ENLINK MIDSTREAM

March Investor Presentation

March 2024

Key Takeaways

1. EnLink Is Becoming the Future of Midstream
2. Expanding Legacy Midstream and CCS Businesses
3. Solid 4th Quarter Results, 2024 Financial Guidance
4. Compelling Investment Proposition

EnLink Is Becoming the Future of Midstream

Here's how…

Operating a large-scale, cash-flow-generating midstream platform generates sustainable growth and unitholder returns

- >$1.3 billion Adj. EBITDA[1,2]
- Disciplined, flexible investment approach
- Focus on FCFAD[1] to return capital to investors

Integrated & efficient business model fuels growth opportunities

- Scale G&P positions in key production basins
- Capital efficient expansions in Louisiana demand-driven market
- Increasing gas supply to next wave of export LNG projects

Revolutionizing traditional midstream systems to support the energy transformation

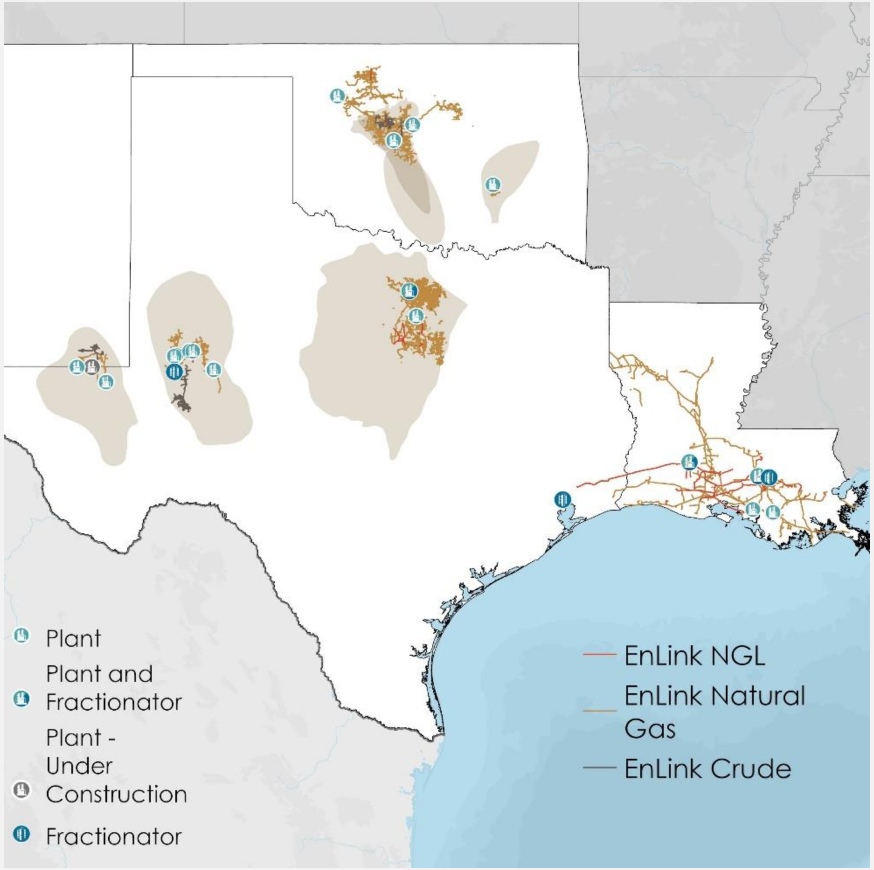
- First mover in CO_2 transportation
- Increasing business mix of energy transformation alongside traditional midstream

Environmentally responsible operations means prioritizing safety and minimizing environmental impacts

- Bridgeport processing plant carbon capture project completed in 4th quarter of 2023
- Sustainability and operational excellence tied into strategic plan and employee incentives

[1]Non-GAAP measures are defined in the appendix. [2]2024 Guidance provided on February 20, 2024.

EnLink Asset Overview



Premier production basins connected to key demand centers

Basin / Geography	Natural Gas	NGL	Crude
Permian Basin	✓	✓	✓
Gulf Coast	✓	✓	
Haynesville	✓		
Anadarko Basin	✓	✓	✓
North Texas	✓	✓	

~1,100
Employees

25
Processing Facilities

~5.8
Bcf/d Processing Capacity

~13,600
Miles of Pipeline

7
Fractionators

~316,000
bbl/d Fractionation Capacity

Note: As of December 31, 2022. Ascension Pipeline is 50% owned by a joint venture with a Marathon Petroleum Corp. subsidiary. Delaware Basin gas G&P assets are 49.9% owned by Natural Gas Partners. EnLink owns 15% of Matterhorn JV, the owner of the natural gas pipeline under construction.

Today's EnLink

2019	TODAY
Traditional Midstream Model	*Creating Sustainable Value in the Energy Transformation*
Higher Leverage: 4.3x	Lower Leverage: 3.3x
Adjusted EBITDA[1]: $1.08B	Adjusted EBITDA[1,2]: $1.31B - $1.41B
Negative FCFAD[1]	Positive FCFAD[1]
Largest Segment: Oklahoma	Largest Segment: Permian[2]
No units repurchased	Repurchased ~9% of common units[3]
	First Mover in CO_2 Transportation

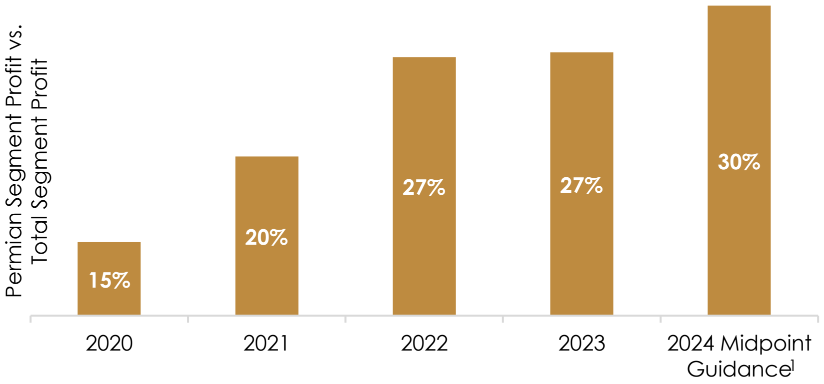
[1]Non-GAAP measures are defined in the appendix. [2]2024 Guidance provided on February 20, 2024. [3]Approximately ~42 million common units repurchased since year-end 2021, when approximately ~484 million common units were outstanding.

Growing Permian Footprint

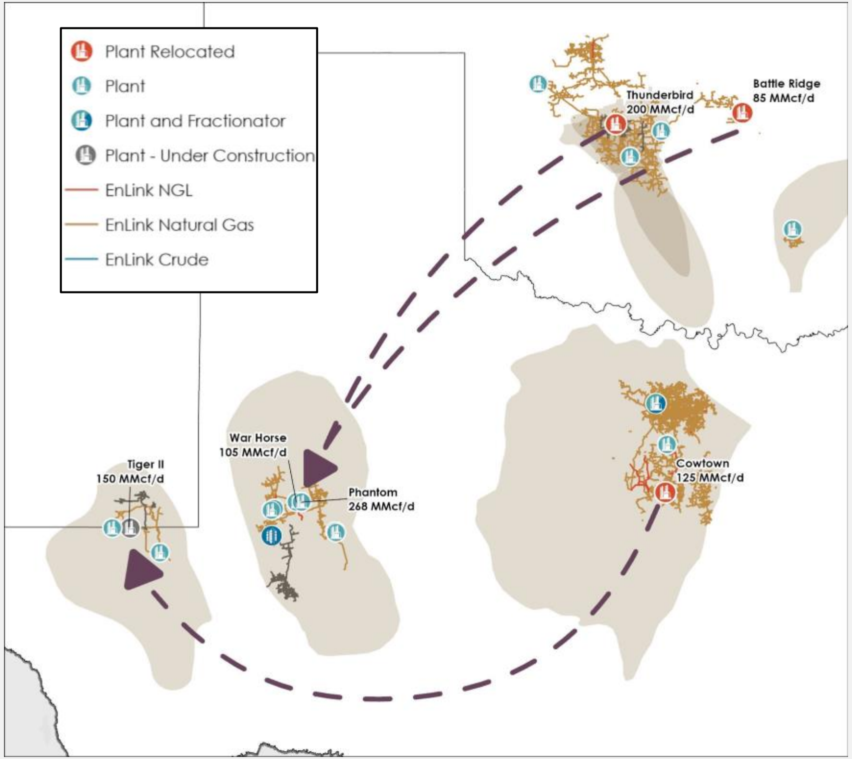
Growing Alongside Customers

- Diverse mix of over 15 customers
- In process of relocating our 3rd processing plant
  - Represents ~50% cost vs. newbuild project
  - Lowers supply chain risks of sourcing materials
  - Lowers inflation risk on project
- Equity investor and shipper on Matterhorn pipeline

Sustained Growth in EnLink's Largest Segment



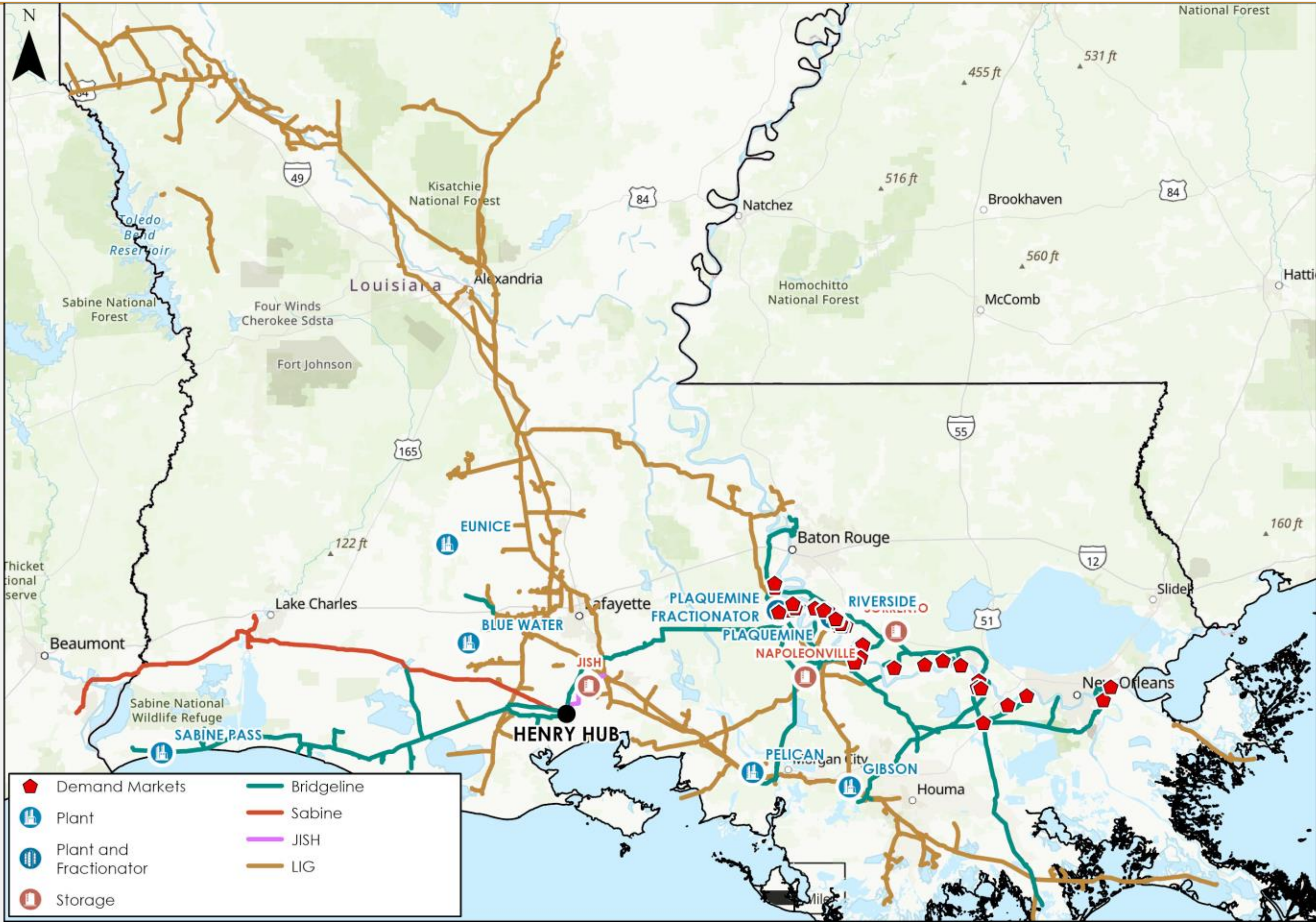
[1]2024 Financial guidance provided on February 20, 2024. Note: Delaware Basin gas G&P assets are 49.9% owned by Natural Gas Partners



Strong Experience & Operational Capabilities in Louisiana

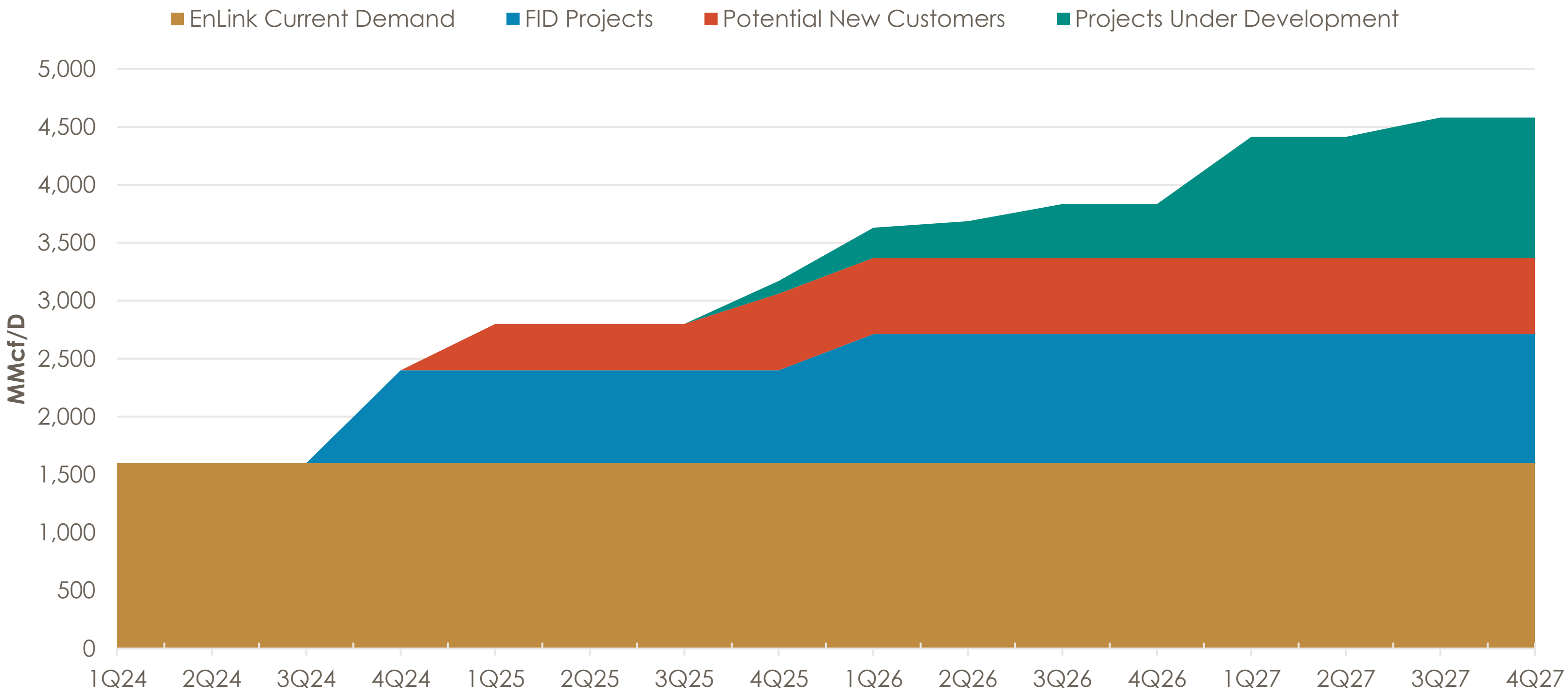
Strategically Positioned Assets Serve Growing Demand Market

- 3 natural gas processing facilities with 710 MMcf/d capacity
- 3,100 miles gas transmission pipelines
- 800 miles NGL pipelines
- 3 NGL fractionation facilities
- ~11 Bcf of working natural gas storage, with potential to expand capacity
- 245 employees in state of Louisiana



Mississippi River Industrial Demand Is Growing

EnLink currently serves and is connected to ~1.6 Bcf/d of industrial demand & we are working with another ~2 Bcf/d of industrial demand



Louisiana Assets are Strategically Positioned

Future Pipeline Opportunities Include:

- Phase 1: existing contracts renew at higher rates and longer tenor
- Phase 2: expand capacity through quick-to-market, high-return debottleneck projects
  - This includes additional compression and looping existing pipelines
- Phase 3: potential for larger and longer return projects to resupply industrial customers with contracted new pipelines and storage

Future Storage Opportunities Include:

- ~11 Bcf current working natural gas storage capacity[1]
- Currently progressing with permitting and project efforts to expand working gas storage capacity by up to 9 Bcf

[1]Estimated working capacity for gas storage excludes linefill capacity necessary to operate facilities.

EnLink's Differentiated CCS Investment

- Investable today
- Attacking existing industrial CO_2 emissions
- Short distance between emitters and sequestration providers
- Focused on Gulf Coast, which is uniquely positioned for sequestration
- Meaningful opportunity relative to current size of the company
- Building diverse book of business focused on CO_2 transportation

Exploring Broader CCS Commercialization with ExxonMobil

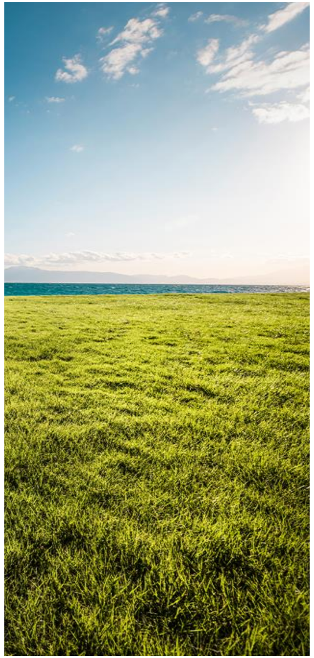
EnLink is supporting ExxonMobil efforts beyond the Mississippi River Corridor

- Commercial efforts initially centered around the Mississippi River Corridor
- Expanded evaluations to across the Gulf Coast area
- EnLink and ExxonMobil are developing safe, reliable, and cost-effective CCS solutions to CO_2 emitting companies and industries
- EnLink and ExxonMobil have agreed to reassess the Pecan Island project's near-term role
- Expect that other joint opportunities may be prioritized ahead of Pecan Island

~80Mtpa

Existing Industrial Emissions along Mississippi River Corridor

~215 Mtpa



Total Industrial Emissions along Gulf Coast

Source: US EPA: Industrial GHG emissions data as of 8/18/23 (https://ghgdata.epa.gov/ghgp/main.do).

EnLink Commences Carbon Capture Project in NTX

Bridgeport CO_2 capture project advances EnLink's CO_2 reduction efforts

Project Overview

- CO_2 captured from natural gas produced by BKV and processed at EnLink's Bridgeport plant
- CO_2 previously vented into atmosphere is collected and transported to permanent sequestration site operated by BKV
  - BKV utilizing Class II well for underground injection control well
- Expected to achieve an average sequestration rate of up to 210,000 metric tonnes of CO_2 per year over the course of the project life

Takeaways

- EnLink and BKV are among the first energy companies to have commercial CCS operations in the nation
- EnLink now has experience in capturing and transporting CO2 via new build pipelines as well as converted pipelines from natural gas service
- Demonstrates EnLink's commitment to reducing emissions from its own operations

Solid Q4 & Full-Year 2023 Results

$MM, unless noted	4Q23	FY23
Net Income (Loss)	**$100**	**$350**
Adjusted EBITDA, net to EnLink[1]	**$351**	**$1,350**
Capex, Plant Relocation Costs[2], net to EnLink & Investment Contributions[3]	**$122**	**$493**
Net Cash Provided by Operating Activities	**$361**	**$1,223**
Free Cash Flow After Distributions[1]	**$79**	**$247**
Declared Distribution per Common Unit	**$0.1325/unit**	**$0.5075/unit**
		As of December 31, 2023
Debt-to-Adjusted EBITDA[4]		**3.3x**
Amount Outstanding on $1.4BN Revolving Credit Facility		**$0**
Cash, net to EnLink		**$0**

Consistent execution drives strong results

Adjusted EBITDA
Grew full-year and 4th quarter year-over-year Adj. EBITDA by ~5%

Free Cash Flow after Distributions
17 consecutive quarters generating positive FCFAD

Capital Expenditures
Third capital efficient plant relocation remains on track for in-service in 2Q24

Proactively Hedged Commodity Exposure
Extending more aggressive hedging program for equity volumes into 2024

Returning Capital to Investors
Completed $250MM of common unit repurchases[5] for 2023 and increased 4Q23 distribution ~6%

[1]Non-GAAP measures are defined in the appendix. [2]Includes $5.7MM in the Permian in 4Q23 for relocation costs net to EnLink. These costs are related to plant relocation and are classified as operating expenses in accordance with GAAP. [3]Contributions of $9.7MM to the equity method investments for 4Q23, principally for Gulf Coast Fractionators. [4]Calculated according to credit facility agreement leverage covenant. [5]Includes $41.5MM of common units repurchased from GIP pursuant to our Unit Repurchase Agreement, which settled on February 19, 2024.

Segment Results Overview

SEGMENT RESULTS ($MM)	4Q22	3Q23	4Q23
Permian Gas Segment Profit	77.7	83.1	93.4
Permian Crude Segment Profit	11.3	19.6	12.5
Total Segment Profit	**89.0**	**102.7**	**105.9**
Plant Relocation OPEX[1]	11.7	2.5	9.6
Unrealized Derivatives Loss/(Gain)	(0.6)	7.4	(4.0)
Louisiana Gas Segment Profit	24.7	20.4	32.7
Louisiana NGL Segment Profit	71.2	63.2	71.3
ORV Crude Segment Profit	1.9	3.5	(0.4)
Total Segment Profit	**97.8**	**87.1**	**103.6**
Unrealized Derivatives Loss/(Gain)	2.5	6.0	(0.9)
Oklahoma Gas Segment Profit	94.8	101.4	108.1
Oklahoma Crude Segment Profit	4.0	3.2	3.9
Total Segment Profit	**98.8**	**104.6**	**112.0**
Plant Relocation OPEX	0.0	0.4	0.0
Unrealized Derivatives Loss/(Gain)	5.0	4.1	(1.3)
North Texas Gas Segment Profit	**84.3**	**63.8**	**68.6**
Unrealized Derivatives Loss/(Gain)	(8.7)	5.4	(0.7)

Note: Includes segment results associated with non-controlling interests. Segment results include realized and unrealized derivatives and Plant Relocation OPEX. [1]Includes costs that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

QUARTERLY HIGHLIGHTS

Permian

- Tiger II plant relocation remains on schedule and on budget
- Diversified drilling activity during the quarter with >15 different operators on the Midland and Delaware systems

Louisiana

- Completed sale of the non-core Ohio River Valley assets for total proceeds of ~$70MM
- Tightening gas market dynamics increase the value of EnLink's system and create project opportunities

Oklahoma

- Consistent DVN/Dow JV drilling activity
- Held G&P volumes flat sequentially

North Texas

- Bridgeport CO_2 capture project came on line during the 4th quarter
- Additional processing capacity can be relocated as needed

2024 Financial Guidance

$MM, unless noted	**2024**
Net Income	$370 - $470
Adjusted EBITDA, net to EnLink[1,2]	$1,310 - $1,410
Capex & Plant Relocation Costs[3], net to EnLink, & Investment Contributions[4]	$435 - $485
Growth Capex & Plant Relocation Costs, net to EnLink	$345 - $375
Maintenance Capex, net to EnLink	$85 - $95
Investment Contributions[4]	$5 - $15
Free Cash Flow After Distributions[1]	$265 - $315
Annualized 4Q23 Distribution per Common Unit	$0.53/unit

Commodity Price Assumptions (average):

- **WTI $75/bbl and Henry Hub $3.00/MMBtu**
- **Impact of +/- $5/bbl WTI: $6 MM**
- **Impact of +/- $0.50/MMBtu: $5 MM**
- **Hypothetical impact from major producers 6 month completion deferral in OK and NTX: $20MM**

Adjusted EBITDA
Midpoint represents ~4% organic growth in our base business over full-year 2023, excluding ~$50MM impact from legacy contract resets and non-core asset sale

Free Cash Flow after Distributions
Maintaining significant financial flexibility while increasing the quarterly distribution ~6% in 4Q23

Capital Expenditures
Maintaining total capex spending profile

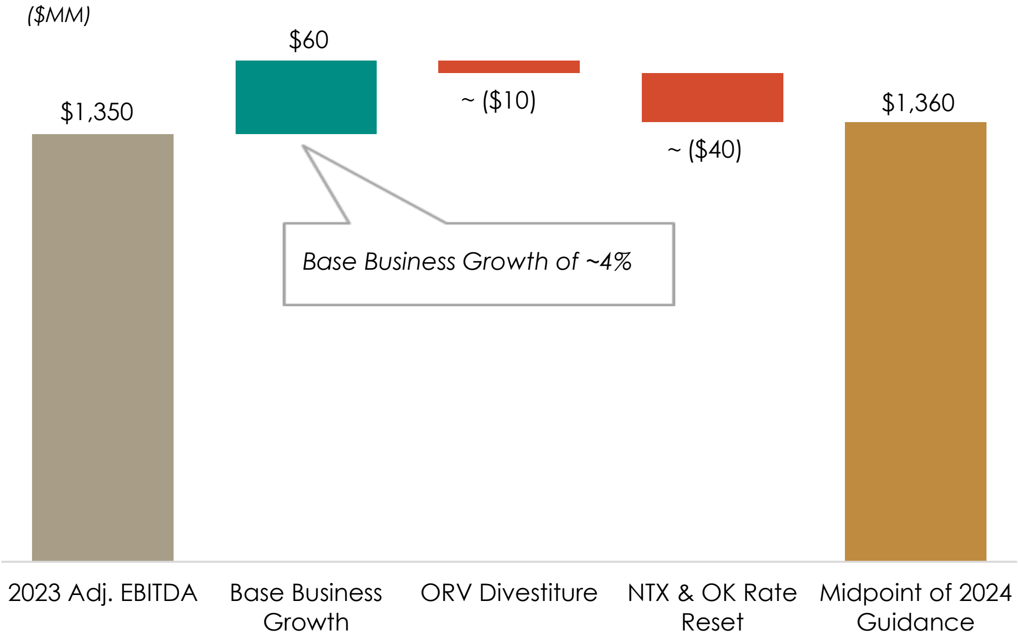
Capital Allocation
Announced 2024 unit repurchase authorization of $200MM

Proactively Hedged Commodity Exposure
Extending more aggressive hedging program for equity volumes into 2024

[1]Non-GAAP measures are defined in the appendix. [2]Adjusted EBITDA does not reflect the one-time $15MM net to EnLink expense related to relocating available processing capacity. [3]Includes $15MM classified as operating expense in accordance with GAAP net to EnLink related to the plant relocation cost. [4]Consists principally of contributions to Gulf Coast Fractionators.

Organic Growth in 2024

Solid underlying growth impacted by one-time items



2024 Commentary

- Anticipating solid year-over-year growth, driven by continued expansion of the Permian business and rate increases in Louisiana
- Divested non-core ORV assets for ~$70MM in 4Q23
- Legacy G&P contract reset
  - 2018: Extended contracts 5 years
  - Extension included a one-time reset in 2024 to pre-agreed fees
  - Partially reverses recent years of outsized annual inflation escalators
  - Contracts expire in 2029-2033 with inflation escalators and no further rate resets

Note: Financial figures presented are net of non-controlling interest contributions.

2024 Segment Guidance

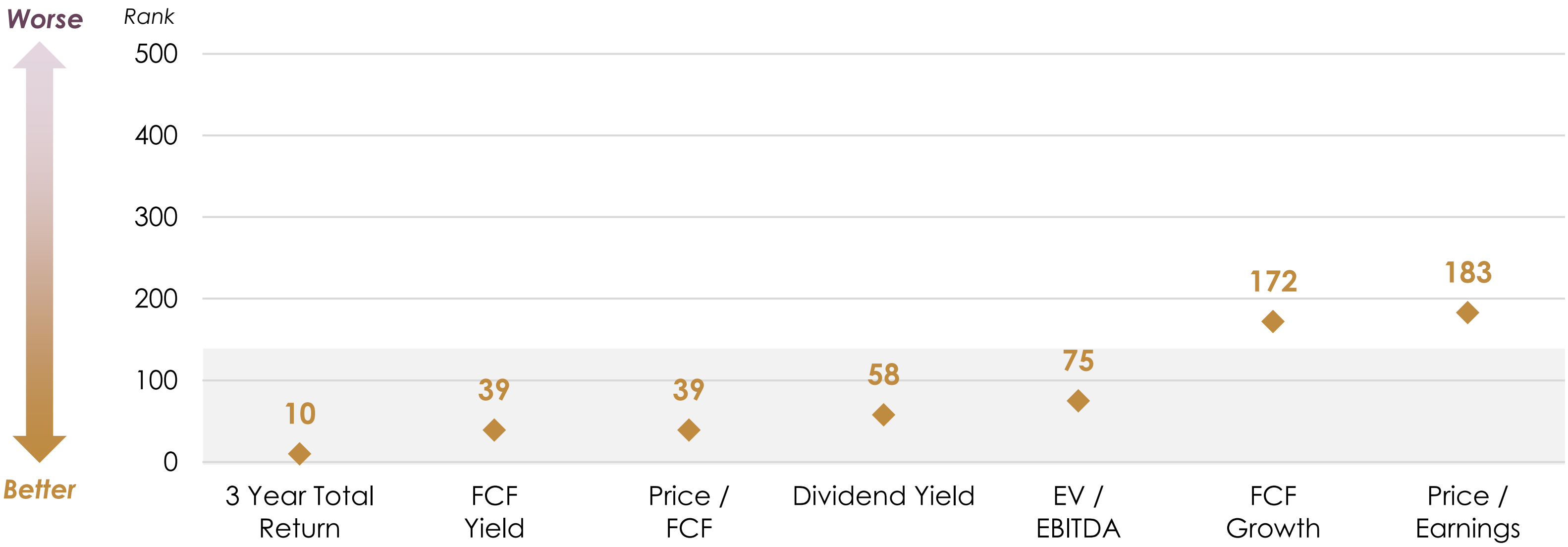
$MM	2023 Segment Profit	2024 Segment Profit Guidance				Segment Capex	Segment Profit Less Capex	Producer / Customer Update
		Low	Mid	High	% of Total			
PERMIAN[1]	**$396**[1]	$420	**$455**[2]	$490	~30%	$150[2]	$305	3rd plant relocation, Tiger II, on line in 2Q24; Robust activity continues in both the Midland and Delaware
Plant Relocation Expense	$14[1]		$30[2]					
LOUISIANA	**$392**	$405	**$420**	$435	~30%	$100	$320	Benefiting from tighter supply and demand dynamics; favorable rate renewals in LA Gas continue through FY24
OKLAHOMA	**$422**[1]	$375	**$390**	$405	~25%	$75	$315	Steady activity from DVN/DOW JV offset by one-time G&P rate reset
NORTH TEXAS	**$276**	$230	**$240**	$250	~15%	$50	$190	Impact from one-time G&P rate reset

Segments Continue to Generate Significant Excess Cash Flow

[1]Permian and Oklahoma include $14.2MM and $0.4MM, respectively, related to plant relocation as an operating expense in segment profit in accordance with GAAP.
[2]Permian includes $30MM, of which approximately $15MM is net to EnLink, related to relocating available processing capacity from Oklahoma, NTX segments to the Permian segment.

Compelling Investment Versus S&P 500

	3 Year Total Return	FCF Yield	Price / FCF	Dividend Yield	EV / EBITDA	FCF Growth	Price / Earnings
EnLink:	**44.9%**	**11.7%**	**8.6x**	**4.5%**	**9.1x**	**17.1%**	**17.8x**
Median:	7.6%	3.9%	23.8x	2.2%	15.0x	10.8%	21.6x
Average:	7.8%	4.2%	33.5x	2.5%	18.7x	(22.4%)	40.6x



Exhibiting top-quartile value & performance vs. Blue Chip Companies

Note: Based on bottoms-up analysis of S&P 500 constituents as of February 13, 2024, Source: Bloomberg. Data as of February 13, 2024. Rank based on highest-to-lowest for Dividend Yield, FCF Yield, FCF Growth, and TRR 3 year. Rank based on lowest-to-highest for EV / EBITDA, Price / FCF, and Price / Earnings.

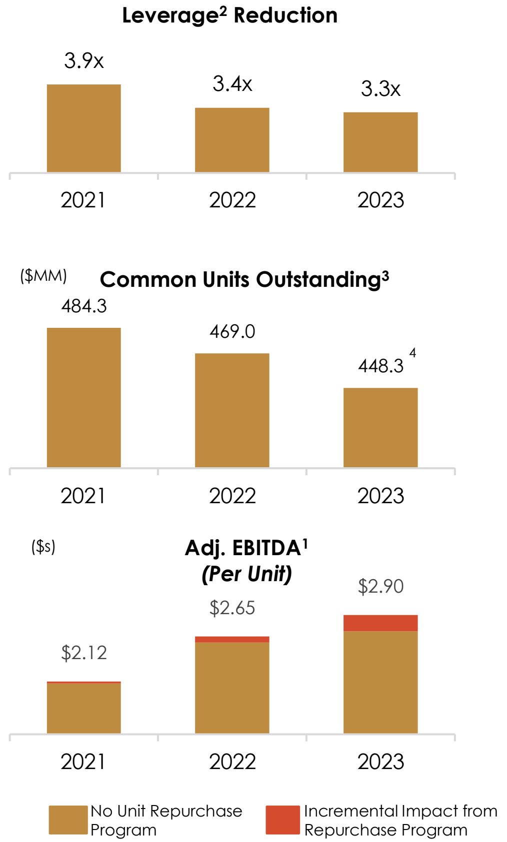
Balanced Capital Allocation Builds Value With Flexibility

Uses of Free Cash Flow

6% distribution increase in 4Q23	Maintain significant FCFAD[1] and financial flexibility	Disciplined growth

Financial Flexibility

$200MM common repurchase authorization – 3rd consecutive year	Fund incremental high return projects	Ability to repurchase preferred units



[1]Non-GAAP measure defined in the appendix. [2]Calculated according to revolving credit facility agreement leverage covenant. [3]Common Units Outstanding as of December 31st for the respective years. [4]For 2023, amount is pro forma for ~3.28MM units repurchased from GIP pursuant to our Unit Repurchase Agreement, which settled on February 19, 2024.

Driving Attractive Cash Returns to Shareholders

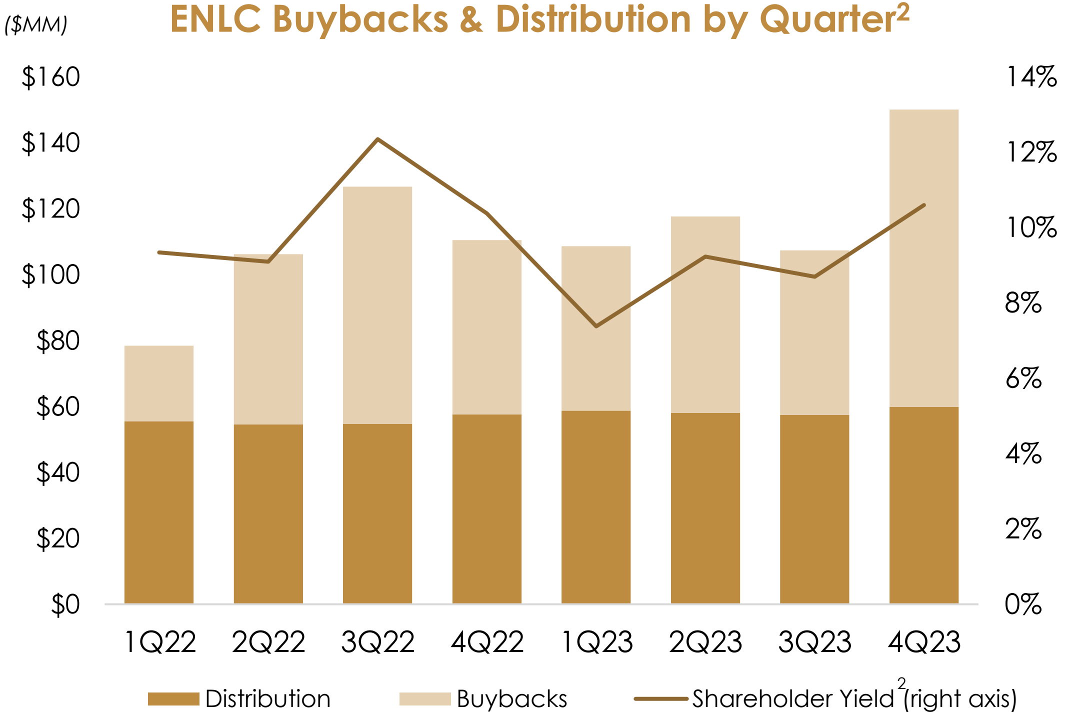
Distribution Yield + Buybacks + Growth

S&P 500 Average Buyback Yields[1]

EnLink Ranks in the Top 10% of S&P 500 Companies

ENLC	6.4%
Consumer Discretionary	3.4%
Communication Services	3.1%
Financials	2.6%
Materials	2.1%
Information Technology	1.7%
Health Care	1.6%
Industrials	1.5%
Consumer Staples	1.2%
Utilities	0.8%
Real Estate	0.5%

ENLC Buybacks & Distribution by Quarter[2]



[1]FactSet data. S&P data reflects 9/30/23 quarter. Buyback yield is annualized buyback divided by beginning period market cap. [2]Shareholder yield includes annualized common equity buybacks and declared common unit distributions divided by beginning period market cap.

For More Information

Thank you.

ENLINK MIDSTREAM

www.enlink.com

EnLink Investor Relations Website

EnLink's Latest Sustainability Report

EnLink Leadership Biographies

APPENDIX

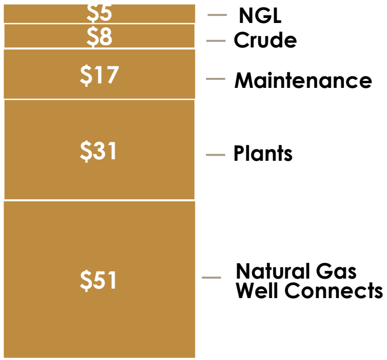
Q4 2023 Capital Expenditures, Relocation Costs & Investment Contributions

Capex, Plant Relocation Costs[1], net to EnLink, & Investment Contributions[2] ($MM)

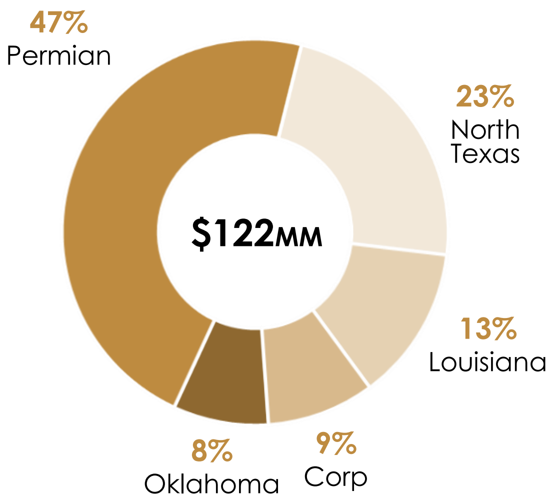
Segment	4Q23	FY23
Permian	$85.8	$281.5
Louisiana	$15.5	$68.6
Oklahoma	$9.9	$69.6
North Texas	$28.6	$75.5
Corporate	$11.0	$74.3
Total	$150.8	$569.5
JV Contributions	($28.4)	($76.5)
Net to EnLink	$122.4	$493.0

Capital Spending by Project Type[1,3]
Net to EnLink ($MM)

- ✓ Continued to connect highly accretive wells in Permian
- ✓ Investing in attractive demand driven projects



Capital Spending by Segment[1,3]
Net to EnLink (4Q23)



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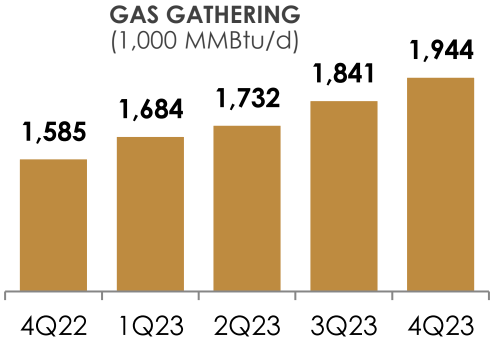
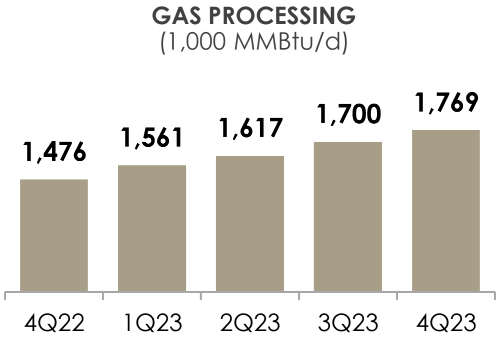
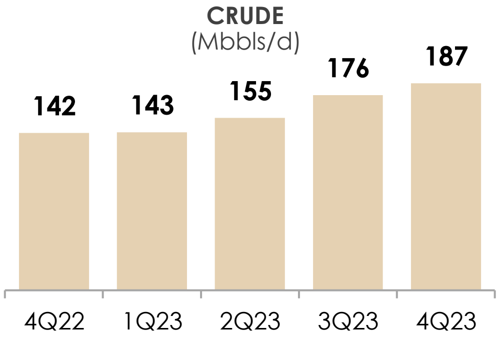
Quarterly Volumes (Permian, Louisiana)

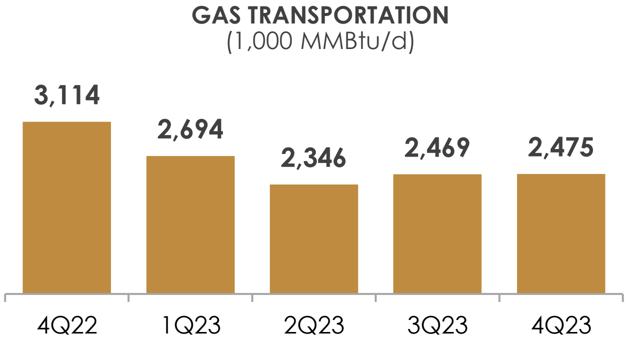
Permian

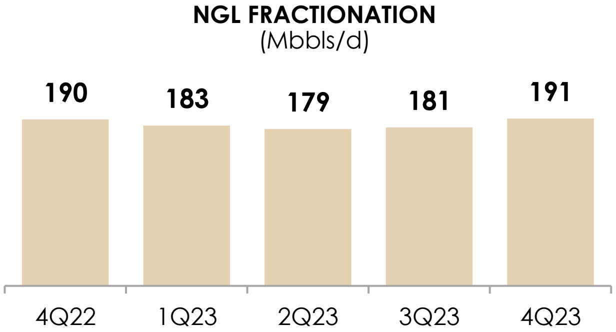






Louisiana



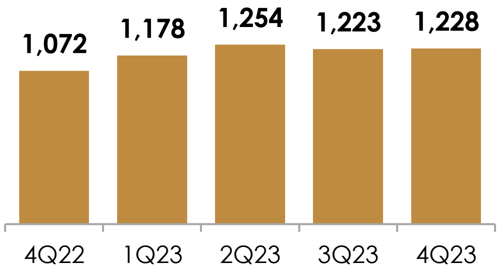


Note: Includes volumes associated with non-controlling interests

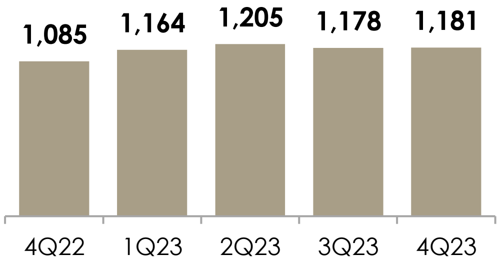
Quarterly Volumes (Oklahoma, North Texas)

Oklahoma

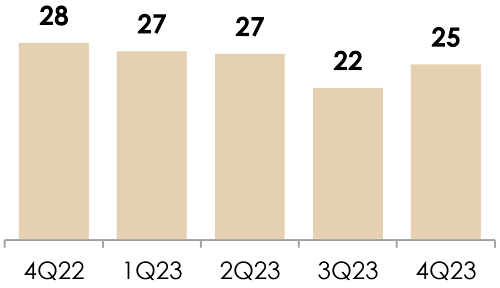
GAS GATHERING
(1,000 MMBtu/d)



GAS PROCESSING
(1,000 MMBtu/d)

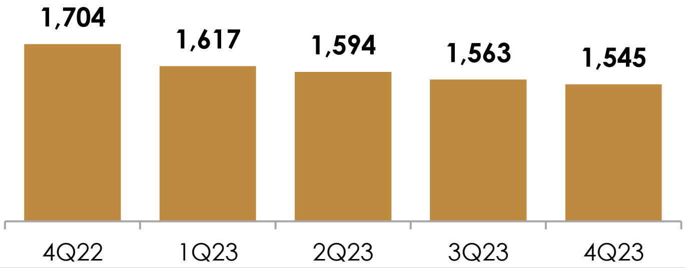


CRUDE
(Mbbls/d)

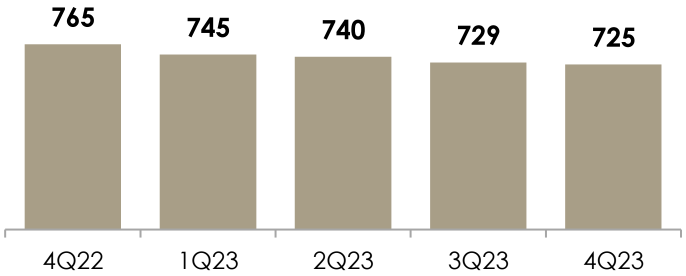


North Texas

GAS GATHERING
(1,000 MMBtu/d)



GAS PROCESSING
(1,000 MMBtu/d)

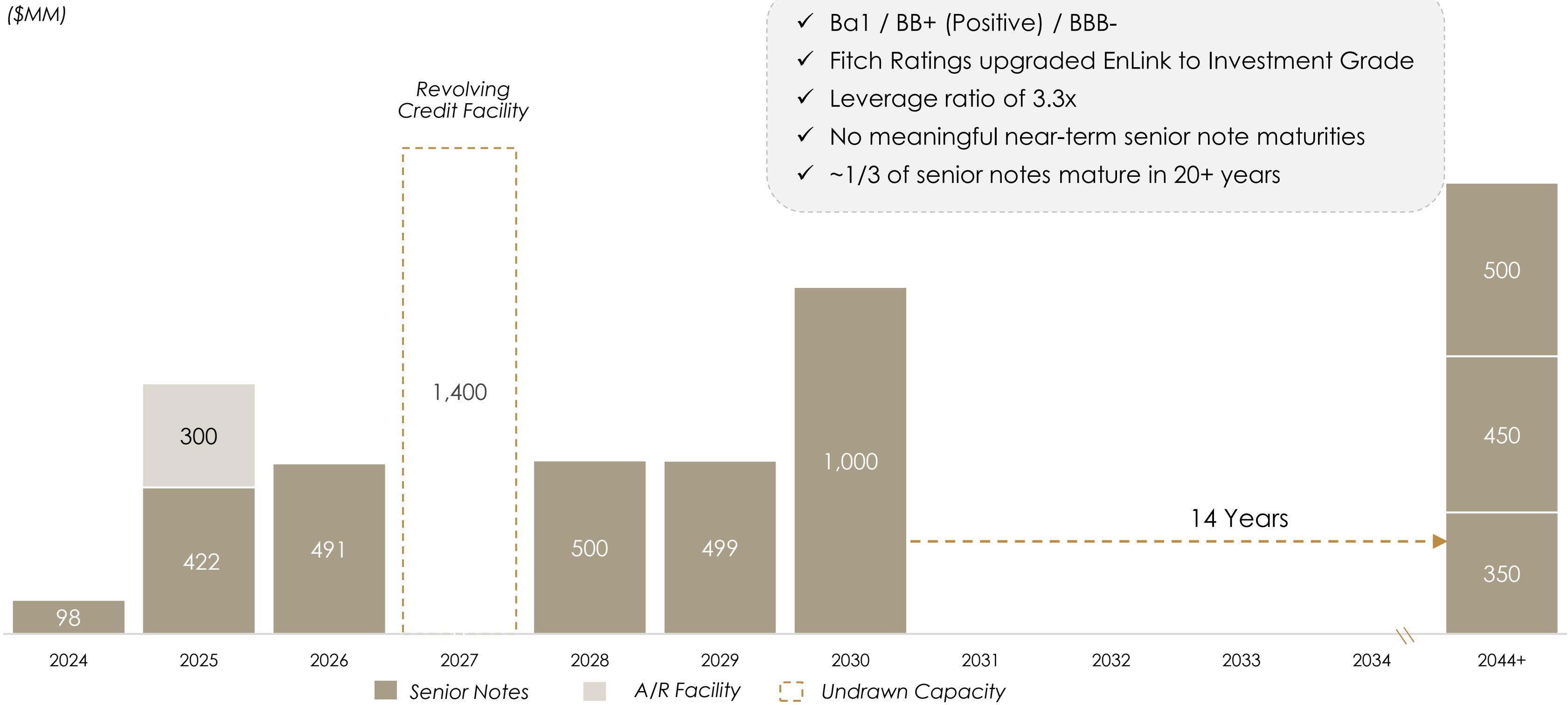


Quarterly Segment Profit & Volumes

$ amounts in millions unless otherwise noted	3 Months Ended Dec. 31, 2022	Mar. 31, 2023	Jun. 30, 2023	Sep. 30, 2023	Dec. 31, 2023	12 months Ended Dec. 31, 2023
Permian						
Segment Profit	$89.0	$96.0	$91.8	$102.7	$105.9	$396.4
Adjusted Gross Margin	$143.9	$144.1	$144.9	$157.7	$171.0	$617.7
Gathering and Transportation (MMBtu/d)	1,584,700	1,683,700	1,732,200	1,840,800	1,943,500	1,800,900
Processing (MMBtu/d)	1,475,900	1,560,700	1,617,400	1,699,700	1,769,100	1,662,400
Crude Oil Handling (Bbls/d)	141,800	142,600	155,400	176,100	186,700	165,300
Louisiana						
Segment Profit	$97.8	$96.4	$104.5	$87.1	$103.6	$391.6
Adjusted Gross Margin	$133.1	$130.0	$136.5	$122.1	$133.3	$521.9
Gathering and Transportation (MMBtu/d)	3,113,900	2,693,500	2,345,600	2,468,900	2,474,700	2,495,000
NGL Fractionation (Bbls/d)	189,800	183,100	179,000	180,800	190,900	183,500
Crude Oil Handling (Bbls/d)	17,600	18,300	16,500	18,600	6,500	14,900
Brine Disposal (Bbls/d)	2,900	3,000	2,700	3,400	1,000	2,500
Oklahoma						
Segment Profit	$98.8	$94.7	$110.7	$104.6	$112.0	$422.0
Adjusted Gross Margin	$122.1	$119.4	$137.7	$131.2	$137.5	$525.8
Gathering and Transportation (MMBtu/d)	1,071,500	1,178,400	1,253,800	1,223,000	1,228,100	1,221,000
Processing (MMBtu/d)	1,085,000	1,164,300	1,204,600	1,178,200	1,180,800	1,182,000
Crude Oil Handling (Bbls/d)	28,400	27,200	26,800	21,900	25,300	25,300
North Texas						
Segment Profit	$84.3	$76.1	$67.3	$63.8	$68.6	$275.8
Adjusted Gross Margin	$109.1	$102.1	$92.0	$90.5	$94.0	$378.6
Gathering and Transportation (MMBtu/d)	1,704,300	1,617,100	1,593,600	1,563,100	1,544,800	1,579,400
Processing (MMBtu/d)	764,900	744,600	740,000	729,000	725,200	734,600

Note: Includes segment profit and volumes associated with non-controlling interests.

Ample Financial Flexibility



Financial Flexibility

- ✓ Ba1 / BB+ (Positive) / BBB-
- ✓ Fitch Ratings upgraded EnLink to Investment Grade
- ✓ Leverage ratio of 3.3x
- ✓ No meaningful near-term senior note maturities
- ✓ ~1/3 of senior notes mature in 20+ years

Note: As of December 31, 2023.

Capitalization

($ in MM)	12/31/23
Cash and cash equivalents, net to EnLink	0.0
$1.4Bn Unsecured Revolving Credit Facility due June 2027	0.0
$500MM A/R Securitization due August 2025	300.0
ENLK 4.400% Senior unsecured notes due April 2024	97.9
ENLK 4.150% Senior unsecured notes due June 2025	421.6
ENLK 4.850% Senior unsecured notes due July 2026	491.0
ENLC 5.625% Senior unsecured notes due January 2028	500.0
ENLC 5.375% Senior unsecured notes due June 2029	498.7
ENLC 6.500% Senior unsecured notes due September 2030	1,000.0
ENLK 5.600% Senior unsecured notes due April 2044	350.0
ENLK 5.050% Senior unsecured notes due April 2045	450.0
ENLK 5.450% Senior unsecured notes due June 2047	500.0
Net Debt	**4,609.2**
Series B Preferred Units	818.6
Series C Preferred Units	366.5
Members' Equity	5,557.9
Total Capitalization	**11,352.2**

Note: As of December 31, 2023. Members' Equity based on unit price of $12.16 and 457,060,066 common units (consisting of 451,614,086 issued units and 5,445,980 restricted incentive units).

2024 GUIDANCE RECONCILIATION OF NET INCOME TO ADJUSTED EBITDA AND FREE CASH FLOW AFTER DISTRIBUTIONS

	2024 Outlook (1)
Net income of EnLink (2)	$420
Interest expense, net of interest income	263
Depreciation and amortization	632
Income from unconsolidated affiliate investments	(19)
Distribution from unconsolidated affiliate investments	6
Unit-based compensation	24
Income taxes	90
Plant relocation costs (3)	29
Other (4)	5
Adjusted EBITDA before non-controlling interest	1,450
Non-controlling interest share of adjusted EBITDA (5)	(90)
Adjusted EBITDA, net to EnLink	1,360
Interest expense, net of interest income	(263)
Maintenance capital expenditures, net to EnLink (6)	(90)
Preferred unit accrued cash distributions (7)	(102)
Other (8)	(8)
Common distributions declared	(237)
Growth capital expenditures, net to EnLink & plant relocation costs (3)(6)	(360)
Contribution to investment in unconsolidated affiliates	(10)
Free cash flow after distributions	$290

1) Represents the forward-looking net income guidance of EnLink Midstream, LLC for the year ended December 31, 2024. The forward-looking net income guidance excludes the potential impact of gains or losses on derivative activity, gains or losses on disposition of assets, impairment expense, gains or losses as a result of legal settlements, gains or losses on extinguishment of debt, the financial effects of future acquisitions, proceeds from the sale of equipment, and repurchases of common units, ENLC Series C Preferred Units, or ENLK Series B Preferred Units. The exclusion of these items is due to the uncertainty regarding the occurrence, timing and/or amount of these events.
2) Net income includes estimated net income attributable to (i) NGP Natural Resources XI, L.P.'s ("NGP") 49.9% share of net income from the Delaware Basin JV, (ii) Marathon Petroleum Corp.'s ("Marathon") 50% share of net income from the Ascension JV.
3) Represents costs incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
4) Includes (i) estimated accretion expense associated with asset retirement obligations and (ii) estimated non-cash rent, which relates to lease incentives pro-rated over the lease term.
5) Non-controlling interest share of adjusted EBITDA includes estimates for (i) NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, (ii) Marathon's 50% share of adjusted EBITDA from the Ascension JV.
6) Excludes capital expenditures that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
7) Represents the cash distributions earned by the ENLK Series B Preferred Units and ENLK Series C Preferred Units. Cash distributions to be paid to holders of the ENLK Series B Preferred Units and ENLK Series C Preferred Units are not available to common unitholders.
8) Includes non-cash interest (income)/expense and current income tax (income)/expense.

Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA and Free Cash Flow After Distributions

	Three Months Ended					12 Months Ended
	12/31/2022	3/31/2023	6/30/2023	9/30/2023	12/31/2023	12/31/2023
Net cash provided by operating activities	$223.4	$272.1	$315.7	$274.2	$360.7	$1,222.7
Interest expense (1)	70.4	67.0	67.0	66.3	65.0	265.3
Utility credits redeemed (2)	(3.2)	(1.4)	(0.1)	—	—	(1.5)
Distributions from unconsolidated affiliate investment in excess of earnings	0.1	0.1	2.2	0.1	0.1	2.5
Costs associated with the relocation of processing facilities (3)	11.7	0.4	1.7	2.9	9.6	14.6
Other (4)	(1.0)	0.1	(0.1)	0.8	(1.5)	(0.7)
Changes in operating assets and liabilities which (provided) used cash:						
Accounts receivable, accrued revenues, inventories, and other	(243.0)	(169.4)	(80.3)	156.9	(62.4)	(155.2)
Accounts payable, accrued product purchases, and other accrued liabilities	295.1	171.0	44.0	(142.3)	(1.7)	71.0
Adjusted EBITDA before non-controlling interest	353.5	339.9	350.1	358.9	369.8	1,418.7
Non-controlling interest share of adjusted EBITDA from joint ventures (5)	(16.3)	(16.2)	(16.5)	(17.0)	(19.0)	(68.7)
Adjusted EBITDA, net to ENLC	337.2	323.7	333.6	341.9	350.8	1,350.0
Growth capital expenditures, net to ENLC (6)	(94.0)	(92.7)	(74.6)	(97.4)	(90.1)	(354.8)
Maintenance capital expenditures, net to ENLC (6)	(11.2)	(14.2)	(20.0)	(18.3)	(16.9)	(69.4)
Interest expense, net of interest income	(67.5)	(68.5)	(68.8)	(67.9)	(66.5)	(271.7)
Distributions declared on common units	(57.6)	(58.7)	(58.1)	(57.5)	(60.0)	(234.3)
ENLK preferred unit cash distributions earned (7)	(23.1)	(23.6)	(24.0)	(24.6)	(24.8)	(97.0)
Payment to redeem mandatorily redeemable non-controlling interest (8)	—	(10.5)	—	—	—	(10.5)
Costs associated with the relocation of processing facilities, net to ENLC (3)(6)(9)	(11.7)	(0.4)	7.1	(1.7)	(5.7)	(0.7)
Contributions to investment in unconsolidated affiliates	(19.6)	(49.7)	—	(8.7)	(9.7)	(68.1)
Non-cash interest expense	1.4	—	—	—	—	—
Other (10)	1.2	0.3	0.5	0.4	2.3	3.5
Free cash flow after distributions	$55.1	$5.7	$95.7	$66.2	$79.4	$247.0

1. Net of amortization of debt issuance costs, net discount of senior unsecured notes, and designated cash flow hedge, which are included in interest expense but not included in net cash provided by operating activities, and non-cash interest income, which is netted against interest expense but not included in adjusted EBITDA.
2. Under our utility agreements, we are entitled to a base load of electricity and pay or receive credits, based on market pricing, when we exceed or do not use the base load amounts.
3. Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
4. Includes transaction costs, current income tax expense, and non-cash rent, which relates to lease incentives pro-rated over the lease term.
5. Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV.
6. Excludes capital expenditures and costs associated with the relocation of processing facilities that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
7. Represents the cash distributions earned by the Series B Preferred Units and Series C Preferred Units, which are not available to common unitholders.
8. In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries.
9. Includes a one-time $8.0 million contribution from an affiliate of NGP in May 2023 in connection with the Delaware Basin JV's purchase of the Cowtown processing plant.
10. Includes current income tax expense and proceeds from the sale of surplus or unused equipment and land, which occurred in the normal operation of our business.

Reconciliation of Net Income (Loss) to Adjusted EBITDA and Free Cash Flow After Distributions

	Three Months Ended					12 Months Ended
	12/31/2022	3/31/2023	6/30/2023	9/30/2023	12/31/2023	12/31/2023
Net income	$194.2	$94.2	$89.9	$65.8	$100.1	$350.0
Interest expense, net of interest income	74.0	68.5	68.8	67.9	66.5	271.7
Depreciation and amortization	164.9	160.4	165.3	163.8	167.6	657.1
Impairments	—	—	—	20.7	—	20.7
(Income) loss from unconsolidated affiliate investments	1.6	0.1	4.6	(1.0)	4.5	8.2
Distributions from unconsolidated affiliate investments	0.1	0.1	2.2	0.1	0.1	2.5
(Gain) loss on disposition of assets	14.1	(0.4)	(0.8)	(0.6)	1.5	(0.3)
Unit-based compensation	6.7	4.0	4.5	5.7	5.0	19.2
Income tax expense	(112.0)	10.9	19.0	10.6	22.3	62.8
Unrealized (gain) loss on commodity derivatives	(1.8)	1.4	(5.3)	22.9	(6.9)	12.1
Costs associated with the relocation of processing facilities (1)	11.7	0.4	1.7	2.9	9.6	14.6
Other (2)	—	0.3	0.2	0.1	(0.5)	0.1
Adjusted EBITDA before non-controlling interest	353.5	339.9	350.1	358.9	369.8	1,418.7
Non-controlling interest share of adjusted EBITDA from joint ventures (3)	(16.3)	(16.2)	(16.5)	(17.0)	(19.0)	(68.7)
Adjusted EBITDA, net to ENLC	337.2	323.7	333.6	341.9	350.8	1,350.0
Growth capital expenditures, net to ENLC (4)	(94.0)	(92.7)	(74.6)	(97.4)	(90.1)	(354.8)
Maintenance capital expenditures, net to ENLC (4)	(11.2)	(14.2)	(20.0)	(18.3)	(16.9)	(69.4)
Interest expense, net of interest income	(67.5)	(68.5)	(68.8)	(67.9)	(66.5)	(271.7)
Distributions declared on common units	(57.6)	(58.7)	(58.1)	(57.5)	(60.0)	(234.3)
ENLK preferred unit cash distributions earned (5)	(23.1)	(23.6)	(24.0)	(24.6)	(24.8)	(97.0)
Payment to redeem mandatorily redeemable non-controlling interest (6)	—	(10.5)	—	—	—	(10.5)
Costs associated with the relocation of processing facilities, net to ENLC (1)(4)(7)	(11.7)	(0.4)	7.1	(1.7)	(5.7)	(0.7)
Contributions to investment in unconsolidated affiliates	(19.6)	(49.7)	—	(8.7)	(9.7)	(68.1)
Non-cash interest expense	1.4	—	—	—	—	—
Other (8)	1.2	0.3	0.5	0.4	2.3	3.5
Free cash flow after distributions	$55.1	$5.7	$95.7	$66.2	$79.4	$247.0

1. Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
2. Includes transaction costs, non-cash expense related to changes in the fair value of contingent consideration, accretion expense associated with asset retirement obligations, and non-cash rent, which relates to lease incentives pro-rated over the lease term.
3. Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV.
4. Excludes capital expenditures and costs associated with the relocation of processing facilities that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
5. Represents the cash distributions earned by the Series B Preferred Units and Series C Preferred Units, which are not available to common unitholders.
6. In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries.
7. Includes a one-time $8.0 million contribution from an affiliate of NGP in May 2023 in connection with the Delaware Basin JV's purchase of the Cowtown processing plant.
8. Includes current income tax expense and proceeds from the sale of surplus or unused equipment and land, which occurred in the normal operation of our business.

Reconciliation of Net Income (Loss) to ADJUSTED EBITDA Per Unit

	Twelve months ended		
	12/31/2021	12/31/2022	12/31/2023
Net income (loss)attributable to ENLC	$22.4	$361.3	$206.2
Net income attributable to non-controlling interest	120.5	139.4	143.8
Net income (loss)	142.9	500.7	$350.0
Interest expense, net of interest income	238.7	245.0	271.7
Depreciation and amortization	607.5	639.4	657.1
Impairments	0.8	-	20.7
(Income) loss from unconsolidated affiliates	11.5	5.6	8.2
Distributions from unconsolidated affiliates	3.9	0.7	2.5
(Gain) loss on disposition of assets	(1.5)	18.0	(0.3)
Loss on extinguishment of debt	-	6.2	-
Unit-based compensation	25.3	30.4	19.2
Income tax expense (benefit)	25.4	(94.9)	62.8
Unrealized (gain) loss on commodity swaps	12.4	(40.2)	12.1
Costs associated with the relocation of processing facilities (1)	28.3	43.8	14.6
Other (2)	(0.6)	(2.4)	0.1
Adjusted EBITDA before non-controlling interest	1,094.6	1,352.3	1,418.7
Non-controlling interest share of adjusted EBITDA from joint ventures (3)	(44.9)	(67.7)	(68.7)
Adjusted EBITDA, net to ENLC	$1,049.7	$1,284.6	$1,350.0
Weighted average diluted common units outstanding	494.3	485.3	466.0
Net income attributable to ENLC per common unit (diluted)	$0.05	$0.74	$0.44
Adjusted EBITDA, net to ENLC per common unit	$2.12	$2.65	$2.90
Units repurchased	6.1	18.4	20.4

1) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
2) Includes transaction costs, non-cash expense related to changes in the fair value of a contingent consideration, accretion expense associated with asset retirement obligations and non-cash rent, which relates to lease incentives pro-rated over the lease term.
3) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV

Reconciliation of Gross Margin to Adjusted Gross Margin

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Q4 2023						
Gross margin	$62.9	$63.8	$57.4	$39.9	$(1.5)	$222.5
Depreciation and amortization	43.0	39.8	54.6	28.7	1.5	167.6
Segment profit (loss)	105.9	103.6	112.0	68.6	0.0	390.1
Operating expenses	65.1	29.7	25.5	25.4	0.0	145.7
Adjusted gross margin	$171.0	$133.3	$137.5	$94.0	$0.0	$535.8
Q3 2023						
Gross margin	$60.6	$50.8	$50.0	$34.5	$(1.5)	$194.4
Depreciation and amortization	42.1	36.3	54.6	29.3	1.5	163.8
Segment profit (loss)	102.7	87.1	104.6	63.8	0.0	358.2
Operating expenses	55.0	35.0	26.6	26.7	0.0	143.3
Adjusted gross margin	$157.7	$122.1	$131.2	$90.5	$0.0	$501.5
Q2 2023						
Gross margin	$50.3	$67.6	$54.1	$38.3	$(1.3)	$209.0
Depreciation and amortization	41.5	36.9	56.6	29.0	1.3	165.3
Segment profit (loss)	91.8	104.5	110.7	67.3	0.0	374.3
Operating expenses	53.1	32.0	27.0	24.7	0.0	136.8
Adjusted gross margin	$144.9	$136.5	$137.7	$92.0	$0.0	$511.1
Q1 2023						
Gross margin	$56.0	$58.1	$42.8	$47.3	$(1.4)	$202.8
Depreciation and amortization	40.0	38.3	51.9	28.8	1.4	160.4
Segment profit (loss)	96.0	96.4	94.7	76.1	0.0	363.2
Operating expenses	48.1	33.6	24.7	26.0	0.0	132.4
Adjusted gross margin	$144.1	$130.0	$119.4	$102.1	$0.0	$495.6
Q4 2022						
Gross margin	$45.1	$55.9	$51.7	$53.7	$(1.4)	$205.0
Depreciation and amortization	43.9	41.9	47.1	30.6	1.4	164.9
Segment profit (loss)	89.0	97.8	98.8	84.3	0.0	369.9
Operating expenses	54.9	35.3	23.3	24.8	0.0	138.3
Adjusted gross margin	$143.9	$133.1	$122.1	$109.1	$0.0	$508.2

Realized and Unrealized Derivative Gain/(Loss) Activity by Segment

	Permian	Louisiana	Oklahoma	North Texas	Totals
Q4 2023					
Realized	$6.0	$3.2	$1.7	$1.7	$12.6
Unrealized	$4.0	$0.9	$1.3	$0.7	$6.9
Q3 2023					
Realized	$(4.4)	$—	$0.9	$4.4	$0.9
Unrealized	$(7.4)	$(6.0)	$(4.1)	$(5.4)	$(22.9)
Q2 2023					
Realized	$5.4	$(7.8)	$1.9	$6.5	$6.0
Unrealized	$(7.9)	$18.2	$2.0	$(7.0)	$5.3
Q1 2023					
Realized	$(4.0)	$7.2	$2.0	$8.1	$13.3
Unrealized	$6.3	$(9.0)	$(1.4)	$2.7	$(1.4)
Q4 2022					
Realized	$2.3	$8.7	$5.8	$1.9	$18.7
Unrealized	$0.6	$(2.5)	$(5.0)	$8.7	$1.8

Non-GAAP Financial Information, Other Definitions, & Notes

- This presentation contains non-generally accepted accounting principles (GAAP) financial measures that we refer to as Adjusted Gross Margin, adjusted EBITDA, adjusted EBITDA per unit, and free cash flow after distributions. Each of the foregoing measures is defined below. EnLink Midstream believes these measures are useful to investors because they may provide users of this financial information with meaningful comparisons between current results and prior-reported results and a meaningful measure of EnLink Midstream's cash flow after satisfaction of the capital and related requirements of their respective operations. Adjusted EBITDA achievement is also a primary metric used in the ENLC credit facility and adjusted EBITDA and free cash flow after distributions are both used as metrics in EnLink's short-term incentive program for compensating its employees and in EnLink's performance awards for executives.
- The referenced non-GAAP measurements are not measures of financial performance or liquidity under GAAP. They should not be considered in isolation or as an indicator of EnLink Midstream's performance. Furthermore, they should not be seen as a substitute for metrics prepared in accordance with GAAP. Reconciliations of these measures to their most directly comparable GAAP measures for the periods that are presented in this presentation are included in the Appendix to this presentation. See ENLC's filings with the Securities and Exchange Commission for more information. The payment and amount of distributions is subject to approval by the Board of Directors and to economic conditions and other factors existing at the time of determination.
- Definitions of non-GAAP measures used in this presentation:

1) Adjusted Gross Margin is revenue less cost of sales, exclusive of operating expenses and depreciation and amortization.
2) Adjusted EBITDA is net income (loss) plus (less) interest expense, net of interest income; depreciation and amortization; impairments; (income) loss from unconsolidated affiliate investments; distributions from unconsolidated affiliate investments; (gain) loss on disposition of assets; (gain) loss on extinguishment of debt; unit-based compensation; income tax expense (benefit); unrealized (gain) loss on commodity derivatives; transaction costs; costs associated with the relocation of processing facilities; accretion expense associated with asset retirement obligations; non-cash expense related to changes in the fair value of a contingent consideration; (non-cash rent); and (non-controlling interest share of adjusted EBITDA from joint ventures). Adjusted EBITDA, net to ENLC, is after non-controlling interest.
3) Adjusted EBITDA per unit is Adjusted EBITDA, net to ENLC, divided by weighted average diluted common units outstanding.
4) Free cash flow after distributions (FCFAD) is adjusted EBITDA, net to ENLC, plus (less) (growth and maintenance capital expenditures, excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (interest expense, net of interest income); (distributions declared on common units); (cash distributions earned by the Series B Preferred Units and Series C Preferred Units); (payments to redeem mandatorily redeemable non-controlling interest); (costs associated with the relocation of processing facilities, excluding costs that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (payments to terminate interest rate swaps); non-cash interest (income)/expense; (contributions to investment in unconsolidated affiliates); (current income taxes); and proceeds from the sale of equipment and land.

Non-GAAP Financial Information, Other Definitions, & Notes (Cont.)

- Other definitions and explanations of terms used in this presentation:

1) Growth capital expenditures (GCE) generally include capital expenditures made for acquisitions or capital improvements that we expect will increase our asset base, operating income or operating capacity over the long-term.
2) Maintenance capital expenditures (MCX) include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives.
3) Segment profit (loss) is defined as revenues, less cost of sales (exclusive of operating expenses and depreciation and amortization), less operating expenses.
4) Gathering is defined as a pipeline that transports hydrocarbons from a production facility to a transmission line or processing facility. Transportation is defined to include pipelines connected to gathering lines or a facility. Gathering and transportation are referred to as “G&T.” Gathering and processing are referred to as “G&P.”
5) Bcf/d is defined as billion cubic feet per day; MMcf/d is defined as million cubic feet per day; BBL/d is defined as barrels per day; Mbbls/d is defined as thousand barrels per day; NGL is defined as natural gas liquids; MMbtu/d is million British thermal units a day.
6) Year-over-Year and YoY is one calendar year as compared to the previous calendar year.
7) GIP is defined as Global Infrastructure Partners.
8) The Delaware Basin JV is a joint venture between EnLink and an affiliate of NGP in which EnLink owns a 50.1% interest and NGP owns a 49.9% interest. The Delaware Basin JV, which was formed in August 2016, owns the Lobo processing facilities, the Tiger processing plant and the future Tiger II processing plant located in the Delaware Basin in Texas.
9) The Ascension JV is a joint venture between a subsidiary of EnLink and a subsidiary of Marathon Petroleum Corporation in which EnLink owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects EnLink’s Riverside fractionator to Marathon Petroleum Corporation’s Garyville refinery.
10) CCS is defined as carbon capture and storage.
11) Mtpa is defined as million tonnes per annum.
12) FID is defined as final investment decision.
13) TRR is total rate of return.
14) Adjusted EBITDA per unit is Adjusted EBITDA, net to ENLC, divided by weighted average diluted common units outstanding.

Forward-Looking Statements

- This presentation contains forward-looking statements within the meaning of the federal securities laws. Although these statements reflect the current views, assumptions and expectations of our management, the matters addressed herein involve certain assumptions, risks and uncertainties that could cause actual activities, performance, outcomes and results to differ materially from those indicated herein. Therefore, you should not rely on any of these forward-looking statements. All statements, other than statements of historical fact, included in this press release constitute forward-looking statements, including but not limited to statements identified by the words “forecast,” “may,” “believe,” “will,” “should,” “plan,” “predict,” “anticipate,” “intend,” “estimate,” “expect,” "continue," and similar expressions. Such forward-looking statements include, but are not limited to, statements about guidance, projected or forecasted financial and operating results, future results or growth of our CCS business, expected financial and operations results associated with certain projects, acquisitions, or growth capital expenditures, timing for completion of construction or expansion projects, results in certain basins, cost savings or operational initiatives, profitability, financial or leverage metrics, repurchases of common or preferred units, future expectations regarding sustainability initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, and other statements that are not historical facts. Factors that could result in such differences or otherwise materially affect our financial condition, results of operations, or cash flows include, without limitation (a) potential conflicts of interest of Global Infrastructure Partners (“GIP”) with us and the potential for GIP to compete with us or favor GIP’s own interests to the detriment of our other unitholders, (b) adverse developments in the midstream business that may reduce our ability to make distributions, (d) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (c) decreases in the volumes that we gather, process, fractionate, or transport, (d) our ability or our customers’ ability to receive or renew required government or third party permits and other approvals, (e) increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing resulting in increased costs and reductions or delays in natural gas production by our customers, (f) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (g) changes in the availability and cost of capital, (h) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (i) our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities, (j) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (k) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (l) our dependence on significant customers for a substantial portion of the natural gas and crude that we gather, process, and transport, (m) construction risks in our major development projects, (n) challenges we may face in connection with our strategy to enter into new lines of business related to the energy transition, (o) the impact of the coronavirus (COVID-19) pandemic (including the impact of any new variants of the virus) and similar pandemics,(p) impairments to goodwill, long-lived assets and equity method investments, and (q) the effects of existing and future laws and governmental regulations, and other uncertainties. These and other applicable uncertainties, factors, and risks are described more fully in EnLink Midstream, LLC’s filings with the Securities and Exchange Commission, including its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K. EnLink assumes no obligation to update any forward-looking statements.
- The EnLink management team based the forecasted financial information included herein on certain information and assumptions, including, among others, the producer budgets / forecasts to, which EnLink has access as of the date of this presentation and the projects / opportunities expected to require growth capital expenditures as of the date of this presentation. The assumptions, information, and estimates underlying the forecasted financial information included in the guidance information in this presentation are inherently uncertain and, though considered reasonable by the EnLink management team as of the date of its preparation, are subject to a wide variety of significant business, economic, and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the forecasted financial information. Accordingly, there can be no assurance that the forecasted results are indicative of EnLink's future performance or that actual results will not differ materially from those presented in the forecasted financial information. Inclusion of the forecasted financial information in this presentation should not be regarded as a representation by any person that the results contained in the forecasted financial information will be achieved.