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, 2024

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 August 1, 2024, the Registrant had 461,449,461 common units outstanding.

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	**Definition**
/d	Per day.
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 FASB Accounting Standards Codification.
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 transmission pipeline that connects ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
ASU	The FASB Accounting Standards Update.
Bbl	Barrel.
Bbtu	Billion British thermal units.
Bcf	Billion cubic feet.
Board	The board of directors of the Managing Member.
CCS	Carbon capture, transportation, and sequestration.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture in which we own a 30% 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 natural gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity.
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 plants located in the Delaware Basin in Texas.
ENLC	EnLink Midstream, LLC together with its consolidated subsidiaries.
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.
FASB	The Financial Accounting Standards Board.
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, a joint venture in which we own a 38.75% interest. GCF owns an NGL fractionator in Mont Belvieu, Texas. The GCF assets were idled to reduce operating expenses in 2021 but are expected to resume operations in the third quarter of 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.

LNG	Liquified natural gas.
Managing Member	EnLink Midstream Manager, LLC, the managing member of ENLC.
Matterhorn JV	Matterhorn JV, a joint venture in which we own a 15% interest. The Matterhorn JV is constructing 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, which were divested in November 2023.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
PIK Distribution	A quarterly distribution in-kind of Series B Preferred Units. We agreed with the holders of the Series B Preferred Units to make a PIK Distribution until the quarterly distribution in respect of the earlier of (x) any quarter in which the holders of the Series B Preferred Units give notice to the General Partner of their election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024.
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, 2024 (Unaudited)	December 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.8	$ 28.7
Accounts receivable:		
Trade receivables (1)	59.9	85.9
Accrued revenue and other	583.3	581.4
Fair value of derivative assets	62.5	76.9
Other current assets	102.7	65.4
Total current assets	814.2	838.3
Property and equipment, net of accumulated depreciation of $5,357.9 and $5,137.2, respectively	6,313.4	6,407.0
Intangible assets, net of accumulated amortization of $1,114.9 and $1,051.2, respectively	729.9	793.6
Investment in unconsolidated affiliates	162.8	150.5
Fair value of derivative assets	11.3	27.0
Other assets, net	120.7	112.2
Total assets	$ 8,152.3	$ 8,328.6
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 86.9	$ 126.5
Accrued natural gas, NGLs, condensate, and crude oil purchases	433.2	428.0
Fair value of derivative liabilities	64.1	62.7
Current maturities of long-term debt	421.2	97.9
Other current liabilities	249.3	278.5
Total current liabilities	1,254.7	993.6
Long-term debt, net of unamortized issuance cost	4,236.2	4,471.0
Other long-term liabilities	79.0	98.0
Deferred tax liability, net	111.0	104.2
Fair value of derivative liabilities	13.1	26.7
Members' equity:		
Members' equity (452,144,847 and 451,614,086 units issued and outstanding, respectively)	914.2	1,000.5
Accumulated other comprehensive income	3.8	0.7
Non-controlling interest	1,540.3	1,633.9
Total members' equity	2,458.3	2,635.1
Commitments and contingencies (Note 13)		
Total liabilities and members' equity	$ 8,152.3	$ 8,328.6

(1) There was no allowance for bad debt at June 30, 2024 and December 31, 2023.

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, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(Unaudited)			
Revenues:				
Product sales	$ 1,278.6	$ 1,239.3	$ 2,683.6	$ 2,715.6
Midstream services	273.3	279.5	545.2	558.8
Gain (loss) on derivative activity	(0.8)	11.3	(29.8)	23.2
Total revenues	1,551.1	1,530.1	3,199.0	3,297.6
Operating costs and expenses:				
Cost of sales, exclusive of operating expenses and depreciation and amortization	1,062.6	1,019.0	2,213.0	2,290.9
Operating expenses	155.2	136.8	307.8	269.2
Depreciation and amortization	162.6	165.3	327.9	325.7
Impairments	—	—	14.2	—
(Gain) loss on disposition of assets	0.9	(0.8)	(0.8)	(1.2)
General and administrative	30.2	27.9	85.4	57.4
Total operating costs and expenses	1,411.5	1,348.2	2,947.5	2,942.0
Operating income	139.6	181.9	251.5	355.6
Other income (expense):				
Interest expense, net of interest income	(66.7)	(68.8)	(132.1)	(137.3)
Income (loss) from unconsolidated affiliate investments	0.3	(4.6)	(0.5)	(4.7)
Other income	3.8	0.4	4.3	0.4
Total other expense	(62.6)	(73.0)	(128.3)	(141.6)
Income before non-controlling interest and income taxes	77.0	108.9	123.2	214.0
Income tax expense	(10.0)	(19.0)	(6.2)	(29.9)
Net income	67.0	89.9	117.0	184.1
Net income attributable to non-controlling interest	28.9	35.6	64.4	71.6
Net income attributable to ENLC	$ 38.1	$ 54.3	$ 52.6	$ 112.5
Net income attributable to ENLC per unit:				
Basic common unit	$ 0.07	$ 0.12	$ 0.11	$ 0.24
Diluted common unit	$ 0.07	$ 0.12	$ 0.10	$ 0.24

See accompanying notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
	(Unaudited)			
Net income	$ 67.0	$ 89.9	$ 117.0	$ 184.1
Unrealized gain on designated cash flow hedge (1)	0.1	5.7	3.1	4.5
Comprehensive income	67.1	95.6	120.1	188.6
Comprehensive income attributable to non-controlling interest	28.9	35.6	64.4	71.6
Comprehensive income attributable to ENLC	$ 38.2	$ 60.0	$ 55.7	$ 117.0

(1) Includes tax expense of $0.2 million and $1.1 million for the three and six months ended June 30, 2024, respectively, and 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 Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	$	$
			(Unaudited)		
Balance, March 31, 2024	$ 892.5	448.8	$ 3.7	$ 1,642.9	$ 2,539.1
Conversion of unit-based awards for common units, net of units withheld for taxes	(1.6)	0.2	—	—	(1.6)
Unit-based compensation	5.2	—	—	—	5.2
Contributions from non-controlling interests	—	—	—	0.8	0.8
Distributions	(60.1)	—	—	(42.4)	(102.5)
Unrealized gain on designated cash flow hedge (1)	—	—	0.1	—	0.1
Exchange of Series B Preferred Units	95.1	7.0	—	(89.9)	5.2
Loss on exchange of Series B Preferred Units	(5.2)	—	—	—	(5.2)
Common units repurchased	(50.0)	(3.9)	—	—	(50.0)
Accrued common unit repurchase (2)(3)	0.2	—	—	—	0.2
Net income	38.1	—	—	28.9	67.0
Balance, June 30, 2024	$ 914.2	452.1	$ 3.8	$ 1,540.3	$ 2,458.3

(1) Includes tax expense of $0.2 million for the three months ended June 30, 2024.
(2) Excludes the $23.1 million repurchase of ENLC common units held by GIP on April 29, 2024, which was accrued at March 31, 2024.
(3) Relates to the change in the repurchase accrual of ENLC common units held by GIP, which are contractually subject to repurchase by ENLC at the end of each quarter and settled in the subsequent quarter. For additional information, see "Note 8—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 Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	$	$
			(Unaudited)		
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 (1)	—	—	5.7	—	5.7
Adjustment related to the redemption of the mandatorily redeemable non-controlling interest (2)	0.8	—	—	—	0.8
Common units repurchased	(56.1)	(5.2)	—	—	(56.1)
Accrued common unit repurchase (3)	(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 expense of $1.8 million for the three months ended June 30, 2023.
(2) Relates to book-to-tax differences recorded upon the settlement of the mandatorily redeemable non-controlling interest.
(3) Relates to the change in the repurchase accrual of ENLC common units held by GIP, which are contractually subject to repurchase by ENLC at the end of each quarter and settled in the subsequent quarter. For additional information, see "Note 8—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 Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	$	$
			(Unaudited)		
Balance, December 31, 2023	$ 1,000.5	451.6	$ 0.7	$ 1,633.9	$ 2,635.1
Conversion of unit-based awards for common units, net of units withheld for taxes	(17.1)	2.8	—	—	(17.1)
Unit-based compensation	10.8	—	—	—	10.8
Contributions from non-controlling interests	—	—	—	13.8	13.8
Distributions	(122.5)	—	—	(81.9)	(204.4)
Unrealized gain on designated cash flow hedge (1)	—	—	3.1	—	3.1
Exchange of Series B Preferred Units	95.1	7.0	—	(89.9)	5.2
Loss on exchange of Series B Preferred Units	(5.2)	—	—	—	(5.2)
Common units repurchased (2)	(77.1)	(9.3)	—	—	(77.1)
Accrued common unit repurchase (3)	(22.9)	—	—	—	(22.9)
Net income	52.6	—	—	64.4	117.0
Balance, June 30, 2024	$ 914.2	452.1	$ 3.8	$ 1,540.3	$ 2,458.3

(1) Includes tax expense of $1.1 million for the six months ended June 30, 2024.
(2) Excludes the $41.5 million repurchase of ENLC common units held by GIP on February 19, 2024, which was accrued at December 31, 2023.
(3) Relates to the repurchase of ENLC common units held by GIP, which are contractually subject to repurchase by ENLC at the end of each quarter and settled in the subsequent quarter. For additional information, see "Note 8—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 Income (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	(16.9)	2.6	—	—	(16.9)
Unit-based compensation	8.5	—	—	—	8.5
Contributions from non-controlling interests	—	—	—	22.1	22.1
Distributions	(120.2)	—	—	(82.5)	(202.7)
Unrealized gain on designated cash flow hedge (1)	—	—	4.5	—	4.5
Adjustment related to the redemption of the mandatorily redeemable non-controlling interest (2)	0.8	—	—	—	0.8
Repurchase of Series C Preferred Units	—	—	—	(3.9)	(3.9)
Common units repurchased	(107.5)	(9.6)	—	—	(107.5)
Accrued common unit repurchase (3)	(27.5)	—	—	—	(27.5)
Net income	112.5	—	—	71.6	184.1
Balance, June 30, 2023	$ 1,156.1	462.0	$ 4.5	$ 1,613.6	$ 2,774.2

(1) Includes tax expense of $1.4 million for the six months ended June 30, 2023.
(2) Relates to book-to-tax differences recorded upon the settlement of the mandatorily redeemable non-controlling interest.
(3) Relates to the repurchase of ENLC common units held by GIP, which are contractually subject to repurchase by ENLC at the end of each quarter and settled in the subsequent quarter. For additional information, see "Note 8—Members' Equity."

See accompanying notes to consolidated financial statements.

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

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 117.0	$ 184.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	327.9	325.7
Gain on disposition of assets	(0.8)	(1.2)
Non-cash unit-based compensation	10.8	8.5
Non-cash (gain) loss on derivatives recognized in net income	22.1	(3.9)
Amortization of debt issuance costs and net discount of senior unsecured notes	3.0	3.3
Deferred income tax expense	5.8	29.6
Loss from unconsolidated affiliate investments	0.5	4.7
Impairments	14.2	—
Other operating activities	(2.1)	2.3
Changes in assets and liabilities, net of the effects of acquisitions:		
Accounts receivable, accrued revenue, and other	24.5	183.1
Product inventory, prepaid expenses, and other	(36.0)	66.6
Accounts payable, accrued product purchases, and other accrued liabilities	(31.0)	(215.0)
Net cash provided by operating activities	455.9	587.8
Cash flows from investing activities:		
Additions to property and equipment	(210.8)	(203.1)
Contributions to unconsolidated affiliate investments	(20.1)	(49.7)
Other investing activities	(3.2)	3.7
Net cash used in investing activities	(234.1)	(249.1)
Cash flows from financing activities:		
Proceeds from borrowings	1,377.5	2,004.1
Repayments on borrowings	(1,292.0)	(1,989.0)
Distributions to members	(122.5)	(120.2)
Distributions to non-controlling interests	(81.9)	(82.5)
Earnout payments	(2.5)	—
Payment to redeem mandatorily redeemable non-controlling interest	—	(10.5)
Repurchase of Series C Preferred Units	—	(3.9)
Contributions from non-controlling interests	13.8	22.1
Common unit repurchases	(118.6)	(107.5)
Payment of taxes related to the conversion of unit-based awards for common units	(17.1)	(16.9)
Other financing activities	(1.4)	(2.2)
Net cash used in financing activities	(244.7)	(306.5)
Net increase (decrease) in cash and cash equivalents	(22.9)	32.2
Cash and cash equivalents, beginning of period	28.7	22.6
Cash and cash equivalents, end of period	$ 5.8	$ 54.8
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 133.6	$ 131.1
Cash paid for income taxes	$ 0.6	$ 1.0
Non-cash investing activities:		
Right-of-use assets obtained in exchange for operating lease liabilities	$ 28.2	$ 11.6
Non-cash accrual of property and equipment	$ (21.2)	$ 15.7
Non-cash financing activities:		
Issuance of ENLC common units from Series B Preferred Units exchange	$ 95.1	$ —
Redemption of Series B Preferred Units from Series B Preferred Units exchange	$ (89.9)	$ —

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements
June 30, 2024
(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, 2024, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 45.0% 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 owning, operating, investing in, and developing midstream energy infrastructure assets to provide midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, storing, trans-loading, and selling crude oil and condensate.

As of June 30, 2024, our midstream infrastructure network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.9 Bcf/d of processing capacity, seven fractionators with approximately 316,300 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

(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, 2023 filed with the Commission on February 21, 2024. 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. 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 (1)
2024 (remaining)	$ 85.3
2025	157.1
2026	159.3
2027	130.9
2028	127.1
Thereafter	1,133.5
Total	$ 1,793.2

(1) The contractually committed fees include $19.8 million in 2025, $33.8 million in 2026, $33.7 million in 2027, $33.8 million in 2028, and $722.9 million from 2029 through 2050 for MVCs under our transportation services agreement with a subsidiary of ExxonMobil. We may not realize the full value of these fees or realize them in different periods under any financial arrangement entered into in respect of the Pecan Island transportation agreement. See “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Other Recent Developments” for additional information.

c. Property and Equipment

In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances, or triggering events, indicate that their carrying value may not be recoverable. When the carrying amount of a long-lived asset is not recoverable, an impairment is recognized equal to the excess of the asset’s carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs.

During the first quarter of 2024, we identified changes in our outlook for future cash flows and the anticipated use of certain non-core assets in our North Texas segment. We determined that the carrying amounts of these assets exceeded their fair values, based on market inputs and certain assumptions, and recorded an impairment expense of $14.2 million for the three months ended March 31, 2024. In April 2024, we sold these non-core assets in our North Texas segment.

We did not record any impairment expense for the three months ended June 30, 2024 and the three and six months ended June 30, 2023.

d. Non-controlling Interests

Our non-controlling interests are 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 50.0% share of the Ascension JV. Certain of our joint venture arrangements provide us or our joint venture partners with the right, under certain circumstances, to cause a purchase or sale of interest in the joint venture or to seek to sell the entire joint venture. At any time after June 30, 2025, NGP has the right to arrange a sale of the Delaware Basin JV for the best available price; provided that, if NGP exercises this right, we are permitted, but not required, to purchase NGP’s interest at a certain call price.

e. Recent Accounting Pronouncements

On November 27, 2023, the FASB issued ASU No. 2023-07, *“Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures.”* (“ASU 2023-07”). ASU 2023-07 amends reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. This ASU is effective for annual periods beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. The impact of ASU 2023-07 would be limited to the disclosures within the footnotes of the consolidated financial statements.

On December 14, 2023, the FASB issued ASU No. 2023-09, *“Income Taxes (Topic 740): Improvements to Income Tax Disclosures.”* (“ASU 2023-09”). ASU 2023-09 is intended to improve the transparency of income tax disclosures by requiring

(i) consistent categories and greater disaggregation of information in the rate reconciliation and (ii) income taxes paid disaggregated by jurisdiction. ASU 2023-09 will become effective for annual periods beginning after December 15, 2024, with early adoption permitted. Management is currently evaluating ASU 2023-09 to determine its impact on the Company's annual disclosures.

On March 6, 2024, the Commission adopted a new set of rules that require a wide range of climate-related disclosures, including material climate-related risks, information on any climate-related targets or goals that are material to the registrant's business, results of operations, or financial condition, Scope 1 and Scope 2 GHG emissions on a phased-in basis by certain larger registrants when those emissions are material and the filing of an attestation report covering the same, and disclosure of the financial statement effects of severe weather events and other natural conditions including costs and losses. Compliance dates under the final rule are phased in by registrant category. Multiple lawsuits have been filed challenging the Commission's new climate rules, which have been consolidated and will be heard in the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the Commission issued an order staying the final rules until judicial review is complete.

(3) 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, 2024			
Customer relationships, beginning of period	$ 1,844.8	$ (1,051.2)	$ 793.6
Amortization expense	—	(63.7)	(63.7)
Customer relationships, end of period	$ 1,844.8	$ (1,114.9)	$ 729.9

Amortization expense was $31.9 million for each of the three months ended June 30, 2024 and 2023 and $63.7 million and $63.8 million for the six months ended June 30, 2024 and 2023, respectively.

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

2024 (remaining)	$ 63.9
2025	110.2
2026	106.3
2027	106.3
2028	106.3
Thereafter	236.9
Total	$ 729.9

(4) Related Party Transactions

(a) Transactions with the Cedar Cove JV

We process natural gas and purchase the related residue natural gas and NGLs from the Cedar Cove JV.We recorded the following amounts (in millions) on our consolidated balance sheets related to our transactions with the Cedar Cove JV:

	June 30, 2024	December 31, 2023
Accrued natural gas, NGLs, condensate, and crude oil purchases	$ 0.3	$ 0.3

We recorded the following amounts (in millions) on our consolidated statements of operations related to our transactions with the Cedar Cove JV:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Midstream services revenue	$ 0.5	$ 0.6	$ 1.0	$ 1.3
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1.4)	(2.5)	(2.8)	(4.0)

(b) Transactions with GIP

GIP Repurchase Agreement. On January 16, 2024, we entered into a new repurchase agreement with GIP with terms substantially similar to the repurchase agreement with GIP for 2023 entered into on December 20, 2022, which repurchase agreement terminated on December 31, 2023 in accordance with its terms. The current repurchase agreement will renew for successive one-year terms (each, a “Renewal Year”) on January 1 of each Renewal Year, with the first Renewal Year beginning on January 1, 2025, unless either the Company or the GIP Entities elects to terminate the Repurchase Agreement prior to the start of any Renewal Year, during a two-week period in December preceding the applicable Renewal Year. See “Note 8—Members’ Equity” for additional information on the activity related to the GIP repurchase agreement.

(5) Long-Term Debt

As of June 30, 2024 and December 31, 2023, long-term debt consisted of the following (in millions):

	June 30, 2024			December 31, 2023		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Revolving Credit Facility due 2027 (1)	$ 229.0	$ —	$ 229.0	$ —	$ —	$ —
AR Facility due 2025 (2)	254.4	—	254.4	300.0	—	300.0
ENLK's 4.40% Senior unsecured notes due 2024	—	—	—	97.9	—	97.9
ENLK's 4.15% Senior unsecured notes due 2025	421.6	—	421.6	421.6	—	421.6
ENLK's 4.85% Senior unsecured notes due 2026	491.0	(0.1)	490.9	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	(2.5)	997.5	1,000.0	(2.7)	997.3
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	(4.9)	445.1	450.0	(5.0)	445.0
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	$ 4,694.7	$ (7.8)	4,686.9	$ 4,609.2	$ (8.2)	4,601.0
Debt issuance cost (3)			(29.5)			(32.1)
Less: Current maturities of long-term debt (4)(5)			(421.2)			(97.9)
Long-term debt, net of unamortized issuance cost			$ 4,236.2			$ 4,471.0

(1) The effective interest rate was 6.9% at June 30, 2024.
(2) The effective interest rate was 6.3% and 6.4% at June 30, 2024 and December 31, 2023, respectively.
(3) Net of accumulated amortization of $22.6 million and $20.0 million at June 30, 2024 and December 31, 2023, respectively.
(4) The outstanding balance, net of debt issuance costs, of ENLK's 4.40% senior unsecured notes are classified as "Current maturities of long-term debt" in the consolidated balance sheet as of December 31, 2023 as these notes matured on April 1, 2024.
(5) The outstanding balance, net of debt issuance costs, of ENLK's 4.15% senior unsecured notes are classified as "Current maturities of long-term debt" in the consolidated balance sheet as of June 30, 2024 as these notes mature on June 1, 2025.

Revolving Credit Facility

The Revolving Credit Facility permits ENLC to borrow up to $1.4 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. There were $229.0 million in outstanding borrowings under the Revolving Credit Facility and $14.6 million in outstanding letters of credit as of June 30, 2024.

At June 30, 2024, 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 $600.6 million as of June 30, 2024. As of June 30, 2024, the AR Facility had a borrowing base of $345.5 million and there were $254.4 million in outstanding borrowings under the AR Facility.

The amount available for borrowings at any one time under the AR Facility is limited to a borrowing base amount calculated based on the outstanding balance of eligible receivables held as collateral, subject to certain reserves, concentration limits, and other limitations. Depending on our operational needs, we may not borrow the total amount available for borrowings.

At June 30, 2024, 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.

(6) Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Current income tax expense	$ (0.2)	$ (0.2)	$ (0.4)	$ (0.3)
Deferred income tax expense	(9.8)	(18.8)	(5.8)	(29.6)
Income tax expense	$ (10.0)	$ (19.0)	$ (6.2)	$ (29.9)

The following schedule reconciles income tax 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,	
	2024	2023	2024	2023
Expected income tax expense based on federal statutory tax rate	$ (8.3)	$ (15.4)	$ (10.5)	$ (29.9)
State income tax expense, net of federal benefit	(1.1)	(2.0)	(1.5)	(3.8)
Unit-based compensation (1)	0.4	0.1	7.7	6.6
Other	(1.0)	(1.7)	(1.9)	(2.8)
Income tax expense	$ (10.0)	$ (19.0)	$ (6.2)	$ (29.9)

(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, 2024, we had $784.9 million of deferred tax assets, net of a $1.2 million valuation allowance, and $895.9 million of deferred tax liabilities for net deferred tax liabilities of $111.0 million. As of December 31, 2023, we had $758.3 million of deferred tax assets, net of a $1.2 million valuation allowance, and $862.5 million of deferred tax liabilities for net deferred tax liabilities of $104.2 million.

As of June 30, 2024, management believes it is more likely than not that the Company will realize the benefits of the deferred tax assets, net of valuation allowance.

(7) Certain Provisions of the ENLK Partnership Agreement

a. Series B Preferred Units

As of June 30, 2024 and December 31, 2023, there were48,760,039 and 54,575,638 Series B Preferred Units issued and outstanding, respectively.

Conversion

Series B Preferred Units are exchangeable for ENLC common units in an amount equal to the number of applicable Series B Preferred Units multiplied by the exchange ratio of 1.15, subject to certain adjustments. The exchange is subject to ENLK's option to pay cash instead of ENLC issuing additional ENLC common units, and can occur in whole or in part at the option of the holder of the Series B Preferred Units at any time, or in whole at our option, provided the daily volume-weighted average closing price of the ENLC common units for the 30 trading days ending two trading days prior to the exchange is greater than150% of the $15.00 per Series B Preferred Unit issue price divided by the conversion ratio of 1.15.

A summary of the exchange activity by the holders of the Series B Preferred Units during the three months ended June 30, 2024 is provided below (in millions, except per unit amounts):

	Series B Preferred Units Canceled	Series B Preferred Units Exchanged		ENLC Common Units Issued		Loss on Exchange of Series B Preferred Units
Transaction date	Units	Units	$	Units	$	$
April 2024	2,604,046	2,608,696 (1)	$ 38.3	3,000,000	$ 41.2	$ (2.9)
May 2024	3,478,262	3,478,262	$ 51.6	4,000,000	$ 53.9	$ (2.3)

(1) Includes 4,650 accrued and unpaid Series B Preferred Units that holders were entitled to receive in a PIK Distribution in respect of the first quarter of 2024 as of the date of the exchange of such Series B Preferred Units.

In July 2024, the holders of the Series B Preferred Units exchanged8,695,654 Series B Preferred Units into10,000,000 ENLC common units. Additionally, on August 5, 2024, we purchased 12,698,414 Series B Preferred Units for $200.2 million. Subsequent to these post-quarter exchanges and the unit purchase, there were27,365,971 outstanding Series B Preferred Units as of August 7, 2024, the date of this report.

Transfer Fee

Holders of Series B Preferred Units must pay a $0.15 fee (A) on each Series B Preferred Unit that is transferred to (i) anyone other than an affiliate of such holder or (ii) another holder, or (B) following the exchange of each Series B Preferred Unit into an ENLC common unit, upon the sale of each ENLC common unit in a registered offering. An initial non-refundable fee of $3.5 million, which will be credited against and reduce any fees payable upon a subsequent transfer or registered sale, was received from the holders of the Series B Preferred Units in May 2024 in connection with the exchange of Series B Preferred Units in April 2024, and was recorded as "Other income" in the consolidated statements of operations for the three and six months ended June 30, 2024.

Income and 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, 2024 and 2023 is provided below:

Declaration period	PIK Distribution	Cash distribution (in millions)		Date paid/payable
2024				
Fourth Quarter of 2023	136,439	$	15.3	February 9, 2024
First Quarter of 2024	130,270	$	14.7	May 14, 2024
Second Quarter of 2024 (1)	—	$	12.8	August 14, 2024
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

(1) On September 8, 2023, we amended and restated the limited partnership agreement of ENLK (the "ENLK LPA") to terminate the rights of the holders of the Series B Preferred Units to receive PIK distributions beginning with the quarter ending June 30, 2024, and in connection with such termination of PIK distributions, increase the cash distribution per Series B Preferred Unit from $0.28125 to $0.31875, in addition to the continued payment of the Series B Excess Cash Payment Amount (as defined in the ENLK LPA).

Allocation of Taxable Income to the Series B Preferred Units

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 the positive net income of ENLK for the allocation year (the "Allocation Cap"). As of June 30, 2024, 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 $7.32 per Series B Preferred Unit (the "Catch-Up 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 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, 2024 and December 31, 2023, there were366,500 Series C Preferred Units issued and outstanding.

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 is provided below:

Declaration period (1)	Distribution rate (2)	Cash distribution (in millions)	Date paid/payable
2024			
December 15, 2023 – March 14, 2024	9.749 %	$ 9.0	March 15, 2024
March 15, 2024 – June 14, 2024	9.701 %	$ 9.1	June 17, 2024
June 15, 2024 – September 14, 2024	9.716 %	$ 9.0	September 16, 2024
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

(1) Distributions on the Series C Preferred Units 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) 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%. Starting on September 15, 2023, distributions on the Series C Preferred Units are 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%.

(8) Members' Equity

a. Common Unit Repurchase Program

The table below provides a summary of the Board's authorizations of the 2023 and 2024 common unit repurchase programs.

Date	Board Action	Authorized Amount (in millions)(1)
December 2022	Reauthorization of common unit repurchase program and set amount available for repurchases for 2023	$ 200
November 2023	Increase in 2023 common unit repurchase program	$ 50
December 2023	Reauthorization of common unit repurchase program and set amount available for repurchases for 2024	$ 200
July 2024	Increase in 2024 common unit repurchase program	$ 50

(1) The authorized amount includes repurchases of common units held by GIP. Refer to "Note 4—Related Party Transactions" for more information on our ENLC common unit repurchase agreement with 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.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

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,	
	2024	2023	2024	2023
Publicly held ENLC common units	2,035,157	3,230,504	4,201,962	5,437,809
ENLC common units held by GIP (1)	1,862,695	1,910,877	5,143,332	4,147,987
Total ENLC common units	3,897,852	5,141,381	9,345,294	9,585,796
Aggregate cost for publicly held ENLC common units	$ 27.1	$ 32.2	$ 54.0	$ 59.0
Aggregate cost for ENLC common units held by GIP	23.1	23.2	64.6	47.8
Excise tax on common unit repurchases	(0.2)	0.7	—	0.7
Total aggregate cost for ENLC common units	$ 50.0	$ 56.1	$ 118.6	$ 107.5
Average price paid per publicly held ENLC common unit (2)	$ 13.32	$ 9.96	$ 12.85	$ 10.85
Average price paid per ENLC common unit held by GIP (2)(3)	$ 12.40	$ 12.12	$ 12.56	$ 11.53

(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 August 5, 2024, we repurchased 1,718,847 ENLC common units held by GIP at an aggregate cost of $22.9 million, or an average of $13.31 per common unit. These units represented GIP's pro rata share of the aggregate number of common units repurchased by us during the three months ended June 30, 2024. 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, 2024, $22.9 million is classified as "Other current liabilities" in the consolidated balance sheets related to our obligation to repurchase our common units from GIP. See "Note 4—Related Party Transactions" for additional information relating to the GIP repurchase agreement.

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,	
	2024	2023	2024	2023
Distributed earnings allocated to:				
Common units (1)	$ 59.8	$ 57.8	$ 119.6	$ 116.4
Unvested unit-based awards (1)	0.8	1.0	1.5	1.9
Total distributed earnings	$ 60.6	$ 58.8	$ 121.1	$ 118.3
Distribution in excess of earnings:				
Common units	$ (27.4)	$ (4.4)	$ (72.8)	$ (5.7)
Unvested unit-based awards	(0.3)	(0.1)	(0.9)	(0.1)
Total distribution in excess of earnings	$ (27.7)	$ (4.5)	$ (73.7)	$ (5.8)
Net income attributable to ENLC allocated to:				
Common units (2)	$ 32.4	$ 53.4	$ 46.8	$ 110.7
Unvested unit-based awards (2)	0.5	0.9	0.6	1.8
Total net income attributable to ENLC (2)	$ 32.9	$ 54.3	$ 47.4	$ 112.5
Net income attributable to ENLC per unit:				
Basic (2)	$ 0.07	$ 0.12	$ 0.11	$ 0.24
Diluted (2)	$ 0.07	$ 0.12	$ 0.10	$ 0.24

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(1) Represents distribution activity consistent with the distribution activity table below.
(2) Includes the loss on exchange of Series B Preferred Units.

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,	
	2024	2023	2024	2023
Basic weighted average units outstanding:				
Weighted average common units outstanding	451.4	462.7	451.3	465.8
Diluted weighted average units outstanding:				
Weighted average basic common units outstanding	451.4	462.7	451.3	465.8
Dilutive effect of unvested restricted units	2.7	4.0	2.7	4.1
Total weighted average diluted common units outstanding	454.1	466.7	454.0	469.9

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, 2024 and 2023, respectively, is provided below:

Declaration period	Distribution/unit	Date paid/payable
2024		
Fourth Quarter of 2023	$ 0.1325	February 9, 2024
First Quarter of 2024	$ 0.1325	May 14, 2024
Second Quarter of 2024	$ 0.1325	August 14, 2024
2023		
Fourth Quarter of 2022	$ 0.1250	February 13, 2023
First Quarter of 2023	$ 0.1250	May 12, 2023
Second Quarter of 2023	$ 0.1250	August 11, 2023

(9) Derivatives

Interest Rate Swap

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, including borrowings on the Revolving Credit Facility and the AR Facility. 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 a 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 our interest rate swap as a cash flow hedge in accordance with ASC 815, *Derivatives and Hedging*. There is no ineffectiveness related to our hedge.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Change in fair value of interest rate swap	$ 0.3	$ 7.5	$ 4.2	$ 5.9
Tax expense	(0.2)	(1.8)	(1.1)	(1.4)
Unrealized gain on designated cash flow hedge	$ 0.1	$ 5.7	$ 3.1	$ 4.5

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

	June 30, 2024	December 31, 2023
Fair value of derivative assets—current	$ 4.4	$ 3.3
Fair value of derivative assets—long-term	0.7	—
Fair value of derivative liabilities—long-term	—	(2.4)
Net fair value of interest rate swap	$ 5.1	$ 0.9

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Interest income	$ 1.5	$ 1.1	$ 3.0	$ 1.6

We expect to recognize an additional $4.4 million of interest income out of accumulated other comprehensive income (loss) over the next twelve months.

Commodity Derivatives

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations by utilizing various over-the-counter and exchange-traded commodity financial instrument contracts. Commodity swaps and futures 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 crude, condensate, natural gas, and NGLs. We do not designate commodity swaps or futures as cash flow or fair value hedges for hedge accounting treatment under ASC 815, *Derivatives and Hedging*. Therefore, changes in the fair value of our derivatives are recorded in revenue in the period incurred. In addition, our commodity risk management policy does not allow us to take speculative positions with our derivative contracts.

We commonly enter into index (float-for-float) or fixed-for-float swaps in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, NGLs, and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced natural gas versus first-of-month priced natural gas. For condensate, crude oil, and natural gas, index swaps are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. Similarly, we use futures in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, crude, and condensate. For natural gas, NGLs, condensate, and crude oil, fixed-for-float swaps and futures are used to protect cash flows against price fluctuations: (1) where we receive a percentage of liquids as a fee for processing third-party natural gas or where we receive a portion of the proceeds of the sales of natural gas and liquids as a fee, (2) in the natural gas processing and fractionation components of our business and (3) where we are mitigating the price risk for product held in inventory or storage.

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities, and the change in fair value of these contracts is recorded net as a gain (loss) on derivative activity on the consolidated statements of operations. We estimate the fair value of all of our derivative contracts based upon actively-quoted prices of the underlying commodities.

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,	
	2024	2023	2024	2023
Change in fair value of derivatives	$ 4.0	$ 5.3	$ (22.1)	$ 3.9
Realized gain (loss) on derivatives	(4.8)	6.0	(7.7)	19.3
Gain (loss) on derivative activity	$ (0.8)	$ 11.3	$ (29.8)	$ 23.2

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

	June 30, 2024	December 31, 2023
Fair value of derivative assets—current	$ 58.1	$ 73.6
Fair value of derivative assets—long-term	10.6	27.0
Fair value of derivative liabilities—current	(64.1)	(62.7)
Fair value of derivative liabilities—long-term	(13.1)	(24.3)
Net fair value of commodity derivatives	$ (8.5)	$ 13.6

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, 2024 (in millions, except volumes). The remaining term of the contracts extend no later than January 2029.

Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	MMgals	(126.4)	$ (13.9)
NGL (long contracts)	Swaps	MMgals	63.6	(0.1)
Natural gas (short contracts)	Swaps and futures	Bbtu	(116.7)	50.7
Natural gas (long contracts)	Swaps and futures	Bbtu	105.5	(45.7)
Crude and condensate (short contracts)	Swaps and futures	MMbbls	(6.6)	(5.6)
Crude and condensate (long contracts)	Swaps and futures	MMbbls	1.3	6.1
Total fair value of commodity derivatives				$ (8.5)

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 $68.7 million as of June 30, 2024 would be reduced to $2.7 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs and the FCDTCs.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

(10) Fair Value Measurements

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

	Level 2	
	June 30, 2024	December 31, 2023
Interest rate swap (1)	$ 5.1	$ 0.9
Commodity derivatives (2)	$ (8.5)	$ 13.6

(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.

Long-term debt, including current maturities of long-term debt. The carrying value and estimated fair value of our outstanding debt balances are disclosed below (in millions):

	June 30, 2024		December 31, 2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,657.4	$ 4,495.9	$ 4,568.9	$ 4,427.0

(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 $ 29.5 million and $32.1 million as of June 30, 2024 and December 31, 2023, respectively. The respective fair values do not factor in debt issuance costs.

The fair values of all senior unsecured notes as of June 30, 2024 and December 31, 2023 were based on Level 2 inputs from third-party market quotations.

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.

(11) Segment Information

We manage and report our operations primarily according to the geography and the nature of the 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 transmission pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and, prior to its sale in November 2023, 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.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

We evaluate the performance of our operating segments based on segment profit. 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, 2024						
Natural gas sales	$ 15.3	$ 110.9	$ 19.9	$ 31.4	$ —	$ 177.5
NGL sales	(6.2)	665.5	(0.6)	(3.6)	—	655.1
Crude oil and condensate sales	410.4	—	34.7	—	—	445.1
Other	—	—	—	0.9	—	0.9
Product sales	419.5	776.4	54.0	28.7	—	1,278.6
NGL sales—related parties	237.6	9.0	105.6	68.5	(420.7)	—
Crude oil and condensate sales—related parties	—	—	—	3.6	(3.6)	—
Product sales—related parties	237.6	9.0	105.6	72.1	(424.3)	—
Gathering and transportation	41.6	27.9	64.7	41.0	—	175.2
Processing	14.5	0.6	35.4	21.9	—	72.4
NGL services	—	13.9	—	—	—	13.9
Crude services	6.2	—	3.2	0.2	—	9.6
Other services	1.7	0.1	0.2	0.2	—	2.2
Midstream services	64.0	42.5	103.5	63.3	—	273.3
NGL services—related parties	—	—	—	1.0	(1.0)	—
Midstream services—related parties	—	—	—	1.0	(1.0)	—
Revenue from contracts with customers	721.1	827.9	263.1	165.1	(425.3)	1,551.9
Realized gain (loss) on derivatives	2.4	(7.3)	(1.0)	1.1	—	(4.8)
Change in fair value of derivatives	(1.3)	5.6	0.8	(1.1)	—	4.0
Total revenues	722.2	826.2	262.9	165.1	(425.3)	1,551.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(552.6)	(710.8)	(135.5)	(89.0)	425.3	(1,062.6)
Operating expenses	(76.5)	(31.1)	(23.9)	(23.7)	—	(155.2)
Segment profit	$ 93.1	$ 84.3	$ 103.5	$ 52.4	$ —	$ 333.3
Capital expenditures	$ 31.6	$ 21.3	$ 25.0	$ 7.1	$ 1.2	$ 86.2

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

	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)
Operating expenses	(53.1)	(32.0)	(27.0)	(24.7)	—	(136.8)
Segment profit	$ 91.8	$ 104.5	$ 110.7	$ 67.3	$ —	$ 374.3
Capital expenditures	$ 51.6	$ 17.7	$ 22.1	$ 11.8	$ 1.5	$ 104.7

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2024						
Natural gas sales	$ 119.5	$ 230.5	$ 52.7	$ 56.3	$ —	$ 459.0
NGL sales	(12.8)	1,433.6	(1.6)	(8.4)	—	1,410.8
Crude oil and condensate sales	747.0	—	65.6	—	—	812.6
Other	—	—	—	1.2	—	1.2
Product sales	853.7	1,664.1	116.7	49.1	—	2,683.6
Natural gas sales—related parties	—	0.1	—	—	(0.1)	—
NGL sales—related parties	495.2	18.5	214.3	139.1	(867.1)	—
Crude oil and condensate sales—related parties	—	—	—	6.9	(6.9)	—
Product sales—related parties	495.2	18.6	214.3	146.0	(874.1)	—
Gathering and transportation	81.3	52.3	120.5	86.6	—	340.7
Processing	31.5	1.2	69.0	49.5	—	151.2
NGL services	—	31.2	—	0.1	—	31.3
Crude services	10.0	0.1	6.9	0.4	—	17.4
Other services	3.6	0.2	0.3	0.5	—	4.6
Midstream services	126.4	85.0	196.7	137.1	—	545.2
NGL services—related parties	—	—	—	1.5	(1.5)	—
Midstream services—related parties	—	—	—	1.5	(1.5)	—
Revenue from contracts with customers	1,475.3	1,767.7	527.7	333.7	(875.6)	3,228.8
Realized loss on derivatives	(4.4)	(0.9)	(2.0)	(0.4)	—	(7.7)
Change in fair value of derivatives	(3.7)	(13.9)	(3.3)	(1.2)	—	(22.1)
Total revenues	1,467.2	1,752.9	522.4	332.1	(875.6)	3,199.0
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,134.7)	(1,500.3)	(283.3)	(170.3)	875.6	(2,213.0)
Operating expenses	(150.4)	(57.9)	(49.9)	(49.6)	—	(307.8)
Segment profit	$ 182.1	$ 194.7	$ 189.2	$ 112.2	$ —	$ 678.2
Capital expenditures	$ 80.2	$ 52.9	$ 36.8	$ 17.6	$ 2.1	$ 189.6

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

	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)
Operating expenses	(101.2)	(65.6)	(51.7)	(50.7)	—	(269.2)
Segment profit	$ 187.8	$ 200.9	$ 205.4	$ 143.4	$ —	$ 737.5
Capital expenditures	$ 108.3	$ 30.0	$ 47.8	$ 29.9	$ 2.8	$ 218.8

The following table reconciles segment profit to income before non-controlling interest and income taxes in the consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Segment profit	$ 333.3	$ 374.3	$ 678.2	$ 737.5
Depreciation and amortization	(162.6)	(165.3)	(327.9)	(325.7)
Impairments	—	—	(14.2)	—
Gain (loss) on disposition of assets	(0.9)	0.8	0.8	1.2
General and administrative	(30.2)	(27.9)	(85.4)	(57.4)
Interest expense, net of interest income	(66.7)	(68.8)	(132.1)	(137.3)
Income (loss) from unconsolidated affiliate investments	0.3	(4.6)	(0.5)	(4.7)
Other income	3.8	0.4	4.3	0.4
Income before non-controlling interest and income taxes	$ 77.0	$ 108.9	$ 123.2	$ 214.0

The table below represents information about segment assets as of June 30, 2024 and December 31, 2023 (in millions):

Segment Identifiable Assets:	**June 30, 2024**	**December 31, 2023**
Permian	$ 2,813.0	$ 2,813.6
Louisiana	2,000.9	2,031.8
Oklahoma	2,177.8	2,275.8
North Texas	943.7	1,017.7
Corporate (1)	216.9	189.7
Total identifiable assets	$ 8,152.3	$ 8,328.6

(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.

(12) 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, 2024**	**December 31, 2023**
Product inventory	$ 73.3	$ 46.4
Prepaid expenses and other	29.4	19.0
Other current assets	$ 102.7	$ 65.4

Other current liabilities:	**June 30, 2024**	**December 31, 2023**
Accrued interest	$ 62.9	$ 63.4
Accrued wages and benefits, including taxes	15.3	23.2
Accrued ad valorem taxes	23.3	33.3
Capital expenditure accruals	41.0	64.6
Short-term lease liability	36.6	28.2
Operating expense accruals	19.7	21.5
Accrued common unit repurchase	22.9	41.5
Other	27.6	2.8
Other current liabilities	$ 249.3	$ 278.5

(13) 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 natural gas during the storm, including one that resulted in litigation. The litigation was between one of our subsidiaries, EnLink Gas Marketing, LP (“EnLink Gas”), and Koch Energy Services, LLC in the 162nd District Court in Dallas County, Texas. In April 2024, we settled this matter and all claims related to this dispute have been dismissed.

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 approximately 90 natural gas producers, pipelines, marketers, sellers, and traders, including EnLink Gas. The plaintiffs asserted claims of tortious interference, nuisance, and unjust enrichment against all defendants and are seeking economic and punitive damages and disgorgement of profits. EnLink Gas believes it has substantial defenses to these claims and intends to vigorously dispute these allegations and 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.

Our revenues and adjusted gross margins are generated from six 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; 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, 2024 and 2023. 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,	
	2024	2023	2024	2023
The Dow Chemical Company (1)	11.0 %	11.5 %	10.7 %	11.5 %
Marathon Petroleum Corporation (2)	18.1 %	19.6 %	21.6 %	19.8 %

(1) The Dow Chemical Company together with its consolidated subsidiaries.
(2) Marathon Petroleum Corporation together with its consolidated subsidiaries.

CCS Business

We are continuing to work on building a carbon transportation business in support of CCS activity along the Gulf Coast, including the Mississippi River corridor in Louisiana, one of the highest CO_2 emitting regions in the United States. We believe that CCS remains an important solution to address carbon emissions by industrial emitters and that our existing asset footprint, including our extensive network of natural gas pipelines in Louisiana, our operating expertise, including our current operation of CCS pipelines in North Texas, and our customer relationships, provide us with an advantage in building a carbon transportation business and becoming a transporter of choice in the regions in which we operate.

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 crude 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 for our natural gas and crude oil gathering, natural gas processing, and NGL fractionation operations are driven in large part by the level of crude oil and natural gas prices. New drilling activity is necessary to maintain or increase production levels as crude 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 natural gas and crude oil gathering, natural gas processing, and NGL fractionation 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.

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)
2024 by quarter:			
1st Quarter	$ 76.91	$ 0.55	$ 2.10
2nd Quarter	$ 80.66	$ 0.52	$ 2.32
2024 Averages	**$ 78.81**	**$ 0.53**	**$ 2.21**
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**

(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 closing prices based on the OPIS Napoleonville daily average spot liquids prices.
(4) Natural gas closing prices based on Henry Hub Natural Gas Daily closing prices.

Capital markets and the demands of public investors also affect producer behavior, production levels, and our business. In past years, public investors exerted pressure on crude oil and natural gas producers to increase capital discipline and focus on higher investment returns even if it meant 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. However, in response to the rise of crude oil and natural gas prices during 2021 and 2022, capital investments by United States crude oil and natural gas producers have risen, although global capital investments by crude 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 continued into 2023. Although producer activity did rise during much of 2023, we expect that the decline in natural gas prices in the past year will dampen producer activity in these areas.

Our Louisiana segment, while subject to commodity price trends, is less dependent on gathering and processing activities and more affected by, in the case of NGLs, industrial demand for the NGLs that we supply, and in the case of natural gas, the demand for transportation of natural gas on our pipelines to industrial, utility and LNG facilities as well as to other natural gas pipelines. Industrial demand for NGLs along the Gulf Coast region has remained strong for the last few years, supported by regional industrial activity and export markets. Similarly, the demand for transportation of natural gas on our pipelines to industrial, utility, and LNG facilities as well as to other natural gas pipelines has also remained strong. Our activities and, in turn, our financial performance in the Louisiana segment are highly dependent on the availability of natural gas for transportation on our pipelines, including to our customers, and NGLs to supply our customers. To date, the availability of natural gas and NGLs to supply our customers has remained at sufficient levels, and maintaining such availability and supply is a key business focus.

Competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, volatile prices, and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control could each adversely affect our financial condition, results of operation, or cash flows. For more information, see "Item 1A—Risk Factors—Business and Industry Risks" in our Annual Report on Form 10-K for the year ended December 31, 2023 filed with the Commission on February 21, 2024.

Inflation

In recent years, U.S. inflation has increased significantly. 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 2023. Inflation has moderated in 2023 and the first half of 2024, and the Federal Reserve has signaled an end to rate hikes and may cut rates in the second half of 2024.

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.

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, 2023 filed with the Commission on February 21, 2024.

Regulatory Developments

In accordance with the requirements of the Inflation Reduction Act of 2022, on January 26, 2024, the U.S. Environmental Protection Agency (the "EPA") published its proposed rule regarding the Waste Emissions Charge, applicable to excess methane emissions at certain crude oil and natural gas facilities. Further, On March 8, 2024, the EPA published its final rules imposing new, stricter requirements for methane monitoring, reporting, and emissions control at certain crude oil and natural gas facilities. Finally, on April 10, 2024, the U.S. Bureau of Land Management published its final Waste Prevention Rule, which requires operators of crude oil and natural gas leases to take reasonable steps to avoid natural gas waste, as well as develop leak detection, repair, and waste minimization plans.

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, 2023 filed with the Commission on February 21, 2024.

Other Recent Developments

Organic Growth

Henry Hub to the River Project. In 2024, we plan to expand the natural gas transmission capacity of the Bridgeline pipeline from the Henry Hub to the Mississippi River Corridor by 210 MMcf/d through additional compression. We expect to complete the project in the fourth quarter of 2025.

Jefferson Island Storage Facility Expansion. We plan to expand the Jefferson Island storage facility by approximately 8 Bcf, which will increase the estimated working gas storage capacity from 2 Bcf to 10 Bcf. We expect to complete the Jefferson Island storage facility expansion in 2028.

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 to operate as the Tiger II processing plant. The move has been completed and the Tiger II processing plant began operations in May 2024, which increased our Permian Basin processing capacity by 150 MMcf/d.

GCF Operations. In January 2023, we and our partners started the process to restart the GCF assets. We expect the assets to become operational in the third quarter of 2024.

Matterhorn JV. We own a 15% interest in the Matterhorn JV. The Matterhorn JV is constructing 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 (the "Matterhorn Express Pipeline"). We expect the Matterhorn Express Pipeline to be in service in the third quarter of 2024, pending the receipt of customary regulatory and other approvals.

Exxon Mobil Agreement. In October 2022, we entered into a transportation services agreement with a subsidiary of ExxonMobil in connection with the development of a CCS project in southeastern Louisiana at Pecan Island in Vermilion Parish. In February 2024, we and ExxonMobil agreed to reassess the Pecan Island project's near-term role with the expectation that other joint CCS opportunities along the Gulf Coast might be prioritized ahead of the Pecan Island Project. Since that time, we and ExxonMobil have been unable to identify alternative CO_2 transportation projects for EnLink. We are now pursuing a financial arrangement for the value to EnLink of the Pecan Island transportation agreement. There can be no assurance that we would recover the value to EnLink of the Pecan Island transportation agreement in any financial arrangement or when such arrangement would be realized.

Equity

See "Item 1. Financial Statements—Note 7" for more information regarding our Series B Preferred Unit exchanges and purchase activity.

See "Item 1. Financial Statements—Note 8" for more information regarding our common unit repurchase activity.

Rate Reset

Beginning March 2024, certain legacy contracts in the Oklahoma and North Texas segments experienced a one-time rate reset. The rate reset was negotiated in 2018 in exchange for adding an additional five years of term to these contracts. The rate reset is a one-time adjustment down to a pre-negotiated rate (which partially reverses recent annual inflation cost escalation adjustments). These contracts are set to expire between 2029 and 2033 and continue to have cost escalation provisions that allow for rate increases from the reset rate based on future changes in inflation.

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 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,	
	2024	2023	2024	2023
Total revenues	$ 1,551.1	$ 1,530.1	$ 3,199.0	$ 3,297.6
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,062.6)	(1,019.0)	(2,213.0)	(2,290.9)
Operating expenses	(155.2)	(136.8)	(307.8)	(269.2)
Depreciation and amortization	(162.6)	(165.3)	(327.9)	(325.7)
Gross margin	170.7	209.0	350.3	411.8
Operating expenses	155.2	136.8	307.8	269.2
Depreciation and amortization	162.6	165.3	327.9	325.7
Adjusted gross margin	$ 488.5	$ 511.1	$ 986.0	$ 1,006.7

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; (gain) loss on litigation settlement; 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, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Net income	$ 67.0	$ 89.9	$ 117.0	$ 184.1
Interest expense, net of interest income	66.7	68.8	132.1	137.3
Depreciation and amortization	162.6	165.3	327.9	325.7
Impairments	—	—	14.2	—
(Income) loss from unconsolidated affiliate investments	(0.3)	4.6	0.5	4.7
Distributions from unconsolidated affiliate investments	—	2.2	—	2.3
(Gain) loss on disposition of assets	0.9	(0.8)	(0.8)	(1.2)
Loss on litigation settlement (1)	—	—	23.0	—
Unit-based compensation	5.2	4.5	10.8	8.5
Income tax expense	10.0	19.0	6.2	29.9
Unrealized (gain) loss on commodity derivatives	(4.0)	(5.3)	22.1	(3.9)
Costs associated with the relocation of processing facilities (2)	16.9	1.7	26.2	2.1
Other (3)	(0.1)	0.2	1.5	0.5
Adjusted EBITDA before non-controlling interest	324.9	350.1	680.7	690.0
Non-controlling interest share of adjusted EBITDA from joint ventures (4)	(18.9)	(16.5)	(37.0)	(32.7)
Adjusted EBITDA, net to ENLC	$ 306.0	$ 333.6	$ 643.7	$ 657.3

(1) Relates to the loss incurred to settle litigation that arose from Winter Storm Uri and is not part of our ongoing operations.
(2) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
(3) 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.
(4) 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); (cash distributions earned by the Series B Preferred Units and the Series C Preferred Units); (payment to redeem mandatorily redeemable non-controlling interest); (earnout payments related to the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition); (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); (non-cash gain associated with a lease modification); 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, processing assets, or CCS initiatives, 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,	
	2024	2023	2024	2023
Net cash provided by operating activities	$ 162.6	$ 315.7	$ 455.9	$ 587.8
Interest expense (1)	65.2	67.0	129.1	134.0
Costs associated with the relocation of processing facilities (2)	16.9	1.7	26.2	2.1
Loss on litigation settlement (3)	—	—	23.0	—
Other (4)	0.2	2.0	4.0	0.8
Changes in operating assets and liabilities which (provided) used cash:				
Accounts receivable, accrued revenues, inventories, and other	149.5	(80.3)	11.5	(249.7)
Accounts payable, accrued product purchases, and other accrued liabilities	(69.5)	44.0	31.0	215.0
Adjusted EBITDA before non-controlling interest	324.9	350.1	680.7	690.0
Non-controlling interest share of adjusted EBITDA from joint ventures (5)	(18.9)	(16.5)	(37.0)	(32.7)
Adjusted EBITDA, net to ENLC	306.0	333.6	643.7	657.3
Growth capital expenditures, net to ENLC (6)	(62.6)	(74.6)	(143.4)	(167.3)
Maintenance capital expenditures, net to ENLC (6)	(20.0)	(20.0)	(34.3)	(34.2)
Interest expense, net of interest income	(66.7)	(68.8)	(132.1)	(137.3)
Distributions declared on common units	(60.9)	(58.1)	(120.6)	(116.8)
ENLK preferred unit cash distributions earned (7)	(23.8)	(24.0)	(48.2)	(47.6)
Earnout payments (8)	—	—	(2.5)	—
Payment to redeem mandatorily redeemable non-controlling interest (9)	—	—	—	(10.5)
Costs associated with the relocation of processing facilities, net to ENLC (2) (6)	(9.5)	7.1	(15.8)	6.7
Contributions to investment in unconsolidated affiliates	(10.7)	—	(20.1)	(49.7)
Other (10)	1.5	0.5	0.6	0.8
Free cash flow after distributions	$ 53.3	$ 95.7	$ 127.3	$ 101.4

(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) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.
(3) Relates to the loss incurred to settle litigation that arose from Winter Storm Uri and is not part of our ongoing operations.
(4) Includes utility credits redeemed, distributions from unconsolidated affiliate investments in excess of earnings, 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 7 " 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) Earnout payments were made in connection to the consideration paid for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition, both of which included a contingent component payable beginning in 2024.
(9) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries.
(10) Includes current income tax expense, a reduction for non-cash gain associated with a lease modification, 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, 2024						
Total revenues	$ 722.2	$ 826.2	$ 262.9	$ 165.1	$ (425.3)	$ 1,551.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(552.6)	(710.8)	(135.5)	(89.0)	425.3	(1,062.6)
Adjusted gross margin	169.6	115.4	127.4	76.1	—	488.5
Operating expenses	(76.5)	(31.1)	(23.9)	(23.7)	—	(155.2)
Segment profit	93.1	84.3	103.5	52.4	—	333.3
Depreciation and amortization	(45.8)	(31.4)	(56.0)	(27.9)	(1.5)	(162.6)
Gross margin	$ 47.3	$ 52.9	$ 47.5	$ 24.5	$ (1.5)	$ 170.7

	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
Six Months Ended June 30, 2024						
Total revenues	$ 1,467.2	$ 1,752.9	$ 522.4	$ 332.1	$ (875.6)	$ 3,199.0
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,134.7)	(1,500.3)	(283.3)	(170.3)	875.6	(2,213.0)
Adjusted gross margin	332.5	252.6	239.1	161.8	—	986.0
Operating expenses	(150.4)	(57.9)	(49.9)	(49.6)	—	(307.8)
Segment profit	182.1	194.7	189.2	112.2	—	678.2
Depreciation and amortization	(89.4)	(66.5)	(112.5)	(56.4)	(3.1)	(327.9)
Gross margin	$ 92.7	$ 128.2	$ 76.7	$ 55.8	$ (3.1)	$ 350.3

	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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Midstream Volumes:				
Consolidated				
Gathering and Transportation (MMbtu/d)	7,545,100	6,925,200	7,396,300	7,048,300
Processing (MMbtu/d)	3,701,100	3,562,000	3,603,100	3,516,000
Crude Oil Handling (Bbls/d)	208,900	198,700	197,000	193,400
NGL Fractionation (Bbls/d)	175,300	179,000	179,500	181,100
Brine Disposal (Bbls/d)	—	2,700	—	2,800
Permian Segment				
Gathering and Transportation (MMbtu/d)	2,033,300	1,732,200	1,966,300	1,708,100
Processing (MMbtu/d)	1,850,400	1,617,400	1,797,800	1,589,200
Crude Oil Handling (Bbls/d)	191,100	155,400	177,900	149,000
Louisiana Segment				
Gathering and Transportation (MMbtu/d)	2,819,700	2,345,600	2,786,800	2,518,600
Crude Oil Handling (Bbls/d)	—	16,500	—	17,400
NGL Fractionation (Bbls/d)	175,300	179,000	179,500	181,100
Brine Disposal (Bbls/d)	—	2,700	—	2,800
Oklahoma Segment				
Gathering and Transportation (MMbtu/d)	1,219,000	1,253,800	1,181,700	1,216,300
Processing (MMbtu/d)	1,173,200	1,204,600	1,132,100	1,184,500
Crude Oil Handling (Bbls/d)	17,800	26,800	19,100	27,000
North Texas Segment				
Gathering and Transportation (MMbtu/d)	1,473,100	1,593,600	1,461,500	1,605,300
Processing (MMbtu/d)	677,500	740,000	673,200	742,300

Three Months Ended June 30, 2024 Compared to Three Months Ended June 30, 2023

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 with respect to 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, increased $21.0 million and $43.6 million, respectively, for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 due to the following:

- Product sales revenues increased $39.3 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 primarily due to:

  - A $71.4 million increase in crude oil and condensate sales primarily driven by higher crude oil prices; and
  - An $8.0 million increase in NGL sales primarily driven by higher NGL prices.

  These increases were partially offset by a $41.0 million decrease in natural gas sales primarily driven by lower natural gas prices.

- The changes in natural gas, NGL, and crude oil prices also had a corresponding impact to cost of sales, exclusive of operating expenses and depreciation and amortization, contributing to the $43.6 million increase for the three months ended June 30, 2024 compared to the three months ended June 30, 2023.

- Revenues from midstream services decreased $6.2 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 primarily due to:

  - A $9.1 million decrease in processing revenues primarily driven by a one-time rate reset to a lower fee on certain existing contracts in our North Texas and Oklahoma segments;
  - A $3.6 million decrease in NGL service revenues primarily driven by lower NGL service volumes; and
  - An $8.1 million decrease in crude services revenues primarily driven by the divestiture of our ORV crude assets.

  These decreases were partially offset by a $14.8 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes in our Permian segment.

- Derivative losses increased $12.1 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 due to $10.8 million of increased realized losses and $1.3 million of decreased unrealized gains.

Operating Expenses. Operating expenses increased $18.4 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 primarily due to a $17.5 million increase in construction fees and services and a $4.2 million increase in compressor rentals. These increases were partially offset by a $1.5 million decrease in vehicle expenses, a $1.3 million decrease in labor and benefits costs, a $1.3 million decrease in compressor overhauls, and a $1.1 million decrease in materials and supplies expense.

Depreciation and Amortization. Depreciation and amortization decreased $2.7 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023 primarily due to a $6.4 million decrease related to assets reaching the end of their depreciable lives and a $2.6 million decrease due to the divestiture of our ORV assets in November 2023. These decreases were partially offset by a $6.3 million increase resulting from additional assets being placed in service.

General and Administrative Expenses. General and administrative expenses were $30.2 million for the three months ended June 30, 2024 compared to $27.9 million for the three months ended June 30, 2023, an increase of $2.3 million. The increase was primarily due to a $1.3 million increase in labor and benefits costs and a $1.0 million increase related to computer software fees and services.

Interest Expense, Net of Interest Income. Interest expense, net of interest income, was $66.7 million for the three months ended June 30, 2024 compared to $68.8 million for the three months ended June 30, 2023, a decrease of $2.1 million. Interest expense, net of interest income, consisted of the following (in millions):

	Three Months Ended June 30,	
	2024	2023
ENLK and ENLC senior notes	$ 57.7	$ 58.7
Revolving Credit Facility	3.7	4.3
AR Facility	5.6	5.5
Amortization of debt issuance costs and net discount of senior unsecured notes	1.5	1.8
Interest rate swap – realized	(1.5)	(1.1)
Other	(0.3)	(0.4)
Interest expense, net of interest income	$ 66.7	$ 68.8

(Income) Loss from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $0.3 million for the three months ended June 30, 2024 compared to a loss of $4.6 million for the three months ended June 30, 2023, a decrease in loss of $4.9 million. (Income) loss from unconsolidated affiliate investments consisted of the following (in millions):

	Three Months Ended June 30,	
	2024	2023
GCF	$ 2.6	$ 1.7
Cedar Cove JV	(8.0)	0.5
Matterhorn JV	5.1	2.4
(Income) loss from unconsolidated affiliate investments	$ (0.3)	$ 4.6

Income Tax Expense. Income tax expense was $10.0 million for the three months ended June 30, 2024 compared to an income tax expense of $19.0 million for the three months ended June 30, 2023, a decrease in income tax expense of $9.0 million. The decrease in income tax expense was primarily attributable to the decrease in income between periods. See “Item 1. Financial Statements—Note 6” for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $28.9 million for the three months ended June 30, 2024 compared to net income of $35.6 million for the three months ended June 30, 2023, a decrease of $6.7 million. Net income attributable to non-controlling interest consisted of the following (in millions):

	Three Months Ended June 30,	
	2024	2023
NGP’s 49.9% share of the Delaware Basin JV	$ 5.1	$ 9.6
Marathon Petroleum Corporation’s 50% share of the Ascension JV	0.1	0.6
Series B Preferred Units	14.7	16.7
Series C Preferred Units	9.0	8.7
Net income attributable to non-controlling interest	$ 28.9	$ 35.6

Analysis of Operating Segments

We manage and report our operations primarily according to the geography and the nature of the 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 segment profit and adjusted gross margin is gross margin. We 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, 2024 compared to the three months ended June 30, 2023.

- *Permian Segment.*
    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $97.4 million and $72.7 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $24.7 million, due to:
        - A $23.2 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $18.9 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian natural gas assets increased adjusted gross margin by $4.3 million, which included $5.2 million from decreased realized gains and $9.5 million from decreased unrealized losses; and
        - A $1.5 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $2.2 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $0.7 million, which included $2.2 million from increased realized gains and $2.9 million from increased unrealized losses.
    - Operating expenses in the Permian segment increased $23.4 million primarily due to an increase in construction fees and services due to the relocation of the Tiger II processing plant.
    - Depreciation and amortization in the Permian segment increased $4.3 million primarily due to additional assets being placed in service.
- *Louisiana Segment.*
    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $25.3 million and $4.2 million, respectively, resulting in a decrease in adjusted gross margin in the Louisiana segment of $21.1 million, due to:
        - A $15.6 million decrease in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, decreased $6.6 million, which was primarily due to lower volumes. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $9.0 million, which included $2.5 million from increased realized losses and $6.5 million from decreased unrealized gains;
        - A $4.3 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $7.3 million, which was primarily due to a $14.1 million increase from higher volumes from existing customers, partially offset by a settlement payment resulting from a customer account dispute in the amount of $6.8 million received in the second quarter of 2023. Derivative activity associated with our Louisiana natural gas assets decreased adjusted gross margin by $3.0 million, which included $3.1 million from decreased realized losses and $6.1 million from decreased unrealized gains; and
        - A $9.8 million decrease in adjusted gross margin associated with our ORV crude assets, due to their divestiture in November 2023.
    - Operating expenses in the Louisiana segment decreased $0.9 million primarily due to the divestiture of our ORV assets in November 2023.
    - Depreciation and amortization in the Louisiana segment decreased $5.5 million primarily due to a $3.0 million decrease resulting from assets reaching the end of their depreciable lives and a $2.6 million decrease due to the divestiture of our ORV assets in November 2023.

- *Oklahoma Segment.*

  - Revenues decreased $5.3 million and cost of sales, exclusive of operating expenses and depreciation amortization increased $5.0 million, resulting in a decrease in adjusted gross margin in the Oklahoma segment of $10.3 million, due to:

    - An $8.5 million decrease in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, decreased $4.6 million, which was primarily due to a one-time rate reset to a lower fee on certain existing contracts. For additional information on the one-time rate reset, see “Other Recent Developments.” Derivative activity associated with our Oklahoma natural gas assets decreased adjusted gross margin by $3.9 million, which included $2.7 million from increased realized losses and $1.2 million from decreased unrealized gains; and
    - A $1.8 million decrease in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, decreased $1.6 million, which was primarily due to lower volumes from existing customers. Derivative activity associated with our Oklahoma crude assets decreased adjusted gross margin by $0.2 million from increased realized losses.

  - Operating expenses in the Oklahoma segment decreased $3.1 million primarily due to a decrease in operating activity.

  - Depreciation and amortization in the Oklahoma segment decreased $0.6 million primarily due to a $1.0 million decrease resulting from assets reaching the end of their depreciable lives, partially offset by a $0.4 million increase due to additional assets being placed in service.

- *North Texas Segment.*

  - Revenues decreased $2.0 million and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $13.9 million, resulting in a decrease in adjusted gross margin in the North Texas segment of $15.9 million. Adjusted gross margin, excluding derivative activity, decreased $16.4 million, which was primarily due to a one-time rate reset to a lower fee on certain existing contracts. For additional information on the one-time rate reset, see “Other Recent Developments.” Derivative activity associated with our North Texas segment increased adjusted gross margin by $0.5 million, which included $5.4 million from decreased realized gains and $5.9 million from decreased unrealized losses.

  - Operating expenses in the North Texas segment decreased $1.0 million primarily due to a decrease in operating activity.

  - Depreciation and amortization in the North Texas segment decreased $1.1 million primarily due to a $2.4 million decrease due to assets reaching the end of their depreciable lives, partially offset by a $1.3 million increase due to additional assets being placed in service.

- *Corporate Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each decreased $43.8 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 increased $0.2 million due to additional assets being placed in service.

Six Months Ended June 30, 2024 Compared to Six Months Ended June 30, 2023

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

Total revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $98.6 million and $77.9 million, respectively, for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 due to the following:

- Product sales revenues decreased $32.0 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 primarily due to:

  - A $101.9 million decrease in natural gas sales primarily driven by lower natural gas prices; and
  - A $102.2 million decrease in NGL sales primarily driven by lower NGL volumes.

  These decreases were partially offset by a $170.9 million increase in crude oil and condensate sales primarily driven by higher crude oil prices.

- The changes in natural gas, NGL, and crude oil prices also had a corresponding impact to cost of sales, exclusive of operating expenses and depreciation and amortization, contributing to the $77.9 million decrease for the six months ended June 30, 2024 compared to the six months ended June 30, 2023.

- Revenues from midstream services decreased $13.6 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 primarily due to:

  - A $12.0 million decrease in processing revenues primarily driven by a one-time rate reset to a lower fee on certain existing contracts in our North Texas and Oklahoma segments;
  - A $14.0 million decrease in NGL service revenues primarily driven by lower NGL service volumes; and
  - A $17.5 million decrease in crude services revenues primarily driven by the divestiture of our ORV crude assets.

  These decreases were partially offset by a $30.1 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes in our Permian segment.

- Derivative losses increased $53.0 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 due to $27.0 million of increased realized losses and $26.0 million of increased unrealized losses.

Operating Expenses. Operating expenses increased $38.6 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 primarily due to a $23.9 million increase in construction fees and services, an $8.6 million increase in compressor rentals, a $5.6 million increase in utilities expense, a $2.5 million increase in materials and supplies expense, a $1.7 million increase in pipeline integrity compliance costs, and a $1.2 million increase in regulatory expenses. These increases were partially offset by a $2.9 million decrease in vehicle expenses, a $2.0 million decrease in labor and benefits costs, and a $1.8 million decrease in compressor overhauls.

Depreciation and Amortization. Depreciation and amortization increased $2.2 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 primarily due to a $12.1 million increase resulting from additional assets being placed in service and a $5.3 million increase related to changes in estimated useful lives. These increases were partially offset by a $10.0 million decrease related to assets reaching the end of their depreciable lives and a $5.3 million decrease due to the divestitures of our ORV assets in November 2023.

Impairments. For the six months ended June 30, 2024, we recognized an impairment expense of $14.2 million due to changes in our outlook for future cash flows and the anticipated use of certain non-core assets in our North Texas segment. We determined that the carrying amounts of these assets exceeded their fair value, based on market inputs and certain assumptions. In April 2024, we sold these non-core assets. We did not record any impairment expense for the six months ended June 30, 2023.

General and Administrative Expenses. General and administrative expenses were $85.4 million for the six months ended June 30, 2024 compared to $57.4 million for the six months ended June 30, 2023, an increase of $28.0 million. The increase was primarily due to a $23.3 million increase in legal settlements, a $3.2 million increase in labor and benefits costs, and a $2.2 million increase in unit-based compensation. These increases were partially offset by a $2.6 million decrease in office rental costs.

Interest Expense. Interest expense was $132.1 million for the six months ended June 30, 2024 compared to $137.3 million for the six months ended June 30, 2023, a decrease of $5.2 million. Interest expense consisted of the following (in millions):

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
ENLK and ENLC senior notes	$ 116.5	$ 112.6
Revolving Credit Facility	5.2	11.8
AR Facility	11.4	11.7
Amortization of debt issuance costs and net discount of senior unsecured notes	3.0	3.3
Interest rate swap – realized	(3.0)	(1.6)
Other	(1.0)	(0.5)
Interest expense, net of interest income	$ 132.1	$ 137.3

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $0.5 million for the six months ended June 30, 2024 compared to a loss of $4.7 million for the six months ended June 30, 2023, a decrease in loss of $4.2 million. Loss from unconsolidated affiliate investments consisted of the following (in millions):

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
GCF	$ 4.4	$ 2.8
Cedar Cove JV	(7.3)	1.1
Matterhorn JV	3.4	0.8
Loss from unconsolidated affiliate investments	$ 0.5	$ 4.7

Income Tax Expense. Income tax expense was $6.2 million for the six months ended June 30, 2024 compared to an income tax expense of $29.9 million for the six months ended June 30, 2023, a decrease in income tax expense of $23.7 million. The decrease in income tax expense was primarily attributable to the decrease in income between periods. See "Item 1. Financial Statements—Note 6" for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $64.4 million for the six months ended June 30, 2024 compared to net income of $71.6 million for the six months ended June 30, 2023, a decrease of $7.2 million. Net income attributable to non-controlling interest consisted of the following (in millions):

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
NGP's 49.9% share of the Delaware Basin JV	$ 12.7	$ 18.8
Marathon Petroleum Corporation's 50% share of the Ascension JV	1.7	2.3
Series B Preferred Units	32.0	33.4
Series C Preferred Units	18.0	17.1
Net income attributable to non-controlling interest	$ 64.4	$ 71.6

Analysis of Operating Segments

See below for our discussion of segment results for the six months ended June 30, 2024 compared to the six months ended June 30, 2023.

- *Permian Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $241.2 million and $197.7 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $43.5 million, due to:
    - A $38.1 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $47.9 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian natural gas assets decreased adjusted gross margin by $9.8 million, which included $10.1 million from increased realized losses and $0.3 million from decreased unrealized losses; and
    - A $5.4 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $3.5 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian crude assets increased adjusted gross margin by $1.9 million, which included $4.3 million from increased realized gains and $2.4 million from decreased unrealized gains.
  - Operating expenses in the Permian segment increased $49.2 million, which was due to a $27.3 million increase primarily from an increase in operating activity, in addition to a $21.9 million increase in construction fees and services primarily due to the relocation of the Tiger II processing plant.
  - Depreciation and amortization in the Permian segment increased $7.9 million primarily due to additional assets being placed in service.
- *Louisiana Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $202.5 million and $188.6 million, respectively, resulting in a decrease in adjusted gross margin in the Louisiana segment of $13.9 million, due to:
    - A $21.8 million decrease in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, decreased $7.6 million, which was primarily due to lower seasonal fees for delivery of normal butane. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $14.2 million, which included $6.0 million from increased realized losses and $8.2 million from increased unrealized losses;
    - A $28.4 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $36.4 million, which was primarily due to a $43.2 million increase primarily from higher volumes from existing customers, partially offset by a settlement payment resulting from a customer account dispute in the amount of $6.8 million received in the second quarter of 2023. Derivative activity associated with our Louisiana natural gas assets decreased adjusted gross margin by $8.0 million, which included $6.9 million from increased realized gains and $14.9 million from increased unrealized losses; and
    - A $20.5 million decrease in adjusted gross margin associated with our ORV crude assets, which was due to the divestiture of our ORV assets in our Louisiana segment in November 2023.
  - Operating expenses in the Louisiana segment decreased $7.7 million primarily due to the divestiture of our ORV assets in November 2023.
  - Depreciation and amortization in the Louisiana segment decreased $8.7 million primarily due to a $6.1 million decrease resulting from assets reaching the end of their depreciable lives and a $5.3 million decrease due to the divestiture of our ORV assets in November 2023. These decreases were partially offset by a $2.1 million increase related to changes in estimated useful lives and a $0.6 million increase resulting from additional assets being placed in service.

- *Oklahoma Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $59.2 million and $41.2 million, respectively, resulting in a decrease in adjusted gross margin in the Oklahoma segment of $18.0 million, due to:
    - A $15.3 million decrease in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, decreased $6.0 million, which was primarily due to a one-time rate reset to a lower fee on certain existing contracts. For additional information on the one-time rate reset, see "Other Recent Developments." Derivative activity associated with our Oklahoma natural gas assets decreased adjusted gross margin by $9.3 million, which included $5.4 million from increased realized losses and $3.9 million from increased unrealized losses; and
    - A $2.7 million decrease in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, decreased $2.2 million, which was primarily due to lower volumes from existing customers. Derivative activity associated with our Oklahoma crude assets decreased adjusted gross margin by $0.5 million from increased realized losses.
  - Operating expenses in the Oklahoma segment decreased $1.8 million primarily due to a decrease in operating activity.
  - Depreciation and amortization in the Oklahoma segment increased $4.0 million primarily due to a $3.2 millionincrease related to changes in estimated useful lives and an $0.8 million increase due to additional assets being placed in service.
- *North Texas Segment.*
  - Revenues decreased $26.7 million and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $5.6 million, resulting in a decrease in adjusted gross margin in the North Texas segment of $32.3 million. Adjusted gross margin, excluding derivative activity, decreased $20.4 million, which was primarily due to a one-time rate reset to a lower fee on certain existing contracts. For additional information on the one-time rate reset, see "Other Recent Developments." Derivative activity associated with our North Texas segment decreased adjusted gross margin by $11.9 million, which included $15.0 million from increased realized losses and $3.1 million from decreased unrealized losses.
  - Operating expenses in the North Texas segment decreased $1.1 million primarily due to a decrease in operating activity.
  - Depreciation and amortization in the North Texas segment decreased $1.4 million primarily due to a $3.9 million decrease due to assets reaching the end of their depreciable lives, partially offset by a $2.5 million increase due to additional assets being placed in service.
- *Corporate Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each decreased $51.4 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 increased $0.4 million due to additional assets being placed in service.

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, 2023 filed with the Commission on February 21, 2024.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $455.9 million for the six months ended June 30, 2024 compared to $587.8 million for the six months ended June 30, 2023. Net cash provided by operating activities decreased $131.9 million due to the following:

- Gross margin, excluding depreciation and amortization, non-cash commodity derivative activity, utility credits redeemed, and unit-based compensation, decreased $34.7 million. The decrease in gross margin is due to a $40.0 million increase in operating expenses, excluding utility credits redeemed or earned and unit-based compensation, and was partially offset by a $5.3 million increase in adjusted gross margin, excluding non-cash commodity derivative activity. For more information regarding the changes in gross margin for the six months ended June 30, 2024 compared to the six months ended June 30, 2023, see “Results of Operations.”

- General and administrative expenses, excluding unit-based compensation, increased $25.8 million.

- Changes in working capital decreased net cash provided by operating activities by $77.2 million, 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 purchases.

Cash Flows from Investing Activities. Net cash used in investing activities was $234.1 million for the six months ended June 30, 2024 compared to $249.1 million for the six months ended June 30, 2023. Our primary investing activities consisted of the following (in millions):

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Additions to property and equipment (1)	$ (210.8)	$ (203.1)
Contributions to unconsolidated affiliate investments (2)	(20.1)	(49.7)

(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.

Cash Flows from Financing Activities. Net cash used in financing activities was $244.7 million for the six months ended June 30, 2024 compared to $306.5 million for the six months ended June 30, 2023. Our primary financing activities consisted of the following (in millions):

	Six Months Ended June 30,	
	2024	2023
Net repayments on the AR Facility (1)	$ (45.6)	$ (186.9)
Net borrowings (repayments) on the Revolving Credit Facility (1)	229.0	(95.0)
Net borrowings on ENLC's senior unsecured notes (1)	—	297.0
Net repayments on ENLK's senior unsecured notes (1)	(97.9)	—
Distributions to members	(122.5)	(120.2)
Distributions to the holders of the Series B Preferred Units (2)	(30.0)	(32.5)
Distributions to the holders of the Series C Preferred Units (2)	(18.1)	(17.1)
Distributions to joint venture partners (3)	(33.8)	(32.9)
Earnout payments (4)	(2.5)	—
Contributions from non-controlling interests (5)	13.8	22.1
Common unit repurchases (6)	(118.6)	(107.5)
Conversion of unit-based awards for common units, net of units withheld for taxes	(17.1)	(16.9)

(1) See "Item 1. Financial Statements—Note 5" for more information regarding our long-term debt.
(2) See "Item 1. Financial Statements—Note 7" for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units.
(3) 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.
(4) Earnout payments were made in connection to the consideration paid for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition, both of which included a contingent component payable beginning in 2024.
(5) Represents contributions from NGP to the Delaware Basin JV.
(6) See "Item 1. Financial Statements—Note 8" for more information regarding our common unit repurchase program.

Capital Requirements

As of June 30, 2024, the following table summarizes our expected remaining capital requirements for 2024 (in millions):

Capital expenditures, net to ENLC (1)	$	221
Operating expenses associated with the relocation of processing facilities, net to ENLC (2)		1
Total	$	222

(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 to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations. These costs exclude amounts that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

Our primary remaining capital projects for 2024 include continued development of our existing systems through well connects and other low-cost development projects. We expect to fund our remaining 2024 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, 2024.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2024 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2024	2025	2026	2027	2028	Thereafter
ENLC's & ENLK's senior unsecured notes	$ 4,211.3	$ —	$ 421.6	$ 491.0	$ —	$ 500.0	$ 2,798.7
AR Facility (1)	254.4	—	254.4	—	—	—	—
Revolving Credit Facility (1)	229.0	—	—	—	229.0	—	—
Interest payable on fixed long-term debt obligations (1)	2,242.0	115.4	222.1	213.3	189.5	175.4	1,326.3
Acquisition contingent consideration (2)	5.5	—	4.2	0.9	0.4	—	—
Repurchase of ENLC common units held by GIP (3)	22.9	22.9	—	—	—	—	—
Operating lease obligations	123.6	19.8	35.9	22.0	8.4	5.9	31.6
Purchase obligations	7.3	7.3	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (4)	891.0	51.9	115.6	101.7	88.3	84.9	448.6
Total contractual cash obligations	$ 7,987.0	$ 217.3	$ 1,053.8	$ 828.9	$ 515.6	$ 766.2	$ 4,605.2

(1) The interest payable related to the Revolving Credit Facility and the AR Facility is not reflected in the 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. See "Item 1. Financial Statements—Note 5" for more information regarding the Revolving Credit Facility and the AR Facility.

(2) 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.

(3) Relates to the repurchase of ENLC common units held by GIP on August 5, 2024. See "Item 1. Financial Statements—Note 8" for more information.

(4) 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.

Our contractual cash obligations for the remainder of 2024 are expected to be funded from cash flows generated from our operations.

Indebtedness

Revolving Credit Facility. As of June 30, 2024, there were $229.0 million in outstanding borrowings and $14.6 million in outstanding letters of credit under the Revolving Credit Facility.

AR Facility. As of June 30, 2024, the AR Facility had a borrowing base of $345.5 million and there were $254.4 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, 2024, we had $4.2 billion in aggregate principal amount of outstanding senior unsecured notes maturing from 2025 to 2047, of which $421.2 million matures on June 1, 2025 and is classified as "Current maturities of long-term debt" in 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, 2024, 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 5" for more information on our outstanding debt.

Inflation

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

See "Item 1. Financial Statements—Note 2" for more information on recently issued and/or adopted accounting pronouncements.

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,” “shall,” “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, potential financial arrangements with CCS counterparties, expected financial and operational results associated with certain projects, acquisitions, or growth capital expenditures, 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, repurchases of common or preferred units. 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 other 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 or a change in control of GIP 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) debt levels that 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 connection with our strategy to build a CCS transportation business and to enter into other new lines of business related to the energy transition, including entry into the CCS business, (u) our ability to effectively integrate and manage assets we acquire through acquisitions, and (v) 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, 2023, filed with the Commission on February 21, 2024, 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 and equity.

Commodity Price Risk

We are also subject to direct risks due to fluctuations in commodity prices. While approximately 90% of our adjusted gross margin for the six months ended June 30, 2024 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 natural 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, 2023 filed with the Commission on February 21, 2024.

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, 2024.

Period	Underlying	Notional Volume (Net Position)	Reference Price	Price Range	Net Fair Value Asset/(Liability) (In Millions)
July 2024 - June 2025	Ethane	5.9 MMgals	OPIS Mt Belvieu	$0.19 - $0.25/Gal	$ —
July 2024 - June 2025	Propane	(100.7) MMgals	OPIS Mt Belvieu	$0.64 - $0.85/Gal	(11.4)
July 2024 - June 2025	Normal Butane	(14.5) MMgals	OPIS Mt Belvieu	$0.77 - $0.90/Gal	(2.1)
July 2024 - January 2025	Natural Gasoline	(0.8) MMgals	NYMEX WTI Average	$1.43 - $1.75/Gal	(0.1)
July 2024 - December 2024	Natural Gasoline and Condensate	47.3 MMgals	OPIS Mt Belvieu and NYMEX WTI Average differential	($0.34) - ($0.29)/Gal	(0.4)
July 2024 - January 2029	Natural Gas	(7.7) Bbtu	NYMEX Henry Hub	$2.25 - $5.30/MMbtu	4.4
July 2024 - June 2025	Natural Gas	1.7 Bbtu	Waha basis differential	($1.25) - ($0.09)/MMbtu	(0.3)
July 2024 - July 2024	Natural Gas	0.7 Bbtu	Henry Hub Natural Gas Daily	$2.55 - $2.62/MMbtu	—
July 2024 - July 2024	Natural Gas	(1.2) Bbtu	NGPL TEXOK Natural Gas Daily	$2.24 - $2.27/MMbtu	—
July 2024 - December 2024	Natural Gas	(5.5) Bbtu	NGPL TEXOK basis differential	($0.25) - ($0.25)/MMbtu	1.0
July 2024 - August 2024	Natural Gas	0.9 Bbtu	IFSOUTHSTARTOK Basis Differential	($0.44) - ($0.44)/MMbtu	(0.1)
July 2024 - July 2024	Natural Gas	(0.1) Bbtu	OneOK Gas Daily	$1.75 - $1.75/MMbtu	—
August 2024 - March 2025	Crude and Condensate	(0.2) MMbbls	NYMEX WTI	$69.88 - $83.33/Bbl	(0.7)
July 2024 - December 2024	Crude and Condensate	0.1 MMbbls	OPIS Mt Belvieu	$67.20 - $67.20/Bbl	(0.1)
July 2024 - December 2024	Crude and Condensate	(0.1) MMbbls	NYMEX WTI Average	$80.20 - $80.20/Bbl	0.1
August 2024 - December 2025	Crude and Condensate	(5.1) MMbbls	WTI-Houston and Midland basis differential	$0.70 - $0.90/Bbl	1.2
Total fair value of commodity derivatives					$ (8.5)

Another price risk we face is the risk of mismatching volumes of natural 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, 2024, our outstanding commodity derivative instruments had a net fair value liability of $8.5 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in natural gas, crude and condensate, and NGL prices would result in a change of approximately $19.4 million in the net fair value of these contracts as of June 30, 2024.

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, 2024, we had $229.0 million in outstanding borrowings under the Revolving Credit Facility and $254.4 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 our floating rate, SOFR-based borrowings, including borrowings on the Revolving Credit Facility and the AR Facility. This swap has been designated as a cash flow hedge. See “Item 1. Financial Statements—Note 9” for more information on our outstanding derivatives.

A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $2.3 million and $2.5 million for the Revolving Credit Facility and the AR Facility, respectively, based on our outstanding borrowings at June 30, 2024. This change in interest expense would be 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 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, 2024, the estimated fair value of the senior unsecured notes was approximately $4,012.5 million, based on the market prices of ENLK’s and our publicly traded debt at June 30, 2024. 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 $217.9 million decrease in fair value of the senior unsecured notes at June 30, 2024. See “Item 1. Financial Statements—Note 5” for more information on our outstanding indebtedness.

Prior to December 15, 2022, distributions on ENLK’s Series C Preferred Units were based on a fixed interest rate. Beginning with the interest period which commenced on December 15, 2022, distributions on ENLK’s Series C Preferred Units were based on a floating rate tied to LIBOR plus a spread of 4.11%. As a result of the floating rate, the amount paid by ENLK for distributions became more sensitive to changes in interest rates. Beginning with the interest period which commenced on September 15, 2023, distributions are 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%. See “Item 1. Financial Statements—Note 7” 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, 2024), 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, 2024 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 13, "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, 2023 filed with the Commission on February 21, 2024.

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

During the three months ended June 30, 2024, 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, 2024 to April 30, 2024	640,671	$ 13.72	620,046	$ 141.5
May 1, 2024 to May 31, 2024	865,515	13.21	826,824	$ 130.6
June 1, 2024 to June 30, 2024 (3)	2,378,473	13.23	2,307,134	$ 150.0
Total	3,884,659	$ 13.30	3,754,004	

(1) The total number of units purchased shown in the table includes 130,655 ENLC common units received by us from employees for the payment of personal income tax withholding on vesting transactions.

(2) In December 2023, the Board reauthorized our common unit repurchase program for 2024 and set the amount available for repurchases of outstanding common units at up to $200.0 million. In July 2024, the Board authorized an increase in the 2024 common unit repurchase program by $50.0 million to $250.0 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 8."

(3) Includes the ENLC common units repurchased from GIP pursuant to the GIP repurchase agreement, which settled on August 5, 2024. These units represented GIP's pro rata share of the aggregate number of common units repurchased by us during the three months ended June 30, 2024. See "Item 1. Financial Statements—Note 4 and Note 8" for additional information on the GIP repurchase agreement.

Item 5. Other Information

Insider Trading Plans

During the three months ended June 30, 2024,no director or officer of the Company adopted a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement" as each term is defined in Item 408(a) of Regulation S-K.

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		—	Eleventh Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of September 8, 2023 (incorporated by reference to Exhibit 3.14 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2023, filed with the Commission on November 1, 2023, 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, 2023, filed with the Commission on February 21, 2024, 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, 2024, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of June 30, 2024 and December 31, 2023, (ii) Consolidated Statements of Operations for the three and six months ended June 30, 2024 and 2023, (iii) Consolidated Statements of Changes in Members' Equity for the three and six months ended June 30, 2024 and 2023, (iv) Consolidated Statements of Cash Flows for the six months ended June 30, 2024 and 2023, 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 7, 2024

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 7, 2024

/s/ JESSE ARENIVAS
Jesse Arenivas
President and 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 7, 2024

/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, 2024 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 7, 2024	/s/ JESSE ARENIVAS
	Jesse Arenivas
	President and Chief Executive Officer
Date: August 7, 2024	/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.