UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

☒ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2023

OR

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission file number: 001-36336

ENLINK MIDSTREAM, LLC

(Exact name of registrant as specified in its charter)

Delaware	**46-4108528**
(State of organization)	(I.R.S. Employer Identification No.)
1722 Routh St., Suite 1300	
Dallas, Texas	**75201**
(Address of principal executive offices)	(Zip Code)

(214) 953-9500
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE SECURITIES EXCHANGE ACT OF 1934:

Title of Each Class	Trading Symbol	Name of Exchange on which Registered
Common Units Representing Limited Liability Company Interests	ENLC	The New York Stock Exchange

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Securities Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of July 27, 2023, the Registrant had 461,497,730 common units outstanding.

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	Definition
/d	Per day.
2014 Plan	ENLC's 2014 Long-Term Incentive Plan.
Adjusted gross margin	Revenue less cost of sales, exclusive of operating expenses and depreciation and amortization. Adjusted gross margin is a non-GAAP financial measure. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" for additional information.
Amarillo Rattler Acquisition	On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin.
AR Facility	An accounts receivable securitization facility of up to $500 million entered into by EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity and our indirect subsidiary, with PNC Bank, National Association, as administrative agent and lender, and PNC Capital Markets, LLC, as structuring agent and sustainability agent.
ASC	The Financial Accounting Standards Board Accounting Standards Codification.
ASC 718	ASC 718, *Compensation—Stock Compensation*.
ASC 815	ASC 815, *Derivatives and Hedging.*
ASC 820	ASC 820, *Fair Value Measurements.*
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK 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 ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
Barnett Shale	A natural gas producing shale reservoir located in North Texas.
Barnett Shale Acquisition	On July 1, 2022, we acquired all of the equity interest in the gathering and processing assets of Crestwood Equity Partners LP located in the Barnett Shale.
Bbl	Barrel.
Bbtu	Billion British thermal units.
Bcf	Billion cubic feet.
Beginning TSR Price	The beginning total shareholder return ("TSR") price, which is the closing unit price of ENLC on the grant date of the performance award agreement or the previous trading day if the grant date was not a trading day, is one of the assumptions used to calculate the grant-date fair value of performance award agreements.
CCS	Carbon capture, transportation, and sequestration.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Kinder Morgan, Inc. in which ENLK owns a 30% interest and Kinder Morgan, Inc. owns a 70% interest. The Cedar Cove JV, which was formed in November 2016, owns gathering and compression assets in Blaine County, Oklahoma, located in the STACK play.
Central Oklahoma Acquisition	On December 19, 2022, we acquired gathering and processing assets located in Central Oklahoma, including approximately 900 miles of lean and rich gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity.
CFTC	U.S. Commodity Futures Trading Commission.
CO_2	Carbon dioxide.
Commission	U.S. Securities and Exchange Commission.
Delaware Basin	A large sedimentary basin in West Texas and New Mexico.
Delaware Basin JV	Delaware G&P LLC, a joint venture between a subsidiary of ENLK and an affiliate of NGP in which ENLK 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 and the Tiger processing plant located in the Delaware Basin in Texas.
ENLC	EnLink Midstream, LLC together with its consolidated subsidiaries.
ENLC Class C Common Units	A class of non-economic ENLC common units equal to the number of Series B Preferred Units in order to provide certain voting rights with respect to ENLC to the holders of such Series B Preferred Units.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FCDTCs	Futures and Cleared Derivatives Transactions Customer Agreements.
Federal Reserve	The Board of Governors of the Federal Reserve System of the United States.
GAAP	Generally accepted accounting principles in the United States of America.

Gal	Gallon.
GCF	Gulf Coast Fractionators, which owns an NGL fractionator in Mont Belvieu, Texas. We own 38.75% of GCF. The GCF assets were temporarily idled to reduce operating expenses in 2021 but are expected to resume operations in 2024.
General Partner	EnLink Midstream GP, LLC, the general partner of ENLK.
GIP	Global Infrastructure Management, LLC, an independent infrastructure fund manager, itself, its affiliates, or managed fund vehicles, including GIP III Stetson I, L.P., GIP III Stetson II, L.P., and their affiliates.
ISDAs	International Swaps and Derivatives Association Agreements.
LIBOR	U.S. Dollar London Interbank Offered Rate.
Managing Member	EnLink Midstream Manager, LLC, the managing member of ENLC.
Matterhorn JV	A joint venture with WhiteWater Midstream, LLC, Devon Energy Corporation, and MPLX LP. The Matterhorn JV is expected to construct a pipeline designed to transport up to 2.5 Bcf/d of natural gas through approximately 490 miles of 42-inch pipeline from the Waha Hub in West Texas to Katy, Texas.
Midland Basin	A large sedimentary basin in West Texas.
MMbbls	Million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MMgals	Million gallons.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
NYMEX	New York Mercantile Exchange.
Operating Partnership	EnLink Midstream Operating, LP, a Delaware limited partnership and wholly owned subsidiary of ENLK.
OPIS	Oil Price Information Service.
ORV	ENLK’s Ohio River Valley crude oil, condensate stabilization, natural gas compression, and brine disposal assets in the Utica and Marcellus shales.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Revolving Credit Facility	A $1.40 billion unsecured revolving credit facility entered into by ENLC, which includes a $500.0 million letter of credit subfacility. The Revolving Credit Facility is guaranteed by ENLK.
Series B Preferred Unit	ENLK’s Series B Cumulative Convertible Preferred Unit.
Series C Preferred Unit	ENLK’s Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Unit.
SOFR	Secured overnight financing rate.
SPV	EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity that is an indirect subsidiary of ENLC.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.

PART I—FINANCIAL INFORMATION
Item 1. Financial Statements
ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Balance Sheets
(In millions, except unit data)

	June 30, 2023 (Unaudited)	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54.8	$ 22.6
Accounts receivable:		
Trade receivables (1)	82.6	89.2
Accrued revenue and other	459.3	636.0
Fair value of derivative assets	83.8	68.4
Other current assets	101.3	166.6
Total current assets	781.8	982.8
Property and equipment, net of accumulated depreciation of $5,026.1 and $4,774.5, respectively	6,503.9	6,556.0
Intangible assets, net of accumulated amortization of $987.4 and $923.6, respectively	857.4	921.2
Investment in unconsolidated affiliates	134.3	90.2
Fair value of derivative assets	18.3	2.9
Other assets, net	104.2	97.9
Total assets	$ 8,399.9	$ 8,651.0
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 101.2	$ 126.9
Accrued gas, NGLs, condensate, and crude oil purchases (2)	314.6	476.0
Fair value of derivative liabilities	49.2	42.9
Current maturities of long-term debt	97.9	—
Other current liabilities	238.8	229.6
Total current liabilities	801.7	875.4
Long-term debt, net of unamortized issuance cost	4,640.9	4,723.5
Other long-term liabilities	92.9	94.0
Deferred tax liability, net	72.8	42.7
Fair value of derivative liabilities	17.4	2.7
Members' equity:		
Members' equity (462,025,317 and 468,980,630 units issued and outstanding, respectively)	1,156.1	1,306.4
Accumulated other comprehensive income	4.5	—
Non-controlling interest	1,613.6	1,606.3
Total members' equity	2,774.2	2,912.7
Commitments and contingencies (Note 16)		
Total liabilities and members' equity	$ 8,399.9	$ 8,651.0

(1) There was no allowance for bad debt at June 30, 2023. Includes allowance for bad debt of $ 0.1 million at December 31, 2022.
(2) Includes related party accounts payable balances of $0.3 million and $2.5 million at June 30, 2023 and December 31, 2022, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Operations
(In millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(Unaudited)			
Revenues:				
Product sales	$ 1,239.3	$ 2,370.5	$ 2,715.6	$ 4,414.4
Midstream services (1)	279.5	225.6	558.8	440.6
Gain (loss) on derivative activity	11.3	4.5	23.2	(26.7)
Total revenues	1,530.1	2,600.6	3,297.6	4,828.3
Operating costs and expenses:				
Cost of sales, exclusive of operating expenses and depreciation and amortization (2)	1,019.0	2,105.1	2,290.9	3,899.6
Operating expenses	136.8	128.9	269.2	249.8
Depreciation and amortization	165.3	159.0	325.7	311.9
(Gain) loss on disposition of assets	(0.8)	(0.4)	(1.2)	4.7
General and administrative	27.9	28.4	57.4	57.4
Total operating costs and expenses	1,348.2	2,421.0	2,942.0	4,523.4
Operating income	181.9	179.6	355.6	304.9
Other income (expense):				
Interest expense, net of interest income	(68.8)	(55.5)	(137.3)	(110.6)
Loss on extinguishment of debt	—	(0.5)	—	(0.5)
Loss from unconsolidated affiliate investments	(4.6)	(1.2)	(4.7)	(2.3)
Other income	0.4	0.2	0.4	0.3
Total other expense	(73.0)	(57.0)	(141.6)	(113.1)
Income before non-controlling interest and income taxes	108.9	122.6	214.0	191.8
Income tax benefit (expense)	(19.0)	1.3	(29.9)	(1.9)
Net income	89.9	123.9	184.1	189.9
Net income attributable to non-controlling interest	35.6	38.6	71.6	69.4
Net income attributable to ENLC	$ 54.3	$ 85.3	$ 112.5	$ 120.5
Net income attributable to ENLC per unit:				
Basic common unit	$ 0.12	$ 0.18	$ 0.24	$ 0.25
Diluted common unit	$ 0.12	$ 0.17	$ 0.24	$ 0.25

(1) Includes related party revenue of $0.6 million and $1.3 million for the three and six months ended June 30, 2023, respectively. We did not have related party revenue for the three and six months ended June 30, 2022.
(2) Includes related party cost of sales of $2.5 million and $9.1 million for the three months ended June 30, 2023 and 2022, respectively, and $4.0 million and $19.7 million for the six months ended June 30, 2023 and 2022, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income
(In millions)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(Unaudited)			
Net income	$ 89.9	$ 123.9	$ 184.1	$ 189.9
Unrealized gain on designated cash flow hedge (1)	5.7	—	4.5	0.1
Comprehensive income	95.6	123.9	188.6	190.0
Comprehensive income attributable to non-controlling interest	35.6	38.6	71.6	69.4
Comprehensive income attributable to ENLC	$ 60.0	$ 85.3	$ 117.0	$ 120.6

(1) Includes tax expense of $1.8 million and $1.4 million for the three and six months ended June 30, 2023, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Changes in Members' Equity
(In millions)

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total
	$	Units	$	$	$
			(Unaudited)		
Balance, December 31, 2022	$ 1,306.4	469.0	$ —	$ 1,606.3	$ 2,912.7
Conversion of unit-based awards for common units, net of units withheld for taxes	(16.8)	2.5	—	—	(16.8)
Unit-based compensation	4.0	—	—	—	4.0
Contributions from non-controlling interests	—	—	—	8.4	8.4
Distributions	(61.7)	—	—	(42.4)	(104.1)
Unrealized loss on designated cash flow hedge (1)	—	—	(1.2)	—	(1.2)
Repurchase of Series C Preferred Units	—	—	—	(3.9)	(3.9)
Common units repurchased	(51.4)	(4.4)	—	—	(51.4)
Net income	58.2	—	—	36.0	94.2
Balance, March 31, 2023	1,238.7	467.1	(1.2)	1,604.4	2,841.9
Conversion of unit-based awards for common units, net of units withheld for taxes	(0.1)	0.1	—	—	(0.1)
Unit-based compensation	4.5	—	—	—	4.5
Contributions from non-controlling interests	—	—	—	13.7	13.7
Distributions	(58.5)	—	—	(40.1)	(98.6)
Unrealized gain on designated cash flow hedge (2)	—	—	5.7	—	5.7
Adjustment related to the redemption of the mandatorily redeemable non-controlling interest (3)	0.8	—	—	—	0.8
Common units repurchased	(56.1)	(5.2)	—	—	(56.1)
Accrued common unit repurchase (4)	(27.5)	—	—	—	(27.5)
Net income	54.3	—	—	35.6	89.9
Balance, June 30, 2023	$ 1,156.1	462.0	$ 4.5	$ 1,613.6	$ 2,774.2

(1) Includes tax benefit of $0.4 million for the three months ended March 31, 2023.
(2) Includes tax expense of $1.8 million for the three months ended June 30, 2023.
(3) Relates to book-to-tax differences recorded upon the settlement of the mandatorily redeemable non-controlling interest.
(4) Relates to the repurchase of ENLC common units held by GIP on July 31, 2023. For additional information, see "Note 9—Members' Equity."

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Changes in Members' Equity (Continued)
(In millions)

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total
	$	Units	$	$	$
			(Unaudited)		
Balance, December 31, 2021	$ 1,325.8	484.3	$ (1.4)	$ 1,662.6	$ 2,987.0
Conversion of unit-based awards for common units, net of units withheld for taxes	(4.2)	1.2	—	—	(4.2)
Unit-based compensation	8.1	—	—	—	8.1
Contributions from non-controlling interests	—	—	—	7.3	7.3
Distributions	(56.4)	—	—	(34.6)	(91.0)
Unrealized gain on designated cash flow hedge	—	—	0.1	—	0.1
Redemption of Series B Preferred Units	—	—	—	(50.5)	(50.5)
Common units repurchased	(17.0)	(2.1)	—	—	(17.0)
Net income	35.2	—	—	30.8	66.0
Balance, March 31, 2022	1,291.5	483.4	(1.3)	1,615.6	2,905.8
Conversion of unit-based awards for common units, net of units withheld for taxes	(0.2)	—	—	—	(0.2)
Unit-based compensation	5.7	—	—	—	5.7
Contributions from non-controlling interests	—	—	—	2.0	2.0
Distributions	(55.3)	—	—	(42.2)	(97.5)
Common units repurchased	(33.7)	(3.6)	—	—	(33.7)
Net income	85.3	—	—	38.6	123.9
Balance, June 30, 2022	$ 1,293.3	479.8	$ (1.3)	$ 1,614.0	$ 2,906.0

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(In millions)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 184.1	$ 189.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	325.7	311.9
Utility credits redeemed	1.5	11.6
Deferred income tax expense	29.6	1.2
(Gain) loss on disposition of assets	(1.2)	4.7
Non-cash unit-based compensation	8.5	12.3
Non-cash gain on derivatives recognized in net income	(3.9)	(18.6)
Amortization of debt issuance costs and net discount of senior unsecured notes	3.3	2.6
Loss from unconsolidated affiliate investments	4.7	2.3
Other operating activities	0.8	(1.4)
Changes in assets and liabilities:		
Accounts receivable, accrued revenue, and other	183.1	(226.7)
Natural gas and NGLs inventory, prepaid expenses, and other	66.6	(83.2)
Accounts payable, accrued product purchases, and other accrued liabilities	(215.0)	276.0
Net cash provided by operating activities	587.8	482.6
Cash flows from investing activities:		
Additions to property and equipment	(203.1)	(124.1)
Contributions to unconsolidated affiliate investments	(49.7)	(26.6)
Other investing activities	3.7	1.4
Net cash used in investing activities	(249.1)	(149.3)
Cash flows from financing activities:		
Proceeds from borrowings	2,004.1	1,135.0
Repayments on borrowings	(1,989.0)	(1,177.0)
Payment of installment payable for the Amarillo Rattler Acquisition	—	(10.0)
Distributions to members	(120.2)	(111.7)
Distributions to non-controlling interests	(82.5)	(76.8)
Payment to redeem mandatorily redeemable non-controlling interest	(10.5)	—
Redemption of Series B Preferred Units	—	(50.5)
Repurchase of Series C Preferred Units	(3.9)	—
Contributions from non-controlling interests	22.1	9.3
Common unit repurchases	(107.5)	(50.7)
Conversion of unit-based awards for common units, net of units withheld for taxes	(16.9)	(4.4)
Other financing activities	(2.2)	(4.6)
Net cash used in financing activities	(306.5)	(341.4)
Net increase (decrease) in cash and cash equivalents	32.2	(8.1)
Cash and cash equivalents, beginning of period	22.6	26.2
Cash and cash equivalents, end of period	$ 54.8	$ 18.1
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 131.1	$ 107.8
Cash paid for income taxes	$ 1.0	$ 0.8
Non-cash investing activities:		
Right-of-use assets obtained in exchange for operating lease liabilities	$ 11.6	$ 15.3
Non-cash accrual of property and equipment	$ 15.7	$ (1.6)

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements
June 30, 2023
(Unaudited)

(1) General

In this report, the terms "Company" or "Registrant," as well as the terms "ENLC," "our," "we," "us," or like terms, are sometimes used as abbreviated references to EnLink Midstream, LLC itself or EnLink Midstream, LLC together with its consolidated subsidiaries, including ENLK and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK," or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Please read the notes to the consolidated financial statements in conjunction with the Definitions page set forth in this report prior to Part I—Financial Information.

a. Organization of Business

ENLC is a Delaware limited liability company formed in October 2013. The Company's common units are traded on the New York Stock Exchange under the symbol "ENLC." As of June 30, 2023, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 41.3% of the outstanding limited liability company interests in ENLC. In addition to GIP's equity interests in ENLC, GIP III Stetson I, L.P. maintains control over the Managing Member through its ownership of all of the equity interests in the Managing Member. ENLC owns all of ENLK's common units and also owns all of the membership interests of the General Partner. The General Partner manages ENLK's operations and activities.

b. Nature of Business

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

As of June 30, 2023, our midstream energy asset network includes approximately13,600 miles of pipelines, 26 natural gas processing plants with approximately 6.0 Bcf/d of processing capacity, seven fractionators with approximately 320,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

Our natural gas business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or near producing wells and transport it to our processing plants or to larger pipelines for further transmission. We operate processing plants that remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, marketers, and pipelines. Our transmission pipelines receive natural gas from our gathering systems and from third-party gathering and transmission systems and deliver natural gas to industrial end-users, utilities, and other pipelines.

Our fractionators separate NGLs into separate purity products, including ethane, propane, iso-butane, normal butane, and natural gasoline. Our fractionators receive NGLs primarily through our transmission lines that transport NGLs from East Texas and from our South Louisiana processing plants. Our fractionators also have the capability to receive NGLs by truck or rail terminals. We also have agreements pursuant to which third parties transport NGLs from our West Texas and Central Oklahoma operations to our NGL transmission lines that then transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

Our crude oil and condensate business includes the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

Across our businesses, we primarily earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodities purchased.

(2) Significant Accounting Policies

a. Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q, are unaudited, and do not include all the information and disclosures required by GAAP for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023. Certain reclassifications were made to the financial statements for the prior period to conform to current period presentation. The effect of these reclassifications had no impact on previously reported members' equity or net income. All significant intercompany balances and transactions have been eliminated in consolidation.

b. Revenue Recognition

The following table summarizes the contractually committed fees (in millions) that we expect to recognize in our consolidated statements of operations, in either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. Under these agreements, our customers or suppliers agree to transport or process a minimum volume of commodities on our system over an agreed period. If a customer or supplier fails to meet the minimum volume specified in such agreement, the customer or supplier is obligated to pay a contractually determined fee based upon the shortfall between actual volumes and the contractually stated volumes. All amounts in the table below are determined using the contractually-stated MVC or firm transportation volumes specified for each period multiplied by the relevant deficiency or reservation fee. Actual amounts could differ due to the timing of revenue recognition or reductions to cost of sales resulting from make-up right provisions included in our agreements, as well as due to nonpayment or nonperformance by our customers. We record revenue under MVC and firm transportation contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency. These fees do not represent the shortfall amounts we expect to collect under our MVC and firm transportation contracts, as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs and firm transportation contracts during these periods.

Contractually Committed Fees	Commitments
2023 (remaining)	$ 76.6
2024	127.5
2025	110.4
2026	115.0
2027	98.1
Thereafter	1,120.1
Total	$ 1,647.7

c. Redeemable Non-Controlling Interest

During the first quarter of 2020, the non-controlling interest holder in one of our non-wholly owned subsidiaries exercised its option to require us to purchase its remaining interest. At the time of the exercise, we and the interest holder did not agree on the value of the interest and a lawsuit was filed by the interest holder. As part of a settlement effected with the interest holder in January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest for $10.5 million.

(3) Acquisition

Central Oklahoma Acquisition

On December 19, 2022, we completed the Central Oklahoma Acquisition. The acquired assets include approximately900 miles of lean and rich gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity. We completed this acquisition to increase the scale and efficiency of our Central Oklahoma assets.

The following table presents the preliminary fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration		
Cash (including working capital payment)	$	100.9
Contingent consideration		1.3
Total consideration	$	102.2

Purchase price allocation (1)		
Assets acquired:		
Current assets	$	6.0
Property and equipment		97.1
Other assets, net (2)		0.9
Liabilities assumed:		
Current liabilities		(1.4)
Other long-term liabilities (2)		(0.4)
Net assets acquired	$	102.2

(1) The purchase price allocation was based on preliminary estimates and assumptions, which are subject to change within the measurement period (up to one year from the acquisition date), as we finalize the valuations of the assets acquired and liabilities assumed upon the closing of the acquisition.
(2) “Other assets, net” and “Other long-term liabilities” consist of the right-of-use assets and lease liabilities, respectively, obtained through the Central Oklahoma Acquisition.

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Contingent Consideration. The following table represents our change in carrying value of the Amarillo Rattler Acquisition and Central Oklahoma Acquisition contingent consideration liabilities for the periods presented (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Amarillo Rattler Acquisition contingent consideration				
Contingent consideration liability, beginning of period (1)	$ 4.7	$ 6.9	$ 4.2	$ 6.9
Change in fair value	(0.1)	0.3	0.4	0.3
Contingent consideration liability, end of period	$ 4.6	$ 7.2	$ 4.6	$ 7.2
Central Oklahoma Acquisition contingent consideration				
Contingent consideration liability, beginning of period (2)	$ 1.5	$ —	$ 1.3	$ —
Change in fair value	0.3	—	0.5	—
Contingent consideration liability, end of period	$ 1.8	$ —	$ 1.8	$ —
Total contingent consideration				
Contingent consideration liability, beginning of period (1)(2)	$ 6.2	$ 6.9	$ 5.5	$ 6.9
Change in fair value	0.2	0.3	0.9	0.3
Contingent consideration liability, end of period	$ 6.4	$ 7.2	$ 6.4	$ 7.2

(1) The contingent consideration for the Amarillo Rattler Acquisition was recorded on April 30, 2021.
(2) The contingent consideration for the Central Oklahoma Acquisition was recorded on December 19, 2022.

Pro Forma of Acquisitions for the Three and Six Months Ended June 30, 2022

The following unaudited pro forma condensed consolidated financial information (in millions) for the three and six months ended June 30, 2022 gives effect to the Barnett Shale Acquisition on July 1, 2022 and the Central Oklahoma Acquisition on December 19, 2022 as if each of the acquisitions had occurred on January 1, 2022.

The unaudited pro forma condensed consolidated financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Three Months Ended June 30, 2022	Six Months Ended June 30, 2022
Pro forma total revenues	$ 2,635.5	$ 4,892.4
Pro forma net income	$ 139.2	$ 214.4

(4) Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which ranged from 10 to 20 years at the time the intangible assets were originally recorded. The weighted average amortization period for intangible assets is 14.9 years.

The following table represents our change in carrying value of intangible assets (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Six Months Ended June 30, 2023			
Customer relationships, beginning of period	$ 1,844.8	$ (923.6)	$ 921.2
Amortization expense	—	(63.8)	(63.8)
Customer relationships, end of period	$ 1,844.8	$ (987.4)	$ 857.4

Amortization expense was $31.9 million for each of the three months ended June 30, 2023 and 2022 and $63.8 million and $64.7 million for the six months ended June 30, 2023 and 2022, respectively.

The following table summarizes our estimated aggregate amortization expense for the next five years and thereafter (in millions):

2023 (remaining)	$	63.8
2024		127.6
2025		110.2
2026		106.3
2027		106.3
Thereafter		343.2
Total	$	857.4

(5) Related Party Transactions

(a) Transactions with Cedar Cove JV

For the three and six months ended June 30, 2023, we recorded revenue of $0.6 million and $1.3 million, respectively, related to the receipt of residue gas and NGLs from the Cedar Cove JV. For each of the three and six months ended June 30, 2022, we did not record any revenue related to the receipt of residue gas and NGLs from the Cedar Cove JV. For the three and six months ended June 30, 2023, we recorded cost of sales of $2.5 million and $4.0 million, respectively, and for the three and six months ended June 30, 2022, we recorded cost of sales of $9.1 million and $19.7 million, respectively, related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our Central Oklahoma processing facilities. Additionally, we had accounts payable balances related to transactions with the Cedar Cove JV of $0.3 million and $2.5 million at June 30, 2023 and December 31, 2022, respectively.

(b) Transactions with GIP

General and Administrative Expenses. We did not record any expenses related to transactions with GIP and its affiliates for the three and six months ended June 30, 2023 and 2022.

Management believes the foregoing transactions with related parties were executed on terms that are fair and reasonable to us. The amounts related to related party transactions are specified in the accompanying consolidated financial statements.

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(6) Long-Term Debt

As of June 30, 2023 and December 31, 2022, long-term debt consisted of the following (in millions):

	June 30, 2023			December 31, 2022		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Revolving Credit Facility due 2027 (1)	$ 160.0	$ —	$ 160.0	$ 255.0	$ —	$ 255.0
AR Facility due 2025 (2)	313.1	—	313.1	500.0	—	500.0
ENLK's 4.40% Senior unsecured notes due 2024	97.9	—	97.9	97.9	—	97.9
ENLK's 4.15% Senior unsecured notes due 2025	421.6	—	421.6	421.6	(0.1)	421.5
ENLK's 4.85% Senior unsecured notes due 2026	491.0	(0.2)	490.8	491.0	(0.2)	490.8
ENLC's 5.625% Senior unsecured notes due 2028	500.0	—	500.0	500.0	—	500.0
ENLC's 5.375% Senior unsecured notes due 2029	498.7	—	498.7	498.7	—	498.7
ENLC's 6.50% Senior unsecured notes due 2030	1,000.0	(2.9)	997.1	700.0	—	700.0
ENLK's 5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
ENLK's 5.05% Senior unsecured notes due 2045	450.0	(5.1)	444.9	450.0	(5.2)	444.8
ENLK's 5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term, including current maturities of long-term debt	$ 4,782.3	$ (8.5)	4,773.8	$ 4,764.2	$ (5.8)	4,758.4
Debt issuance cost (3)			(35.0)			(34.9)
Less: Current maturities of long-term debt (4)			(97.9)			—
Long-term debt, net of unamortized issuance cost			$ 4,640.9			$ 4,723.5

(1) The effective interest rate was 6.8% and 6.5% at June 30, 2023 and December 31, 2022, respectively.
(2) The effective interest rate was 6.1% and 5.3% at June 30, 2023 and December 31, 2022, respectively.
(3) Net of accumulated amortization of $18.0 million and $15.1 million at June 30, 2023 and December 31, 2022, respectively.
(4) The outstanding balance, net of debt issuance costs, of ENLK's 4.40% senior unsecured notes as of June 30, 2023 are classified as "Current maturities of long-term debt" on the consolidated balance sheet as these notes mature on April 1, 2024.

Revolving Credit Facility

The Revolving Credit Facility permits ENLC to borrow up to $1.40 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. There were $160.0 million in outstanding borrowings under the Revolving Credit Facility and $21.3 million in outstanding letters of credit as of June 30, 2023.

At June 30, 2023, we were in compliance with and expect to be in compliance with the financial covenants of the Revolving Credit Facility for at least the next twelve months.

AR Facility

On October 21, 2020, the SPV entered into the AR Facility. We are the primary beneficiary of the SPV, and we consolidate its assets and liabilities, which consist primarily of billed and unbilled accounts receivable of $509.2 million as of June 30, 2023. As of June 30, 2023, the AR Facility had a borrowing base of $371.7 million and there were $313.1 million in outstanding borrowings under the AR Facility.

At June 30, 2023, we were in compliance with and expect to be in compliance with the financial covenants of the AR Facility for at least the next twelve months.

Senior Unsecured Notes

On April 3, 2023, we completed the sale of an additional $300.0 million aggregate principal amount of 6.500% senior notes due 2030 (the "Additional Notes") at 99% of their face value. The Additional Notes were offered as an additional issue of our existing 6.500% senior notes due 2030 that we issued on August 31, 2022 in an aggregate principal amount of $700.0 million. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by ENLK.

(7) Income Taxes

The components of our income tax benefit (expense) are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Current income tax expense	$ (0.2)	$ (0.5)	$ (0.3)	$ (0.7)
Deferred income tax benefit (expense)	(18.8)	1.8	(29.6)	(1.2)
Income tax benefit (expense)	$ (19.0)	$ 1.3	$ (29.9)	$ (1.9)

The following schedule reconciles income tax benefit (expense) and the amount calculated by applying the statutory U.S. federal tax rate to income before non-controlling interest and income taxes (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Expected income tax expense based on federal statutory rate	$ (15.4)	$ (17.8)	$ (29.9)	$ (25.9)
State income tax expense, net of federal benefit	(2.0)	(2.5)	(3.8)	(3.6)
Unit-based compensation (1)	0.1	—	6.6	(2.0)
Change in valuation allowance	—	21.0	—	28.1
Other	(1.7)	0.6	(2.8)	1.5
Income tax benefit (expense)	$ (19.0)	$ 1.3	$ (29.9)	$ (1.9)

(1) Related to book-to-tax differences recorded upon the vesting of unit-based awards.

Deferred Tax Assets and Liabilities

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The deferred tax liabilities, net of deferred tax assets, are included in "Deferred tax liability, net" in the consolidated balance sheets. As of June 30, 2023, we had $800.9 million of deferred tax assets and $873.7 million of deferred tax liabilities for net deferred tax liabilities of $72.8 million. As of December 31, 2022, we had $714.1 million of deferred tax assets and $756.8 million of deferred tax liabilities for net deferred tax liabilities of $42.7 million.

We provide a valuation allowance, if necessary, to reduce deferred tax assets, if all, or some portion, of such assets will more than likely not be realized. As of June 30, 2023, we did not record a valuation allowance and management believes it is more likely than not that the Company will realize the benefits of the deferred tax assets.

Excise Tax on Common Unit Repurchases

In August 2022, the Inflation Reduction Act of 2022 was signed into law, which, among other things, imposed a 1.0% excise tax on net common unit repurchases made after December 31, 2022. As a result, we accrued $0.7 million of excise tax in connection with the common unit repurchases we completed for each of the three and six months ended June 30, 2023, which was recorded as an adjustment to the cost basis of common units repurchased in "Members' equity" and "Other current liabilities" on the consolidated balance sheet as of June 30, 2023.

(8) Certain Provisions of the ENLK Partnership Agreement

a. Series B Preferred Units

As of June 30, 2023 and December 31, 2022, there were54,303,780 and 54,168,359 Series B Preferred Units issued and outstanding, respectively.

Redemption

In January 2022, we redeemed 3,333,334 Series B Preferred Units for total consideration of $50.5 million plus accrued distributions. In addition, upon such redemption, a corresponding number of ENLC Class C Common Units were automatically cancelled. The redemption price represented 101% of the preferred units' par value. In connection with the Series B Preferred Unit redemption, we agreed with the holders of the Series B Preferred Units to pay cash in lieu of making a quarterly distribution in-kind of additional Series B Preferred Units (the "PIK Distribution") through the distribution declared for the fourth quarter of 2022. Beginning with the quarterly distribution declared for the first quarter of 2023, we have resumed paying the PIK distribution.

Distributions

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earnedA summary of the distribution activity relating to the Series B Preferred Units during the six months ended June 30, 2023 and 2022 is provided below:

Declaration period	PIK Distribution	Cash distribution (in millions)	Date paid/payable
2023			
Fourth Quarter of 2022	—	$ 17.3	February 13, 2023
First Quarter of 2023	135,421	$ 15.2	May 12, 2023
Second Quarter of 2023	135,759	$ 15.3	August 11, 2023
2022			
Fourth Quarter of 2021	—	$ 19.2	February 11, 2022 (1)
First Quarter of 2022	—	$ 17.5	May 13, 2022 (2)
Second Quarter of 2022	—	$ 17.3	August 12, 2022

(1) In December 2021 and January 2022, we paid $0.9 million and $1.0 million, respectively, of accrued distributions related to the fourth quarter of 2021 on redeemed Series B Preferred Units. The remaining distribution of $17.3 million related to the fourth quarter of 2021 was paid on February 11, 2022.
(2) In January 2022, we paid $0.3 million of accrued distributions related to the first quarter of 2022 on redeemed Series B Preferred Units. The remaining distribution of $ 17.2 million related to the first quarter of 2022 was paid on May 13, 2022.

Series B Preferred Units Taxable Income

For tax purposes, holders of Series B Preferred Units are allocated items of gross income from ENLK in respect of each Series B Preferred Unit until the cumulative amount of gross income so allocated equals the cumulative amount of distributions made in respect of such Series B Preferred Unit, but not in excess of such Series B Preferred Unit's pro rata share of the net income of ENLK for the allocation year (the "Allocation Cap"). As of June 30, 2023, due to the application of the Allocation Cap, the cumulative amount of distributions made in respect of each Series B Preferred Unit exceeded the cumulative amount of gross income allocated to each Series B Preferred Unit by $6.26 per Series B Preferred Unit (the "Catch-Up Taxable Income Allocation"). As a result, holders of Series B Preferred Units will ultimately be allocated taxable income during future periods equal to the Catch-Up Taxable Income Allocation plus the amount of distributions received in respect of Series B Preferred Units, if ENLK generates positive net income.

b. Series C Preferred Units

As of June 30, 2023 and December 31, 2022, there were376,500 and 381,000 Series C Preferred Units issued and outstanding, respectively.

Repurchase

In February 2023, we repurchased 4,500 Series C Preferred Units for total consideration of $3.9 million. The repurchase price represented 87% of the preferred units' par value.

Distributions

Income is allocated to the Series C Preferred Units in an amount equal to the earned distribution for the respective reporting period. A summary of the distribution activity relating to the Series C Preferred Units during the six months ended June 30, 2023 and 2022 is provided below:

Declaration period (1)	Distribution rate (2)	Cash distribution (in millions)	Date paid/payable
2023			
December 15, 2022 – March 14, 2023	8.846 %	$ 8.4	March 15, 2023
March 15, 2023 – June 14, 2023	9.051 %	$ 8.7	June 15, 2023
June 15, 2023 – September 14, 2023	9.618 %	$ 9.3	September 15, 2023
2022			
December 15, 2021 – June 14, 2022	6.000 %	$ 12.0	June 15, 2022
June 15, 2022 – December 14, 2022	6.000 %	$ 12.0	December 15, 2022

(1) Distributions on the Series C Preferred Units accrued and were cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, accrue quarterly in arrears on the 15th day of March, June, September, and December of each year, in each case, if and when declared by the General Partner out of legally available funds for such purpose.

(2) The initial distribution rate for the Series C Preferred Units from the date of original issue through December 14, 2022 was 6.0% per year. Starting on December 15, 2022, distributions on the Series C Preferred Units accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to the floating rate of the three-month LIBOR plus a spread of 4.11%. Beginning with the interest period starting on September 15, 2023, distributions on the Series C Preferred Units will accumulate at a forward-looking term rate based on SOFR ("Term SOFR"), plus a Term SOFR spread adjustment of 0.26161%, plus a spread of 4.11%.

(9) Members' Equity

a. Common Unit Repurchase Program

In December 2022, the board of directors of the Managing Member (the "Board") reauthorized our common unit repurchase program for 2023 and set the amount available for repurchases of outstanding common units during 2023 at up to $200.0 million, including repurchases of common units held by GIP. Repurchases under the common unit repurchase program will be made, in accordance with applicable securities laws, from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time.

The following table summarizes our ENLC common unit repurchase activity for the periods presented (in millions, except for unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Publicly held ENLC common units	3,230,504	2,921,370	5,437,809	5,015,212
ENLC common units held by GIP (1)	1,910,877	675,095	4,147,987	675,095
Total ENLC common units	5,141,381	3,596,465	9,585,796	5,690,307
Aggregate cost for publicly held ENLC common units	$ 32.2	$ 27.7	$ 59.0	$ 44.7
Aggregate cost for ENLC common units held by GIP	23.2	6.0	47.8	6.0
Excise tax on common unit repurchases	0.7	—	0.7	—
Total aggregate cost for ENLC common units	$ 56.1	$ 33.7	$ 107.5	$ 50.7
Average price paid per publicly held ENLC common unit (2)	$ 9.96	$ 9.49	$ 10.85	$ 8.92
Average price paid per ENLC common unit held by GIP (2)(3)	$ 12.12	$ 8.92	$ 11.53	$ 8.92

(1) The units repurchased in each quarter represent GIP's pro rata share of the aggregate number of common units repurchased by us under our common unit repurchase program during the prior quarter.
(2) The average price paid per common unit excludes excise tax on common unit repurchases.
(3) The per unit price we paid to GIP in each quarter was the average per unit price paid by us for publicly held ENLC common units repurchased in the prior quarter, less broker commissions.

Additionally, on July 31, 2023, we repurchased 2,763,581 ENLC common units held by GIP at an aggregate cost of $27.5 million, or an average of $9.94 per common unit. These units represent GIP's pro rata share of the aggregate number of common units repurchased by us during the three months ended June 30, 2023. The per unit price we paid to GIP was the same as the average per unit price paid by us for publicly held ENLC common units repurchased during the same period, less broker commissions, which were not paid with respect to the GIP units. As of June 30, 2023, $27.5 million is classified as "Other current liabilities" on the consolidated balance sheets related to our obligation to repurchase our common units from GIP.

b. Earnings Per Unit and Dilution Computations

As required under ASC 260, *Earnings Per Share*, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities for earnings per unit calculations. The following table reflects the computation of basic and diluted earnings per unit for the periods presented (in millions, except per unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Distributed earnings allocated to:				
Common units (1)	$ 57.8	$ 54.3	$ 116.4	$ 108.7
Unvested unit-based awards (1)	1.0	1.4	1.9	2.5
Total distributed earnings	$ 58.8	$ 55.7	$ 118.3	$ 111.2
Undistributed loss allocated to:				
Common units	$ (4.4)	$ 29.0	$ (5.7)	$ 9.1
Unvested unit-based awards	(0.1)	0.6	(0.1)	0.2
Total undistributed loss	$ (4.5)	$ 29.6	$ (5.8)	$ 9.3
Net income attributable to ENLC allocated to:				
Common units	$ 53.4	$ 83.3	$ 110.7	$ 117.8
Unvested unit-based awards	0.9	2.0	1.8	2.7
Total net income attributable to ENLC	$ 54.3	$ 85.3	$ 112.5	$ 120.5
Net income attributable to ENLC per unit:				
Basic	$ 0.12	$ 0.18	$ 0.24	$ 0.25
Diluted	$ 0.12	$ 0.17	$ 0.24	$ 0.25

(1) Represents distribution activity consistent with the distribution activity table below.

The following are the unit amounts used to compute the basic and diluted earnings per unit for the periods presented (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Basic weighted average units outstanding:				
Weighted average common units outstanding	462.7	482.0	465.8	483.0
Diluted weighted average units outstanding:				
Weighted average basic common units outstanding	462.7	482.0	465.8	483.0
Dilutive effect of unvested unit-based awards	4.0	7.0	4.1	6.7
Total weighted average diluted common units outstanding	466.7	489.0	469.9	489.7

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented.

*c. **Distributions***

A summary of our distribution activity related to the ENLC common units for the six months ended June 30, 2023 and 2022, respectively, is provided below:

Declaration period	Distribution/unit		Date paid/payable
2023			
Fourth Quarter of 2022	$	0.12500	February 13, 2023
First Quarter of 2023	$	0.12500	May 12, 2023
Second Quarter of 2023	$	0.12500	August 11, 2023
2022			
Fourth Quarter of 2021	$	0.11250	February 11, 2022
First Quarter of 2022	$	0.11250	May 13, 2022
Second Quarter of 2022	$	0.11250	August 12, 2022

(10) Investment in Unconsolidated Affiliates

As of June 30, 2023, our unconsolidated investments consisted of a38.75% ownership in GCF, a 30% ownership in the Cedar Cove JV, and a 15% ownership in the Matterhorn JV. The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2023		2022		2023		2022	
GCF								
Contributions	$	—	$	0.5	$	6.2	$	0.5
Distributions	$	(2.0)	$	—	$	(2.0)	$	—
Equity in loss	$	(1.7)	$	(0.9)	$	(2.8)	$	(1.6)
Cedar Cove JV								
Distributions	$	(0.2)	$	(0.2)	$	(0.3)	$	(0.4)
Equity in loss	$	(0.5)	$	(0.3)	$	(1.1)	$	(0.7)
Matterhorn JV								
Contributions	$	—	$	26.1	$	43.5	$	26.1
Equity in loss	$	(2.4)	$	—	$	(0.8)	$	—
Total								
Contributions	$	—	$	26.6	$	49.7	$	26.6
Distributions	$	(2.2)	$	(0.2)	$	(2.3)	$	(0.4)
Equity in loss	$	(4.6)	$	(1.2)	$	(4.7)	$	(2.3)

The following table shows the balances related to our investment in unconsolidated affiliates as of June 30, 2023 and December 31, 2022 (in millions):

	June 30, 2023		December 31, 2022	
GCF	$	27.7	$	26.3
Cedar Cove JV (1)		(5.8)		(4.4)
Matterhorn JV		106.6		63.9
Total investment in unconsolidated affiliates	$	128.5	$	85.8

(1) As of June 30, 2023 and December 31, 2022, our investment in the Cedar Cove JV is classified as “Other long-term liabilities” on the consolidated balance sheets.

(11) Employee Incentive Plans

a. Long-Term Incentive Plans

We account for unit-based compensation in accordance with ASC 718, which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is valued at fair value at the date of grant, and that grant date fair value is recognized as expense over each award's requisite service period with a corresponding increase to equity or liability based on the terms of each award and the appropriate accounting treatment under ASC 718.

Amounts recognized on the consolidated financial statements with respect to these plans are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Cost of unit-based compensation charged to operating expense	$ 0.7	$ 1.2	$ 1.6	$ 2.8
Cost of unit-based compensation charged to general and administrative expense	3.8	4.5	6.9	9.5
Total unit-based compensation expense	$ 4.5	$ 5.7	$ 8.5	$ 12.3
Amount of related income tax benefit recognized in net income (1)	$ 1.1	$ 1.3	$ 2.0	$ 2.9

(1) The amount of related income tax benefit recognized in net income excluded book-to-tax differences recorded upon the vesting of unit-based awards. For additional information, see "Note 7—Income Taxes."

b. Restricted Incentive Units

The restricted incentive units were valued at their fair value at the date of grant, which is equal to the market value of ENLC common units on such dateA summary of the restricted incentive unit activity for the six months ended June 30, 2023 is provided below:

	Six Months Ended June 30, 2023	
Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Unvested, beginning of period	6,775,186	$ 5.89
Granted	1,290,501	10.81
Vested (1)	(2,240,049)	6.04
Forfeited	(230,507)	6.17
Unvested, end of period	5,595,131	$ 6.95
Aggregate intrinsic value, end of period (in millions)	$ 59.3	

(1) Vested units included 668,083 ENLC common units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and six months ended June 30, 2023 and 2022 is provided below (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
Restricted Incentive Units:	2023	2022	2023	2022
Aggregate intrinsic value of units vested	$ 0.4	$ 0.6	$ 27.5	$ 8.2
Fair value of units vested	$ 0.1	$ 0.5	$ 13.5	$ 11.2

As of June 30, 2023, there were $22.1 million of unrecognized compensation costs that related to non-vested ENLC restricted incentive units. These costs are expected to be recognized over a weighted-average period of 1.9 years.

c. Performance Units

We grant performance awards under the 2014 Plan. The performance award agreements provide that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder is dependent on the achievement of certain performance goals over the applicable performance period. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of such units ranges from zero to 200% of the units granted depending on the extent to which the related performance goals are achieved over the relevant performance period.

The following table presents a summary of the performance units:

	Six Months Ended June 30, 2023	
Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,979,154	$ 6.44
Granted	420,128	11.67
Vested (1)	(899,919)	9.03
Non-vested, end of period	2,499,363	$ 6.39
Aggregate intrinsic value, end of period (in millions)	$ 26.5	

(1) Vested units included 668,829 ENLC common units withheld for payroll taxes paid on behalf of employees.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the six months ended June 30, 2023 and 2022 is provided below (in millions).

	Six Months Ended June 30,	
Performance Units:	**2023**	**2022**
Aggregate intrinsic value of units vested	$ 22.0	$ 5.6
Fair value of units vested	$ 8.1	$ 11.0

As of June 30, 2023, there were $12.5 million of unrecognized compensation costs that related to non-vested ENLC performance units. These costs are expected to be recognized over a weighted-average period of 1.8 years.

The following table presents a summary of the grant-date fair value assumptions by performance unit grant date:

Performance Units:	**March 2023**
Grant-date fair value	$ 10.40
Beginning TSR Price	$ 11.67
Risk-free interest rate	3.76 %
Volatility factor	64.00 %

(12) Derivatives

Interest Rate Swaps

In January 2023, we entered into a $400.0 million interest rate swap to manage the interest rate risk associated with our floating-rate, SOFR-based borrowings. Under this arrangement, we pay a fixed interest rate of 3.8565% in exchange for SOFR-based variable interest through February 2026. Assets or liabilities related to this interest rate swap contract are included in the fair value of derivative assets and liabilities on the consolidated balance sheets, and the change in fair value of this contract is recorded net as gain or loss on designated cash flow hedges on the consolidated statements of comprehensive income. Monthly, upon settlement, we reclassify the gain or loss associated with the interest rate swap into interest expense from accumulated other comprehensive income (loss). We designated this interest rate swap as a cash flow hedge in accordance with ASC 815. There is no ineffectiveness related to this hedge.

The components of the unrealized gain on designated cash flow hedge related to changes in the fair value of our interest rate swaps were as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Change in fair value of interest rate swaps	$ 7.5	$ —	$ 5.9	$ 0.1
Tax expense	(1.8)	—	(1.4)	—
Unrealized gain on designated cash flow hedge	$ 5.7	$ —	$ 4.5	$ 0.1

The fair value of derivative assets and liabilities related to interest rate swaps are as follows (in millions):

	June 30, 2023	December 31, 2022
Fair value of derivative assets—current	$ 5.5	$ —
Fair value of derivative assets—long-term	0.4	—
Net fair value of interest rate swaps	$ 5.9	$ —

Interest expense (income) is recognized from accumulated other comprehensive income from the monthly settlement of our interest rate swaps and was included in our consolidated statements of operations as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Interest expense, net of interest income	$ (1.1)	$ —	$ (1.6)	$ 0.1

We expect to recognize an additional $5.5 million of interest income out of accumulated other comprehensive income (loss) over the next twelve months.

Commodity Derivatives

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity derivatives are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Change in fair value of derivatives	$ 5.3	$ 35.3	$ 3.9	$ 20.2
Realized gain (loss) on derivatives	6.0	(30.8)	19.3	(46.9)
Gain (loss) on derivative activity	$ 11.3	$ 4.5	$ 23.2	$ (26.7)

The fair value of derivative assets and liabilities related to commodity derivatives are as follows (in millions):

	June 30, 2023	December 31, 2022
Fair value of derivative assets—current	$ 78.3	$ 68.4
Fair value of derivative assets—long-term	17.9	2.9
Fair value of derivative liabilities—current	(49.2)	(42.9)
Fair value of derivative liabilities—long-term	(17.4)	(2.7)
Net fair value of commodity derivatives	$ 29.6	$ 25.7

Set forth below are the summarized notional volumes and fair values of all instruments related to commodity derivatives that we held for price risk management purposes and the related physical offsets at June 30, 2023 (in millions, except volumes). The remaining term of the contracts extend no later than January 2028.

Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	MMgals	(83.4)	$ 23.8
NGL (long contracts)	Swaps	MMgals	72.7	(7.5)
Natural gas (short contracts)	Swaps and futures	Bbtu	(126.0)	32.5
Natural gas (long contracts)	Swaps and futures	Bbtu	109.6	(20.6)
Crude and condensate (short contracts)	Swaps and futures	MMbbls	(8.2)	5.9
Crude and condensate (long contracts)	Swaps and futures	MMbbls	0.7	(4.5)
Total fair value of commodity derivatives				$ 29.6

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with financial institutions when entering into financial derivatives on commodities. We have entered into Master ISDAs that allow for netting of swap contract receivables and payables in the event of default by either party. Additionally, we have entered into FCDTCs that allow for netting of futures contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing commodity swap and futures contracts, the maximum loss on our gross receivable position of $96.2 million as of June 30, 2023 would be reduced to $30.5 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs and the FCDTCs.

(13) Fair Value Measurements

Derivative assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	Level 2	
	June 30, 2023	December 31, 2022
Interest rate swaps (1)	$ 5.9	$ —
Commodity derivatives (2)	$ 29.6	$ 25.7

(1) The fair values of the interest rate swaps are estimated based on the difference between expected cash flows calculated at the contracted interest rates and the expected cash flows using observable benchmarks for the variable interest rates.
(2) The fair values of commodity derivatives represent the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for our credit risk and/or the counterparty credit risk as required under ASC 820.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments has been determined using available market information and valuation methodologies.Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount we could realize upon the sale or refinancing of such financial instruments (in millions):

	June 30, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,738.8	$ 4,485.2	$ 4,723.5	$ 4,385.9
Contingent consideration (2)(3)	$ 6.4	$ 6.4	$ 5.5	$ 5.5

(1) The carrying value of long-term debt, including current maturities of long-term debt, is reduced by debt issuance cost, net of accumulated amortization, of $ 35.0 million and $34.9 million as of June 30, 2023 and December 31, 2022, respectively. The respective fair values do not factor in debt issuance costs.
(2) Consideration for the Amarillo Rattler Acquisition included a contingent component capped at $15.0 million and payable, if at all, between 2024 and 2026 based on Diamondback E&P LLC's drilling activity above historical levels. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.
(3) Consideration for the Central Oklahoma Acquisition included a contingent component, which is payable, if at all, between 2024 and 2027 based on fee revenue earned on certain contractually specified volumes for the annual periods beginning January 1, 2023 through December 31, 2026. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.

The carrying amounts of our cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The fair values of all senior unsecured notes as of June 30, 2023 and December 31, 2022 were based on Level 2 inputs from third-party market quotations.

(14) Segment Information

We manage and report our activities primarily according to the geography and nature of activity. We havefive reportable segments:

- *Permian Segment.* The Permian segment includes our natural gas gathering, processing, and transmission activities and our crude oil operations in the Midland and Delaware Basins in West Texas and Eastern New Mexico;

- *Louisiana Segment.* The Louisiana segment includes our natural gas and NGL pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and our crude oil operations in ORV;

- *Oklahoma Segment.* The Oklahoma segment includes our natural gas gathering, processing, and transmission activities, and our crude oil operations in Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and adjacent areas;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, fractionation, and transmission activities in North Texas; and

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, GCF in South Texas, and the Matterhorn JV in West Texas, as well as our corporate assets and expenses.

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We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. Adjusted gross margin is a non-GAAP financial measure. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" for additional information. Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2023						
Natural gas sales	$ 76.4	$ 92.5	$ 32.9	$ 16.7	$ —	$ 218.5
NGL sales	—	648.6	0.4	(1.9)	—	647.1
Crude oil and condensate sales	294.4	52.6	26.7	—	—	373.7
Product sales	370.8	793.7	60.0	14.8	—	1,239.3
NGL sales—related parties	204.1	5.3	102.3	66.2	(377.9)	—
Crude oil and condensate sales—related parties	—	—	—	2.8	(2.8)	—
Product sales—related parties	204.1	5.3	102.3	69.0	(380.7)	—
Gathering and transportation	29.3	18.7	60.5	51.9	—	160.4
Processing	14.5	0.1	36.4	30.5	—	81.5
NGL services	—	17.4	—	0.1	—	17.5
Crude services	7.0	5.6	4.9	0.2	—	17.7
Other services	1.6	0.3	0.2	0.3	—	2.4
Midstream services	52.4	42.1	102.0	83.0	—	279.5
NGL services—related parties	—	—	—	0.8	(0.8)	—
Midstream services—related parties	—	—	—	0.8	(0.8)	—
Revenue from contracts with customers	627.3	841.1	264.3	167.6	(381.5)	1,518.8
Realized gain (loss) on derivatives	5.4	(7.8)	1.9	6.5	—	6.0
Change in fair value of derivatives	(7.9)	18.2	2.0	(7.0)	—	5.3
Total revenues	624.8	851.5	268.2	167.1	(381.5)	1,530.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(479.9)	(715.0)	(130.5)	(75.1)	381.5	(1,019.0)
Adjusted gross margin	144.9	136.5	137.7	92.0	—	511.1
Operating expenses	(53.1)	(32.0)	(27.0)	(24.7)	—	(136.8)
Segment profit	91.8	104.5	110.7	67.3	—	374.3
Depreciation and amortization	(41.5)	(36.9)	(56.6)	(29.0)	(1.3)	(165.3)
Gross margin	50.3	67.6	54.1	38.3	(1.3)	209.0
Gain on disposition of assets	0.1	0.1	0.1	0.5	—	0.8
General and administrative	—	—	—	—	(27.9)	(27.9)
Interest expense, net of interest income	—	—	—	—	(68.8)	(68.8)
Loss from unconsolidated affiliate investments	—	—	—	—	(4.6)	(4.6)
Other income	—	—	—	—	0.4	0.4
Income (loss) before non-controlling interest and income taxes	$ 50.4	$ 67.7	$ 54.2	$ 38.8	$ (102.2)	$ 108.9
Capital expenditures	$ 51.6	$ 17.7	$ 22.1	$ 11.8	$ 1.5	$ 104.7

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	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2022						
Natural gas sales	$ 323.0	$ 272.9	$ 87.1	$ 37.9	$ —	$ 720.9
NGL sales	—	1,163.7	3.6	0.1	—	1,167.4
Crude oil and condensate sales	331.6	110.0	40.6	—	—	482.2
Product sales	654.6	1,546.6	131.3	38.0	—	2,370.5
NGL sales—related parties	427.5	43.1	242.6	165.8	(879.0)	—
Crude oil and condensate sales—related parties	—	—	—	4.0	(4.0)	—
Product sales—related parties	427.5	43.1	242.6	169.8	(883.0)	—
Gathering and transportation	19.9	15.7	44.7	40.6	—	120.9
Processing	9.9	0.3	28.6	27.9	—	66.7
NGL services	—	18.4	—	0.1	—	18.5
Crude services	6.0	9.2	3.2	0.2	—	18.6
Other services	0.2	0.4	0.1	0.2	—	0.9
Midstream services	36.0	44.0	76.6	69.0	—	225.6
Crude services—related parties	—	—	0.1	—	(0.1)	—
Midstream services—related parties	—	—	0.1	—	(0.1)	—
Revenue from contracts with customers	1,118.1	1,633.7	450.6	276.8	(883.1)	2,596.1
Realized loss on derivatives	(10.2)	(2.5)	(15.8)	(2.3)	—	(30.8)
Change in fair value of derivatives	12.5	11.8	8.2	2.8	—	35.3
Total revenues	1,120.4	1,643.0	443.0	277.3	(883.1)	2,600.6
Cost of sales, exclusive of operating expenses and depreciation and amortization	(958.0)	(1,519.2)	(321.3)	(189.7)	883.1	(2,105.1)
Adjusted gross margin	162.4	123.8	121.7	87.6	—	495.5
Operating expenses	(50.3)	(34.8)	(23.1)	(20.7)	—	(128.9)
Segment profit	112.1	89.0	98.6	66.9	—	366.6
Depreciation and amortization	(37.1)	(39.4)	(52.3)	(28.7)	(1.5)	(159.0)
Gross margin	75.0	49.6	46.3	38.2	(1.5)	207.6
Gain on disposition of assets	—	—	0.2	0.2	—	0.4
General and administrative	—	—	—	—	(28.4)	(28.4)
Interest expense, net of interest income	—	—	—	—	(55.5)	(55.5)
Loss on extinguishment of debt	—	—	—	—	(0.5)	(0.5)
Loss from unconsolidated affiliate investments	—	—	—	—	(1.2)	(1.2)
Other income	—	—	—	—	0.2	0.2
Income (loss) before non-controlling interest and income taxes	$ 75.0	$ 49.6	$ 46.5	$ 38.4	$ (86.9)	$ 122.6
Capital expenditures	$ 34.7	$ 6.3	$ 11.5	$ 8.1	$ 1.9	$ 62.5

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	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2023						
Natural gas sales	$ 205.7	$ 224.3	$ 99.7	$ 31.2	$ —	$ 560.9
NGL sales	0.4	1,506.5	9.0	(2.9)	—	1,513.0
Crude oil and condensate sales	481.1	109.2	51.4	—	—	641.7
Product sales	687.2	1,840.0	160.1	28.3	—	2,715.6
NGL sales—related parties	441.6	9.7	220.3	145.7	(817.3)	—
Crude oil and condensate sales—related parties	—	—	—	5.5	(5.5)	—
Product sales—related parties	441.6	9.7	220.3	151.2	(822.8)	—
Gathering and transportation	52.6	38.7	115.3	104.0	—	310.6
Processing	28.5	0.4	71.7	62.6	—	163.2
NGL services	—	45.2	—	0.1	—	45.3
Crude services	13.0	12.1	9.4	0.4	—	34.9
Other services	3.3	0.7	0.3	0.5	—	4.8
Midstream services	97.4	97.1	196.7	167.6	—	558.8
NGL services—related parties	—	—	—	1.4	(1.4)	—
Midstream services—related parties	—	—	—	1.4	(1.4)	—
Revenue from contracts with customers	1,226.2	1,946.8	577.1	348.5	(824.2)	3,274.4
Realized gain (loss) on derivatives	1.4	(0.6)	3.9	14.6	—	19.3
Change in fair value of derivatives	(1.6)	9.2	0.6	(4.3)	—	3.9
Total revenues	1,226.0	1,955.4	581.6	358.8	(824.2)	3,297.6
Cost of sales, exclusive of operating expenses and depreciation and amortization	(937.0)	(1,688.9)	(324.5)	(164.7)	824.2	(2,290.9)
Adjusted gross margin	289.0	266.5	257.1	194.1	—	1,006.7
Operating expenses	(101.2)	(65.6)	(51.7)	(50.7)	—	(269.2)
Segment profit	187.8	200.9	205.4	143.4	—	737.5
Depreciation and amortization	(81.5)	(75.2)	(108.5)	(57.8)	(2.7)	(325.7)
Gross margin	106.3	125.7	96.9	85.6	(2.7)	411.8
Gain on disposition of assets	0.1	0.2	0.3	0.6	—	1.2
General and administrative	—	—	—	—	(57.4)	(57.4)
Interest expense, net of interest income	—	—	—	—	(137.3)	(137.3)
Loss from unconsolidated affiliate investments	—	—	—	—	(4.7)	(4.7)
Other income	—	—	—	—	0.4	0.4
Income (loss) before non-controlling interest and income taxes	$ 106.4	$ 125.9	$ 97.2	$ 86.2	$ (201.7)	$ 214.0
Capital expenditures	$ 108.3	$ 30.0	$ 47.8	$ 29.9	$ 2.8	$ 218.8

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	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2022						
Natural gas sales	$ 518.6	$ 484.4	$ 163.4	$ 63.3	$ —	$ 1,229.7
NGL sales	—	2,315.2	6.7	—	—	2,321.9
Crude oil and condensate sales	603.6	183.9	75.3	—	—	862.8
Product sales	1,122.2	2,983.5	245.4	63.3	—	4,414.4
NGL sales—related parties	827.3	80.0	450.7	312.7	(1,670.7)	—
Crude oil and condensate sales—related parties	—	—	0.3	7.0	(7.3)	—
Product sales—related parties	827.3	80.0	451.0	319.7	(1,678.0)	—
Gathering and transportation	33.5	32.0	87.4	79.4	—	232.3
Processing	17.7	0.8	54.0	55.5	—	128.0
NGL services	—	42.3	—	0.1	—	42.4
Crude services	10.3	18.6	6.9	0.4	—	36.2
Other services	0.4	0.8	0.2	0.3	—	1.7
Midstream services	61.9	94.5	148.5	135.7	—	440.6
Crude services—related parties	—	—	0.1	—	(0.1)	—
Other services—related parties	—	0.1	—	—	(0.1)	—
Midstream services—related parties	—	0.1	0.1	—	(0.2)	—
Revenue from contracts with customers	2,011.4	3,158.1	845.0	518.7	(1,678.2)	4,855.0
Realized loss on derivatives	(12.6)	(9.1)	(19.5)	(5.7)	—	(46.9)
Change in fair value of derivatives	6.6	6.2	1.1	6.3	—	20.2
Total revenues	2,005.4	3,155.2	826.6	519.3	(1,678.2)	4,828.3
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,724.7)	(2,907.9)	(598.1)	(347.1)	1,678.2	(3,899.6)
Adjusted gross margin	280.7	247.3	228.5	172.2	—	928.7
Operating expenses	(95.6)	(67.8)	(44.1)	(42.3)	—	(249.8)
Segment profit	185.1	179.5	184.4	129.9	—	678.9
Depreciation and amortization	(73.8)	(74.9)	(103.2)	(57.1)	(2.9)	(311.9)
Gross margin	111.3	104.6	81.2	72.8	(2.9)	367.0
Gain (loss) on disposition of assets	—	0.2	0.4	(5.3)	—	(4.7)
General and administrative	—	—	—	—	(57.4)	(57.4)
Interest expense, net of interest income	—	—	—	—	(110.6)	(110.6)
Loss on extinguishment of debt	—	—	—	—	(0.5)	(0.5)
Loss from unconsolidated affiliate investments	—	—	—	—	(2.3)	(2.3)
Other income	—	—	—	—	0.3	0.3
Income (loss) before non-controlling interest and income taxes	$ 111.3	$ 104.8	$ 81.6	$ 67.5	$ (173.4)	$ 191.8
Capital expenditures	$ 68.9	$ 12.0	$ 26.9	$ 11.2	$ 3.5	$ 122.5

The table below represents information about segment assets as of June 30, 2023 and December 31, 2022 (in millions):

Segment Identifiable Assets:	June 30, 2023	December 31, 2022
Permian	$ 2,708.3	$ 2,661.4
Louisiana	2,077.6	2,310.7
Oklahoma	2,350.4	2,420.4
North Texas	1,038.9	1,094.6
Corporate (1)	224.7	163.9
Total identifiable assets	$ 8,399.9	$ 8,651.0

(1) Accounts receivable and accrued revenue sold to the SPV for collateral under the AR Facility are included within the Permian, Louisiana, Oklahoma, and North Texas segments.

(15) Other Information

The following tables present additional detail for other current assets and other current liabilities, which consists of the following (in millions):

Other current assets:	June 30, 2023	December 31, 2022
Natural gas and NGLs inventory	$ 74.9	$ 147.1
Prepaid expenses and other	26.4	19.5
Other current assets	$ 101.3	$ 166.6

Other current liabilities:	June 30, 2023	December 31, 2022
Accrued interest	$ 64.3	$ 57.6
Accrued wages and benefits, including taxes	15.3	38.1
Accrued ad valorem taxes	26.1	32.0
Accrued settlement of mandatorily redeemable non-controlling interest (1)	—	10.5
Capital expenditure accruals	42.7	23.4
Short-term lease liability	26.6	26.2
Operating expense accruals	19.7	18.5
Other	44.1	23.3
Other current liabilities	$ 238.8	$ 229.6

(1) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries.

(16) Commitments and Contingencies

In February 2021, the areas in which we operate experienced a severe winter storm, with extreme cold, ice, and snow occurring over an unprecedented period of approximately 10 days ("Winter Storm Uri"). As a result of Winter Storm Uri, we have encountered customer billing disputes related to the delivery of gas during the storm, including one that resulted in litigation. The litigation is between one of our subsidiaries, EnLink Gas Marketing, LP ("EnLink Gas"), and Koch Energy Services, LLC ("Koch") in the 162nd District Court in Dallas County, Texas. The dispute centers on whether EnLink Gas was excused from delivering gas or performing under certain delivery or purchase obligations during Winter Storm Uri, given our declaration of force majeure during the storm. Koch has invoiced us approximately $53.9 million (after subtracting amounts owed to EnLink Gas) and does not recognize the declaration of force majeure. We believe the declaration of force majeure was valid and appropriate and we intend to vigorously defend against Koch's claims.

One of our subsidiaries, EnLink Energy GP, LLC ("EnLink Energy"), was involved in industry-wide multi-district litigation arising out of Winter Storm Uri, pending in Harris County, Texas, in which multiple individual plaintiffs asserted personal injury and property damage claims arising out of Winter Storm Uri against an aggregate of over 350 power generators, transmission/distribution utility, retail electric provider, and natural gas defendants across over 150 filed cases. On January 26, 2023, the court dismissed the claims against the pipeline and other natural gas-related defendants in the multi-district litigation, including EnLink Energy. The court's order was not appealed and the case is continuing without EnLink Energy and the other natural gas-related defendants. Subsequently, several suits were filed in February 2023 by individual plaintiffs (including one matter in which the plaintiffs seek to certify a class of Texas residents affected by Winter Storm Uri) and the alleged assignee of the claims of individual plaintiffs against 90 natural gas producers, pipelines, marketers, sellers, and traders, including EnLink Gas. We believe the claims in these matters against EnLink Gas lack merit and we intend to vigorously defend against such claims.

In addition, we are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations, or cash flows. We may also be involved from time to time in the future in various proceedings in the normal course of business, including litigation on disputes related to contracts, property rights, property use or damage (including nuisance claims), personal injury, or the value of pipeline easements or other rights obtained through the exercise of eminent domain or common carrier rights.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Please read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. In addition, please refer to the Definitions page set forth in this report prior to Part I—Financial Information.

In this report, the terms "Company" or "Registrant," as well as the terms "ENLC," "our," "we," "us," or like terms, are sometimes used as abbreviated references to EnLink Midstream, LLC itself or EnLink Midstream, LLC together with its consolidated subsidiaries, including ENLK and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK," or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Overview

ENLC is a Delaware limited liability company formed in October 2013. ENLC's assets consist of all of the outstanding common units of ENLK and all of the membership interests of the General Partner. All of our midstream energy assets are owned and operated by ENLK and its subsidiaries. We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

As of June 30, 2023, our midstream energy asset network includes approximately 13,600 miles of pipelines, 26 natural gas processing plants with approximately 6.0 Bcf/d of processing capacity, seven fractionators with approximately 320,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. We manage and report our activities primarily according to the geography and nature of activity. We have five reportable segments:

- *Permian Segment.* The Permian segment includes our natural gas gathering, processing, and transmission activities and our crude oil operations in the Midland and Delaware Basins in West Texas and Eastern New Mexico;

- *Louisiana Segment.* The Louisiana segment includes our natural gas and NGL pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and our crude oil operations in ORV;

- *Oklahoma Segment.* The Oklahoma segment includes our natural gas gathering, processing, and transmission activities, and our crude oil operations in Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and adjacent areas;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, fractionation, and transmission activities in North Texas; and

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, GCF in South Texas, and the Matterhorn JV in West Texas, as well as our corporate assets and expenses.

We manage our consolidated operations by focusing on adjusted gross margin because our business is generally to gather, process, transport, or market natural gas, NGLs, crude oil, and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Adjusted gross margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 85% of our adjusted gross margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the six months ended June 30, 2023.

Our revenues and adjusted gross margins are generated from eight primary sources:

- gathering and transporting natural gas, NGLs, and crude oil on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing recovered NGLs;
- providing compression services;
- providing crude oil and condensate transportation and terminal services;
- providing condensate stabilization services;
- providing brine disposal services; and
- providing natural gas, crude oil, and NGL storage.

The following customers individually represented greater than 10% of our consolidated revenues for the three and six months ended June 30, 2023 and 2022. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Dow Hydrocarbons and Resources LLC	11.5 %	14.8 %	11.5 %	14.4 %
Marathon Petroleum Corporation	19.6 %	15.5 %	19.8 %	15.8 %

We gather, transport, or store gas owned by others under fee-only contract arrangements based either on the volume of gas gathered, transported, or stored or, for firm transportation arrangements, a stated monthly fee for a specified monthly quantity with an additional fee based on actual volumes. We also buy natural gas from producers or shippers at a market index less a fee-based deduction subtracted from the purchase price of the natural gas. We then gather or transport the natural gas and sell the natural gas at a market index, thereby earning a margin through the fee-based deduction. We attempt to execute substantially all purchases and sales concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the fee we will receive for each natural gas transaction. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

We typically buy mixed NGLs from our suppliers to our gas processing plants at a fixed discount to market indices for the component NGLs with a deduction for our fractionation fee. We subsequently sell the fractionated NGL products based on the same index-based prices. To a lesser extent, we transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. The operating results of our NGL fractionation business are largely dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With our fractionation business, we also have the opportunity for product upgrades for each of the discrete NGL products. We realize higher adjusted gross margins from product upgrades during periods with higher NGL prices.

We gather or transport crude oil and condensate owned by others by rail, truck, pipeline, and barge facilities under fee-only contract arrangements based on volumes gathered or transported. We also buy crude oil and condensate on our own gathering systems, third-party systems, and trucked from producers at a market index less a stated transportation deduction. We then transport and resell the crude oil and condensate through a process of basis and fixed price trades. We execute substantially all purchases and sales concurrently, thereby establishing the net margin we will receive for each crude oil and condensate transaction.

We realize adjusted gross margins from our gathering and processing services primarily through different contractual arrangements: processing margin (“margin”) contracts, POL contracts, POP contracts, fixed-fee based contracts, or a combination of these contractual arrangements. Under any of these gathering and processing arrangements, we may earn a fee for the services performed, or we may buy and resell the gas and/or NGLs as part of the processing arrangement and realize a net margin as our fee. Under margin contract arrangements, our adjusted gross margins are higher during periods of high NGL prices relative to natural gas prices. Adjusted gross margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Adjusted gross margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our adjusted gross margins are driven by throughput volume.

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services, and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in the volume of gas, liquids, crude oil, and condensate moved through or by our assets.

CCS Business

We are building a carbon transportation business in support of CCS activity along the Mississippi River corridor in Louisiana, one of the highest CO_2 emitting regions in the United States. We believe our existing asset footprint, including our extensive network of natural gas pipelines in Louisiana, our operating expertise and our customer relationships, provide us with an advantage in building a carbon transportation business and becoming the transporter of choice in the region.

Recent Developments Affecting Industry Conditions and Our Business

Current Market Environment

The midstream energy business environment and our business are affected by the level of production of natural gas and oil in the areas in which we operate and the various factors that affect this production, including commodity prices, capital markets trends, competition, and regulatory changes. We believe these factors will continue to affect production and therefore the demand for midstream services and our business in the future. To the extent these factors vary from our underlying assumptions, our business and actual results could vary materially from market expectations and from the assumptions discussed in this section.

Production levels by our exploration and production customers are driven in large part by the level of oil and natural gas prices. New drilling activity is necessary to maintain or increase production levels as oil and natural gas wells experience production declines over time. New drilling activity generally moves in the same direction as crude oil and natural gas prices as those prices drive investment returns and cash flow available for reinvestment by exploration and production companies. Accordingly, our operations are affected by the level of crude, natural gas, and NGL prices, the relationship among these prices, and related activity levels from our customers. Low prices for these commodities could reduce the demand for our services and the volumes in our systems.

There has been, and we believe there will continue to be, volatility in commodity prices and in the relationships among NGL, crude oil, and natural gas prices. Commodity markets have now recovered from the reduction in global demand and low market prices experienced in 2020 due to the COVID-19 pandemic. However, oil and natural gas prices continue to remain volatile. Oil and natural gas prices rose during 2021 and rose especially rapidly in the first half of 2022 due to various factors, including a rebound in demand from economic activity after COVID-19 shutdowns, supply issues, and geopolitical events, including Russia’s invasion of Ukraine. Since that time, both oil and especially natural gas prices have declined from their peaks during 2022, with natural gas prices declining significantly since the beginning of 2023 and returning to pre-pandemic price levels.

The table below presents selected average index prices for crude oil, NGL, and natural gas for the periods indicated.

	Crude oil $/Bbl (1)(2)		NGL $/Gal (1)(3)		Natural gas $/MMbtu (1)(4)	
2023 by quarter:						
1st Quarter	$	75.99	$	0.61	$	2.74
2nd Quarter	$	73.56	$	0.43	$	2.33
2023 Averages	$	74.77	$	0.52	$	2.54
2022 by quarter:						
1st Quarter	$	95.01	$	0.92	$	4.56
2nd Quarter	$	108.52	$	0.97	$	7.50
2022 Averages	$	101.77	$	0.95	$	6.03

(1) The average closing price was computed by taking the sum of the closing prices of each trading day divided by the number of trading days during the period presented.
(2) Crude oil closing prices based on the NYMEX futures daily close prices.
(3) Weighted average NGL gas closing prices based on the OPIS Napoleonville daily average spot liquids prices.
(4) Natural gas closing prices based on Henry Hub Gas Daily closing prices.

The volatility in commodity prices may cause the adjusted gross margin and cash flows in certain areas of our business to vary from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes.

Capital markets and the demands of public investors also affect producer behavior, production levels, and our business. Over the last several years, public investors have exerted pressure on oil and natural gas producers to increase capital discipline and focus on higher investment returns even if it means lower growth. This demand by investors for increased capital discipline from energy companies led to more modest capital investment by producers, curtailed drilling and production activity, and, accordingly, slower growth for us and other midstream companies during the past few years. This trend was amplified in 2020 by the COVID-19 pandemic, which reduced demand for commodities. However, in response to the rise of oil and natural gas prices during 2021 and 2022, capital investments by United States oil and natural gas producers have risen, although global capital investments by oil and natural gas producers remain below historical levels and producers continue to remain cautious.

Producers generally focus their drilling activity on certain producing basins depending on commodity price fundamentals and favorable drilling economics. In the last few years, many producers have increasingly focused their activities in the Permian Basin, because of the availability of higher investment returns. Currently, a large percentage of all drilling rigs operating in the United States are operating in the Permian Basin. We continue to experience a robust increase in volumes in our Permian segment as our operations in that basin are in a favorable position relative to producer activity. As a result of this concentration of drilling activity in the Permian Basin, other basins, including those in which we operate in Oklahoma and North Texas, experienced reduced investment and declines in volumes produced. However, the rise in commodity prices during 2022 led to renewed producer interest in Oklahoma and North Texas which has continued into 2023. However, we expect that the continuing weakness in natural gas prices will reduce producer activity in these areas during the second half of 2023.

Our Louisiana segment, while subject to commodity price trends, is less dependent on gathering and processing activities and more affected by industrial demand for the natural gas and NGLs that we supply. Industrial demand along the Gulf Coast region has remained strong throughout 2022 and has continued into 2023, supported by regional industrial activity and export markets. Our activities and, in turn, our financial performance in the Louisiana segment are highly dependent on the availability of natural gas and NGLs produced by our upstream gathering and processing business and by other market participants. To date, the supply of natural gas and NGLs has remained at levels sufficient for us to supply our customers, and maintaining such supply is a key business focus.

For additional discussion regarding these factors, see “Item 1A—Risk Factors—Business and Industry Risks” in our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023.

Inflation

Inflation in the United States increased significantly in 2022 and has continued to increase at a more modest pace during the first half of 2023. In addition, in order to reduce the inflation rate, the Federal Reserve increased its target for the federal funds rate (the benchmark for most interest rates) several times in 2022 and 2023. This trend may continue during the remainder of 2023.

To the extent that a rising cost environment impacts our results, there are typically offsetting benefits either inherent in our business or that result from other steps we take proactively to reduce the impact of inflation on our net operating results. These benefits include: (1) provisions included in our long-term fee-based revenue contracts that offset cost increases in the form of rate escalations based on positive changes in the U.S. Consumer Price Index, Producer Price Index for Finished Goods, or other factors; (2) provisions in our contracts that enable us to pass through higher costs to customers; and (3) higher commodity prices, which generally enhance our results in the form of increased volumetric throughput and demand for our services. For these reasons, the increased cost environment, caused in part by inflation, has not had a material impact on our historical results of operations for the periods presented in this report. However, a significant or prolonged period of high inflation could adversely impact our results if costs were to increase at a rate greater than the increase in the revenues we receive.

Regulatory Developments

Any regulatory changes could adversely affect our business, financial condition, results of operations or cash flows, including our ability to make cash distributions to our unitholders. For more information, see our risk factors under Item 1A—Risk Factors—"Environmental, Legal Compliance, and Regulatory Risk" in our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023.

Other Recent Developments

Organic Growth

Tiger II Processing Plant. In April 2023, we began moving equipment and facilities associated with the non-operational Cowtown processing plant in North Texas to our Delaware Basin JV operations in the Permian. The relocation is expected to increase the processing capacity of our Permian Basin processing facilities by approximately 150 MMcf/d. We expect to complete the relocation in the second quarter of 2024.

GCF Operations. In January 2023, we began the process to restart the GCF assets and expect operations to begin in 2024. We will continue to make capital contributions during 2023 associated with the restart of these assets.

Equity

Common Unit Repurchase Program. For the three months ended June 30, 2023, we repurchased 3,230,504 outstanding common units in open market purchases, for an aggregate cost, including commissions, of $32.2 million, or an average of $9.96 per common unit. For the six months ended June 30, 2023, we repurchased 5,437,809 outstanding common units in open market purchases, for an aggregate cost, including commissions, of $59.0 million, or an average of $10.85 per common unit.

GIP Repurchase Agreement. For the three months ended June 30, 2023, we repurchased 1,910,877 ENLC common units held by GIP for an aggregate cost of $23.2 million, or an average of $12.12 per common unit. For the six months ended June 30, 2023, we repurchased 4,147,987 ENLC common units held by GIP for an aggregate cost of $47.8 million, or an average of $11.53 per common unit.

See "Item 1. Financial Statements—Note 9" for more information regarding our common unit repurchases.

Repurchase of Series C Preferred Units. In February 2023, we repurchased 4,500 Series C Preferred Units for total consideration of $3.9 million. The repurchase price represented 87% of the preferred units' par value. See "Item 1. Financial Statements—Note 8" for more information regarding the Series C Preferred Units.

Debt

Senior Unsecured Notes Issuance. On April 3, 2023, we completed the sale of an additional $300.0 million aggregate principal amount of 6.500% senior notes due 2030 (the "Additional Notes") at 99% of their face value. The Additional Notes were offered as an additional issue of our existing 6.500% senior notes due 2030 that we issued on August 31, 2022 in an aggregate principal amount of $700.0 million. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by ENLK.

Non-GAAP Financial Measures

To assist management in assessing our business, we use the following non-GAAP financial measures: adjusted gross margin; adjusted earnings before interest, taxes, and depreciation and amortization ("adjusted EBITDA"); and free cash flow after distributions.

Adjusted Gross Margin

We define adjusted gross margin as revenues less cost of sales, exclusive of operating expenses and depreciation and amortization. We present adjusted gross margin by segment in "Results of Operations." We disclose adjusted gross margin in addition to gross margin as defined by GAAP because it is the primary performance measure used by our management to evaluate consolidated operations. We believe adjusted gross margin is an important measure because, in general, our business is to gather, process, transport, or market natural gas, NGLs, condensate, and crude oil for a fee or to purchase and resell natural gas, NGLs, condensate, and crude oil for a margin. Operating expense is a separate measure used by our management to evaluate the operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities, and contract services comprise the most significant portion of our operating expenses. We exclude all operating expenses and depreciation and amortization from adjusted gross margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. The GAAP measure most directly comparable to adjusted gross margin is gross margin. Adjusted gross margin should not be considered an alternative to, or more meaningful than, gross margin as determined in accordance with GAAP. Adjusted gross margin has important limitations because it excludes all operating expenses and depreciation and amortization that affect gross margin. Our adjusted gross margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table reconciles total revenues and gross margin to adjusted gross margin (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Total revenues	$ 1,530.1	$ 2,600.6	$ 3,297.6	$ 4,828.3
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,019.0)	(2,105.1)	(2,290.9)	(3,899.6)
Operating expenses	(136.8)	(128.9)	(269.2)	(249.8)
Depreciation and amortization	(165.3)	(159.0)	(325.7)	(311.9)
Gross margin	209.0	207.6	411.8	367.0
Operating expenses	136.8	128.9	269.2	249.8
Depreciation and amortization	165.3	159.0	325.7	311.9
Adjusted gross margin	$ 511.1	$ 495.5	$ 1,006.7	$ 928.7

Adjusted EBITDA

We define adjusted EBITDA as 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; costs associated with the relocation of processing facilities; accretion expense associated with asset retirement obligations; transaction costs; non-cash expense related to changes in the fair value of contingent consideration; (non-cash rent); and (non-controlling interest share of adjusted EBITDA from joint ventures). Adjusted EBITDA is one of the primary metrics used in our short-term incentive program for compensating employees. In addition, adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, and make cash distributions to our unitholders;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The GAAP measures most directly comparable to adjusted EBITDA are net income (loss) and net cash provided by operating activities. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities, or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly titled measures of other companies because other companies may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, net of interest income; income tax expense (benefit); and depreciation and amortization. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we have capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider net income (loss) and net cash provided by operating activities as determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following table reconciles net income to adjusted EBITDA (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Net income	$ 89.9	$ 123.9	$ 184.1	$ 189.9
Interest expense, net of interest income	68.8	55.5	137.3	110.6
Depreciation and amortization	165.3	159.0	325.7	311.9
Loss from unconsolidated affiliate investments	4.6	1.2	4.7	2.3
Distributions from unconsolidated affiliate investments	2.2	0.2	2.3	0.4
(Gain) loss on disposition of assets	(0.8)	(0.4)	(1.2)	4.7
Loss on extinguishment of debt	—	0.5	—	0.5
Unit-based compensation	4.5	5.7	8.5	12.3
Income tax expense (benefit)	19.0	(1.3)	29.9	1.9
Unrealized gain on commodity derivatives	(5.3)	(35.3)	(3.9)	(20.2)
Costs associated with the relocation of processing facilities (1)	1.7	11.1	2.1	22.4
Other (2)	0.2	0.4	0.5	0.7
Adjusted EBITDA before non-controlling interest	350.1	320.5	690.0	637.4
Non-controlling interest share of adjusted EBITDA from joint ventures (3)	(16.5)	(20.8)	(32.7)	(33.4)
Adjusted EBITDA, net to ENLC	$ 333.6	$ 299.7	$ 657.3	$ 604.0

(1) Represents cost incurred that are not part of our ongoing operations related to the relocation of equipment and facilities from the Thunderbird processing plant in the Oklahoma segment to the Permian segment, where it is operating as the Phantom processing plant, and the relocation of equipment and facilities from the Cowtown processing plant in the North Texas segment to the Permian segment, where it will operate as the Tiger II processing plant. The Phantom processing plant began operations in October 2022 and we expect the Tiger II processing plant to begin operations in the second quarter of 2024.

(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.

Free Cash Flow After Distributions

We define free cash flow after distributions as 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); (accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid); (payment 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); non-cash interest (income)/expense; (contributions to investment in unconsolidated affiliates); (payments to terminate interest rate swaps); (current income taxes); and proceeds from the sale of equipment and land.

Free cash flow after distributions is the principal cash flow metric used by the Company. It is also used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, pay back our indebtedness, make cash distributions, and make capital expenditures.

Growth capital expenditures 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. Examples of growth capital expenditures include the acquisition of assets and the construction or development of additional pipeline, storage, well connections, gathering, or processing assets, in each case, to the extent such capital expenditures are expected to expand our asset base, operating capacity, or our operating income.

Maintenance capital expenditures 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. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets, and processing assets up to their original operating capacity, to maintain pipeline and equipment reliability, integrity, and safety, and to address environmental laws and regulations.

The GAAP measure most directly comparable to free cash flow after distributions is net cash provided by operating activities. Free cash flow after distributions should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP. Free cash flow after distributions has important limitations because it excludes some items that affect net income (loss), operating income (loss), and net cash provided by operating activities. Free cash flow after distributions may not be comparable to similarly titled measures of other companies because other companies may not calculate this non-GAAP metric in the same manner. To compensate for these limitations, we believe that it is important to consider net cash provided by operating activities determined under GAAP, as well as free cash flow after distributions, to evaluate our overall liquidity.

The following table reconciles net cash provided by operating activities to adjusted EBITDA and free cash flow after distributions (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Net cash provided by operating activities	$ 315.7	$ 174.9	$ 587.8	$ 482.6
Interest expense (1)	67.0	54.2	134.0	107.9
Utility credits redeemed (2)	(0.1)	(6.0)	(1.5)	(11.6)
Accruals for settled commodity derivative transactions	—	0.6	—	(1.6)
Distributions from unconsolidated affiliate investment in excess of earnings	2.2	0.2	2.3	0.4
Costs associated with the relocation of processing facilities (3)	1.7	11.1	2.1	22.4
Other (4)	(0.1)	1.7	—	3.4
Changes in operating assets and liabilities which (provided) used cash:				
Accounts receivable, accrued revenues, inventories, and other	(80.3)	137.2	(249.7)	309.9
Accounts payable, accrued product purchases, and other accrued liabilities	44.0	(53.4)	215.0	(276.0)
Adjusted EBITDA before non-controlling interest	350.1	320.5	690.0	637.4
Non-controlling interest share of adjusted EBITDA from joint ventures (5)	(16.5)	(20.8)	(32.7)	(33.4)
Adjusted EBITDA, net to ENLC	333.6	299.7	657.3	604.0
Growth capital expenditures, net to ENLC (6)	(74.6)	(49.9)	(167.3)	(90.4)
Maintenance capital expenditures, net to ENLC (6)	(20.0)	(11.1)	(34.2)	(25.0)
Interest expense, net of interest income	(68.8)	(55.5)	(137.3)	(110.6)
Distributions declared on common units	(58.1)	(54.6)	(116.8)	(110.1)
ENLK preferred unit accrued cash distributions (7)	(24.0)	(23.3)	(47.6)	(46.8)
Payment to redeem mandatorily redeemable non-controlling interest (8)	—	—	(10.5)	—
Costs associated with the relocation of processing facilities, net to ENLC (3)(6)(9)	7.1	(11.1)	6.7	(22.4)
Contribution to investment in unconsolidated affiliates	—	(26.6)	(49.7)	(26.6)
Other (10)	0.5	(0.1)	0.8	0.3
Free cash flow after distributions	$ 95.7	$ 67.5	$ 101.4	$ 172.4

(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. Due to Winter Storm Uri, we received credits from our utility providers based on market rates for our unused electricity. These utility credits are recorded as "Other current assets" on our consolidated balance sheets and amortized as we incur utility expenses.
(3) Represents cost incurred that are not part of our ongoing operations related to the relocation of equipment and facilities from the Thunderbird processing plant in the Oklahoma segment to the Permian segment, where it is operating as the Phantom processing plant, and the relocation of equipment and facilities from the Cowtown processing plant in the North Texas segment to the Permian segment, where it will operate as the Tiger II processing plant. The Phantom processing plant began operations in October 2022 and we expect the Tiger II processing plant to begin operations in the second quarter of 2024.
(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. See "Item 1. Financial Statements—Note 8 " for information on the cash distributions earned by holders of the Series B Preferred Units and Series C Preferred Units. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units 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. See "Item 1. Financial Statements—Note 2" for more information regarding the redemption.
(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.

Results of Operations

The tables below set forth certain financial and operating data for the periods indicated. We evaluate the performance of our consolidated operations by focusing on adjusted gross margin, while we evaluate the performance of our operating segments based on segment profit and adjusted gross margin, as reflected in the tables below (in millions, except volumes):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2023						
Total revenues	$ 624.8	$ 851.5	$ 268.2	$ 167.1	$ (381.5)	$ 1,530.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(479.9)	(715.0)	(130.5)	(75.1)	381.5	(1,019.0)
Adjusted gross margin	144.9	136.5	137.7	92.0	—	511.1
Operating expenses	(53.1)	(32.0)	(27.0)	(24.7)	—	(136.8)
Segment profit	91.8	104.5	110.7	67.3	—	374.3
Depreciation and amortization	(41.5)	(36.9)	(56.6)	(29.0)	(1.3)	(165.3)
Gross margin	$ 50.3	$ 67.6	$ 54.1	$ 38.3	$ (1.3)	$ 209.0

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2022						
Total revenues	$ 1,120.4	$ 1,643.0	$ 443.0	$ 277.3	$ (883.1)	$ 2,600.6
Cost of sales, exclusive of operating expenses and depreciation and amortization	(958.0)	(1,519.2)	(321.3)	(189.7)	883.1	(2,105.1)
Adjusted gross margin	162.4	123.8	121.7	87.6	—	495.5
Operating expenses	(50.3)	(34.8)	(23.1)	(20.7)	—	(128.9)
Segment profit	112.1	89.0	98.6	66.9	—	366.6
Depreciation and amortization	(37.1)	(39.4)	(52.3)	(28.7)	(1.5)	(159.0)
Gross margin	$ 75.0	$ 49.6	$ 46.3	$ 38.2	$ (1.5)	$ 207.6

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2023						
Total revenues	$ 1,226.0	$ 1,955.4	$ 581.6	$ 358.8	$ (824.2)	$ 3,297.6
Cost of sales, exclusive of operating expenses and depreciation and amortization	(937.0)	(1,688.9)	(324.5)	(164.7)	824.2	(2,290.9)
Adjusted gross margin	289.0	266.5	257.1	194.1	—	1,006.7
Operating expenses	(101.2)	(65.6)	(51.7)	(50.7)	—	(269.2)
Segment profit	187.8	200.9	205.4	143.4	—	737.5
Depreciation and amortization	(81.5)	(75.2)	(108.5)	(57.8)	(2.7)	(325.7)
Gross margin	$ 106.3	$ 125.7	$ 96.9	$ 85.6	$ (2.7)	$ 411.8

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2022						
Total revenues	$ 2,005.4	$ 3,155.2	$ 826.6	$ 519.3	$ (1,678.2)	$ 4,828.3
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,724.7)	(2,907.9)	(598.1)	(347.1)	1,678.2	(3,899.6)
Adjusted gross margin	280.7	247.3	228.5	172.2	—	928.7
Operating expenses	(95.6)	(67.8)	(44.1)	(42.3)	—	(249.8)
Segment profit	185.1	179.5	184.4	129.9	—	678.9
Depreciation and amortization	(73.8)	(74.9)	(103.2)	(57.1)	(2.9)	(311.9)
Gross margin	$ 111.3	$ 104.6	$ 81.2	$ 72.8	$ (2.9)	$ 367.0

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Midstream Volumes:				
Consolidated				
Gathering and Transportation (MMbtu/d)	6,925,200	6,636,900	7,048,300	6,424,100
Processing (MMbtu/d)	3,562,000	3,141,700	3,516,000	3,021,600
Crude Oil Handling (Bbls/d)	198,700	214,100	193,400	202,300
NGL Fractionation (Gals/d)	7,519,300	7,896,900	7,604,100	7,965,000
Brine Disposal (Bbls/d)	2,700	3,200	2,800	3,100
Permian Segment				
Gathering and Transportation (MMbtu/d)	1,732,200	1,494,400	1,708,100	1,421,200
Processing (MMbtu/d)	1,617,400	1,432,200	1,589,200	1,344,700
Crude Oil Handling (Bbls/d)	155,400	175,000	149,000	162,900
Louisiana Segment				
Gathering and Transportation (MMbtu/d)	2,345,600	2,696,500	2,518,600	2,597,700
Crude Oil Handling (Bbls/d)	16,500	17,700	17,400	16,800
NGL Fractionation (Gals/d)	7,519,300	7,896,900	7,604,100	7,965,000
Brine Disposal (Bbls/d)	2,700	3,200	2,800	3,100
Oklahoma Segment				
Gathering and Transportation (MMbtu/d)	1,253,800	1,016,100	1,216,300	1,008,100
Processing (MMbtu/d)	1,204,600	1,047,600	1,184,500	1,038,600
Crude Oil Handling (Bbls/d)	26,800	21,400	27,000	22,600
North Texas Segment				
Gathering and Transportation (MMbtu/d)	1,593,600	1,429,900	1,605,300	1,397,100
Processing (MMbtu/d)	740,000	661,900	742,300	638,300

Three Months Ended June 30, 2023 Compared to Three Months Ended June 30, 2022

Revenues and Cost of Sales, Exclusive of Operating Expenses and Depreciation and Amortization.

Our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, are from natural gas, NGL, crude oil, and condensate product sales and purchases, midstream services that we perform on those commodities, and derivative activity. Fluctuations in our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, reflect in large part changes in commodity prices and volumes. Our adjusted gross margin is not directly affected by the commodity price environment because the commodities that we buy and sell are generally based on the same pricing indices. Both consolidated and segment product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, will fluctuate with market prices; however, the adjusted gross margin related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, fluctuations in these measures from changes in commodity prices may be offset by gains or losses from derivative instruments that we use to manage our exposure to commodity price risk associated with such sales and purchases.

Total revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,070.5 million and $1,086.1 million, respectively, for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 due to the following:

- Product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,131.2 million and $1,086.1 million, respectively, for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 primarily due to lower commodity prices in 2023.

- Revenues from midstream services increased $53.9 million for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 primarily due to higher volumes in 2023. Of these higher volumes in 2023, $11.0 million was related to contributions from acquisitions completed during 2022.

- Derivative gains increased $6.8 million for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 due to $36.8 million of increased realized gains and $30.0 million of decreased unrealized gains.

Operating Expenses. Operating expenses increased $7.9 million for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 primarily due to $5.0 million of increased compressor rentals, $4.3 million of higher materials and supplies expense, $3.6 million of higher labor and benefits costs, $1.0 million of higher utility costs, and $0.8 million of higher ad valorem taxes. The increase was partially offset by $7.7 million of lower construction fees and services.

Depreciation and Amortization. Depreciation and amortization increased $6.3 million for the three months ended June 30, 2023 compared to the three months ended June 30, 2022 primarily due to increases of $4.5 million due to additional assets placed in service, $3.9 million due to acquisitions completed in 2022, and $0.5 million due to changes in estimated useful lives. These increases were partially offset by decreased depreciation of $2.6 million related to assets reaching the end of their useful lives.

Interest Expense, Net of Interest Income. Interest expense, net of interest income, was $68.8 million for the three months ended June 30, 2023 compared to $55.5 million for the three months ended June 30, 2022, an increase of $13.3 million. Interest expense, net of interest income, consisted of the following (in millions):

	Three Months Ended June 30,	
	2023	**2022**
ENLK and ENLC senior notes	$ 58.7	$ 50.3
Revolving Credit Facility	4.3	2.2
AR Facility	5.5	1.7
Amortization of debt issuance costs and net discount of senior unsecured notes	1.8	1.3
Interest rate swaps - realized	(1.1)	—
Other	(0.4)	—
Interest expense, net of interest income	$ 68.8	$ 55.5

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $4.6 million for the three months ended June 30, 2023 compared to a loss of $1.2 million for the three months ended June 30, 2022, an increase in loss of $3.4 million. The increase in loss was primarily attributable to an increase in loss of $2.4 million related to the Matterhorn JV, $0.8 million related to our GCF investment, and $0.2 million related to the Cedar Cove JV.

Income Tax Benefit (Expense). Income tax expense was $19.0 million for the three months ended June 30, 2023 compared to an income tax benefit of $1.3 million for the three months ended June 30, 2022. The increase in income tax expense was primarily attributable to reduced income tax expense for the three months ended June 30, 2022 resulting from a reduction in the valuation allowance recorded on our deferred tax assets. See "Item 1. Financial Statements—Note 7" for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $35.6 million for the three months ended June 30, 2023 compared to net income of $38.6 million for the three months ended June 30, 2022, a decrease of $3.0 million. ENLC's non-controlling interest is comprised of Series B Preferred Units, Series C Preferred Units, NGP's 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation's 50% share of the Ascension JV. The decrease in income was primarily due to a $4.9 million decrease attributable to NGP's 49.9% share of the Delaware Basin JV, a $0.6 million decrease attributable to the Series B Preferred Units, and a $0.2 million decrease attributable to Marathon Petroleum Corporation's 50% share of the Ascension JV. The decrease in income was partially offset by a $2.7 million increase in income attributable to the Series C Preferred Units.

Analysis of Operating Segments

We manage and report our activities primarily according to the geography and nature of activity. We have five reportable segments: Permian segment, Louisiana segment, Oklahoma segment, North Texas segment, and Corporate segment. We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. The GAAP measure most directly comparable to adjusted gross margin and segment profit is gross margin. We also believe that investors benefit from having access to the same financial measures that our management uses to evaluate segment results.

See below for our discussion of segment results for the three months ended June 30, 2023 compared to the three months ended June 30, 2022.

- *Permian Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $495.6 million and $478.1 million, respectively, resulting in a decrease in adjusted gross margin in the Permian segment of $17.5 million, which was primarily driven by:
    - A $26.5 million decrease in adjusted gross margin associated with our Permian gas assets. Adjusted gross margin, excluding derivative activity, decreased $19.1 million, which was primarily due to lower commodity prices. Derivative activity associated with our Permian gas assets decreased adjusted gross margin by $7.4 million, which included $15.2 million from increased realized gains and $22.6 million from increased unrealized losses.
    - A $9.0 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $6.4 million, which was primarily due to higher commodity prices. Derivative activity associated with our Permian crude assets increased adjusted gross margin by $2.6 million, which included $0.4 million from decreased realized losses and $2.2 million from increased unrealized gains.
  - Operating expenses in the Permian segment increased $2.8 million primarily due to $3.1 million of higher utilities costs, $2.8 million of increased compressor rentals, $1.5 million of higher labor and benefits costs, $1.5 million of higher materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity. The increase was offset by $6.6 million of lower construction fees and services.
  - Depreciation and amortization in the Permian segment increased $4.4 million primarily due to an increase of $2.7 million from new assets placed into service and $1.7 million related to the equipment transferred to the Phantom processing facility.

- *Louisiana Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $791.5 million and $804.2 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $12.7 million, resulting from:

    - A $6.3 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, increased $6.8 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $0.5 million from decreased unrealized gains.
    - An $11.7 million increase in adjusted gross margin associated with our Louisiana gas assets. Adjusted gross margin, excluding derivative activity, increased $11.0 million, which was primarily due to a settlement payment received resulting from a customer account dispute in the amount of $6.8 million. Derivative activity associated with our Louisiana gas assets increased adjusted gross margin by $0.7 million, which included $6.2 million from increased realized losses and $6.9 million from increased unrealized gains.
    - A $5.3 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $6.2 million, which was primarily due to lower compression fee revenue resulting from the sale of several compressor units in December 2022. Derivative activity associated with our ORV crude assets increased adjusted gross margin by $0.9 million from increased realized gains.

  - Operating expenses in the Louisiana segment decreased $2.8 million primarily due to lower utility costs.

  - Depreciation and amortization in the Louisiana segment decreased $2.5 million primarily due to changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $174.8 million and $190.8 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $16.0 million, resulting from:

    - A $14.5 million increase in adjusted gross margin associated with our Oklahoma gas assets. Adjusted gross margin, excluding derivative activity, increased $3.5 million, which was primarily due to additional volumes from the Central Oklahoma Acquisition in December 2022. Derivative activity associated with our Oklahoma gas assets increased adjusted gross margin by $11.0 million, which included $17.2 million from increased realized gains and $6.2 million from decreased unrealized gains.
    - A $1.5 million increase in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $1.0 million, which was primarily due to higher volumes. Derivative activity associated with our Oklahoma crude assets increased adjusted gross margin by $0.5 million from increased realized gains.

  - Operating expenses in the Oklahoma segment increased $3.9 million primarily due to $2.0 million of increased compressor rentals and $1.5 million of higher materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity from the Central Oklahoma Acquisition in December 2022.

  - Depreciation and amortization in the Oklahoma segment increased $4.3 million primarily due to increases of $3.0 million related to changes in estimated useful lives, $1.8 million due to new assets placed into service, and $1.0 million related to the Central Oklahoma Acquisition. These increases were partially offset by decreased depreciation of $1.7 million related to the transfer of equipment to the Phantom processing facility.

- *North Texas Segment.*

    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $110.2 million and $114.6 million, respectively, resulting in an increase in adjusted gross margin in the North Texas segment of $4.4 million. Adjusted gross margin, excluding derivative activity, increased $5.4 million, which was primarily due to additional volumes from the Barnett Shale Acquisition in July 2022. Derivative activity associated with our North Texas segment decreased adjusted gross margin by $1.0 million, which included $8.8 million from increased realized gains and $9.8 million from increased unrealized losses.

    - Operating expenses in the North Texas segment increased $4.0 million primarily due to $1.0 million of higher materials and supplies expense, $0.9 million of higher labor and benefits costs, $0.7 million of higher ad valorem taxes, $0.4 million of compressor overhauls, and $0.3 million of higher utility costs. These increases in operating expenses were principally due to an increase in operating activity from the Barnett Shale Acquisition on July 1, 2022.

    - Depreciation and amortization in the North Texas segment increased $0.3 million primarily due to $2.9 million related to the Barnett Shale Acquisition on July 1, 2022, which was partially offset by a $2.6 million decrease due to asset reaching the end of their depreciable lives.

- *Corporate Segment.*

    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased $501.6 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.

    - Depreciation and amortization in the Corporate segment decreased $0.2 million.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

Revenues and Cost of Sales, Exclusive of Operating Expenses and Depreciation and Amortization.

Our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, are from natural gas, NGL, crude oil, and condensate product sales and purchases, midstream services that we perform on those commodities, and derivative activity. Fluctuations in our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, reflect in large part changes in commodity prices and volumes. Our adjusted gross margin is not directly affected by the commodity price environment because the commodities that we buy and sell are generally based on the same pricing indices. Both consolidated and segment product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, will fluctuate with market prices; however, the adjusted gross margin related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, fluctuations in these measures from changes in commodity prices may be offset by gains or losses from derivative instruments that we use to manage our exposure to commodity price risk associated with such sales and purchases.

Total revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,530.7 million and $1,608.7 million, respectively, for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 due to the following:

- Product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,698.8 million and $1,608.7 million, respectively, for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 primarily due to lower commodity prices in 2023.

- Revenues from midstream services increased $118.2 million for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 primarily due to higher volumes in 2023. Of these higher volumes in 2023, $28.5 million was related to contributions from acquisitions completed during 2022.

- Derivative loses decreased $49.9 million for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 due to $66.2 million of increased realized gains and $16.3 million of decreased unrealized gains.

Operating Expenses. Operating expenses increased $19.4 million for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 primarily due to $9.9 million of increased compressor rentals, $7.7 million of higher materials and supplies expense, $6.0 million of higher utility costs, $5.2 million of higher labor and benefits costs, $2.6 million of higher ad valorem taxes, and $1.9 million of increased compressor overhauls. The increase was partially offset by $12.2 million of lower construction fees and services and $2.4 million of lower sales and use tax.

Depreciation and Amortization. Depreciation and amortization increased $13.8 million for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 primarily due to increases of $7.7 million due to acquisitions completed in 2022, $5.9 million due to additional assets placed in service, and $5.3 million due to changes in estimated useful lives. These increases were partially offset by decreased depreciation of $4.9 million related to assets reaching the end of their useful lives.

Interest Expense. Interest expense was $137.3 million for the six months ended June 30, 2023 compared to $110.6 million for the six months ended June 30, 2022, an increase of $26.7 million. Interest expense consisted of the following (in millions):

	Six Months Ended June 30,	
	2023	2022
ENLK and ENLC senior notes	$ 112.6	$ 100.6
Revolving Credit Facility	11.8	4.5
AR Facility	11.7	2.8
Amortization of debt issuance costs and net discount of senior unsecured notes	3.3	2.6
Interest rate swaps - realized	(1.6)	0.1
Other	(0.5)	—
Interest expense, net of interest income	$ 137.3	$ 110.6

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $4.7 million for the six months ended June 30, 2023 compared to a loss of $2.3 million for the six months ended June 30, 2022, an increase in loss of $2.4 million. The increase in loss was primarily attributable to an increase in loss of $1.2 million related to our GCF investment, $0.8 million related to the Matterhorn JV, and $0.4 million related to the Cedar Cove JV.

Income Tax Benefit (Expense). Income tax expense was $29.9 million for the six months ended June 30, 2023 compared to an income tax expense of $1.9 million for the six months ended June 30, 2022. The increase in income tax expense was primarily attributable to reduced income tax expense for the six months ended June 30, 2022 resulting from a reduction in the valuation allowance recorded on our deferred tax asset. See "Item 1. Financial Statements—Note 7" for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $71.6 million for the six months ended June 30, 2023 compared to net income of $69.4 million for the six months ended June 30, 2022, an increase of $2.2 million. ENLC's non-controlling interest is comprised of Series B Preferred Units, Series C Preferred Units, NGP's 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation's 50% share of the Ascension JV. The increase in income was primarily due to a $5.1 million increase attributable to the Series C Preferred Units. The increase in income was partially offset by a $1.4 million decrease attributable to the Series B Preferred Units, a $1.1 million decrease in income attributable to Marathon Petroleum Corporation's 50% share of the Ascension JV, and a $0.4 million decrease attributable to NGP's 49.9% share of the Delaware Basin JV.

Analysis of Operating Segments

We manage and report our activities primarily according to the geography and nature of activity. We have five reportable segments: Permian segment, Louisiana segment, Oklahoma segment, North Texas segment, and Corporate segment. We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. The GAAP measure most directly comparable to adjusted gross margin and segment profit is gross margin. We also believe that investors benefit from having access to the same financial measures that our management uses to evaluate segment results.

See below for our discussion of segment results for the six months ended June 30, 2023 compared to the six months ended June 30, 2022.

- *Permian Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $779.4 million and $787.7 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $8.3 million, which was primarily driven by:
    - An $8.4 million increase in adjusted gross margin associated with our Permian gas assets. Adjusted gross margin, excluding derivative activity, increased $0.9 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian gas assets increased adjusted gross margin by $7.5 million, which included $15.3 million from increased realized gains and $7.8 million from increased unrealized losses.
    - A $0.1 million decrease in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $1.6 million, which was primarily due to higher commodity prices. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $1.7 million, which included $1.3 million from increased realized losses and $0.4 million from decreased unrealized gains.
  - Operating expenses in the Permian segment increased $5.6 million primarily due to $5.5 million in increased compressor rentals, $5.3 million of higher utilities costs, $2.3 million of higher labor and benefits costs, $2.1 million of higher materials and supplies expense, and $1.6 million of higher compressor overhaul costs. These increases in operating expenses were principally due to an increase in operating activity. The increase was offset by $10.6 million of lower construction fees and services and $1.1 million of lower sales and use tax.
  - Depreciation and amortization in the Permian segment increased $7.7 million primarily due to increases of $4.4 million from new assets placed into service and $3.3 million related to the equipment transferred to the Phantom processing facility.
- *Louisiana Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,199.8 million and $1,219.0 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $19.2 million, resulting from:
    - A $10.9 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, increased $7.0 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets increased adjusted gross margin by $3.9 million, which included $3.7 million from increased realized gains and $0.2 million from increased unrealized gains.
    - A $17.4 million increase in adjusted gross margin associated with our Louisiana gas assets. Adjusted gross margin, excluding derivative activity, increased $12.8 million, which was primarily due to a settlement payment resulting from a customer account dispute in the amount of $6.8 million. Derivative activity associated with our Louisiana gas assets increased adjusted gross margin by $4.6 million, which included $1.8 million from decreased realized losses and $2.8 million from increased unrealized gains.
    - A $9.1 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $12.1 million, which was primarily due to lower compression fee revenue resulting from the sale of several compressor units in December 2022. Derivative activity associated with our ORV crude assets increased adjusted gross margin by $3.0 million from increased realized gains.

- Operating expenses in the Louisiana segment decreased $2.2 million primarily due to $1.1 million of lower utilities costs and $0.6 million of lower construction fees and services.

- Depreciation and amortization in the Louisiana segment increased $0.3 million primarily due to changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $245.0 million and $273.6 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $28.6 million, resulting from:

    - A $27.2 million increase in adjusted gross margin associated with our Oklahoma gas assets. Adjusted gross margin, excluding derivative activity, increased $4.9 million, which was primarily due to additional volumes from the Central Oklahoma Acquisition in December 2022. Derivative activity associated with our Oklahoma gas assets increased adjusted gross margin by $22.3 million, which included $22.8 million from increased realized gains and $0.5 million from decreased unrealized gains.
    - A $1.4 million increase in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $0.8 million, which was primarily due to higher volumes. Derivative activity associated with our Oklahoma crude assets increased adjusted gross margin by $0.6 million from increased realized gains.

  - Operating expenses in the Oklahoma segment increased $7.6 million primarily due to $4.0 million of higher compressor rentals, $2.2 million of higher materials and supplies expense, $2.0 million of higher ad valorem taxes, and $1.0 million of higher utility costs. These increases in operating expenses were principally due to an increase in operating activity from the Central Oklahoma Acquisition in December 2022. The increase was offset by $2.2 million of lower construction fees and services.

  - Depreciation and amortization in the Oklahoma segment increased $5.3 million primarily due to increases of $5.0 million related to changes in estimated useful lives and $3.6 million due to new assets placed into service, including $2.1 million related to the Central Oklahoma Acquisition. These increases were partially offset by decreased depreciation of $3.3 million related to the transfer of equipment to the Phantom processing facility.

- *North Texas Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $160.5 million and $182.4 million, respectively, resulting in an increase in adjusted gross margin in the North Texas segment of $21.9 million. Adjusted gross margin, excluding derivative activity, increased $12.2 million, which was primarily due to additional volumes from the Barnett Shale Acquisition in July 2022. Derivative activity associated with our North Texas segment increased adjusted gross margin by $9.7 million, which included $20.3 million from increased realized gains and $10.6 million from increased unrealized losses.

  - Operating expenses in the North Texas segment increased $8.4 million primarily due to $3.0 million of higher materials and supplies expense, $1.5 million of higher labor and benefits costs, $1.4 million of higher ad valorem taxes, $1.3 million of higher construction fees and services, $0.8 million of higher utility costs, and $0.5 million of compressor rentals. These increases in operating expenses were principally due to an increase in operating activity from the Barnett Shale Acquisition on July 1, 2022. The increase was partially offset by $1.0 million of lower sales and use tax.

  - Depreciation and amortization in the North Texas segment increased $0.7 million primarily due to $5.6 million related to the Barnett Shale Acquisition on July 1, 2022, which was partially offset by decreased depreciation of $4.9 million due to assets reaching the end of their depreciable lives.

- *Corporate Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased $854.0 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.
  - Depreciation and amortization in the Corporate segment decreased $0.2 million.

Critical Accounting Policies

Information regarding our critical accounting policies is included in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $587.8 million for the six months ended June 30, 2023 compared to $482.6 million for the six months ended June 30, 2022. Operating cash flows before working capital and changes in working capital for the comparative periods were as follows (in millions):

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
Operating cash flows before working capital	$ 553.1	$ 516.5
Changes in working capital	34.7	(33.9)

Operating cash flows before changes in working capital increased $36.6 million for the six months ended June 30, 2023 compared to the six months ended June 30, 2022. The primary contributor to the increase in operating cash flows before working capital was as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity derivative activity, utility credits redeemed or earned, and unit-based compensation, increased $62.0 million. The increase in gross margin is due to a $92.7 million increase in adjusted gross margin, excluding non-cash commodity derivative activity, which was partially offset by a $30.7 million increase in operating expenses, excluding utility credits redeemed or earned and unit-based compensation. For more information regarding the changes in gross margin for the six months ended June 30, 2023 compared to the six months ended June 30, 2022, see “Results of Operations.”

The increase in operating cash flows were partially offset by the following:

- Interest expense, net of interest income, excluding amortization of debt issue costs and net discounts, increased $26.0 million.

- General and administrative expenses, excluding unit-based compensation, increased $2.6 million.

The changes in working capital for the six months ended June 30, 2023 compared to the six months ended June 30, 2022 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments, changes in inventory balances attributable to normal operating fluctuations, and fluctuations in accrued revenue and accrued cost of sales.

Cash Flows from Investing Activities. Net cash used in investing activities was $249.1 million for the six months ended June 30, 2023 compared to $149.3 million for the six months ended June 30, 2022. Our primary investing activities consisted of the following (in millions):

	Six Months Ended June 30,	
	2023	**2022**
Additions to property and equipment (1)	$ (203.1)	$ (124.1)
Contributions to unconsolidated affiliate investments (2)	(49.7)	(26.6)

(1) The increase in capital expenditures was due to expansion projects to accommodate increased volumes on our systems.
(2) Represents contributions to the Matterhorn JV and GCF. See "Item 1. Financial Statements—Note 10" for more information regarding the contributions to unconsolidated affiliate investments.

Cash Flows from Financing Activities. Net cash used in financing activities was $306.5 million for the six months ended June 30, 2023 compared to $341.4 million for the six months ended June 30, 2022. Our primary financing activities consisted of the following (in millions):

	Six Months Ended June 30,	
	2023	**2022**
Net repayments on the AR Facility (1)	$ (186.9)	$ (25.0)
Net repayments on the Revolving Credit Facility (1)	(95.0)	(15.0)
Net borrowings on ENLC's senior unsecured notes (1)	297.0	—
Net repurchases of ENLK's senior unsecured notes	—	(2.0)
Payment of installment payable for Amarillo Rattler Acquisition (2)	—	(10.0)
Distributions to members	(120.2)	(111.7)
Distributions to Series B Preferred Unitholders (3)	(32.5)	(35.8)
Distributions to Series C Preferred Unitholders (3)	(17.1)	(12.0)
Distributions to joint venture partners (4)	(32.9)	(29.0)
Payment to redeem mandatorily redeemable non-controlling interest (5)	(10.5)	—
Redemption of Series B Preferred Units (3)	—	(50.5)
Repurchase of Series C Preferred Units (3)	(3.9)	—
Contributions from non-controlling interests (6)	22.1	9.3
Common unit repurchases (7)	(107.5)	(50.7)
Conversion of unit-based awards for common units, net of units withheld for taxes	(16.9)	(4.4)

(1) See "Item 1. Financial Statements—Note 6" for more information regarding the AR Facility and the Revolving Credit Facility.
(2) Consideration for the Amarillo Rattler Acquisition included an installment payable, which was paid on April 30, 2022.
(3) See "Item 1. Financial Statements—Note 8" for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units and information on the partial redemption of the Series B Preferred Units and the repurchase of the Series C Preferred Units.
(4) Represents distributions to NGP for its ownership in the Delaware Basin JV and distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV.
(5) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries. See "Item 1. Financial Statements— Note 2" for more information regarding the redemption.
(6) Represents contributions from NGP to the Delaware Basin JV.
(7) See "Item 1. Financial Statements—Note 9" for more information regarding our common unit repurchase program.

Capital Requirements

As of June 30, 2023, the following table summarizes our expected remaining capital requirements for 2023 (in millions):

Capital expenditures, net to ENLC (1)	$	218
Operating expenses associated with the relocation of processing facilities, net to ENLC (2)(3)		14
Contributions to unconsolidated affiliate investments (4)		25
Total	$	257

(1) Excludes capital expenditures that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(2) Represents cost incurred that are not part of our ongoing operations related to the relocation of the equipment and facilities associated with the non-operational Cowtown processing plant in North Texas to our Delaware Basin JV operations in the Permian, where it is expected to operate as the Tiger II processing plant. These costs exclude amounts that will be contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(3) Excludes 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.
(4) Includes contributions made to our GCF investment and the Matterhorn JV.

Our primary remaining capital projects for 2023 include the relocation of the Cowtown processing plant, CCS-related initiatives, contributions to unconsolidated affiliate investments, including the restart of GCF, continued development of our existing systems through well connects, and other low-cost development projects. We expect to fund our remaining 2023 capital requirements from operating cash flows.

It is possible that not all of our planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, to fund planned capital expenditures, to make contributions to unconsolidated affiliate investments, and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry, financial, business, and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2023.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2023 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2023	2024	2025	2026	2027	Thereafter
ENLC's & ENLK's senior unsecured notes	$ 4,309.2	$ —	$ 97.9	$ 421.6	$ 491.0	$ —	$ 3,298.7
Revolving Credit Facility (1)	160.0	—	—	—	—	160.0	—
AR Facility (2)	313.1	—	—	313.1	—	—	—
Acquisition contingent consideration (3)	6.4	—	1.1	0.4	4.6	0.3	—
Interest payable on fixed long-term debt obligations	2,477.2	117.6	233.0	222.1	213.3	189.5	1,501.7
Repurchase of ENLC common units held by GIP (4)	27.5	27.5	—	—	—	—	—
Operating lease obligations	115.3	16.3	23.0	16.1	9.2	8.2	42.5
Purchase obligations	11.1	11.1	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (5)	952.5	36.5	82.3	113.2	100.1	88.0	532.4
Total contractual obligations	$ 8,372.3	$ 209.0	$ 437.3	$ 1,086.5	$ 818.2	$ 446.0	$ 5,375.3

(1) The Revolving Credit Facility permits us to borrow up to $1.40 billion on a revolving credit basis and will mature on June 3, 2027.
(2) The AR Facility will terminate on August 1, 2025.
(3) The estimated fair value of the contingent consideration for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition was calculated in accordance with the fair value guidance contained in ASC 820. There are a number of assumptions and estimates factored into these fair values and actual contingent consideration payments could differ from these estimated fair values. See "Item 1. Financial Statements—Note 13" for additional information.
(4) Relates to the repurchase of ENLC common units held by GIP on July 31, 2023. See "Item 1. Financial Statements—Note 9" for more information.
(5) Consists of pipeline capacity payments for firm transportation and deficiency agreements.

The above table does not include any physical or financial contract purchase commitments for natural gas and NGLs due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount that is not already disclosed in the table above.

The interest payable related to the Revolving Credit Facility and the AR Facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates of the Revolving Credit Facility and the AR Facility, which vary from time to time.

Our contractual cash obligations for the remainder of 2023 are expected to be funded from cash flows generated from our operations.

Indebtedness

Revolving Credit Facility. As of June 30, 2023, there were $160.0 million in outstanding borrowings and $21.3 million in outstanding letters of credit under the Revolving Credit Facility.

AR Facility. As of June 30, 2023, the AR Facility had a borrowing base of $371.7 million and there were $313.1 million in outstanding borrowings under the AR Facility. In connection with the AR Facility, certain subsidiaries of ENLC sold and contributed, and will continue to sell or contribute, their accounts receivable to the SPV to be held as collateral for borrowings under the AR Facility. The SPV's assets are not available to satisfy the obligations of ENLC or any of its affiliates.

Senior Unsecured Notes. As of June 30, 2023, we had $4.3 billion in aggregate principal amount of outstanding unsecured senior notes maturing from 2024 to 2047, of which $97.9 million matures on April 1, 2024 and is classified as "Current maturities of long-term debt" on the consolidated balance sheet.

Guarantees. The amounts outstanding on our senior unsecured notes and the Revolving Credit Facility are guaranteed in full by our subsidiary ENLK, including 105% of any letters of credit outstanding under the Revolving Credit Facility. ENLK's guarantees of these amounts are full, irrevocable, unconditional, and absolute, and cover all payment obligations arising under the senior unsecured notes and the Revolving Credit Facility. Liabilities under the guarantees rank equally in right of payment with all existing and future senior unsecured indebtedness of ENLK.

ENLC's assets consist of all of the outstanding common units of ENLK and all of the membership interests of the General Partner. Other than these equity interests, all of our assets and operations are held by our non-guarantor operating subsidiaries. ENLK, directly and indirectly, owns all of these non-guarantor operating subsidiaries, which in some cases are joint ventures that are partially owned by a third party. As a result, the assets, liabilities, and results of operations of ENLK are not materially different than the corresponding amounts presented in our consolidated financial statements.

As of June 30, 2023, ENLC records, on a stand-alone basis, transactions that do not occur at ENLK, which are primarily related to the taxation of ENLC and the elimination of intercompany borrowings.

See "Item 1. Financial Statements—Note 6" for more information on our outstanding debt.

Inflation

Inflation in the United States increased significantly in 2022 and has continued to increase at a more modest pace during the first half of 2023. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business—Inflation" for more information.

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the three months ended June 30, 2023 and have determined that none had a material impact to our consolidated financial statements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q 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 future results and growth of our CCS business, when additional capacity will be operational, timing for completion of construction or expansion projects, results in certain basins, profitability, financial or leverage metrics, cost savings or operational, environmental and climate change initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, the impact of weather related events on us and our financial results and operations, 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 GIP with us and the potential for GIP to favor GIP’s own interests to the detriment of our unitholders, (b) GIP’s ability to compete with us and the fact that it is not required to offer us the opportunity to acquire additional assets or businesses, (c) a default under GIP’s credit facility could result in a change in control of us, could adversely affect the price of our common units, and could result in a default or prepayment event under our credit facility and certain of our other debt, (d) the dependence on key customers for a substantial portion of the natural gas and crude that we gather, process, and transport, (e) developments that materially and adversely affect our key customers or other customers, (f) adverse developments in the midstream business that may reduce our ability to make distributions, (g) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (h) decreases in the volumes that we gather, process, fractionate, or transport, (i) increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices, (j) our ability to receive or renew required permits and other approvals, (k) 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, (l) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (m) changes in the availability and cost of capital, (n) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (o) 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, (p) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (q) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (r) impairments to goodwill, long-lived assets and equity method investments, (s) construction risks in our major development projects, (t) challenges we may face in or in connection with our strategy to enter into new lines of business related to the energy transition, (u) the impact of the coronavirus (COVID-19) pandemic (including the impact of any new variants of the virus) and similar pandemics, (v) our ability to effectively integrate and manage assets we acquire through acquisitions, and (w) the effects of existing and future laws and governmental regulations, including environmental and climate change requirements and other uncertainties. In addition to the specific uncertainties, factors, and risks discussed above and elsewhere in this Quarterly Report on Form 10-Q, the risk factors set forth in “Item 1A. Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2022, filed with the Commission on February 15, 2023, may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events, or otherwise.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs, condensate, and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the CFTC to regulate certain markets for derivative products, including OTC derivatives. The CFTC has issued several relevant regulations, and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not, and, as a result, the final form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The legislation and potential new regulations may also require counterparties to our derivative instruments to spin off or result in such counterparties spinning off some of their derivative activities to separate entities, which may not be as creditworthy as the current counterparties. The legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Commodity Price Risk

We are also subject to direct risks due to fluctuations in commodity prices. While approximately 85% of our adjusted gross margin for the six months ended June 30, 2023 was generated from arrangements with fee-based structures with minimal direct commodity price exposure, the remainder is subject to more direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the gas processing component of our business. For more information regarding our main types of contractual arrangements, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” of our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas, crude and condensate, and NGLs using OTC derivative financial instruments with only certain well-capitalized counterparties, which have been approved in accordance with our commodity risk management policy.

We have hedged our exposure to fluctuations in prices for natural gas, NGLs, and crude oil volumes produced for our account. We have tailored our hedges to generally match the product composition and the delivery points to those of our physical equity volumes. The hedges cover specific products based upon our expected equity composition.

Commodity derivatives are used both to manage and hedge price and location risk related to these market exposures and to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of NGLs, natural gas, crude, and condensate.

The following table sets forth information related to derivative instruments outstanding at June 30, 2023.

Period	Underlying	Notional Volume (net position)	Reference Price	Price Range	Net Fair Value Asset/(Liability) (In Millions)
July 2023 - March 2024	Propane	(77.1) MMgals	OPIS Mt Belvieu	$0.79 - $0.95/Gal	$ 22.2
July 2023 - December 2023	Normal Butane	(5.7) MMgals	OPIS Mt Belvieu	$0.96 - $0.97/Gal	1.6
July 2023 - July 2023	Natural Gasoline	(0.6) MMgals	NYMEX WTI Average	$1.27 - $1.67/Gal	—
July 2023 - June 2024	Natural Gasoline & Condensate	72.7 MMgals	OPIS Mt Belvieu and NYMEX WTI Average differential	($0.32) - ($0.24)/Gal	(7.5)
July 2023 - January 2028	Natural Gas	(11.3) Bbtu	NYMEX Henry Hub	$2.18 - $6.19/MMbtu	25.4
July 2023 - December 2024	Natural Gas	(4.1) Bbtu	Waha basis differential	($3.02) - ($0.26)/MMbtu	(13.5)
July 2023 - July 2023	Natural Gas	(1.0) Bbtu	Henry Hub Gas Daily	$2.60 - $2.60/MMbtu	—
August 2023 - January 2024	Crude & Condensate	(0.3) MMbbls	NYMEX WTI	$78.43 - $79.84/Bbl	(0.6)
January 2024 - December 2025	Crude & Condensate	(7.2) MMbbls	WTI-Houston and Midland basis differential	$0.70 - $0.90/Bbl	2.0
Total fair value of commodity derivatives					$ 29.6

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of June 30, 2023, our outstanding commodity derivative instruments had a net fair value asset of $29.6 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas, crude and condensate, and NGL prices would result in a change of approximately $14.5 million in the net fair value of these contracts as of June 30, 2023.

Interest Rate Risk

We are exposed to interest rate risk on the Revolving Credit Facility and the AR Facility. Amounts drawn on the Revolving Credit Facility and the AR Facility bear interest at rates based on SOFR. At June 30, 2023, we had $160.0 million in outstanding borrowings under the Revolving Credit Facility and $313.1 million in outstanding borrowings under the AR Facility.

In January 2023, we entered into a $400.0 million interest rate swap to reduce the variability of cash outflows associated with interest payments related to our long-term debt with variable interest rates. This swap has been designated as a cash flow hedge. See "Item 1. Financial Statements—Note 12" for more information on our outstanding derivatives.

A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $1.6 million and $3.1 million for the Revolving Credit Facility and the AR Facility, respectively. This change in interest expense would be partially offset by a $4.0 million change in the opposite direction due to our open interest rate swap hedge.

We are not exposed to changes in interest rates with respect to ENLK's senior unsecured notes due in 2024, 2025, 2026, 2044, 2045, or 2047 or our senior unsecured notes due in 2028, 2029, and 2030 as these are fixed-rate obligations. As of June 30, 2023, the estimated fair value of the senior unsecured notes was approximately $4,012.1 million, based on the market prices of ENLK's and our publicly traded debt at June 30, 2023. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1.0% in interest rates. Such an increase in interest rates would result in an approximate $233.6 million decrease in fair value of the senior unsecured notes at June 30, 2023. See "Item 1. Financial Statements—Note 6" for more information on our outstanding indebtedness.

Beginning with the interest period which commenced on December 15, 2022, distributions on ENLK's Series C Preferred Units are based on a floating rate tied to LIBOR plus a spread of 4.11% and, commencing September 15, 2023, distributions will be based on the forward-looking term rate based on SOFR ("Term SOFR"), plus a Term SOFR spread adjustment of 0.26161%, plus a spread of 4.11% rather than a fixed rate and, therefore, the amount paid by ENLK as a distribution will be more sensitive to changes in interest rates. See "Item 1. Financial Statements—Note 8" for more information regarding distributions with respect to the Series C Preferred Units.

Item 4. Controls and Procedures

a. Evaluation of Disclosure Controls and Procedures

Management of the Managing Member is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for us. We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of the Managing Member, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (June 30, 2023), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

b. Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended June 30, 2023 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

We are involved in various litigation and administrative proceedings arising in the normal course of business. For a discussion of certain litigation and similar proceedings, please refer to Note 16, "Commitments and Contingencies," of the Notes to Consolidated Financial Statements contained in Part I of this Quarterly Report on Form 10-Q, which is incorporated by reference herein.

Item 1A. Risk Factors

Information about risk factors does not differ materially from that set forth in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the Commission on February 15, 2023.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the three months ended June 30, 2023, we re-acquired ENLC common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of unit-based awards and we repurchased common units in open market transactions and from GIP in connection with our common unit repurchase program.

Period	Total Number of Units Purchased (1)	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Dollar Value of Units that May Yet Be Purchased under the Plans or Programs (in millions) (2)
April 1, 2023 to April 30, 2023	1,185,099	$ 10.65	1,176,033	$ 136.0
May 1, 2023 to May 31, 2023	3,232,942	10.94	3,232,360	$ 100.7
June 1, 2023 to June 30, 2023	732,988	10.18	732,988	$ 93.2
Total	5,151,029	$ 10.77	5,141,381	

(1) The total number of units purchased shown in the table includes 9,648 ENLC common units received by us from employees for the payment of personal income tax withholding on vesting transactions.

(2) In December 2022, the Board reauthorized our common unit repurchase program for 2023 and set the amount available for repurchases of outstanding common units during 2023 at up to $200.0 million. Future repurchases under the program may be made from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time. For more information regarding common units repurchased from public unitholders and our repurchase of common units held by GIP, see "Item 1. Financial Statements—Note 9."

Item 5. Other Information

Insider Trading Plans

On May 15, 2023, Alaina K. Brooks, Executive Vice President, Chief Legal and Administrative Officer, and Secretary of the Managing Member, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense of Rule 10b5-1(c) for the sale of up to 173,913 of our common units until May 14, 2024.

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Item 6. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-4, filed with the Commission on November 20, 2013, file No. 333-192419).
3.2	—	Certificate of Amendment to Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.2 to Amendment No. 2 to our Registration Statement on Form S-4, filed with the Commission on January 21, 2014, file No. 333-192419).
3.3	—	Second Amended and Restated Operating Agreement of EnLink Midstream, LLC, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
3.4	—	Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.12 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.5	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.13 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.6	—	Second Amended and Restated Limited Liability Company Agreement of EnLink Midstream Manager, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36336).
3.7	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to EnLink Midstream Partners, LP's Registration Statement on Form S-3, filed with the Commission on March 10, 2014, file No. 333-194465).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36366).
3.10	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, filed with the Commission on August 7, 2012, file No. 333-97779).
3.11	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.12	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.13	—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.14	—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
4.1	—	Indenture, dated as of August 31, 2022, by and among EnLink Midstream, LLC, as issuer, EnLink Midstream Partners, LP, as guarantor, and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to EnLink Midstream, LLC's Current Report on Form 8-K, filed on August 31, 2022, file No. 001-36336).
22.1	—	Subsidiary Guarantors (incorporated by reference to Exhibit 22.1 to our Annual Report on Form 10-K for the year ended December 31, 2022, filed with the Commission on February 15, 2023, file No. 001-36336).
31.1 *	—	Certification of the Principal Executive Officer.
31.2 *	—	Certification of the Principal Financial Officer.
32.1 *	—	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101 *	—	The following financial information from EnLink Midstream, LLC's Quarterly Report on Form 10-Q for the quarter ended June 30, 2023, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of June 30, 2023 and December 31, 2022, (ii) Consolidated Statements of Operations for the three and six months ended June 30, 2023 and 2022, (iii) Consolidated Statements of Changes in Members' Equity for the three months ended June 30, 2023 and 2022 and March 31, 2023 and 2022, (iv) Consolidated Statements of Cash Flows for the six months ended June 30, 2023 and 2022, and (v) the Notes to Consolidated Financial Statements.
104 *	—	Cover Page Interactive Data File (formatted as Inline iXBRL and included in Exhibit 101).

* Filed herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EnLink Midstream, LLC

By: EnLink Midstream Manager, LLC, its managing member

By: /s/ J. PHILIPP ROSSBACH

J. Philipp Rossbach
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

August 2, 2023

Exhibit 31.1

CERTIFICATIONS

I, Jesse Arenivas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2023

/s/ JESSE ARENIVAS
Jesse Arenivas
Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Benjamin D. Lamb, certify that:

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2023

/s/ BENJAMIN D. LAMB

Benjamin D. Lamb
Executive Vice President and Chief Financial Officer
(principal financial officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of EnLink Midstream, LLC (the “Registrant”) on Form 10-Q of the Registrant for the quarter ended June 30, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Jesse Arenivas, Chief Executive Officer of EnLink Midstream Manager, LLC, and Benjamin D. Lamb, Chief Financial Officer of EnLink Midstream Manager, LLC, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: August 2, 2023	/s/ JESSE ARENIVAS
	Jesse Arenivas
	Chief Executive Officer
Date: August 2, 2023	/s/ BENJAMIN D. LAMB
	Benjamin D. Lamb
	Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.