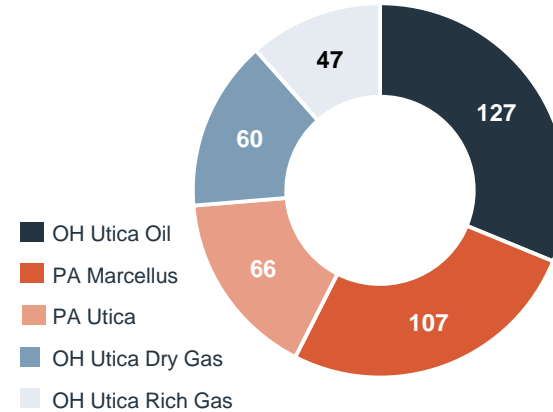
### Net Horizon Acres by State (000's)



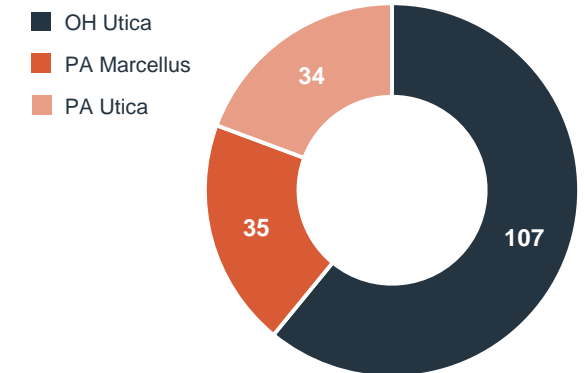
### 1Q26 Production Mix (%)



### Location Count by Operating Area<sup>(1)</sup>



### Net Horizon Acres by Reservoir (000's)



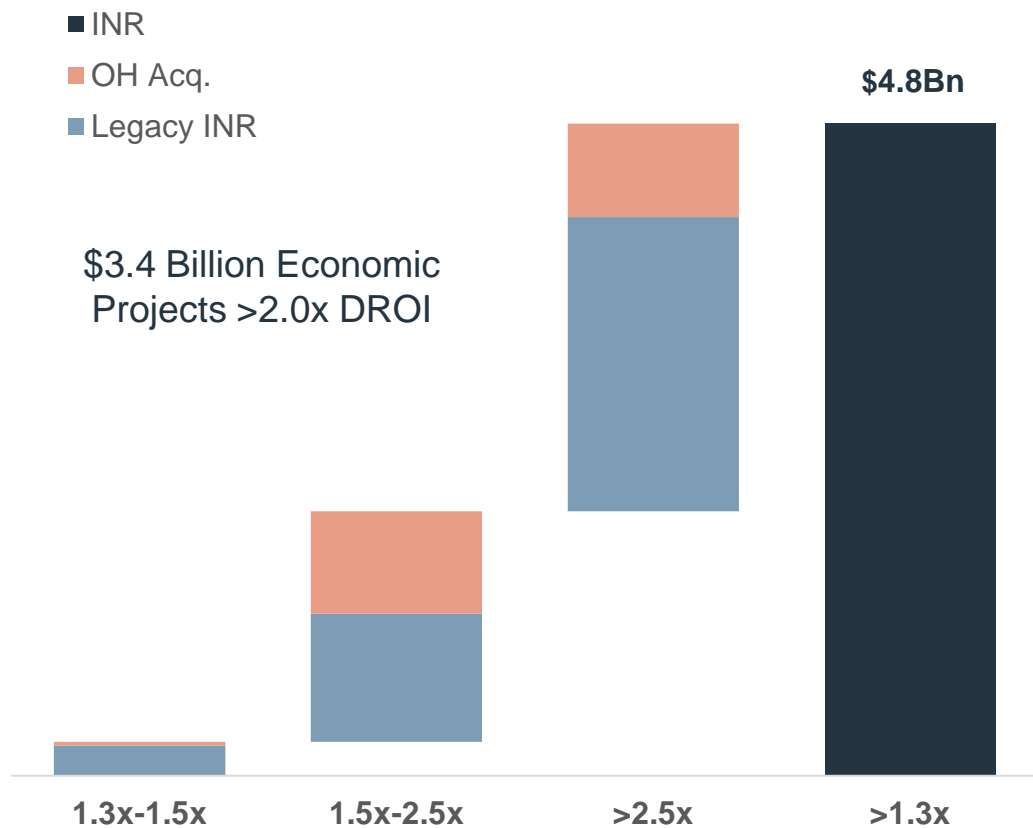
**Assets are uniquely positioned providing high return resource exposure to oil, rich gas, and dry gas drilling inventory**

1. Location counts include all wells in process ("WIPs") and undeveloped locations

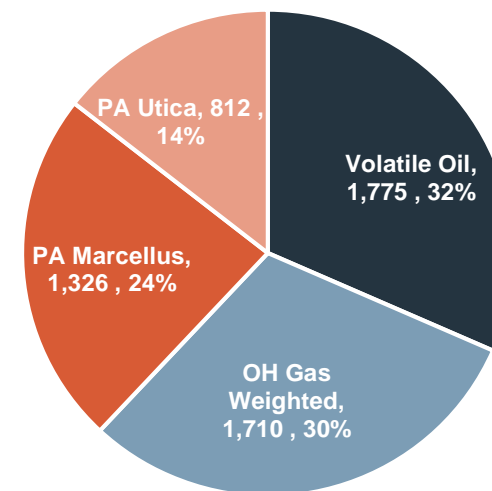


# Expansive High DROI(x) Inventory Across Operating Areas

Economic Capital Projects by DROI<sup>(1)</sup>



Total Inventory Lateral Footage by Area (Mft. , %)



*Acquisition adds substantial lateral footage in Ohio's dry gas, rich gas, and oil windows extending INR's highly economic inventory base*

Note: All type curves reflect internal forecasts. Well costs and operating costs are internal projections. Revenue is based on \$65/bbl WTI and \$4.00/MMBtu Henry Hub  
 1. DROI is a non-GAAP measure. See appendix for additional details.



# Expansive Company Owned Midstream System

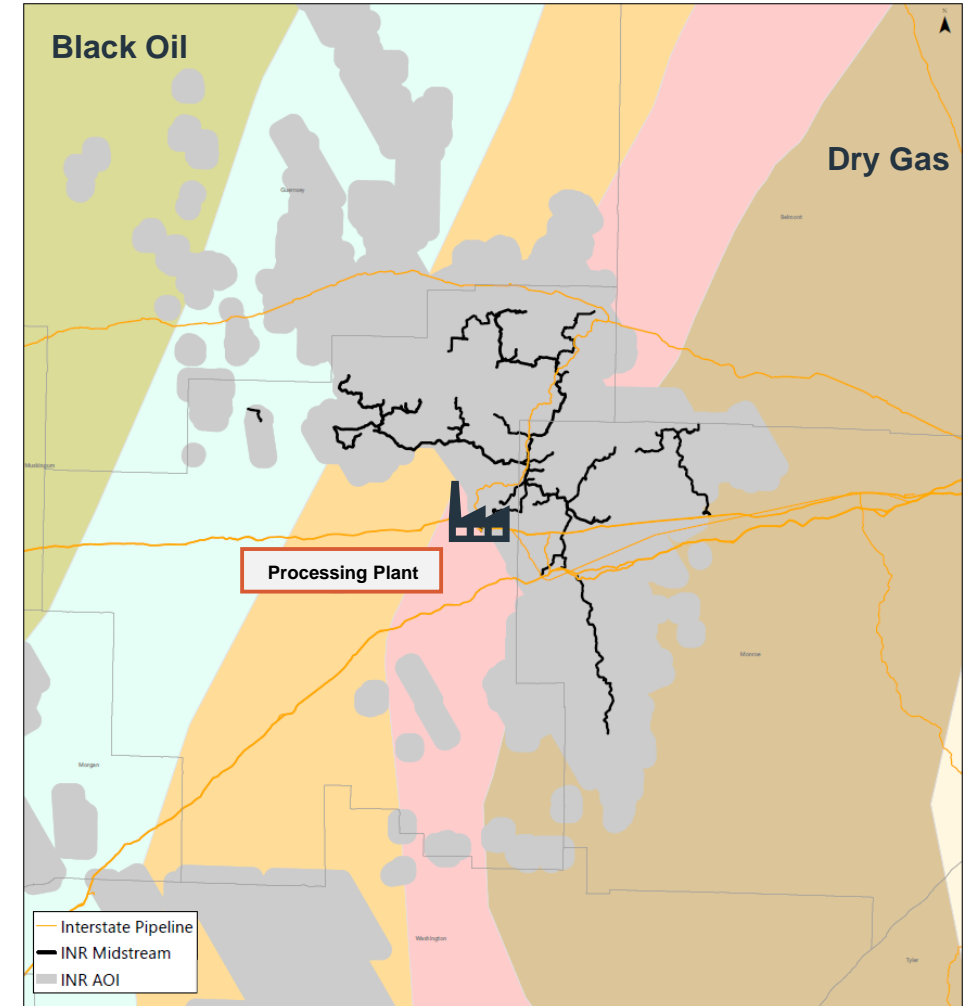
## Key Highlights

- ~1 Bcf/d of throughput capacity capable of supporting INR growth thru end of decade
- 75% of INR net operated natural gas volumes flowing through system
- Vast operational reach supporting operating flexibility and development
- Significantly reduces well breakeven levels in Ohio and Pennsylvania

## Ohio Compressor Station – Noble County



## Ohio Midstream System

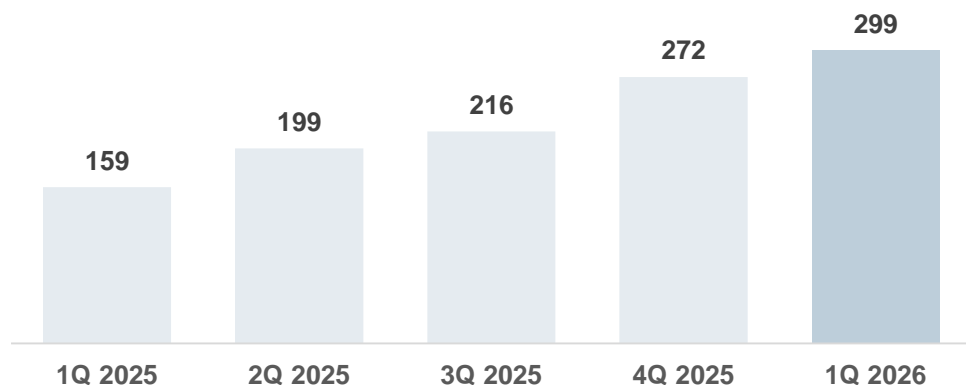




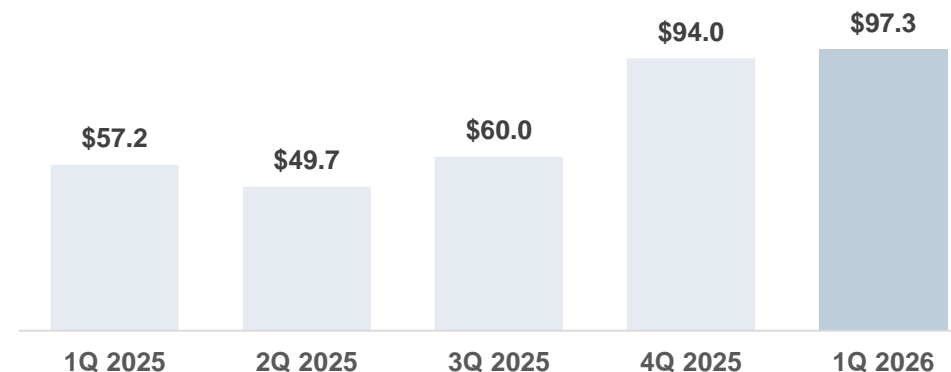
# Delivering Growth with Leading Margins

- **88% production growth** from 1Q25, driven by gas-weighted development in 2025 and strategic acquisitions in 1Q26
- Production growth and increasing natural gas weighting continuing to drive operational costs lower – **down 14% year over year**

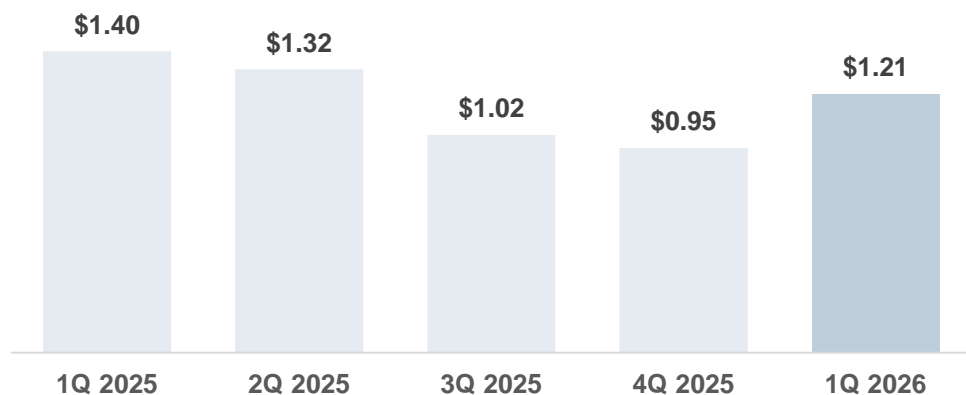
## Total Production (MMcfe/d)



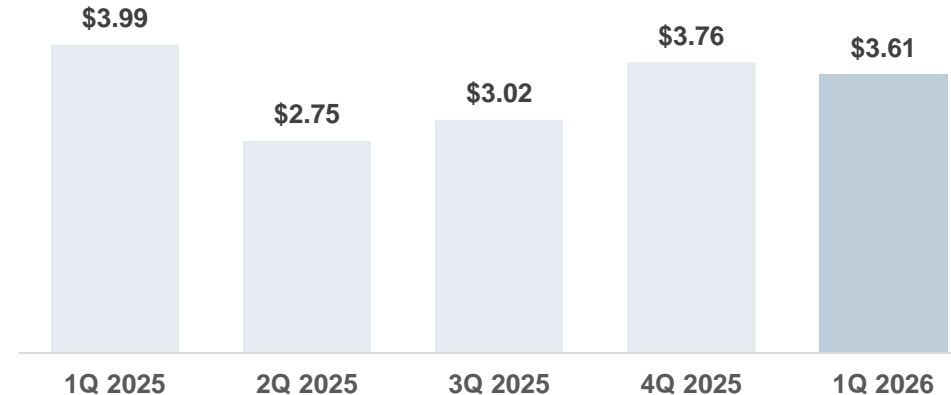
## Adjusted EBITDAX<sup>(1)</sup> (\$MM)



## Operating Expenses (\$ / Mcfe)



## Adjusted EBITDAX Margin<sup>(1)</sup> (\$ / Mcfe)

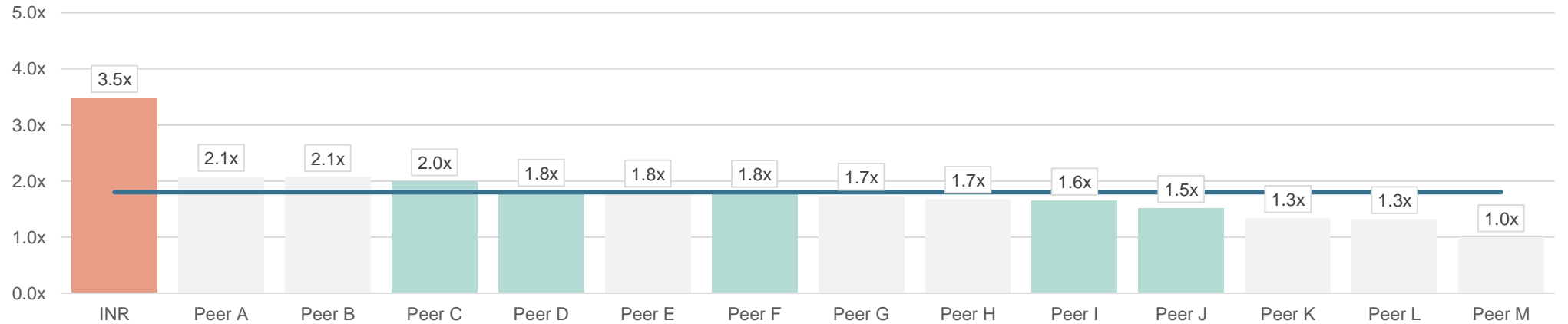


1. Adjusted EBITDAX and Adjusted EBITDAX Margin are non-GAAP measures. See appendix for additional details.

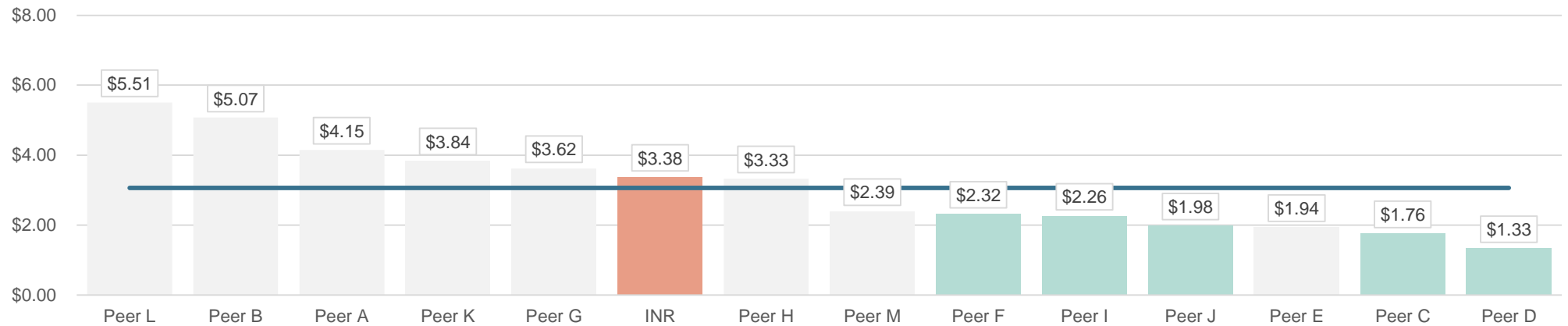


# Generating Leading Capital Efficiency

## 3 Year Average Capital Efficiency Ratio (x)<sup>(1)(2)</sup>



## 2025 EBITDAX Margin (\$ / mcfe)<sup>(1)(2)</sup>



**Leading Adj. EBITDAX margin amongst Appalachian peers driven by product mix and low-cost operating structure**

Source: Company filings, SEC filings and company websites.  
 1. Capital Efficiency Ratio and Adjusted EBITDAX Margin are non-GAAP measures. See appendix for additional details.  
 2. Peer list includes AR, CHRD, CNX, CRGY, CRK, EQT, EXE, GPOR, MGY, MTDR, NOG, PR, and RRC. Green represents Appalachian Basin peers.



# Near Term Development Assets Across Our Portfolio

	Volatile Oil Utica (OH)			Rich Gas Utica (OH)			Dry Gas Marcellus (PA)			Deep Dry Gas Utica (PA)			Total Company		
	1Q26	2Q26	2026E	1Q26	2Q26	2026E	1Q26	2Q26	2026E	1Q26	2Q26	2026E	1Q26	2Q26	2026E
<b><u>Wells Spud</u></b>															
Gross Wells	3.0	8.0	20.0	-	2.0	13.0	4.0	2.0	9.0	-	1.0	1.0	7.0	13.0	43.0
Net Wells	2.1	7.0	15.1	-	1.2	6.4	4.0	2.0	8.8	-	1.0	1.0	6.1	11.2	31.3
Total Lateral Footage (ft)	44,000	133,000	332,000	-	27,000	131,000	63,000	28,000	134,000	-	10,000	10,000	107,000	198,000	607,000
Avg. Lateral (ft)	15,000	17,000	17,000	-	14,000	10,000	16,000	14,000	15,000	-	10,000	10,000	15,000	15,000	14,000
<b><u>Wells Completed</u></b>															
Gross Wells	8.0	7.0	19.0	3.0	-	12.0	-	3.0	6.0	-	-	-	11.0	10.0	37.0
Net Wells	7.8	5.7	16.9	1.7	-	6.3	-	3.0	6.0	-	-	-	9.4	8.7	29.1
Total Lateral Footage (ft)	109,000	89,000	286,000	53,000	-	144,000	-	47,000	91,000	-	-	-	162,000	136,000	521,000
Avg. Lateral (ft)	14,000	13,000	15,000	18,000	-	12,000	-	16,000	15,000	-	-	-	15,000	14,000	14,000
<b><u>Wells Turned-in-Line ("TIL")</u></b>															
Gross Wells	4.0	4.0	15.0	-	3.0	8.0	-	-	6.0	-	-	-	4.0	7.0	29.0
Net Wells	4.0	3.8	13.5	-	1.7	4.5	-	-	6.0	-	-	-	4.0	5.5	24.0
Total Lateral Footage (ft)	53,000	56,000	199,000	-	53,000	110,000	-	-	91,000	-	-	-	53,000	109,000	400,000
Avg. Lateral (ft)	13,000	14,000	13,000	-	18,000	14,000	-	-	15,000	-	-	-	13,000	16,000	14,000

**2026 program weighted towards Ohio development with near term focus on oil-weighted projects**

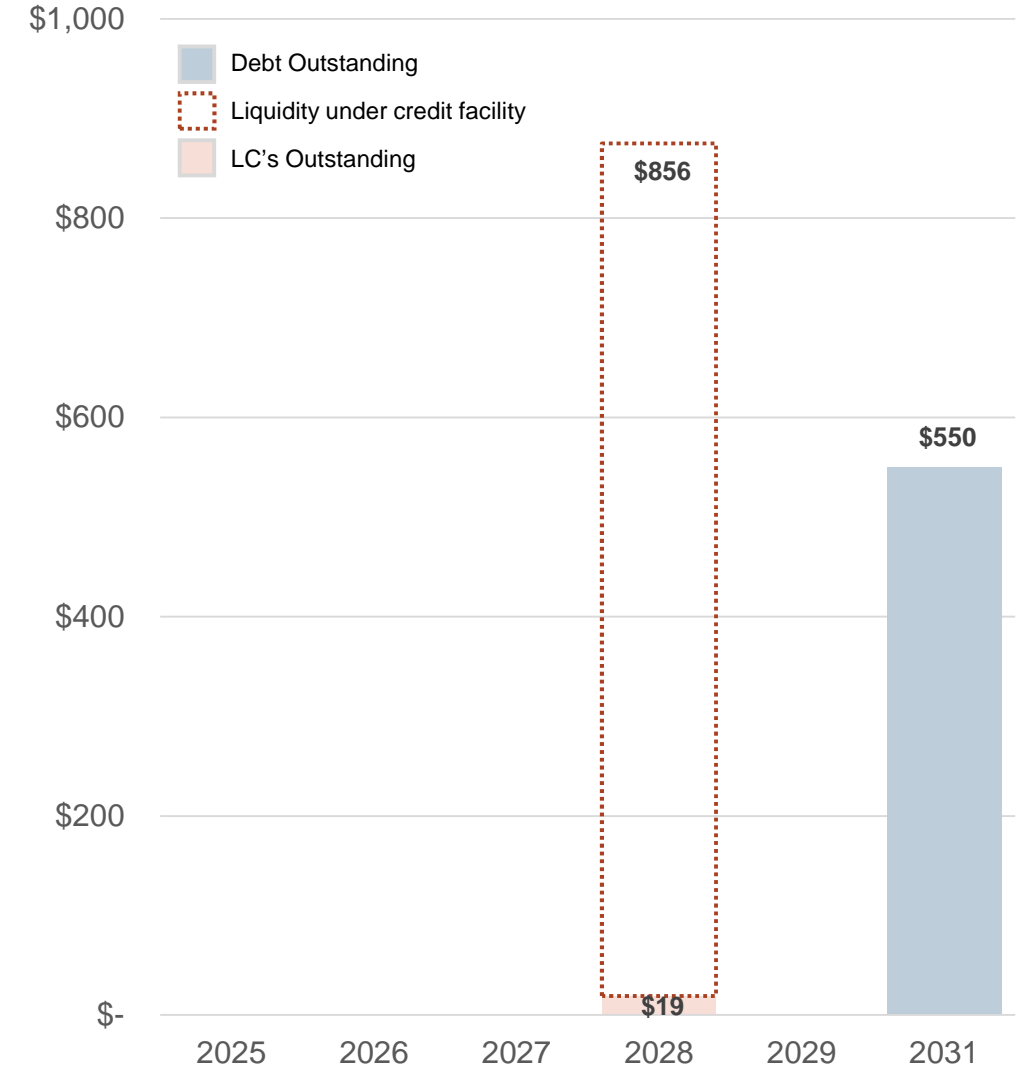
Note: Rich Gas Utica (OH) reflects the assets acquired from Antero.



# Strong Balance Sheet Supports Strategic and Financial Flexibility

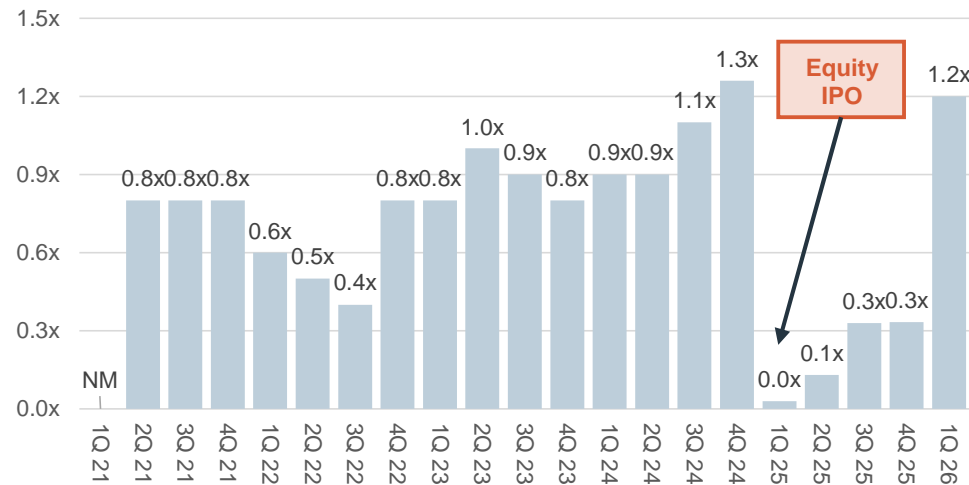
- **Target net leverage of less than 1.0x<sup>(1)</sup>**
- Active hedge program to support forecasted development and cash flow
- \$929 million in liquidity available with largely unfunded revolver and cash on hand
- No near-term maturities

## Significant Liquidity with no Near-Term Maturities



## INR Historically Targets Low Leverage

*Net Debt / LTM Adjusted EBITDAX<sup>(1,2)</sup>*



1. Net debt, Adjusted EBITDAX and net leverage are non-GAAP measures. For a reconciliation to the most directly comparable GAAP measure, see the appendix to this presentation.  
 2. 1Q 2026 represents last quarter annualized to account for Antero EBITDAX contribution from closing on February 23, 2026 through quarter end.



# Appendix



# 2026 Outlook and Guidance

## Net Production

Total Net Production (Mmcfe/d)	345	–	375
Total Natural Gas Net Production (Mmcfe/d)	235	–	255
Total Liquids & Oil Net Production (Mbbls/d)	18	–	20

<b>Incurred Development Capital Expenditures<sup>(1)</sup></b>	<b>\$450</b>	<b>–</b>	<b>\$500</b>
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## Operated Rigs

Operated Rigs	~ 2 Rigs
Legacy INR Asset Base	~ 1 Rigs
Recently Acquired Assets	~ 1 Rigs

## Operated Drilling Program

TILs (Gross)	~30 Wells
Legacy INR Asset TILs (Gross)	~20 Wells
Recently Acquired Assets TILs (Gross)	~10 Wells

## Additional Commentary

- Anticipated to deliver **~70% production** growth year over year at the midpoint of the range
- 77% of drilling activity allocated to Ohio related projects and 23% to Pennsylvania projects
- Continued focus on development of long laterals across all areas of development with average spudded lateral length in 2026 ~14,000'
- Anticipate total wells drilled lateral footage >600,000 lateral feet while turning into sales >400,000 lateral feet
- Anticipate operating two rigs across asset base with ~1 rig targeting development of recently acquired Ohio assets

1. Incurred Development Capital Expenditures includes well development and midstream capital.



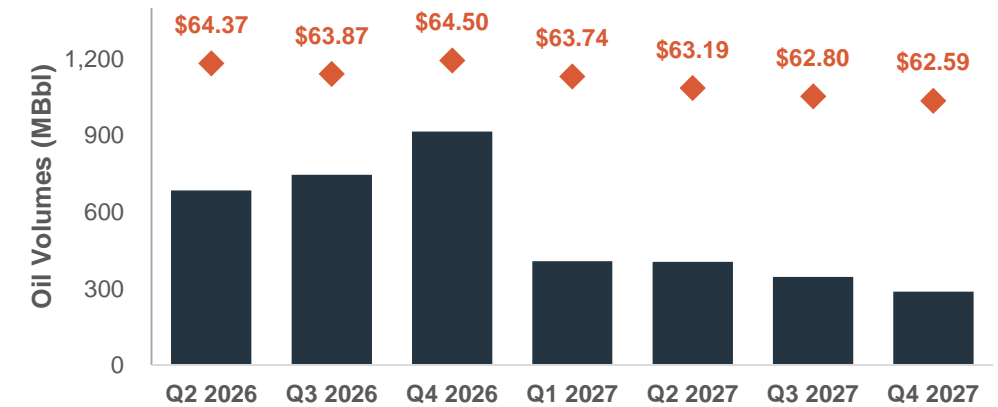
# INR Hedge Position and Philosophy

INR seeks to mitigate commodity fluctuations by actively hedging its anticipated PDP and near-term development production to support cash management and leverage.

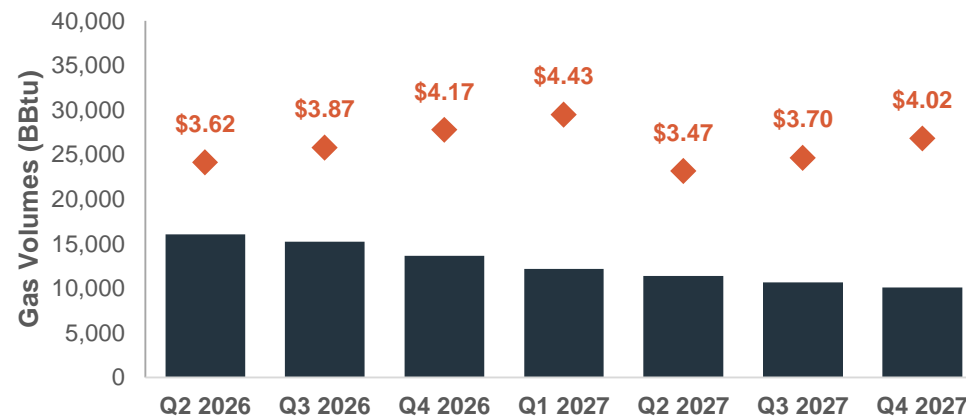
## Hedging Overview

- INR actively hedges within its bank group to secure DROIs and maintain balance sheet strength
- Recent hedging activity has focused on oil and C3+ trades for 2026 and 2027 tracking price increases following start of Iran conflict
- Primarily targeting swaps and collars

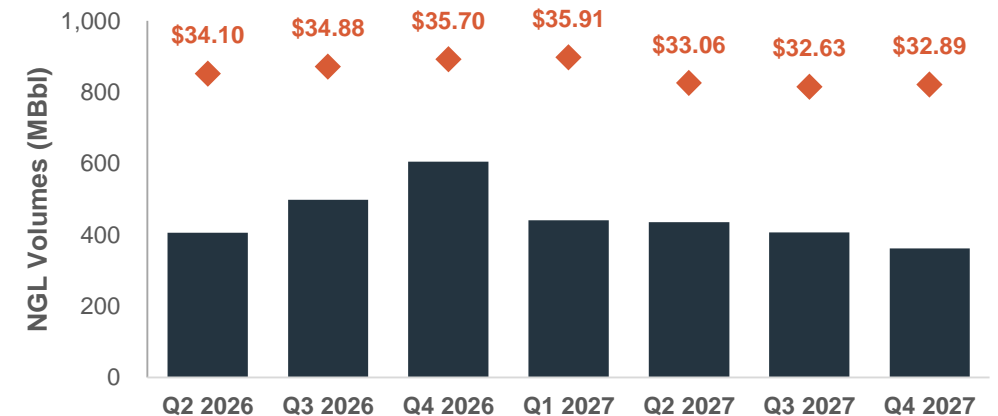
## Oil Hedges



## Natural Gas Hedges<sup>(1)</sup>



## Natural Gas Liquids Hedges



Note: Hedge positions as of 8-May-26.  
 (1) Natural gas hedges represent Henry Hub trades volumes and price



# Hedge Book Overview – As of 8-May-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
<u>WTI Fixed</u>															
Total Volume (MBbl)	634	685	746	916	2,980	408	405	346	289	1,448	98	88	81	73	340
Daily Volume (Bbl/d)	7,039	7,525	8,111	9,951	8,164	4,533	4,453	3,758	3,139	3,966	1,077	967	880	793	929
WAVG Floor Price (\$ / Bbl)	\$63.92	\$64.37	\$63.87	\$64.50	\$64.19	\$63.74	\$63.19	\$62.80	\$62.59	\$63.13	\$70.27	\$69.65	\$69.05	\$68.55	\$69.45
<u>Henry Hub Fixed</u>															
Total Volume (BBtu)	16,061	16,040	15,230	13,644	60,975	12,167	11,390	10,688	10,089	44,334	9,450	8,990	8,670	8,260	35,370
Daily Volume (MMBtu/d)	178,456	176,264	165,543	148,304	167,055	135,189	125,165	116,174	109,663	121,463	103,846	98,791	94,239	89,783	96,639
WAVG Floor Price (\$ / MMBtu)	\$4.31	\$3.62	\$3.87	\$4.17	\$3.99	\$4.43	\$3.47	\$3.70	\$4.02	\$3.91	\$4.26	\$3.29	\$3.56	\$3.90	\$3.76
<u>Dom South Basis</u>															
Total Volume (BBtu)	12,276	11,347	10,137	9,065	42,825	7,131	3,140	3,320	3,280	16,871	2,940	2,780	2,670	2,540	10,930
Daily Volume (MMBtu/d)	136,400	124,692	110,185	98,533	117,329	79,233	34,505	36,087	35,652	46,222	32,308	30,549	29,022	27,609	29,863
WAVG Floor Price (\$ / MMBtu)	(\$0.77)	(\$0.90)	(\$1.21)	(\$1.25)	(\$1.01)	(\$0.76)	(\$0.73)	(\$1.06)	(\$1.05)	(\$0.87)	(\$0.64)	(\$0.82)	(\$1.11)	(\$1.07)	(\$0.90)
<u>Dom South Fixed</u>															
Total Volume (BBtu)	795	2,001	4,544	4,296	11,636	3,220	2,696	2,360	2,096	10,372	-	-	-	-	-
Daily Volume (MMBtu/d)	8,833	21,989	49,391	46,696	31,879	35,778	29,626	25,652	22,783	28,416	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	\$3.70	\$2.83	\$2.99	\$3.12	\$3.06	\$3.60	\$2.62	\$2.60	\$2.84	\$2.96	-	-	-	-	-
<u>Tetco M2 Basis</u>															
Total Volume (BBtu)	473	461	451	436	1,821	366	413	403	385	1,566	1,280	1,228	1,210	1,155	4,873
Daily Volume (MMBtu/d)	5,256	5,066	4,902	4,739	4,989	4,067	4,533	4,375	4,185	4,290	14,066	13,489	13,152	12,554	13,313
WAVG Floor Price (\$ / MMBtu)	(\$0.58)	(\$0.96)	(\$1.19)	(\$1.25)	(\$0.99)	(\$0.58)	(\$0.85)	(\$1.09)	(\$1.08)	(\$0.90)	(\$0.51)	(\$0.83)	(\$1.09)	(\$1.06)	(\$0.86)
<u>REX Zone 3 Basis</u>															
Total Volume (BBtu)	-	4,230	4,640	4,140	13,010	2,775	2,775	2,775	2,775	11,100	4,490	4,366	4,270	4,158	17,284
Daily Volume (MMBtu/d)	-	46,484	50,435	45,000	35,644	30,833	30,495	30,163	30,163	30,411	49,341	47,981	46,413	45,190	47,223
WAVG Floor Price (\$ / MMBtu)	-	(\$0.41)	(\$0.48)	(\$0.31)	(\$0.40)	\$0.13	(\$0.35)	(\$0.35)	(\$0.24)	(\$0.20)	\$0.18	(\$0.28)	(\$0.33)	(\$0.21)	(\$0.16)



# Hedge Book Overview – As of 8-May-26

	FY 2029					FY 2030					FY 2031				
	Q1	Q2	Q3	Q4	2029	Q1	Q2	Q3	Q4	2030	Q1	Q2	Q3	Q4	2031
<u>WTI Fixed</u>															
Total Volume (MBbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (Bbl/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price (\$ / Bbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Henry Hub Fixed</u>															
Total Volume (BBtu)	7,780	7,600	7,420	7,170	29,970	6,800	6,630	6,530	6,350	26,310	-	-	-	-	-
Daily Volume (MMBtu/d)	86,444	83,516	80,652	77,935	82,110	75,556	72,857	70,978	69,022	72,082	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	\$4.06	\$3.14	\$3.44	\$3.80	\$3.61	-	\$4.02	\$3.10	\$3.37	\$3.73	\$3.56	-	-	-	-
<u>Dom South Basis</u>															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Dom South Fixed</u>															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Tetco M2 Basis</u>															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>REX Zone 3 Basis</u>															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price (\$ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-



# Hedge Book Overview – As of 8-May-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
<u>Ethane Fixed</u>															
Total Volume (MGal)	2,441	2,440	2,294	2,137	9,312	1,902	1,854	1,750	1,610	7,116	-	-	-	-	-
Daily Volume (Gal/d)	27,122	26,813	24,935	23,228	25,512	21,133	20,374	19,022	17,500	19,496	-	-	-	-	-
WAVG Floor Price (\$ / Gal)	\$0.28	\$0.27	\$0.28	\$0.29	\$0.28	\$0.27	\$0.23	\$0.23	\$0.24	\$0.24	-	-	-	-	-
<u>Propane Fixed</u>															
Total Volume (MGal)	5,259	8,306	10,736	13,532	37,833	9,619	9,415	8,725	7,747	35,506	-	-	-	-	-
Daily Volume (Gal/d)	58,433	91,275	116,696	147,087	103,652	106,878	103,462	94,837	84,207	97,277	-	-	-	-	-
WAVG Floor Price (\$ / Gal)	\$0.76	\$0.73	\$0.74	\$0.76	\$0.75	\$0.77	\$0.70	\$0.70	\$0.71	\$0.72	-	-	-	-	-
<u>Normal Butane Fixed</u>															
Total Volume (MGal)	1,547	2,449	2,989	3,603	10,588	2,571	2,597	2,435	2,161	9,764	-	-	-	-	-
Daily Volume (Gal/d)	17,189	26,912	32,489	39,163	29,008	28,567	28,538	26,467	23,489	26,751	-	-	-	-	-
WAVG Floor Price (\$ / Gal)	\$0.87	\$0.88	\$0.89	\$0.91	\$0.89	\$0.94	\$0.84	\$0.83	\$0.84	\$0.86	-	-	-	-	-
<u>IsoButane Fixed</u>															
Total Volume (MGal)	951	1,686	2,263	2,914	7,814	2,092	2,027	1,872	1,657	7,648	-	-	-	-	-
Daily Volume (Gal/d)	10,567	18,527	24,598	31,674	21,408	23,244	22,275	20,348	18,011	20,953	-	-	-	-	-
WAVG Floor Price (\$ / Gal)	\$0.89	\$0.92	\$0.94	\$0.94	\$0.93	\$0.97	\$0.89	\$0.87	\$0.88	\$0.91	-	-	-	-	-
<u>Natural Gasoline Fixed</u>															
Total Volume (MGal)	772	2,162	2,671	3,226	8,831	2,354	2,415	2,276	2,005	9,050	-	-	-	-	-
Daily Volume (Gal/d)	8,578	23,758	29,033	35,065	24,195	26,156	26,538	24,739	21,793	24,795	-	-	-	-	-
WAVG Floor Price (\$ / Gal)	\$1.40	\$1.57	\$1.50	\$1.47	\$1.50	\$1.47	\$1.39	\$1.36	\$1.35	\$1.39	-	-	-	-	-



# Non-GAAP Reconciliations and Definitions

## Adjusted EBITDAX

Adjusted EBITDAX is defined as net income (loss) plus interest, net, income tax expense (benefit), depreciation, depletion, and amortization, unrealized (gain) loss on derivative instruments, net cash settlements received (paid) on derivatives, non-cash compensation expense and non-recurring transaction expenses. Adjusted EBITDAX is presented on our management's belief that this non-GAAP measure is useful information to investors when comparing our operating performance, our ability to fund development activities and to service our incurred debt without regard to our financing methods, corporate form or capital structure. Our computations of Adjusted EBITDAX may differ from and may not be comparable to similarly titled measures of other companies.

Adjusted EBITDAX Margin is defined as Adjusted EBITDAX divided by total production.

## Net Debt and Net Debt to Adjusted EBITDAX (or Net Leverage)

Net Debt is calculated by subtracting cash and cash equivalents from total long-term debt. Net Debt is a non-GAAP measure which our management uses to evaluate our financial position, including our ability to service our debt obligations. Net leverage is calculated as Net Debt divided by Adjusted EBITDAX.

## Adjusted EBITDAX Reconciliation

(\$ in thousands)	Three Months Ended			
	06/30/25	09/30/25	12/31/25	03/31/26
Net Income	\$ 71,954	\$ 40,014	\$ 80,354	\$ (6,343)
Interest, net	1,360	2,290	2,949	5,789
Income tax expense (benefit)	(604)	(3,383)	(922)	(348)
Depreciation, depletion and amortization	23,652	27,579	31,262	35,660
(Gain) loss on derivative instruments	(52,121)	(15,250)	(28,254)	65,134
Net cash settlements received (paid) on deriv.	2,778	6,374	6,647	(17,992)
Non-recurring transaction expenses	2,293	2,253	343	13,452
Non-cash compensation expenses <sup>1</sup>	331	172	1,647	1,912
<b>Adjusted EBITDAX</b>	<b>\$ 49,641</b>	<b>\$ 60,049</b>	<b>\$ 94,025</b>	<b>\$ 97,264</b>

Note: Adjusted EBITDAX is a non-GAAP financial measure.

1. Includes stock-based compensation expense for equity awards related to general and administrative employees only.

## Net Leverage (x)

(\$ in thousands)	Three Months Ending			
	06/30/25	09/30/25	12/31/25	03/31/26
Total debt outstanding	\$ 34,378	\$ 75,363	\$ 150,847	\$ 538,565
Plus: Unamortized Issuance Fees	\$ -	\$ -	\$ -	\$ 11,435
Less: Cash and cash equivalents	\$ (6,282)	\$ (4,572)	\$ (64,049)	\$ (72,983)
Net debt outstanding	\$ 28,096	\$ 70,791	\$ 86,798	\$ 477,017
Quarter Ending Adjusted EBITDAX	\$ 49,641	\$ 60,049	\$ 94,042	\$ 97,264
Last Quarter Annualized Adjusted EBITDAX <sup>1</sup>	\$ 198,564	\$ 240,196	\$ 376,169	\$ 389,056
Net debt to LQA EBITDAX	0.1x	0.3x	0.2x	1.2x

1. Represents adjusted EBITDAX (reconciled in the Appendix) for the three months shown on an annualized basis



# Non-GAAP Reconciliations and Definitions

## Proved Reserves Pre-Tax PV-10

Proved Reserves SEC PV-10 represents the estimated present value of the future cash flows less future development and production costs from our proved and probable reserves before income taxes discounted using a 10% discount rate. PV-10 of proved reserves generally differs from the standardized measure of discounted future net cash flows from production of proved oil and natural gas reserves (the “Standardized Measure”), the most directly comparable GAAP financial measure, because it does not include the effects of future income taxes, as is required under GAAP in computing the Standardized Measure. We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and natural gas companies. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of PV-10 value provides greater comparability when evaluating oil and natural gas companies. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. However, the definition of PV-10 value as defined above may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value as defined may not be comparable to similar measures provided by other companies.

## All-In Finding & Development Costs (“F&D”)

All-In F&D is calculated by dividing total costs incurred (which includes the total acquisition, exploration and development costs incurred during the period related to the specified property or group of properties) by the sum of the extensions, discoveries, additions, revisions, and purchases during that period.

## Proved Reserves Pre-Tax PV-10 (\$mm)

(\$ in thousands)	Fiscal Year Ending December 31,		
	2023	2024	2025
Future cash inflows	\$ 3,865,302	\$ 4,181,440	\$ 5,511,802
Future development costs <sup>1</sup>	(545,803)	(652,135)	(764,219)
Future production costs	(1,281,802)	(1,548,957)	(1,824,402)
Future net cash flow	\$ 2,037,697	\$ 1,980,348	\$ 2,923,181
Discounted future income tax expense	-	-	(531,583)
10% discount to reflect timing of cash flows	(1,099,313)	(1,007,830)	(1,310,404)
Standardized measure of disc. net cash flows	\$ 938,384	\$ 972,518	\$ 1,081,193
<b>Pre-Tax PV - 10</b>	<b>\$ 938,384</b>	<b>\$ 972,518</b>	<b>\$ 1,332,993</b>

## All-in F&D (\$ / mcfe)

(\$ in thousands)	Fiscal Year Ending December 31,		
	2023	2024	2025
<b>Acquisition Costs:</b>			
Proved properties	\$ 274,732	\$ 19,172	\$ 44,585
Unproved properties	1,047	89,174	5,236
Development Costs	144,121	165,795	274,723
Exploration Costs	-	-	-
Total Acquisition and Development Costs	\$ 419,900	\$ 274,143	\$ 324,544
<b>Reserve Additions:</b>			
Extensions	267,450	216,108	402,953
Revisions to previous estimates	(144,414)	9,354	2,198
Purchases of reserves in place	289,164	-	-
Total Reserve Additions	412,200	225,462	405,150
<b>All-In F&amp;D (\$ / mcfe)</b>	<b>\$ 1.02</b>	<b>\$ 1.22</b>	<b>\$ 0.80</b>



# Non-GAAP Reconciliations and Definitions

## Capital Efficiency

Capital Efficiency Ratio means Adjusted EBITDAX per unit of production divided by finding and development costs (“F&D”) per mcfe. F&D is calculated by dividing total costs incurred (which includes the total acquisition, exploration and development costs incurred during the period related to the specified property or group of properties) by the sum of the extensions, discoveries, additions, revisions, and purchases during that period.

## DROI

DROI refers to Discounted Return on Investment, which is defined as the present value at a 10% discount rate of future net cashflows excluding capital expenditures divided by the net capital expenditures associated with the development of a horizontal well.

## Capital Efficiency (x)

(\$ in thousands)	Fiscal Year Ending December 31,		
	2023	2024	2025
Adjusted EBITDAX	\$ 126,494	\$ 195,719	\$ 260,961
Total Net Production (MMcfe)	41,406	52,908	77,292
Adjusted EBITDAX Margin (\$ / mcfe)	\$ 3.05	\$ 3.70	\$ 3.38
All-In F&D (\$ / mcfe)	\$ 1.02	\$ 1.22	\$ 0.80
Capital Efficiency	3.00x	3.04x	4.21x