ANNUAL REPORT

CONSOLIDATED FINANCIAL STATEMENTS OF ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

For the fiscal year ended December 31, 2023

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	Definition
/d	Per day.
2014 Plan	ENLC's 2014 Long-Term Incentive Plan.
Adjusted gross margin	Revenue less cost of sales, exclusive of operating expenses and depreciation and amortization. Adjusted gross margin is a non-GAAP financial measure. See "Item 1. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" for additional information.
Amarillo Rattler Acquisition	On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin.
AR Facility	An accounts receivable securitization facility of up to $500 million entered into by EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity and our indirect subsidiary, with PNC Bank, National Association, as administrative agent and lender, and PNC Capital Markets, LLC, as structuring agent and sustainability agent.
ASC	The Financial Accounting Standards Board Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASC 718	ASC 718, *Compensation—Stock Compensation*.
ASC 815	ASC 815, *Derivatives and Hedging.*
ASC 820	ASC 820, *Fair Value Measurements*.
ASC 842	ASC 842, *Leases.*
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.
Barnett Shale	A natural gas producing shale reservoir located in North Texas.
Barnett Shale Acquisition	On July 1, 2022, we acquired all of the equity interest in the gathering and processing assets of Crestwood Equity Partners LP located in the Barnett Shale.
Bbl	Barrel.
Bbtu	Billion British thermal units.
Bcf	Billion cubic feet.
Beginning TSR Price	The beginning total shareholder return ("TSR") price, which is the closing unit price of ENLC on the grant date of the performance award agreement or the previous trading day if the grant date was not a trading day, is one of the assumptions used to calculate the grant-date fair value of performance award agreements.
BKV	BKV Corporation.
CCS	Carbon capture, transportation, and sequestration.
Cedar Cove JV	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.
Devon	Devon Energy Corporation.
EMO	EnLink Midstream Operating, LP.
EMO Preferred B Units	EnLink Midstream Operating, LP Series B Preferred Units. Subsequent to the sale of EORV to ENLC in December 2020, the EMO Preferred B Units were held by ENLC. In December 2021, ENLC redeemed the EMO Preferred B Units.
ENLC	EnLink Midstream, LLC together with its consolidated subsidiaries.
ENLC Class C Common Units	A class of non-economic ENLC common units equal to the number of Series B Preferred Units in order to provide certain voting rights with respect to ENLC to the holders of such Series B Preferred Units. The Class C Common Units were cancelled in September 2023 in connection with an amendment of ENLK's limited partnership agreement.

ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries.
EORV	EnLink ORV Holdings, LLC.
ExxonMobil	ExxonMobil Corporation.
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	A joint venture in which we own a 38.75% interest. Gulf Coast Fractionators 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 first half of 2024.
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.
Manager Board	The board of directors of the managing member of ENLC.
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. In November 2023, we divested these assets. See "Item 2. Financial Statements and Supplementary Data—Note 3" for more information regarding our divestitures.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Revolving Credit Facility	A $1.40 billion unsecured revolving credit facility entered into by ENLC, which includes a $500.0 million letter of credit subfacility. The Revolving Credit Facility is guaranteed by ENLK.
Series B Preferred Unit	ENLK's Series B Cumulative Convertible Preferred Unit.
Series C Preferred Unit	ENLK's Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Unit.
SOFR	Secured overnight financing rate.
SPV	EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity that is an indirect subsidiary of ENLC.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.

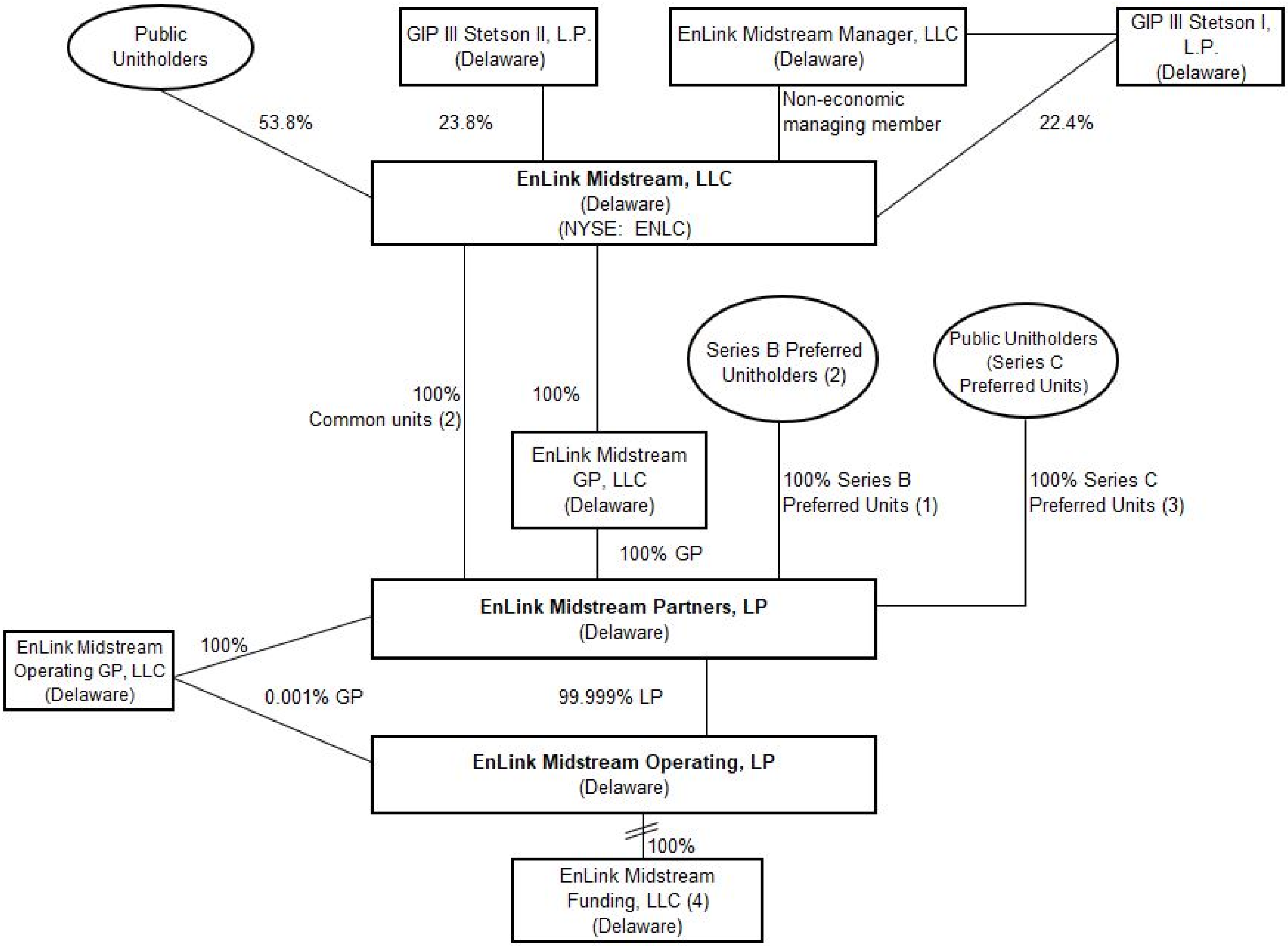
Item 1. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 Item 1. Management's Discussion and Analysis of Financial Condition and Results of Operations. Certain items related to the year ended December 31, 2022 and 2021 and year-to-year comparisons of the year ended December 31, 2022 and the year ended December 31, 2021 have been recast to conform to current period presentation, and therefore are shown below. Items that remain unchanged from the discussion in our prior year's Annual Report can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 1 of ENLK's Annual Report for the year ended December 31, 2022, published on our website on February 15, 2023 and can be found here.

In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," "us," and "its" are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Overview

We are a Delaware limited partnership formed on July 12, 2002. The following diagram depicts our organization and ownership as of December 31, 2023:



(1) Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. The non-economic ENLC Class C Common Units previously held by the Series B Preferred Unitholders were cancelled in September 2023 in connection with an amendment of ENLK's limited partnership agreement. See "Item 2. Financial Statements and Supplementary Data—Note 8" for more information.
(2) All ENLK common units are held by ENLC. The Series B Preferred Units are entitled to vote, on a one-for-one basis (subject to certain adjustments) as a single class with ENLC, on all matters that require approval of the ENLK unitholders.
(3) Series C Preferred Units are perpetual preferred units that are not convertible into other equity interests.
(4) EnLink Midstream Funding, LLC is a bankruptcy-remote special purpose entity that entered into the AR Facility in October 2020. See "Item 2. Financial Statements and Supplementary Data—Note 7" for more information regarding the AR Facility.

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 December 31, 2023, our midstream energy asset network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.8 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.

We manage and report our operations primarily according to the geography and the nature of the activity. We have five reportable segments:

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

- *Louisiana Segment.* The Louisiana segment includes our natural gas and NGL 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.

We manage our consolidated operations by focusing on adjusted gross margin because our business is generally to gather, process, transport, or market natural gas, NGLs, crude oil, and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Adjusted gross margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 90% of our adjusted gross margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2023.

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 years ended December 31, 2023, 2022, or 2021. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Year Ended December 31,		
	2023	2022	2021
Dow Hydrocarbons and Resources LLC	10.4 %	14.2 %	14.5 %
Marathon Petroleum Corporation	19.3 %	14.7 %	13.4 %

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

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

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

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

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

CCS Business

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

Recent Developments Affecting Industry Conditions and Our Business

Current Market Environment

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

Production levels by our exploration and production customers 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 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. Oil and natural gas prices rose in the first half of 2022 due to various factors, including a rebound in demand from economic activity after COVID-19 shutdowns, supply issues, and geopolitical events, including Russia's invasion of Ukraine.

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

	Crude oil $/Bbl (1)(2)		NGL $/Gal (1)(3)		Natural gas $/MMbtu (1)(4)	
2023 by quarter:						
1st Quarter	$	75.99	$	0.61	$	2.74
2nd Quarter	$	73.56	$	0.43	$	2.33
3rd Quarter	$	82.22	$	0.50	$	2.66
4th Quarter	$	78.53	$	0.45	$	2.92
2023 Averages	**$**	**77.60**	**$**	**0.50**	**$**	**2.66**
2022 by quarter:						
1st Quarter	$	95.01	$	0.92	$	4.56
2nd Quarter	$	108.52	$	0.97	$	7.50
3rd Quarter	$	91.43	$	0.82	$	7.95
4th Quarter	$	82.64	$	0.62	$	6.11
2022 Averages	**$**	**94.33**	**$**	**0.83**	**$**	**6.54**

(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 Gas Daily closing prices.

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

Producers generally focus their drilling activity on certain producing basins depending on commodity price fundamentals and favorable drilling economics. In the last few years, many producers have increasingly focused their activities in the Permian Basin, because of the availability of higher investment returns. Currently, a large percentage of all drilling rigs operating in the United States are operating in the Permian Basin. We continue to experience a robust increase in volumes in our Permian segment as our operations in that basin are in a favorable position relative to producer activity. As a result of this concentration of drilling activity in the Permian Basin, other basins, including those in which we operate in Oklahoma and North Texas, experienced reduced investment and declines in volumes produced. However, the rise in commodity prices during 2022 led to renewed producer interest in Oklahoma and North Texas, which 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 in 2024.

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 throughout 2022 and 2023, 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 remained strong throughout 2022 and 2023. 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.

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 2022 and 2023. Inflation has moderated in 2023, and the Federal Reserve has signaled an end to rate hikes and projected cuts in 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 ENLC's Annual Report on Form 10-K for the year ended December 31, 2023, filed with the Commission on February 21, 2024.

Regulatory Developments

On January 20, 2021, the Biden Administration came into office and immediately issued a number of executive orders related to climate change and the production of oil and gas that could affect our operations and those of our customers, particularly those who may operate on public lands. While none of these initiatives to date have materially affected our operations or those of our customers, the Biden Administration could seek, in the future, to put into place executive orders, policy and regulatory reviews, or seek to have Congress pass legislation that could adversely affect the production of oil and natural gas, and our operations and those of our customers.

Only a small percentage of our operations are derived from customers operating on public land, mainly in the Delaware Basin. In addition, we have a robust program to monitor and prevent methane emissions in our operations and we maintain a comprehensive environmental program that is embedded in our operations. However, our activities that take place on public lands require that we and our producer customers obtain leases, permits, and other approvals from the federal government. While the future rules and rulemaking initiatives under the Biden Administration remain uncertain, the regulations that might result from such initiatives, could lead to increased costs for us or our customers, difficulties in obtaining leases, permits, and other approvals for us and our customers, reduced utilization of our gathering, processing, and pipeline systems or reduced rates under renegotiated transportation or storage agreements in affected regions. In July 2023, the Acting Secretary for the Department of the Interior ("DOI") proposed updates to its onshore oil and gas leasing regulations which could further restrict oil and gas exploration and production on federal lands. The DOI expects to issue a final rule in the spring of 2024. These changes and uncertainties could have a negative effect on exploration and production of oil and natural gas and, consequently, negatively impact the demand for our products and services.

Over the past few years, the Biden administration has focused on regulating methane emissions in the production of oil and gas, including through venting and flaring. To this end, the EPA, BLM, and other agencies have issued regulations that may require us to make changes to our operations and may require us to pay a fee associated with our methane emissions. Additional regulatory actions targeting methane and other GHG emissions may be put in place in the future. We cannot predict, what effect, if any, such additional actions might have on our operations.

In addition, on January 26, 2024, the Biden Administration announced that it was pausing decisions on applications for new LNG export projects until the Department of Energy is able to adopt new parameters for analyzing the projects. These new parameters would include the review of the economic and environmental effects of new facilities on US climate goals and other factors. While this pause will not affect operating LNG facilities or facilities that have previously secured government approval, it will affect the approval process for future LNG facilities and for expansions of existing facilities. It is uncertain how long the pause will be in place and what changes to the analysis parameters will be adopted.

Certain enhancements were made to the IRC Section 45Q carbon sequestration tax credit as part of the Inflation Reduction Act of 2022, which was enacted on August 16, 2022. We believe these enhancements to the 45Q carbon sequestration tax credit may help expand and support the development of our CCS business, while the other provisions are not expected to have a material impact to our business, financial condition, results of operations, or cash flows.

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 the risk factors under "Item 1A—Risk Factors—Environmental, Legal Compliance, and Regulatory Risk" in ENLC's 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 and CCS Business

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

GCF Operations. In January 2023, we and our partners started the process to restart the GCF assets and made capital contributions throughout the year related to the restart process. We intend to make additional capital contributions until the assets become operational, which is expected in the first half 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 have made capital contributions towards the construction of the Matterhorn Express Pipeline for the years ended December 31, 2023 and 2022. 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, and we intend to make additional capital contributions until the construction is complete.

See "Item 2. Financial Statements and Supplementary Data—Note 9" for more information regarding GCF and the Matterhorn JV.

BKV Agreement. In November 2023, we began separating CO_2 from lean natural gas in our North Texas gathering systems and from rich natural gas delivered to our natural gas processing plant in Bridgeport, Texas. This CO_2 waste stream is then captured, compressed, transported, and sequestered by BKV.

ExxonMobil 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 the Mississippi River corridor in southeastern Louisiana. Under the transportation agreement, we contracted to deliver CO_2 from the Mississippi River corridor to ExxonMobil's storage location at Pecan Island in Vermilion Parish, Louisiana, beginning in 2025. The agreement also provides for a reserved capacity available of up to 10 million metric tonnes per year, with an initial reserved capacity of 3.2 million metric tonnes per year. In February 2024, we announced that we and ExxonMobil have agreed to reassess the Pecan Island project's near-term role, with the expectation that other joint CCS opportunities along the Gulf Coast, and beyond the Mississippi River corridor, may be prioritized ahead of the Pecan Island project.

Divestitures

On November 1, 2023, we sold certain ORV crude assets in our Louisiana segment to a subsidiary of Ergon, Inc. in exchange for cash consideration of approximately $59.2 million, subject to post-closing purchase price adjustments, and a contingent payment of an additional $0.5 million subject to the buyer’s pursuit of certain commercial opportunities within three years after the acquisition date.

On November 3, 2023, we sold our remaining ORV assets in our Louisiana segment to Blue Racer Midstream, LLC in exchange for cash consideration of approximately $9.8 million, subject to post-closing purchase price adjustments.

Debt

Senior Unsecured Notes Issuance. In April 2023, we completed the sale of an additional $300.0 million aggregate principal amount of ENLC’s 6.50% senior unsecured notes due 2030 (the “Additional Notes”) at a price to the public of 99% of their face value. The Additional Notes were offered as an additional issuance of our existing 6.50% senior unsecured notes due 2030 that we issued on August 31, 2022 in an aggregate principal amount of $700.0 million. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by ENLK. See “Item 2. Financial Statements and Supplementary Data—Note 7” for more information regarding the issuance of new senior unsecured notes by us.

Equity

ENLK’s *Eleventh Amended and Restated Agreement of Limited Partnership.* In September 2023, in connection with ENLK’s qualification of the Series B Preferred Units to be eligible to be deposited through the Depository Trust Company, we amended and restated the limited partnership agreement of ENLK to, among other things, (i) reflect the cancellation of all outstanding ENLC Class C Common Units, which were non-economic equity interests previously held by the holders of the Series B Preferred Units and permitted such holders to participate in any vote of the holders of ENLC common units, (ii) provide for the termination of any rights of the holders of the Series B Preferred Units to PIK Distributions with respect to, and following, the earlier to occur of (x) any quarter in which the holders of the Series B Preferred Units give notice to our general partner of its election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024, and (iii) 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 ENLK’s limited partnership agreement).

Repurchase of Series C Preferred Units. For the year ended December 31, 2023, we repurchased 14,500 Series C Preferred Units for total consideration of $13.1 million. For the year ended December 31, 2022, we repurchased 19,000 Series C Preferred Units for total consideration of $15.2 million.

See “Item 2. Financial Statements and Supplementary Data—Note 8” for more information regarding the Series B Preferred Units and Series C Preferred Units.

Rate Reset

Beginning in 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. For 2024, we expect our adjusted gross margin to decline by approximately $40 million related to the rate reset under these contracts.

Non-GAAP Financial Measures

To assist management in assessing our business, we use the following non-GAAP financial measure: adjusted gross margin.

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):

	Year Ended December 31,	
	2023	2022
Total revenues	$ 6,900.1	$ 9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(4,856.1)	(7,572.8)
Operating expenses	(558.2)	(524.9)
Depreciation and amortization	(657.1)	(639.4)
Gross margin	828.7	805.0
Operating expenses	558.2	524.9
Depreciation and amortization	657.1	639.4
Adjusted gross margin	$ 2,044.0	$ 1,969.3

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
Year Ended December 31, 2023						
Total revenues	$ 2,823.2	$ 3,910.3	$ 1,171.4	$ 721.2	$ (1,726.0)	$ 6,900.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(2,205.5)	(3,388.4)	(645.6)	(342.6)	1,726.0	(4,856.1)
Adjusted gross margin	617.7	521.9	525.8	378.6	—	2,044.0
Operating expenses	(221.3)	(130.3)	(103.8)	(102.8)	—	(558.2)
Segment profit	396.4	391.6	422.0	275.8	—	1,485.8
Depreciation and amortization	(166.6)	(151.3)	(217.7)	(115.8)	(5.7)	(657.1)
Gross margin	$ 229.8	$ 240.3	$ 204.3	$ 160.0	$ (5.7)	$ 828.7

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2022						
Total revenues	$ 3,866.0	$ 5,977.4	$ 1,603.0	$ 1,021.7	$ (2,926.0)	$ 9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(3,280.3)	(5,462.4)	(1,124.4)	(631.7)	2,926.0	(7,572.8)
Adjusted gross margin	585.7	515.0	478.6	390.0	—	1,969.3
Operating expenses	(200.2)	(140.7)	(90.9)	(93.1)	—	(524.9)
Segment profit	385.5	374.3	387.7	296.9	—	1,444.4
Depreciation and amortization	(154.5)	(156.5)	(201.8)	(121.1)	(5.5)	(639.4)
Gross margin	$ 231.0	$ 217.8	$ 185.9	$ 175.8	$ (5.5)	$ 805.0

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2021						
Total revenues	$ 2,307.3	$ 4,539.8	$ 1,204.2	$ 860.4	$ (2,225.8)	$ 6,685.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,996.1)	(4,091.2)	(796.6)	(531.8)	2,225.8	(5,189.9)
Adjusted gross margin	311.2	448.6	407.6	328.6	—	1,496.0
Operating expenses	(81.5)	(123.7)	(80.0)	(77.7)	—	(362.9)
Segment profit	229.7	324.9	327.6	250.9	—	1,133.1
Depreciation and amortization	(139.9)	(141.0)	(204.3)	(114.3)	(8.0)	(607.5)
Gross margin	$ 89.8	$ 183.9	$ 123.3	$ 136.6	$ (8.0)	$ 525.6

	Year Ended December 31,		
	2023	2022	2021
Midstream Volumes:			
Consolidated			
Gathering and Transportation (MMbtu/d)	7,096,300	6,913,600	5,597,600
Processing (MMbtu/d)	3,746,600	3,384,300	2,866,500
Crude Oil Handling (Bbls/d)	205,500	197,500	170,700
NGL Fractionation (Gals/d)	8,752,800	8,605,800	8,412,600
Brine Disposal (Bbls/d)	2,500	3,000	2,700
Permian Segment			
Gathering and Transportation (MMbtu/d)	1,800,900	1,506,600	1,067,000
Processing (MMbtu/d)	1,662,400	1,422,200	1,010,000
Crude Oil Handling (Bbls/d)	165,300	156,300	134,600
Louisiana Segment			
Gathering and Transportation (MMbtu/d)	2,495,000	2,828,200	2,160,800
Crude Oil Handling (Bbls/d)	14,900	17,400	15,900
NGL Fractionation (Gals/d)	7,705,700	7,957,800	7,455,600
Brine Disposal (Bbls/d)	2,500	3,000	2,700
Oklahoma Segment			
Gathering and Transportation (MMbtu/d)	1,221,000	1,031,200	992,400
Processing (MMbtu/d)	1,182,000	1,057,600	1,010,300
Crude Oil Handling (Bbls/d)	25,300	23,800	20,200
North Texas Segment			
Gathering and Transportation (MMbtu/d)	1,579,400	1,547,600	1,377,400
Processing (MMbtu/d)	734,600	705,100	631,500

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

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

Our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, are from natural gas, NGL, crude oil, and condensate product sales and purchases, midstream services that we perform 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, decreased $2,642.0 million and $2,716.7 million, respectively, for the year ended December 31, 2023 compared to the year ended December 31, 2022 due to the following:

- Product sales revenues decreased $2,809.3 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to:

  - A $1,554.4 million decrease in natural gas sales primarily driven by lower natural gas prices,
  - A $1,185.8 million decrease in NGL sales primarily driven by lower NGL prices, and
  - A $69.1 million decrease in crude oil and condensate sales primarily driven by lower crude oil prices.

- Lower 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 $2,716.7 million decrease for the year ended December 31, 2023 compared to the year ended December 31, 2022.

- Revenues from midstream services increased $160.9 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to:

  - A $113.9 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes,
  - A $43.2 million increase in processing revenues primarily driven by higher processing volumes, and
  - A $5.3 million increase in NGL service revenues primarily driven by higher NGL service volumes.

  These increases were primarily offset by the disposition of our ORV crude assets, which contributed to the $8.6 million decrease in crude services revenues.

- Derivative gains increased $6.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 due to $52.3 million of increased unrealized losses and $58.7 million of increased realized gains.

Operating Expenses. Operating expenses increased $33.3 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to a $20.5 million increase in compressor rentals, a $7.3 million increase in materials and supplies expense, a $5.6 million increase in ad valorem taxes, a $4.4 million increase in labor and benefits costs, a $4.1 million increase in utilities expense, a $3.3 million increase in compressor overhauls, a $2.8 million increase in insurance costs, and a $2.8 million increase in regulatory and compliance costs. These increases were partially offset by a $14.4 million decrease in construction fees and services and a $3.6 million decrease in sales and use tax.

Depreciation and Amortization. Depreciation and amortization increased $17.7 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to a $26.2 million increase resulting from changes in estimated useful lives, an $11.9 million increase due to additional assets placed in service, a $6.4 million increase related to the Barnett Shale Acquisition in July 2022, and a $3.8 million increase related to the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $31.1 million decrease in depreciation related to assets reaching the end of their depreciable lives.

Impairments. For the year ended December 31, 2023, we recognized an impairment expense of $20.7 million due to changes in our outlook for future cash flows and the anticipated use of certain ORV crude assets in our Louisiana segment. We determined that the carrying amounts of these assets exceeded their fair value, based on market inputs and certain assumptions.

(Gain) Loss on Disposition of Assets. For the year ended December 31, 2023, we recognized a gain on disposition of assets of $0.3 million, which was primarily due to the divestitures of our ORV assets in our Louisiana segment. See "Item 2. Financial Statements and Supplementary Data—Note 3" for additional information. For the year ended December 31, 2022, we recognized a loss on disposition of assets of $18.0 million, which was primarily due to the sale of compressor units associated with our ORV assets. (Gain) loss on disposition of assets consisted of the following amounts (in millions):

	Year Ended December 31,	
	2023	2022
Net book value of assets disposed	$ 72.9	$ 30.8
Proceeds from sales	(73.1)	(12.8)
Insurance recoveries	(0.1)	—
(Gain) loss on disposition of assets	$ (0.3)	$ 18.0

General and Administrative Expenses. General and administrative expenses were $113.7 million for the year ended December 31, 2023 compared to $124.8 million for the year ended December 31, 2022, a decrease of $11.1 million. The decrease was primarily due to a $9.2 million decrease in unit-based compensation and a $4.0 million decrease in consulting fees and services. The decrease was partially offset by a $3.9 million increase in losses related to an increase in the estimated fair value of the contingent consideration associated with the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition. See "Item 2. Financial Statements and Supplementary Data—Note 3" for more additional information regarding the contingent consideration for Amarillo Rattler and the Central Oklahoma Acquisition.

Interest Expense, Net of Interest Income. Interest expense, net of interest income, was $271.7 million for the year ended December 31, 2023 compared to $245.0 million for the year ended December 31, 2022, an increase of $26.7 million. Interest expense, net of interest income, consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
Senior unsecured notes	$ 116.8	$ 135.8
Related party debt	131.2	83.7
AR Facility	22.8	12.1
Amortization of debt issuance costs and net discount of senior unsecured notes	6.4	5.5
Interest rate swaps - realized	(4.5)	1.9
Redemption of mandatorily redeemable non-controlling interest	—	6.5
Other	(1.0)	(0.5)
Interest expense, net of interest income	$ 271.7	$ 245.0

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt of $6.2 million for the year ended December 31, 2022, which was primarily due to the repurchases of our senior unsecured notes in the debt tender offer completed in the third quarter of 2022. For the year ended December 31, 2023, we and ENLC did not repurchase any senior unsecured notes. See "Item 2. Financial Statements and Supplementary Data—Note 7" for additional information.

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $8.2 million for the year ended December 31, 2023 compared to $5.6 million for the year ended December 31, 2022, an increase in loss of $2.6 million. The increase in loss was primarily attributable to a $1.2 million increase in loss related to our GCF investment, a $0.9 million increase in loss related to the Matterhorn JV, and a $0.5 million increase in loss related to the Cedar Cove JV. See "Item 2. Financial Statements and Supplementary Data—Note 9" for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $40.7 million for the year ended December 31, 2023 compared to net income of $46.2 million for the year ended December 31, 2022, a decrease of $5.5 million. Our non-controlling interests are comprised of NGP's 49.9% share of the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of the Ascension JV. The decrease was primarily due to a $6.4 million decrease attributable to NGP's 49.9% share of the Delaware Basin JV and was partially offset by a $0.9 million increase attributable to Marathon Petroleum Corporation's 50% share of the Ascension JV.

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 year ended December 31, 2023 compared to the year ended December 31, 2022.

- *Permian Segment.*

    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,042.8 million and $1,074.8 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $32.0 million, due to:

        - A $26.3 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $27.7 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 $1.4 million, which included $18.0 million from increased realized gains and $19.4 million from increased unrealized losses.
        - A $5.7 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $6.9 million, which was primarily due to higher commodity prices. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $1.2 million, which included $6.0 million from increased realized losses and $4.8 million from increased unrealized gains.

    - Operating expenses in the Permian segment increased $21.1 million primarily due to a $12.9 million increase in compressor rentals, an $11.5 million increase in utilities expense, a $5.3 million increase in labor and benefits costs, a $3.0 million increase in compressor overhauls, and a $2.1 million increase in materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity. These increases were partially offset by a $14.1 million decrease in construction fees and services.

    - Depreciation and amortization in the Permian segment increased $12.1 million primarily due to $7.0 million increase resulting from additional assets placed in service and a $5.0 million increase related to the equipment transferred to the Phantom processing facility.

- *Louisiana Segment.*

    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $2,067.1 million and $2,074.0 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $6.9 million, due to:

        - A $9.7 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, increased $22.7 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $13.0 million, which included $4.1 million from decreased realized gains and $8.9 million from increased unrealized losses.
        - A $15.7 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $7.2 million, which was primarily due to a settlement payment resulting from a customer account dispute in the amount of $6.8 million. Derivative activity associated with our Louisiana natural gas assets increased adjusted gross margin by $8.5 million, which included $3.2 million from decreased realized losses and $5.3 million from increased unrealized gains.
        - An $18.5 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $19.1 million, which was primarily due to lower compression fee revenue resulting from the sale of several compressor units in December 2022 and the

divestitures of our ORV assets in November 2023. Derivative activity associated with our ORV crude assets increased adjusted gross margin by $0.6 million from increased realized gains.

- Operating expenses in the Louisiana segment decreased $10.4 million primarily due to an $8.2 million decrease in utilities expense, a $1.8 million decrease in labor and benefits costs, and a $1.6 million decrease in vehicle expenses related to the disposal of the heavy truck fleet in ORV. These decreases were partially offset by a $0.8 million increase in regulatory and compliance costs and a $0.7 million increase in ad valorem taxes.

- Depreciation and amortization in the Louisiana segment decreased $5.2 million primarily due to a $14.5 million decrease resulting from assets reaching the end of their depreciable lives and a $4.1 million decrease related to the sale of several compressor units associated with our ORV assets in December 2022. These decreases were partially offset by an $8.9 million increase in depreciation due to changes in estimated useful lives and a $4.2 million increase related to the divestitures of our ORV assets in November 2023.

- *Oklahoma Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $431.6 million and $478.8 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $47.2 million, due to:

    - A $44.7 million increase in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, increased $33.8 million, which was primarily due to additional volumes from the Central Oklahoma Acquisition in December 2022. Derivative activity associated with our Oklahoma natural gas assets increased adjusted gross margin by $10.9 million, which included $18.7 million from increased realized gains and $7.8 million from increased unrealized losses.
    - A $2.5 million increase in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $1.6 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma crude assets increased adjusted gross margin by $0.9 million from increased realized gains.

  - Operating expenses in the Oklahoma segment increased $12.9 million primarily due to a $6.6 million increase in compressor rentals, a $4.8 million increase in ad valorem taxes, a $2.8 million increase in materials and supplies expense, a $1.9 million increase in labor and benefit costs, and a $0.9 million increase in insurance costs. These increases in operating expenses were principally due to an increase in operating activity from the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $3.4 million decrease in construction fees and services and a $1.3 million decrease in compressor overhauls.

  - Depreciation and amortization in the Oklahoma segment increased $15.9 million primarily due to a $12.5 million increase resulting from changes in estimated useful lives, a $4.6 million increase related to additional assets placed in service, and a $3.8 million increase related to the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $5.0 million decrease in depreciation related to the transfer of equipment to the Phantom processing facility.

- *North Texas Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $300.5 million and $289.1 million, respectively, resulting in a decrease in adjusted gross margin in the North Texas segment of $11.4 million. Adjusted gross margin, excluding derivative activity, decreased $12.5 million, which was primarily due to lower market prices. Derivative activity associated with our North Texas segment increased adjusted gross margin by $1.1 million, which included $27.4 million from increased realized gains and $26.3 million from increased unrealized losses.

  - Operating expenses in the North Texas segment increased $9.7 million primarily due to a $2.2 million increase in construction fees and services, a $2.0 million increase in materials and supplies expense, a $1.2 million increase in labor and benefits costs, a $1.1 million increase in compressor overhauls, a $1.0 million increase in pipeline integrity compliance costs, a $1.0 million increase in compressor rentals, a $0.5 million increase in utilities expense, and a $0.5 million increase in insurance costs.

    ◦ Depreciation and amortization in the North Texas segment decreased $5.3 million primarily due to a $16.6 million decrease resulting from assets reaching the end of their depreciable lives, which was partially offset by a $6.4 million increase in depreciation related to the Barnett Shale Acquisition in July 2022 and a $4.7 million decrease resulting from changes in estimated useful lives.

- *Corporate Segment.*

    ◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased $1,200.0 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.

    ◦ Depreciation and amortization in the Corporate segment increased $0.2 million due to additional assets placed in service.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

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 $2,856.2 million and $2,382.9 million, respectively, for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to the following:

- Product sales revenues increased $2,570.9 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to:

    ◦ A $1,047.3 million increase in natural gas sales primarily driven by higher natural gas prices,
    ◦ An $850.2 million increase in NGL sales primarily driven by higher NGL prices, and
    ◦ A $673.4 million increase in crude oil and condensate sales primarily driven by higher crude oil prices.

- Higher 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 $2,382.9 million increase for the year ended December 31, 2022 compared to the year ended December 31, 2021.

- Revenues from midstream services increased $111.9 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to:

    ◦ A $65.9 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes, and
    ◦ A $47.8 million increase in processing revenues primarily driven by higher processing volumes.

- Derivative gains increased $173.4 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to $120.8 million of decreased realized losses and $52.6 million of increased unrealized gains.

Operating Expenses. Operating expenses increased $162.0 million primarily due to a $73.3 million increase in utilities expense primarily related to electricity credits earned in 2021 that did not recur in 2022, a $31.7 increase in construction fees and services, a $27.5 million increase in materials and supplies expense, a $12.7 million increase in labor and benefits costs, and an $11.3 million increase in compressor rentals. These increases in operating expenses were principally due to an increase in operating activity.

Depreciation and Amortization. Depreciation and amortization increased $31.9 million primarily due to additional assets placed into service.

General and Administrative Expenses. General and administrative expenses were $124.8 million for the year ended December 31, 2022 compared to $107.5 million for the year ended December 31, 2021, an increase of $17.3 million. The increase was primarily due to a $6.4 million increase in labor and benefits costs, a $6.0 million increase in unit-based compensation, and a $5.8 million increase in consulting fees and services. The increase was partially offset by a $2.7 million increase in gains related to a decrease in the estimated fair value of the contingent consideration associated with the Amarillo Rattler Acquisition.

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 year ended December 31, 2022 compared to the year ended December 31, 2021.

- *Permian Segment.*
    - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $1,558.7 million and $1,284.2 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $274.5 million, due to:
        - A $259.7 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $174.2 million, which was primarily due to higher volumes from increased producer activity. Derivative activity associated with our Permian natural gas assets increased adjusted gross margin by $85.5 million, which included $69.0 million from decreased realized losses and $16.5 million from increased unrealized gains.
        - A $14.8 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $16.4 million, which was primarily due to higher volumes from increased producer activity. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $1.6 million, which included $2.4 million from decreased realized gains and $0.8 million from decreased unrealized losses.
    - Operating expenses in the Permian segment increased $118.7 million. During the year ended December 31, 2021, our Permian operating expenses were reduced by $46.5 million due to electricity credits earned during Winter Storm Uri in February 2021 that were not available during the same period of 2022. Operating expenses also increased primarily due to a $22.5 million increase in construction fees and services, a $15.0 million increase in materials and supplies expense, a $12.4 million increase in utilities expense, a $10.6 million increase in compressor rentals, and a $3.8 million increase in labor and benefits costs. These increases in operating expenses were principally due to an increase in operating activity. Additionally, $1.5 million of sales and use tax refunds reduced operating expenses in the fourth quarter of 2021, which were not available in 2022.
    - Depreciation and amortization in the Permian segment increased $14.6 million primarily due to depreciation from additional assets placed in service, including a $3.4 million increase associated with the Amarillo Rattler Acquisition in April 2021 and a $7.0 million increase associated with the transfer of equipment related to the Phantom and Warhorse processing facilities.

- *Louisiana Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $1,437.6 million and $1,371.2 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $66.4 million, due to:

    - A $31.3 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, decreased $8.1 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets increased adjusted gross margin by $39.4 million, which included $38.0 million from increased realized gains and $1.4 million from increased unrealized gains.
    - A $40.9 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $27.8 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Louisiana natural gas assets increased adjusted gross margin by $13.1 million, which included $6.4 million from decreased realized losses and $6.7 million from increased unrealized gains.
    - A $5.8 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $5.5 million, which was primarily due to unfavorable price spreads. Derivative activity associated with our ORV crude assets decreased adjusted gross margin by $0.3 million, which included $0.8 million from decreased realized losses and $1.1 million from decreased unrealized gains.

  - Operating expenses in the Louisiana segment increased $17.0 million primarily due to a $10.4 million increase in utilities expense, a $2.6 million increase in construction fees and services, a $1.3 million increase in vehicle expenses, and a $1.0 million increase in materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity.

  - Depreciation and amortization in the Louisiana segment increased $15.5 million primarily due to changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $398.8 million and $327.8 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $71.0 million, due to:

    - A $72.2 million increase in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, increased $54.4 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma natural gas assets increased adjusted gross margin by $17.8 million, which included $9.7 million from decreased realized losses and $8.1 million from increased unrealized gains.
    - A $1.2 million decrease in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $1.5 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma crude assets decreased adjusted gross margin by $2.7 million, which included $0.2 million from decreased realized gains and $2.5 million from decreased unrealized gains.

  - Operating expenses in the Oklahoma segment increased $10.9 million primarily due to a $4.4 million increase in materials and supplies expense, a $3.6 million increase in construction fees and services, and a $2.5 million increase in utilities expense. These increases in operating expenses were principally due to an increase in operating activity. Operating expenses also increased by $1.8 million due to the costs associated with the transfer of equipment to the Phantom processing facility.

  - Depreciation and amortization in the Oklahoma segment decreased $2.5 million primarily due to a $4.8 million decrease from the transfer of equipment related to the Phantom and Warhorse processing facilities. This decrease was partially offset by a $2.3 million increase in depreciation from additional assets placed in service.

- *North Texas Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased \$161.3 million and \$99.9 million, respectively, resulting in an increase in adjusted gross margin in the North Texas segment of \$61.4 million. Adjusted gross margin, excluding derivative activity, increased \$39.2 million, which was primarily due to the Barnett Shale Acquisition on July 1, 2022. Derivative activity associated with our North Texas segment increased adjusted gross margin by \$22.2 million, which included \$0.5 million from increased realized losses and \$22.7 million from increased unrealized gains.

  - Operating expenses in the North Texas segment increased \$15.4 million primarily due to a \$6.4 million increase in materials and supplies expense, a \$2.0 million increase in ad valorem taxes, a \$1.8 million increase in construction fees and services, a \$1.5 million increase in utilities expense, and a \$1.4 million increase in labor and benefits costs. These increases in operating expenses were principally due to an increase in operating activity from the Barnett Shale Acquisition in July 2022. Additionally, \$1.3 million of sales and use tax refunds reduced operating expenses in the fourth quarter of 2021, which were not available in 2022.

  - Depreciation and amortization in the North Texas segment increased \$6.8 million primarily due to an \$8.2 million increase in depreciation related to the Barnett Shale Acquisition in July 2022. This increase was partially offset by a \$1.4 million decrease in depreciation from assets reaching the end of their depreciable lives.

- *Corporate Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased \$700.2 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.

  - Depreciation and amortization in the Corporate segment decreased \$2.5 million primarily due to assets reaching the end of their depreciable lives.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives but involve an interpretation and implementation of existing rules and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

Our critical accounting policies are discussed below. See “Item 2. Financial Statements and Supplementary Data—Note 2” for further details on our accounting policies.

Valuation and Impairment of Long-Lived Assets

We evaluate long-lived assets, including property and equipment, intangible assets, equity method investments, and lease right-of-use assets, for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management’s best estimate based on reasonable and supportable assumptions. Management’s estimate of future cash flows is subject to uncertainty due to the changing business environment, volatility of commodity prices, and a number of other factors that are beyond our ability to consistently predict. Management updates their estimated future cash flows throughout the year and a potential impairment is highly sensitive to unfavorable changes in the underlying estimated cash flows. 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. For additional information about our long-lived asset impairment tests, refer to “Item 2. Financial Statements and Supplementary Data—Note 2.”

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $968.3 million for the year ended December 31, 2023 compared to $858.2 million for the year ended December 31, 2022. Operating cash flows before working capital and changes in working capital for the comparative periods were as follows (in millions):

	Year Ended December 31,	
	2023	2022
Operating cash flows before working capital	$ 1,140.7	$ 1,101.3
Changes in working capital	(172.4)	(243.1)

Operating cash flows before changes in working capital increased $39.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. The primary contributor to the increase in operating cash flows before working capital is as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity derivative activity, utility credits redeemed or earned, and unit-based compensation, increased $60.2 million. The increase in gross margin is due to a $125.1 million increase in adjusted gross margin, excluding non-cash commodity derivative activity, which was partially offset by a $64.9 million increase in operating expenses, excluding utility credits redeemed or earned and unit-based compensation. For more information regarding the changes in gross margin for the year ended December 31, 2023 compared to the year ended December 31, 2022, see "Results of Operations."

This increase was partially offset by a $27.7 million increase in interest expense, net of interest income, excluding amortization of debt issue costs and net discounts.

The changes in working capital for the year ended December 31, 2023 compared to the year ended December 31, 2022 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments, changes in inventory balances attributable to normal operating fluctuations, and fluctuations in accrued revenue and accrued purchases.

Cash Flows from Investing Activities. Net cash used in investing activities was $440.5 million for the year ended December 31, 2023 compared to $773.0 million for the year ended December 31, 2022. Our primary investing activities consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
Additions to property and equipment (1)	$ (445.7)	$ (332.5)
Acquisitions, net of cash acquired (2)	—	(390.3)
Contributions to unconsolidated affiliate investments (3)	(68.1)	(65.9)
Proceeds from disposition of assets (4)	73.1	12.8

(1) The increase in capital expenditures was due to expansion projects to accommodate increased volumes on our systems.
(2) Represents cash paid for the Barnett Shale Acquisition in July 2022 and the Central Oklahoma Acquisition in December 2022.
(3) Represents contributions to the Matterhorn JV and GCF. See "Item 2. Financial Statements and Supplementary Data—Note 9" for more information regarding the contributions to unconsolidated affiliate investments.
(4) Primarily relates to the divestitures of our ORV assets in our Louisiana segment in November 2023 and the sale of compressor units associated with our ORV assets in December 2022. See "Item 2. Financial Statements and Supplementary Data—Note 3" for additional information on the divestitures of our ORV assets in our Louisiana segment in November 2023.

Cash Flows from Financing Activities. Net cash used in financing activities was $521.7 million for the year ended December 31, 2023 compared to $88.8 million for the year ended December 31, 2022. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
Net borrowings (repayments) on the AR Facility (1)	$ (200.0)	$ 150.0
Net borrowings on related party debt (1)	42.0	940.0
Net repurchases of our senior unsecured notes (1)	—	(727.8)
Payment of installment payable for Amarillo Rattler Acquisition (2)	—	(10.0)
Payment of inactive easement commitment (3)	—	(10.0)
Distributions to common units (4)	(236.2)	(221.4)
Distributions to Series B Preferred Unitholders (5)	(63.1)	(70.4)
Distributions to Series C Preferred Unitholders (5)	(35.7)	(23.4)
Distributions to non-controlling interests (6)	(73.8)	(69.1)
Payment to redeem mandatorily redeemable non-controlling interest (7)	(10.5)	—
Redemption of Series B Preferred Units (5)	—	(50.5)
Repurchases of Series C Preferred Units (5)	(13.1)	(15.2)
Contributions from non-controlling interests (8)	69.5	32.9

(1) See “Item 2. Financial Statements and Supplementary Data—Note 7” for more information regarding the AR Facility, our related party debt, and the issuance of new senior unsecured notes by ENLC and repurchases of our senior unsecured notes.
(2) Consideration for the Amarillo Rattler Acquisition included an installment payable, which was paid on April 30, 2022.
(3) Amount related to an inactive easement commitment, which was paid in August 2022.
(4) ENLC owns all of our outstanding common units, and we make quarterly distributions to ENLC related to its ownership of our common units.
(5) See “Item 2. Financial Statements and Supplementary Data—Note 8” for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units and information on the partial redemption of the Series B Preferred Units and the repurchases of the Series C Preferred Units.
(6) 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.
(7) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries. See “Item 2. Financial Statements and Supplementary Data—Note 5” for more information regarding the redemption.
(8) Represents contributions from NGP to the Delaware Basin JV.

Capital Requirements

As of December 31, 2023, the following table summarizes our expected capital requirements for 2024 (in millions):

Capital expenditures, net to ENLK (1)	$ 435
Operating expenses associated with the relocation of processing facilities, net to ENLK (2)(3)	15
Contributions to unconsolidated affiliate investments (3)	10
Total	$ 460

(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.
(3) Includes contributions made to our GCF investment and the Matterhorn JV.

Our primary capital projects for 2024 include the relocation of the Cowtown processing plant, CCS-related initiatives, contributions to unconsolidated affiliate investments, continued development of our existing systems through well connects, and other low-cost development projects. We expect to fund our 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 December 31, 2023 and 2022.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2023 is as follows (in millions):

	Payments Due by Period						
	Total	2024	2025	2026	2027	2028	Thereafter
ENLK's senior unsecured notes	$2,310.5	$ 97.9	$ 421.6	$ 491.0	$ —	$ —	$ 1,300.0
Related party debt (1)(2)	1,998.7	—	—	—	—	500.0	1,498.7
AR Facility (2)	300.0	—	300.0	—	—	—	—
Interest payable on fixed long-term debt obligations (2)	2,359.6	233.0	222.1	213.3	189.5	175.4	1,326.3
Acquisition contingent consideration (3)	6.7	0.3	1.2	4.9	0.3	—	—
Operating lease obligations	123.8	31.8	24.4	15.2	9.1	8.7	34.6
Purchase obligations	9.9	9.9	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (4)	929.5	94.5	113.4	100.1	88.0	84.9	448.6
Total contractual obligations	$8,038.7	$ 467.4	$1,082.7	$ 824.5	$ 286.9	$ 769.0	$ 4,608.2

(1) Related party debt includes borrowings under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes.
(2) 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 2. Financial Statements and Supplementary Data—Note 7" for more information regarding the Revolving Credit Facility and the AR Facility.
(3) The estimated fair value of the contingent consideration for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition was calculated in accordance with the fair value guidance contained in ASC 820. There are a number of assumptions and estimates factored into these fair values and actual contingent consideration payments could differ from these estimated fair values. See "Item 2. Financial Statements and Supplementary Data—Note 12" for additional 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 2024 are expected to be funded from cash flows generated from our operations.

Indebtedness

AR Facility. As of December 31, 2023, the AR Facility had a borrowing base of $404.2 million and there were $300.0 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.

Related Party Debt. We have a related party debt arrangement with ENLC to fund our operations and growth capital expenditures. The interest we are charged for borrowings made through the related party arrangement is substantially the same as interest charged to ENLC on borrowings from third party lenders. The indebtedness under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes was incurred by ENLC but is guaranteed by us. Therefore, the covenants in the agreements governing such indebtedness described in "Item 2. Financial Statements and Supplementary Data—Note 7" affect balances owed by us on the related party debt. As of December 31, 2023, we had $1,996.0 million in outstanding borrowings under the related party debt arrangement related to the 2028 Notes, the 2029 Notes, and the 2030 Notes.

Senior Unsecured Notes. As of December 31, 2023, we had $2.3 billion in aggregate principal amount of outstanding senior unsecured notes maturing from 2024 to 2047, of which $97.9 million matures on April 1, 2024 and is classified as "Current maturities of long-term debt" on the consolidated balance sheet.

See "Item 2. Financial Statements and Supplementary Data—Note 7" for more information on our outstanding debt.

Credit Risk

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Inflation

See "Item 1. Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business—Inflation" for more information.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in substantial compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Item 1. Business—Environmental Matters" in ENLC's Annual Report on Form 10-K for the year ended December 31, 2023, filed with the Commission on February 21, 2024.

Contingencies

See "Item 2. Financial Statements and Supplementary Data—Note 13."

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2023 and have determined that none had a material impact to our consolidated financial statements.

Disclosure Regarding Forward-Looking Statements

This Annual Report 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 Annual Report 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, 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, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, the impact of weather related events on us and our financial results and operations, and other statements that are not historical facts. Factors that could result in such differences or otherwise materially affect our financial condition, results of operations, or cash flows, include, without limitation, (a) potential conflicts of interest of GIP with us and the potential for GIP to favor GIP's own interests to the detriment of our unitholders, (b) GIP's ability to compete with us and the fact that it is not required to offer us the opportunity to acquire additional assets or businesses, (c) a default under GIP's credit facility could result in a change in control of us and a default under ENLC's Revolving Credit Facility and certain of our other debt, (d) the dependence on key customers for a substantial portion of the natural gas and crude that we gather, process, and transport, (e) developments that materially and adversely affect our key customers or other customers, (f) adverse developments in the midstream business that may reduce our ability to make distributions, (g) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (h) decreases in the volumes that we gather, process, fractionate, or transport, (i) increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices, (j) our ability to receive or renew required permits and other approvals, (k) increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing resulting in increased costs and reductions or delays in natural gas production by our customers, (l) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (m) changes in the availability and cost of capital, (n) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (o) our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities, (p) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (q) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (r) impairments to goodwill, long-lived assets and equity method investments, (s) construction risks in our major development projects, (t) challenges we may face in 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 Annual Report, the risk factors set forth in “Item 1A. Risk Factors” in ENLC’s 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 2. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

EnLink Midstream Partners, LP and Subsidiaries Financial Statements:

Report of Independent Registered Public Accounting Firm

To the Partners of EnLink Midstream Partners, LP
and Board of Directors of EnLink Midstream GP, LLC:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries (the Partnership) as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of long-lived assets for impairment triggering events

As discussed in Note 2 to the consolidated financial statements, the Partnership evaluates property, plant, and equipment and intangible assets (collectively, long-lived assets) for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable (triggering events). Triggering events include significant changes in the use of the asset group, current and/or historical operating results that are significantly less than forecasted results, negative industry or economic trends including changes in commodity prices, significant adverse changes in legal or regulatory factors, or an expectation that it is more likely than not that an asset group will be sold before the end of its useful life. The carrying value of property, plant, and equipment and intangible assets as of December 31, 2023, was $6.41 billion and $0.79 billion, respectively.

We identified the evaluation of long-lived assets for impairment triggering events as a critical audit matter. A higher degree of subjective auditor judgement was required to evaluate the impact of forecasted prices for oil, natural gas, and natural gas liquids (NGL) on the recoverability of the Partnership's long-lived assets as sustained declines in commodity prices could result in decreases in volumes gathered, processed, fractionated, and transported by the Partnership.

The following are the primary procedures we performed to address the critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Partnership's process to evaluate triggering events related to the impairment of long-lived assets. This included controls related to the Partnership's selection of forecasted prices for oil, natural gas, and NGL and the identification and assessment of the potential impacts of such prices on oil, natural gas, and NGL volumes available to the Partnership. We examined the Partnership's analysis of potential triggering events for long-lived assets and evaluated the Partnership's responses to the factors identified by inspecting publicly available information regarding rig counts and producer drilling outlook. We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the forecasted prices for oil, natural gas, and NGL used in the Partnership's analysis by comparing such prices to commodity price curves prepared by third parties.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2013

Dallas, Texas
February 21, 2024

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Balance Sheets
(In millions, except unit data)

	December 31, 2023	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28.7	$ 22.6
Accounts receivable:		
Trade receivables (1)	85.9	89.2
Accrued revenue and other	581.4	636.0
Related party	506.8	217.4
Fair value of derivative assets	76.9	68.4
Other current assets	65.5	167.3
Total current assets	1,345.2	1,200.9
Property and equipment, net of accumulated depreciation of $5,137.2 and $4,774.5, respectively	6,407.0	6,556.0
Intangible assets, net of accumulated amortization of $1,051.2 and $923.6, respectively	793.6	921.2
Investment in unconsolidated affiliates	150.5	90.2
Fair value of derivative assets	27.0	2.9
Other assets, net	112.2	97.0
Total assets	$ 8,835.5	$ 8,868.2
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 126.5	$ 126.9
Accrued natural gas, NGLs, condensate, and crude oil purchases	428.0	476.0
Fair value of derivative liabilities	62.7	42.9
Current maturities of long-term debt	97.9	—
Other current liabilities	239.2	198.6
Total current liabilities	954.3	844.4
Long-term debt, net of unamortized issuance cost	4,471.0	4,723.5
Other long-term liabilities	98.0	94.0
Deferred tax liability	3.9	3.6
Fair value of derivative liabilities	26.7	2.7
Partners' equity:		
Common unitholder (144,358,720 units issued and outstanding)	1,423.4	1,373.5
Series B Preferred Unitholders (54,575,638 and 54,168,359 units issued and outstanding, respectively)	803.5	799.2
Series C Preferred Unitholders (366,500 and 381,000 units issued and outstanding, respectively)	367.3	380.4
General partner interest (1,594,974 equivalent units outstanding)	223.4	220.2
Accumulated other comprehensive income	0.9	—
Non-controlling interest	463.1	426.7
Total partners' equity	3,281.6	3,200.0
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 8,835.5	$ 8,868.2

(1) There was no allowance for bad debt at December 31, 2023. Includes allowance for bad debt of $0.1 million at December 31, 2022.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Operations
(In millions)

	Year Ended December 31,		
	2023	2022	2021
Revenues:			
Product sales	$ 5,755.6	$ 8,564.9	$ 5,994.0
Midstream services	1,123.8	962.9	851.0
Gain (loss) on derivative activity	20.7	14.3	(159.1)
Total revenues	6,900.1	9,542.1	6,685.9
Operating costs and expenses:			
Cost of sales, exclusive of operating expenses and depreciation and amortization	4,856.1	7,572.8	5,189.9
Operating expenses	558.2	524.9	362.9
Depreciation and amortization	657.1	639.4	607.5
Impairments	20.7	—	0.8
(Gain) loss on disposition of assets	(0.3)	18.0	(1.5)
General and administrative	113.7	124.8	107.5
Total operating costs and expenses	6,205.5	8,879.9	6,267.1
Operating income	694.6	662.2	418.8
Other income (expense):			
Interest expense, net of interest income	(271.7)	(245.0)	(225.6)
Loss on extinguishment of debt	—	(6.2)	—
Loss from unconsolidated affiliate investments	(8.2)	(5.6)	(11.5)
Other income	—	0.8	0.2
Total other expense	(279.9)	(256.0)	(236.9)
Income before non-controlling interest and income taxes	414.7	406.2	181.9
Income tax benefit (expense)	(0.8)	1.5	(0.2)
Net income	413.9	407.7	181.7
Net income attributable to non-controlling interest	40.7	46.2	40.4
Net income attributable to ENLK	$ 373.2	$ 361.5	$ 141.3

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2023	2022	2021
Net income	$ 413.9	$ 407.7	$ 181.7
Unrealized gain on designated cash flow hedge	0.9	1.9	18.2
Comprehensive income	414.8	409.6	199.9
Comprehensive income attributable to non-controlling interest	40.7	46.2	40.4
Comprehensive income attributable to ENLK	$ 374.1	$ 363.4	$ 159.5

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Changes in Partners' Equity
(In millions)

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	$	$	$
Balance, December 31, 2020	$ 1,418.1	144.4	$ 896.7	60.2	$ 395.1	0.4	$ 216.0	1.6	$ (20.1)	$ 625.8	$ 3,531.6	$ —
Unit-based compensation	—	—	—	—	—	—	23.6	—	—	—	23.6	—
Distributions	(186.8)	—	(68.9)	0.6	(24.0)	—	—	—	—	(54.6)	(334.3)	(0.2)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	3.2	3.2	—
Unrealized gain on designated cash flow hedge	—	—	—	—	—	—	—	—	18.2	—	18.2	—
Fair value adjustment related to redeemable non-controlling interest	(0.2)	—	—	—	—	—	—	—	—	—	(0.2)	0.2
Redemption of Series B Preferred Units	—	—	(50.0)	(3.3)	—	—	—	—	—	—	(50.0)	—
Redemption of the EMO Preferred B Units	—	—	—	—	—	—	—	—	—	(198.1)	(198.1)	—
Net income (loss)	67.0	—	73.0	—	24.0	—	(22.7)	—	—	40.4	181.7	—
Balance, December 31, 2021	1,298.1	144.4	850.8	57.5	395.1	0.4	216.9	1.6	(1.9)	416.7	3,175.7	—
Unit-based compensation	—	—	—	—	—	—	31.8	—	—	—	31.8	—
Distributions	(221.4)	—	(70.4)	—	(23.4)	—	—	—	—	(69.1)	(384.3)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	32.9	32.9	—
Unrealized gain on designated cash flow hedge	—	—	—	—	—	—	—	—	1.9	—	1.9	—
Redemption of Series B Preferred Units	—	—	(50.5)	(3.3)	—	—	—	—	—	—	(50.5)	—
Repurchase of Series C Preferred Units	—	—	—	—	(15.2)	—	—	—	—	—	(15.2)	—
Net income (loss)	296.8	—	69.3	—	23.9	—	(28.5)	—	—	46.2	407.7	—
Balance, December 31, 2022	$ 1,373.5	144.4	$ 799.2	54.2	$ 380.4	0.4	$ 220.2	1.6	$ —	$ 426.7	$ 3,200.0	$ —

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Changes in Partners' Equity (continued)
(In millions)

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units	$	Units	$	$	$
Balance, December 31, 2022	$ 1,373.5	144.4	$ 799.2	54.2	$ 380.4	0.4	$ 220.2	1.6	$ —	$ 426.7	$ 3,200.0
Unit-based compensation	—	—	—	—	—	—	19.2	—	—	—	19.2
Distributions	(236.2)	—	(63.1)	0.4	(35.7)	—	—	—	—	(73.8)	(408.8)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	69.5	69.5
Unrealized gain on designated cash flow hedge	—	—	—	—	—	—	—	—	0.9	—	0.9
Repurchase of Series C Preferred Units	—	—	—	—	(13.1)	—	—	—	—	—	(13.1)
Net income (loss)	286.1	—	67.4	—	35.7	—	(16.0)	—	—	40.7	413.9
Balance, December 31, 2023	$ 1,423.4	144.4	$ 803.5	54.6	$ 367.3	0.4	$ 223.4	1.6	$ 0.9	$ 463.1	$ 3,281.6

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 413.9	$ 407.7	$ 181.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	657.1	639.4	607.5
(Gain) loss on disposition of assets	(0.3)	18.0	(1.5)
Non-cash unit-based compensation	19.2	30.4	25.3
Utility credits redeemed (earned)	1.5	31.1	(32.6)
Non-cash (gain) loss on derivatives recognized in net income	12.1	(38.3)	10.3
Loss on extinguishment of debt	—	6.2	—
Amortization of debt issuance costs and net discount of senior unsecured notes	6.4	5.5	5.2
Amortization of designated cash flow hedge	—	1.9	12.5
Loss from unconsolidated affiliate investments	8.2	5.6	11.5
Impairments	20.7	—	0.8
Other operating activities	1.9	(6.2)	(4.6)
Changes in assets and liabilities, net of the effects of acquisitions:			
Accounts receivable, accrued revenue, and other	(231.3)	(72.7)	(259.0)
Product inventory, prepaid expenses, and other	96.4	(115.8)	(14.0)
Accounts payable, accrued product purchases, and other accrued liabilities	(37.5)	(54.6)	317.2
Net cash provided by operating activities	968.3	858.2	860.3
Cash flows from investing activities:			
Additions to property and equipment	(445.7)	(332.5)	(184.0)
Acquisitions, net of cash acquired	—	(390.3)	(56.7)
Proceeds from disposition of assets	73.1	12.8	4.8
Contributions to unconsolidated affiliate investments	(68.1)	(65.9)	—
Other investing activities	0.2	2.9	4.5
Net cash used in investing activities	(440.5)	(773.0)	(231.4)
Cash flows from financing activities:			
Proceeds from borrowings	2,843.4	4,911.5	1,234.5
Repayments on borrowings	(3,001.4)	(4,549.3)	(1,469.5)
Payment of installment payable for the Amarillo Rattler Acquisition	—	(10.0)	—
Payment of inactive easement commitment	—	(10.0)	—
Distributions to common unitholder	(236.2)	(221.4)	(186.8)
Distributions to non-controlling interests	(73.8)	(69.1)	(54.8)
Distributions to Series B Preferred Unitholders	(63.1)	(70.4)	(68.9)
Distributions to Series C Preferred Unitholders	(35.7)	(23.4)	(24.0)
Payment to redeem mandatorily redeemable non-controlling interest	(10.5)	—	—
Redemption of Series B Preferred Units	—	(50.5)	(50.0)
Repurchases of Series C Preferred Units	(13.1)	(15.2)	—
Redemption of the EMO Preferred B Units	—	—	(198.1)
Contributions from non-controlling interests	69.5	32.9	3.2
Repayment of the EORV note receivable	—	—	170.0
Other financing activities	(0.8)	(13.9)	2.1
Net cash used in financing activities	(521.7)	(88.8)	(642.3)
Net increase (decrease) in cash and cash equivalents	6.1	(3.6)	(13.4)
Cash and cash equivalents, beginning of period	22.6	26.2	39.6
Cash and cash equivalents, end of period	$ 28.7	$ 22.6	$ 26.2

See accompanying notes to consolidated financial statements.

(1) Organization and Nature of Business

(a) Organization of Business

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through the Operating Partnership and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is a direct, wholly owned subsidiary of ENLC. ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." ENLC's managing member is a wholly owned subsidiary of GIP. As of December 31, 2023, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 46.2% of the outstanding limited liability company interests in ENLC. In addition to their equity interests in ENLC, GIP maintains control over the managing member of ENLC.

(b) Nature of Business

We primarily focus on providing midstream energy services, including:

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

As of December 31, 2023, our midstream energy asset network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.8 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.

Our natural gas gathering business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or near producing wells and transport it to our processing plants or to larger diameter pipelines for further transmission. Our processing plants remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, marketers, and pipelines. We also store natural gas and NGLs on behalf of third parties for a fee or to balance our own purchases and sales in marketing natural gas and NGLs for our customers.

Our large diameter natural gas transmission pipelines provide access to multiple domestic production basins to a variety of customers, such as industrial end-users, LNG facilities, and utilities. Our large diameter natural gas transmission pipelines are connected to our gathering systems or third party gathering systems, natural gas transmission pipeline systems, and natural gas storage caverns.

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

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

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

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP. All significant intercompany balances and transactions have been eliminated in consolidation. 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 partners' equity or net income.

(b) Management's Use of Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(c) Revenue Recognition

We generate the majority of our revenues from midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services, and marketing, through various contractual arrangements, which include fee-based contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Revenues from both "Product sales" and "Midstream services" represent revenues from contracts with customers and are reflected on the consolidated statements of operations as follows:

- *Product sales*—Product sales represent the sale of natural gas, NGLs, crude oil, and condensate where the product is purchased and resold in connection with providing our midstream services as outlined above.

- *Midstream services*—Midstream services represent all other revenue generated as a result of performing our midstream services outlined above.

Evaluation of Our Contractual Performance Obligations

Performance obligations in our contracts with customers include:

- promises to perform midstream services for our customers over a specified contractual term and/or for a specified volume of commodities; and

- promises to sell a specified volume of commodities to our customers.

The identification of performance obligations under our contracts requires a contract-by-contract evaluation of when control, including the economic benefit, of commodities transfers to and from us (if at all). For contracts where control of commodities transfers to us before we perform our services, we generally have no performance obligation for our services, and accordingly, we do not consider these revenue-generating contracts. Based on the control determination, all contractually-stated fees that are deducted from our payments to producers or other suppliers for commodities purchased are reflected as a reduction in the cost of such commodity purchases. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating and recognize the fees received for satisfying them as midstream services revenues over time as we satisfy our performance obligations. For contracts where control of commodities never transfers to us and we simply earn a fee for our services, we recognize these fees as midstream services revenues over time as we satisfy our performance obligations.

We also evaluate our contractual arrangements that contain a purchase and sale of commodities under the principal/agent provisions in ASC 606. For contracts where we possess control of the commodity and act as principal in the purchase and sale, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as an agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract.

Accounting Methodology for Certain Contracts

For NGL contracts in which we purchase raw mix NGLs and subsequently transport, fractionate, and market the NGLs, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of the commodities purchased. We account for the contractually-stated fees on the consolidated statements of operations as a reduction of cost of sales of such commodities purchased upon receipt of the raw mix NGLs, because we determined that the control, including the economic benefit, of commodities has passed to us once the raw mix NGLs have been purchased from the customer. Upon sale of the NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

For our crude oil and condensate service contracts in which we purchase the commodity, we utilize a similar approach under as outlined above for NGL contracts.

For our natural gas gathering and processing contracts in which we perform midstream services and also purchase the natural gas, we determine if economic control of the commodities has passed from the producer to us before or after we perform our services (if at all). Control is assessed on a contract-by-contract basis by analyzing each contract's provisions, which can include provisions for: the customer to take its residue gas and/or NGLs in-kind; fixed or actual NGL or keep-whole recovery; commodity purchase prices at weighted average sales price or market index-based pricing; and various other contract-specific considerations. Based on this control assessment, our gathering and processing contracts fall into two primary categories:

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas passes to us when the natural gas is brought into our system, we do not consider these contracts to contain performance obligations for our services. As control of the natural gas passes to us prior to performing our gathering and processing services, we are, in effect, performing our services for our own benefit. Based on this control determination, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the natural gas, rather than being recorded as midstream services revenue. Upon sale of the residue gas and/or NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased, net of fees.

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas does not pass to us until after the natural gas has been gathered and processed, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenues over time as we satisfy our performance obligations.

For midstream service contracts related to NGL, crude oil, or natural gas gathering and processing in which there is no commodity purchase or control of the commodity never passes to us and we simply earn a fee for our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenue over time as we satisfy our performance obligations.

For our natural gas transmission contracts, we determined that control of the natural gas never transfers to us and we simply earn a fee for our services. Therefore, we recognize these fees as midstream services revenue over time as we satisfy our performance obligations.

We also evaluate our commodity marketing contracts, under which we purchase and sell commodities in connection with our natural gas, NGL, and crude and condensate midstream services, pursuant to ASC 606, including the principal/agent provisions. For contracts in which we possess control of the commodity and act as principal in the purchase and sale of commodities, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract.

Satisfaction of Performance Obligations and Recognition of Revenue

For our commodity sales contracts, we satisfy our performance obligations at the point in time at which the commodity transfers from us to the customer. This transfer pattern aligns with our billing methodology. Therefore, we recognize product sales revenue at the time the commodity is delivered and in the amount to which we have the right to invoice the customer. For our midstream service contracts that contain revenue-generating performance obligations, we satisfy our performance obligations over time as we perform the midstream service and as the customer receives the benefit of these services over the term of the contract. We recognize revenue in the amount to which the entity has a right to invoice, since we have a right to consideration from our customer in an amount that corresponds directly with the value to the customer of our performance completed to date. Accordingly, we continue to recognize revenue over time as our midstream services are performed.

We generally accrue one month of sales and the related natural gas, NGL, condensate, and crude oil purchases and reverse these accruals when the sales and purchases are invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. We typically receive payment for invoiced amounts within one month, depending on the terms of the contract. Prior to issuing our financial statements, we review our revenue and purchases estimates based on available information to determine if adjustments are required. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Minimum Volume Commitments and Firm Transportation Contracts

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

Contractually Committed Fees	**Commitments**
2024	$ 145.0
2025	126.2
2026	126.6
2027	105.9
2028	97.1
Thereafter	1,032.9
Total	$ 1,633.7

(d) Imbalance Accounting

Quantities of natural gas, NGLs, or crude and condensate over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas, NGLs, or crude and condensate. We had imbalance payables of $6.3 million and $17.3 million at December 31, 2023 and 2022, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of $8.0 million and $20.2 million at December 31, 2023 and 2022, respectively, which are carried at the lower of cost or market value. Imbalance receivables and imbalance payables are included in the line items "Accrued revenue and other" and "Accrued natural gas, NGLs, condensate, and crude oil purchases," respectively, on the consolidated balance sheets.

(e) Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(f) Income Taxes

Certain of our operations are subject to income taxes assessed by the federal and various state jurisdictions in the U.S. Additionally, certain of our operations are subject to tax assessed by the state of Texas that is computed based on modified gross margin as defined by the State of Texas. The Texas franchise tax is presented as income tax expense in the accompanying statements of operations.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. If the future utilization of some portion of carryforwards is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense. We record deferred tax assets and liabilities on a net basis on the consolidated balance sheets, with deferred tax assets included in "Other assets, net" and deferred tax liabilities included in "Deferred tax liability."

(g) Natural Gas, Natural Gas Liquids, Crude Oil, and Condensate Inventory

Our inventories of products consist of natural gas, NGLs, crude oil, and condensate. We report these assets at the lower of cost or market value which is determined by using the weighted average cost method.

(h) Property and Equipment

Property and equipment are stated at historical cost less accumulated depreciation. Assets acquired in a business combination are recorded at fair value. Routine repairs and maintenance are charged against income when incurred. Renewals and improvements that extend the useful life or improve the function of the properties are capitalized.

The components of property and equipment, net of accumulated depreciation are as follows (in millions):

	Year Ended December 31,	
	2023	2022
Transmission assets	$ 1,459.5	$ 1,452.0
Gathering systems	5,472.4	5,370.0
Natural gas processing plants and fractionation facilities	4,279.1	4,237.8
Other property and equipment	90.1	165.0
Construction in process	243.1	105.7
Property and equipment	11,544.2	11,330.5
Accumulated depreciation	(5,137.2)	(4,774.5)
Property and equipment, net of accumulated depreciation	$ 6,407.0	$ 6,556.0

Depreciation Expense. Depreciation is calculated using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	20 - 25 years
Gathering systems	20 - 25 years
Natural gas processing plants and fractionation facilities	20 - 25 years
Other property and equipment	3 - 25 years

Gain or Loss on Disposition. Upon the disposition or retirement of property and equipment, any gain or loss is recognized in operating income in the consolidated statements of operations. For the years ended December 31, 2023, 2022, and 2021, dispositions primarily related to the sale of certain non-core assets. The (gain) loss on disposition of assets is as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Net book value of assets disposed	$ 72.9	$ 30.8	$ 3.3
Proceeds from sales	(73.1)	(12.8)	(4.8)
Insurance recoveries	(0.1)	—	—
(Gain) loss on disposition of assets	$ (0.3)	$ 18.0	$ (1.5)

Impairment Review. 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. Triggering events include, but are not limited to, significant changes in the use of the asset group, current operating results that are significantly less than forecasted results, and negative industry or economic trends, including changes in commodity prices, significant adverse changes in legal or regulatory factors, or an expectation that it is more likely than not that an asset group will be sold before the end of its useful life. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. 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.

When determining whether impairment of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding:

- the future fee-based rate of new business or contract renewals;
- the purchase and resale margins on natural gas, NGLs, crude oil, and condensate;
- the volume of natural gas, NGLs, crude oil, and condensate available to the asset;
- markets available to the asset;
- operating expenses; and
- future natural gas, NGLs, crude oil, and condensate prices.

The estimated volume of natural gas, NGLs, crude oil, and condensate available to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, crude oil, and condensate prices. Projections of natural gas, NGL, crude oil, and condensate volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions or demand for our products in regions in which our markets are located;
- the availability and prices of natural gas, NGLs, crude oil, and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, NGLs, crude oil, and condensate exploration and production activities will not occur or be successful;
- our dependence on certain key customers, producers, and transporters of natural gas, NGLs, crude oil, and condensate; and
- competition from other midstream companies, including major energy companies.

We recognized impairment expense related to property and equipment as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Property and equipment impairment (1)	$ 20.7	$ —	$ 0.6

(1) During the third quarter of 2023, we identified changes in our outlook for future cash flows and the anticipated use of certain ORV crude assets in our Louisiana segment. We determined that the carrying amounts of these assets exceeded their fair values, based on market inputs and certain assumptions.

(i) Comprehensive Income (Loss)

Comprehensive income (loss) is comprised of net income (loss) and the effective portion of gains or losses on derivative financial instruments that qualify as cash flow hedges pursuant to ASC 815. For additional information about the effect of financial instruments on comprehensive income (loss), see "Note 11—Derivatives."

(j) Equity Method of Accounting

We account for investments where we do not control the investment but have the ability to exercise significant influence using the equity method of accounting. Under this method, unconsolidated affiliate investments are initially carried at the acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

We evaluate our unconsolidated affiliate investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable. We recognize impairments of our investments as a loss from unconsolidated affiliates on our consolidated statements of operations.

For additional information, see "Note 9—Investment in Unconsolidated Affiliates."

(k) Non-controlling Interests

We account for investments where we control the investment using the consolidation method of accounting. Under this method, we consolidate all the assets and liabilities of an investment on our consolidated balance sheets and record non-controlling interest for the portion of the investment that we do not own. We include all of an investment's results of operations on our consolidated statements of operations and record income attributable to non-controlling interests for the portion of the investment that we do not own.

Our non-controlling interests for the years ended December 31, 2023, 2022, and 2021 are comprised of NGP's 49.9% share of the Delaware Basin JV and Marathon Petroleum Corporation's 50.0% share of the Ascension JV. ENLK's non-controlling interests also related to ENLC's ownership of EORV until ENLC's redemption of the EMO Preferred B Units in December 2021. See "Note 5—Related Party Transactions" for additional information regarding the sale of our ownership of EORV to ENLC and ENLC's redemption of EMO Preferred B Units.

Certain of our joint venture arrangements provide our joint venture partners with the right, under certain circumstances, to cause us to purchase their interest in the joint venture or to seek to sell the entire joint venture. For example, at any time after June 30, 2025, NGP has the right to cause the Delaware Basin JV to sell all of the outstanding interests or assets of the Delaware Basin JV for the best available price; provided that, if NGP exercises this right, we are permitted to purchase NGP's interest at a certain call price.

(l) 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 range from ten to twenty years. In accordance with ASC 350, *Intangibles—Goodwill and Other*, we evaluate intangibles for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. For additional information regarding our intangible assets, including our assessment of intangible assets for impairment, see "Note 4—Intangible Assets."

(m) Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with our assets. Such liabilities are recognized when there is a legal obligation associated with the retirement of the assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Our retirement obligations include estimated environmental remediation costs that arise from normal operations and are associated with the retirement of the long-lived assets. The asset retirement cost is depreciated using the straight-line depreciation method similar to that used for the associated property and equipment.

(n) Leases

We account for leases under ASC 842 whereby we recognized leases on our consolidated balance sheet by recording a right-of-use asset and lease liability.

We evaluate new contracts at inception to determine if the contract conveys the right to control the use of an identified asset for a period of time in exchange for periodic payments. A lease exists if we obtain substantially all of the economic benefits of an asset, and we have the right to direct the use of that asset. When a lease exists, we record a right-of-use asset that represents our right to use the asset over the lease term and a lease liability that represents our obligation to make payments over the lease term. Lease liabilities are recorded at the sum of future lease payments discounted by the collateralized rate we could obtain to lease a similar asset over a similar period, and right-of-use assets are recorded equal to the corresponding lease liability, plus any prepaid or direct costs incurred to enter the lease, less the cost of any incentives received from the lessor. For more information, see "Note 6—Leases."

(o) Derivatives

We use derivative instruments to hedge against changes in cash flows related to product price. We generally determine the fair value of swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet at the fair value of derivative assets or liabilities in accordance with ASC 815. Changes in fair value of derivative instruments are recorded in gain or loss on derivative activity in the period of change.

Realized gains and losses on commodity-related derivatives are recorded as gain or loss on derivative activity within revenues in the consolidated statements of operations in the period incurred. Settlements of derivatives are included in cash flows from operating activities.

We periodically enter into interest rate swaps to hedge variability in interest rates and effectively lock in the benchmark interest rate at the inception of the swap. The change in fair value of interest rate swaps 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).

For additional information, see “Note 11—Derivatives.”

(p) Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than our exposure to key customers discussed below, since our customers represent a broad and diverse group of energy marketers and end-users.

The following customers individually represented greater than 10% of our consolidated revenues for the years ended December 31, 2023, 2022, or 2021. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Year Ended December 31,		
	2023	2022	2021
Dow Hydrocarbons and Resources LLC	10.4 %	14.2 %	14.5 %
Marathon Petroleum Corporation	19.3 %	14.7 %	13.4 %

We continually monitor and review the credit exposure of our counterparties based on various credit quality indicators and metrics. We obtain letters of credit or other appropriate security when considered necessary to limit the risk of loss. We record reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers and we do not expect to experience significant levels of default on our trade accounts receivable. As of December 31, 2023, we had no reserve for uncollectible receivables. For the year ended December 31, 2022, we had a $0.1 million reserve for uncollectible receivables.

(q) Environmental Costs

Environmental expenditures are expensed or capitalized depending on the nature of the expenditures and the future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. Environmental expenditures were not material for the years ended December 31, 2023, 2022, and 2021.

(r) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with a loss contingency are expensed as incurred. For additional information, see “Note 13—Commitments and Contingencies.”

(s) Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized into interest expense using the straight-line method over the term of the related debt. Gains or losses on debt repurchases, redemptions, and debt extinguishments include any associated unamortized debt issue costs. Unamortized debt issuance costs totaling $32.1 million and $34.9 million as of December 31, 2023 and 2022, respectively, are included in “Long-term debt” on the consolidated balance sheets as a direct reduction from the carrying amount of the debt.

(t) Redeemable Non-Controlling Interest

Non-controlling interests that contain an option for the non-controlling interest holder to require us to purchase such interests for cash are considered to be redeemable non-controlling interests because the redemption feature is not deemed to be a freestanding financial instrument and because the redemption is not solely within our control. Redeemable non-controlling interests are not considered to be a component of partners' equity and are reported as temporary equity in the mezzanine section on the consolidated balance sheets. The amount recorded as redeemable non-controlling interest at each balance sheet date is the greater of the redemption value and the carrying value of the redeemable non-controlling interest (the initial carrying value increased or decreased for the non-controlling interest holder's share of net income or loss and distributions). When the redemption feature is exercised the redemption value of the non-controlling interest is reclassified to a liability on the consolidated balance sheets.

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

(3) Acquisitions and Divestitures

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. In connection with the purchase, we entered into an amended and restated natural gas gathering and processing agreement with Diamondback E&P LLC, strengthening our dedicated acreage position with that entity. We acquired the system with an upfront payment of $50.0 million, which was paid with cash-on-hand, with an additional $10.0 million that was paid on April 30, 2022, and contingent consideration capped at $15.0 million and payable between 2024 and 2026 based on Diamondback E&P LLC's drilling activity above historical levels.

Under the acquisition method of accounting, the acquired assets of Amarillo Rattler, LLC have been recorded at their respective fair values as of the date of the acquisition. Determining the fair value of the assets of Amarillo Ratter, LLC requires judgment and certain assumptions to be made, particularly related to the valuation of acquired customer relationships. The inputs and assumptions related to the customer relationships are categorized as level 3 in the fair value hierarchy. The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration		
Cash (including working capital payment)	$	50.6
Installment payable		10.0
Contingent consideration fair value (1)		6.9
Total consideration:	$	67.5
Purchase price allocation		
Assets acquired:		
Current assets (including $1.3 million in cash)	$	1.4
Property and equipment		16.3
Intangible assets		50.6
Other assets, net (2)		0.6
Liabilities assumed:		
Current liabilities		(0.8)
Other long-term liabilities (2)		(0.6)
Net assets acquired	$	67.5

(1) The estimated fair value of the Amarillo Rattler, LLC contingent consideration 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 the estimated fair values.
(2) "Other assets, net" and "Other long-term liabilities" consist of the right-of-use asset and lease liability, respectively, recorded through the acquisition of Amarillo Rattler, LLC.

Barnett Shale Acquisition

On July 1, 2022, we completed the Barnett Shale Acquisition for a cash purchase price of $275.0 million plus working capital of $14.5 million. These assets include approximately 400 miles of lean and rich natural gas gathering pipeline and three processing plants with 425 MMcf/d of total processing capacity. We completed this acquisition to increase the scale of our North Texas assets and realize efficiencies by redeploying redundant assets to our other segments, including the Permian segment in the near-term and the CCS business in the future.

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

Consideration		
Cash (including working capital payment)	$	289.5
Purchase price allocation		
Assets acquired:		
Current assets	$	17.3
Property and equipment		275.0
Liabilities assumed:		
Current liabilities		(2.8)
Net assets acquired	$	289.5

We incurred $0.4 million of transaction costs related to the Barnett Shale Acquisition for the year ended December 31, 2022. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from July 1, 2022 through December 31, 2022, we recognized $39.6 million of revenue and $24.1 million of net income related to the assets acquired.

Central Oklahoma Acquisition

On December 19, 2022, we completed the Central Oklahoma Acquisition for a cash purchase price of $95.8 million plus working capital of $5.1 million and an earnout valued at $1.3 million as of December 31, 2022, which was calculated in accordance with ASC 820. The earnout is payable between 2024 and 2027 based on fee revenue earned on certain contractually specified volumes for the annual periods beginning January 1, 2023 through December 31, 2026. The acquired assets include approximately 900 miles of lean and rich natural gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity. We completed this acquisition to increase the scale and efficiency of our Central Oklahoma assets.

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

Consideration		
Cash (including working capital payment)	$	100.9
Contingent consideration		1.3
Total consideration	$	102.2
Purchase price allocation		
Assets acquired:		
Current assets	$	6.0
Property and equipment		97.1
Other assets, net (1)		0.9
Liabilities assumed:		
Current liabilities		(1.4)
Other long-term liabilities (1)		(0.4)
Net assets acquired	$	102.2

(1) "Other assets, net" and "Other long-term liabilities" consist of the right-of-use assets and lease liabilities, respectively, obtained through the Central Oklahoma Acquisition.

We incurred $0.3 million and $0.5 million of transaction costs related to the Central Oklahoma Acquisition for the years ended December 31, 2023 and December 31, 2022, respectively. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from December 19, 2022 through December 31, 2022, we recognized $1.7 million of revenue and $0.6 million of net income related to the assets acquired.

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

	Year Ended December 31,		
	2023	2022	2021
Amarillo Rattler Acquisition contingent consideration			
Contingent consideration liability, beginning of period	$ 4.2	$ 6.9	$ —
Contingent consideration liability recorded upon acquisition (1)	—	—	6.9
Change in fair value	0.6	(2.7)	—
Contingent consideration liability, end of period	$ 4.8	$ 4.2	$ 6.9
Central Oklahoma Acquisition contingent consideration			
Contingent consideration liability, beginning of period	$ 1.3	$ —	$ —
Contingent consideration liability recorded upon acquisition (2)	—	1.3	—
Change in fair value	0.6	—	—
Contingent consideration liability, end of period	$ 1.9	$ 1.3	$ —
Total contingent consideration			
Contingent consideration liability, beginning of period	$ 5.5	$ 6.9	$ —
Contingent consideration liability recorded upon acquisition (1)(2)	—	1.3	6.9
Change in fair value	1.2	(2.7)	—
Contingent consideration liability, end of period	$ 6.7	$ 5.5	$ 6.9

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

Pro Forma of Acquisitions for the Years Ended December 31, 2022 and 2021

The following unaudited pro forma condensed consolidated financial information (in millions) for the years ended December 31, 2022 and 2021 gives effect to the Barnett Shale Acquisition on July 1, 2022 and the Central Oklahoma Acquisition on December 19, 2022 as if each of the acquisitions had occurred on January 1, 2021. On a historical pro forma basis, our consolidated revenues, net income (loss), total assets, and earnings per unit amounts would not have differed materially had the Amarillo Rattler Acquisition been completed on January 1, 2021 rather than April 30, 2021.

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

	Year Ended December 31,	
	2022	2021
Pro forma total revenues	$ 9,630.4	$ 6,782.9
Pro forma net income	$ 441.3	$ 196.3

ORV Divestitures

On November 1, 2023, we sold certain ORV crude assets in our Louisiana segment to a subsidiary of Ergon, Inc. in exchange for cash consideration of approximately $59.2 million, subject to post-closing purchase price adjustments, and a contingent payment of an additional $0.5 million subject to the buyer's pursuit of certain commercial opportunities within three years after the acquisition date.

On November 3, 2023, we sold our remaining ORV assets in our Louisiana segment to Blue Racer Midstream, LLC in exchange for cash consideration of approximately $9.8 million, subject to post-closing purchase price adjustments.

(4) Intangible Assets

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

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Year Ended December 31, 2023			
Customer relationships, beginning of period	$ 1,844.8	$ (923.6)	$ 921.2
Amortization expense	—	(127.6)	(127.6)
Customer relationships, end of period	$ 1,844.8	$ (1,051.2)	$ 793.6
Year Ended December 31, 2022			
Customer relationships, beginning of period	$ 1,844.8	$ (795.1)	$ 1,049.7
Amortization expense	—	(128.5)	(128.5)
Customer relationships, end of period	$ 1,844.8	$ (923.6)	$ 921.2
Year Ended December 31, 2021			
Customer relationships, beginning of period	$ 1,794.2	$ (668.8)	$ 1,125.4
Customer relationships obtained from acquisition of business	50.6	—	50.6
Amortization expense	—	(126.3)	(126.3)
Customer relationships, end of period	$ 1,844.8	$ (795.1)	$ 1,049.7

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

2024	$ 127.6
2025	110.2
2026	106.3
2027	106.3
2028	106.3
Thereafter	236.9
Total	$ 793.6

(5) Related Party Transactions

(a) Transactions with ENLC

Redemption of EMO Preferred Units. In December 2021, ENLC redeemed the EMO Preferred B Units. ENLC repaid the $170.0 million note receivable held by ENLK and we paid ENLC $198.1 million related to the EMO Preferred B Units, for a net settlement of $28.1 million.

Distributions to EORV. For the year ended December 31, 2021, we distributed $16.9 million to EORV for its ownership of the Operating Partnership. As a result of ENLC's redemption of EMO Preferred B Units in December 2021, no additional distributions will be made to EORV. Income was allocated to EORV in an amount equal to the earned distribution for the respective reporting period.

Related Party Debt. Related party debt includes borrowings under the Revolving Credit Facility, $500.0 million in aggregate principal amount of ENLC's 5.625% senior unsecured notes due January 15, 2028 (the "2028 Notes"), $498.7 million in aggregate principal amount of ENLC's 5.375% senior unsecured notes due June 1, 2029 (the "2029 Notes"), and $1.0 billion in aggregate principal amount of ENLC's 6.50% senior unsecured notes due September 1, 2030 (the "2030 Notes") to fund our operations through a related party arrangement with ENLC.

We had related party debt of $1,975.5 million as of December 31, 2023 related to the 2028 Notes, the 2029 Notes, and the 2030 Notes less $2.7 million discount of senior unsecured notes and $20.5 million of related party debt issuance cost, net of accumulated amortization. We had related party debt of $1,932.3 million as of December 31, 2022, which consisted of $255.0 million of borrowings under the Revolving Credit Facility and $1,698.7 million related to the 2028 Notes, the 2029 Notes, and the 2030 Notes less $21.4 million of related party debt issuance cost, net of accumulated amortization. Related party debt is included in "Long-term debt, net of unamortized issuance cost" in the consolidated balance sheets. See "Note 7—Long-Term Debt" for more information on this arrangement.

Related Party Accounts Receivable. We had accounts receivable balances related to transactions with ENLC of $506.8 million and $217.4 million at December 31, 2023 and December 31, 2022, respectively.

Related Party Interest Expense, Net of Interest Income. Interest charged to us for borrowings made through the related party arrangement will be the same as interest charged to ENLC on borrowings under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes, respectively. We incurred related party interest expense of $131.2 million, $83.7 million, and $64.9 million for the years ended December 31, 2023, 2022, and 2021, respectively.

(b) Transactions with the Cedar Cove JV

We process natural gas and purchase the related residue 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:

	December 31, 2023	December 31, 2022
Accrued natural gas, NGLs, condensate, and crude oil purchases	$ 0.3	$ 2.5

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

	Year Ended December 31,		
	2023	2022	2021
Midstream services revenue	$ 2.5	$ 2.2	$ —
Cost of sales	(7.5)	(28.2)	(17.9)

(c) Transactions with GIP

In March 2022, our data center provider since 2009, CyrusOne Inc. ("CyrusOne"), was purchased by an entity that is owned collectively by funds affiliated with GIP and Kohlberg Kravis Roberts & Co. L.P. We paid CyrusOne $0.2 million in fees for data center services for each of the years ended December 31, 2023 and 2022.

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

(6) Leases

The majority of our leases are for the following types of assets:

- *Office space.* Our primary offices are in Dallas, Houston, and Midland, with smaller offices in other locations near our assets. Our office leases are long-term in nature and represented $40.4 million of our lease liability and $20.7 million of our right-of-use asset as of December 31, 2023. Our office leases represented $46.2 million of our lease liability and $24.2 million of our right-of-use asset as of December 31, 2022. These office leases typically include variable lease costs related to utility expenses, which are determined based on our pro-rata share of the building expenses each month and expensed as incurred.

- *Compression and other field equipment.* We pay third parties to provide compressors or other field equipment for our assets. Under these agreements, a third party installs and operates compressor units based on specifications set by us to meet our compression needs at specific locations. While the third party determines which compressors to install and operates and maintains the units, we have the right to control the use of the compressors and are the sole economic beneficiary of the identified assets. These agreements are typically for an initial term of one to three years but will automatically renew month to month until canceled by us or the lessor. Compression and other field equipment rentals represented $41.7 million of our lease liability and $42.5 million of our right-of-use asset as of December 31, 2023. Compression and other field equipment rentals represented $30.6 million of our lease liability and $33.0 million of our right-of-use asset as of December 31, 2022. Under certain agreements, we may incur variable lease costs related to incidental services provided by the equipment lessor, which are expensed as incurred.

- *Land and land easements.* We make periodic payments to lease land or to have access to our assets. Land leases and easements are typically long-term to match the expected useful life of the corresponding asset and represented $15.7 million of our lease liability and $12.4 million of our right-of-use asset as of December 31, 2023. Land and land easement leases represented $15.6 million of our lease liability and $12.3 million of our right-of-use asset as of December 31, 2022.

Lease balances are recorded on the consolidated balance sheets as follows (in millions):

Operating leases:	**December 31, 2023**	**December 31, 2022**
Other assets, net	$ 75.6	$ 69.5
Other current liabilities	$ 28.2	$ 26.2
Other long-term liabilities	$ 69.6	$ 66.2

Other lease information		
Weighted-average remaining lease term—Operating leases	7.7 years	8.7 years
Weighted-average discount rate—Operating leases	5.3 %	4.7 %

Certain of our lease agreements have options to extend the lease for a certain period after the expiration of the initial term. We recognize the cost of a lease over the expected total term of the lease, including optional renewal periods that we can reasonably expect to exercise. We do not have material obligations whereby we guarantee a residual value on assets we lease, nor do our lease agreements impose restrictions or covenants that could affect our ability to make distributions.

Lease expense is recognized on the consolidated statements of operations as “Operating expenses” and “General and administrative” depending on the nature of the leased asset. Impairments of right-of-use assets are recognized in “Impairments” on the consolidated statements of operations. Sublease income is recognized as a reduction in “General and administrative,” “Operating expenses,” or as “Other income” depending on the nature of the subleased asset. The components of total lease expense are as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Operating lease expense:			
Long-term operating lease expense	$ 34.6	$ 28.2	$ 21.7
Short-term lease expense	41.3	34.3	17.5
Variable lease expense	18.6	18.8	15.6
Impairments	—	—	0.2
Total lease expense, before sublease income	94.5	81.3	55.0
Sublease income	(1.8)	(1.1)	—
Total lease expense, net of sublease income	$ 92.7	$ 80.2	$ 55.0

Lease Maturities

The following table summarizes the maturity of our lease liability as of December 31, 2023 (in millions):

	Total	2024	2025	2026	2027	2028	Thereafter
Undiscounted operating lease liability	$ 123.8	$ 31.8	$ 24.4	$ 15.2	$ 9.1	$ 8.7	$ 34.6
Reduction due to present value	(26.0)	(4.3)	(3.2)	(2.3)	(1.8)	(1.4)	(13.0)
Operating lease liability	$ 97.8	$ 27.5	$ 21.2	$ 12.9	$ 7.3	$ 7.3	$ 21.6

(7) Long-Term Debt

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

	December 31, 2023			December 31, 2022		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Related party debt (1)	$ 1,998.7	$ (2.7)	$ 1,996.0	$ 1,953.7	$ —	$ 1,953.7
AR Facility due 2025 (2)	300.0	—	300.0	500.0	—	500.0
4.40% Senior unsecured notes due 2024	97.9	—	97.9	97.9	—	97.9
4.15% Senior unsecured notes due 2025	421.6	—	421.6	421.6	(0.1)	421.5
4.85% Senior unsecured notes due 2026	491.0	(0.2)	490.8	491.0	(0.2)	490.8
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(5.0)	445.0	450.0	(5.2)	444.8
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	$ 4,609.2	$ (8.2)	4,601.0	$ 4,764.2	$ (5.8)	4,758.4
Debt issuance cost (3)(4)			(32.1)			(34.9)
Less: Current maturities of long-term debt (5)			(97.9)			—
Long-term debt, net of unamortized issuance cost			$ 4,471.0			$ 4,723.5

(1) As of December 31, 2023, there were no outstanding borrowings under the Revolving Credit Facility. There were $255.0 million in outstanding borrowings under the Revolving Credit Facility with an effective interest rate of 6.5% at December 31, 2022.
(2) The effective interest rate was 6.4% and 5.3% at December 31, 2023 and 2022, respectively.
(3) Includes related party debt issuance costs, net of accumulated amortization, of $20.5 million and $21.4 million at December 31, 2023 and December 31, 2022, respectively.
(4) Net of accumulated amortization of $20.0 million and $15.1 million at December 31, 2023 and 2022, respectively.
(5) The outstanding balance, net of debt issuance costs, of our 4.40% senior unsecured notes as of December 31, 2023 are classified as "Current maturities of long-term debt" on the consolidated balance sheet as these notes mature on April 1, 2024.

Maturities

Maturities for the long-term debt as of December 31, 2023 are as follows (in millions):

2024	$ 97.9
2025	721.6
2026	491.0
2027	—
2028	500.0
Thereafter	2,798.7
Subtotal	4,609.2
Less: net discount	(8.2)
Less: debt issuance cost	(32.1)
Less: current maturities of long-term debt	(97.9)
Long-term debt, net of unamortized issuance cost	$ 4,471.0

Related Party Debt

Interest charged to us for borrowings made through the related party arrangement will be the same as interest charged to ENLC on borrowings under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes, respectively. As of December 31, 2023 and 2022, $1,975.5 million and $1,932.3 million, respectively, of related party debt is included in "Long-term debt, net of unamortized issuance cost" in the consolidated balance sheets.

The indebtedness under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes was incurred by ENLC but is guaranteed by us. Therefore, the covenants in the agreements governing such indebtedness described below affect balances owed by us on the related party debt.

Revolving Credit Facility

On June 3, 2022, ENLC amended and restated its prior revolving credit facility by entering into the Revolving Credit Facility. As a result, we amended and restated the terms of our related party debt associated with the Revolving Credit Facility with ENLC and recognized a $0.5 million loss on extinguishment of debt. The Revolving Credit Facility amended ENLC's prior revolving credit facility by, among other things, (i) decreasing the lenders' commitments from $1.75 billion to $1.40 billion, (ii) modifying the leverage ratio financial covenant calculation to net from the funded indebtedness numerator the lesser of (a) consolidated unrestricted cash of ENLC and (b) $50.0 million, (iii) removing the consolidated interest coverage ratio financial covenant, (iv) extending the maturity date from January 25, 2024 to June 3, 2027, (v) replacing the ability of ENLC to elect that borrowings accrue interest at LIBOR, plus a margin, with the ability of ENLC to elect that borrowings accrue interest at a forward-looking term rate based on SOFR ("Term SOFR"), plus a margin and a Term SOFR spread adjustment, (vi) increasing the size of a permitted receivables financing to $500.0 million from $350.0 million, and (vii) permitting, but not requiring, the establishment by ENLC (subject to approval by Bank of America, N.A., as administrative agent, and lenders holding a majority of the revolving commitments) of specified key performance indicators with respect to environmental, social, and/or governance targets that may result in a pricing increase or decrease under the Revolving Credit Facility of up to 0.05% per annum for the margin on borrowings and letters of credit and 0.02% per annum for the commitment fees.

The Revolving Credit Facility will mature on June 3, 2027, unless ENLC requests, and the requisite lenders agree, to extend it pursuant to its terms. The Revolving Credit Facility contains certain financial, operational, and legal covenants. The financial covenant is tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenant requires ENLC to maintain a ratio of consolidated net indebtedness to consolidated EBITDA of no more than 5.0 to 1.0.

Under the terms of the Revolving Credit Facility, if we consummate an acquisition in which the aggregate purchase price is $50.0 million or more, ENLC can elect to increase the maximum allowed ratio of consolidated net indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Revolving Credit Facility bear interest at ENLC's option at Term SOFR plus a Term SOFR spread adjustment of 0.10% per annum ("Adjusted Term SOFR") and an applicable margin (ranging from 1.125% to 2.00%) or the Base Rate (the highest of the federal funds rate plus 0.50%, one-month Adjusted Term SOFR plus 1.0% or the administrative agent's prime rate) plus an applicable margin (ranging from 0.125% to 1.00%). The applicable margins vary depending on ENLC's debt rating. Upon breach by ENLC of certain covenants governing the Revolving Credit Facility, or a change in control (as defined in the Revolving Credit Facility) amounts outstanding under the Revolving Credit Facility, if any, may become due and payable immediately.

ENLK is a guarantor under the Revolving Credit Facility. In the event that ENLC's obligations under the Revolving Credit Facility are accelerated due to a default, ENLK will be liable for the entire outstanding balance and 105% of the outstanding letters of credit under the Revolving Credit Facility. There were no outstanding borrowings under the Revolving Credit Facility and $26.7 million in outstanding letters of credit as of December 31, 2023.

At December 31, 2023, ENLC was in compliance with and expects to be in compliance with the financial covenants of the Revolving Credit Facility for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the Revolving Credit Facility.

AR Facility

On October 21, 2020, the SPV entered into 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.

In 2021 and 2022, the SPV entered into several amendments to the AR Facility to, among other things: (i) increase the commitments thereunder to $500.0 million (ii) extend the scheduled termination date to August 1, 2025, unless extended or earlier terminated in accordance with its terms, and (iii) reduce the effective draw down fee to 0.90%.

Since our investment in the SPV is not sufficient to finance its activities without additional support from us, the SPV is a variable interest entity. We are the primary beneficiary of the SPV because we have the power to direct the activities that most significantly affect its economic performance and we are obligated to absorb its losses or receive its benefits from operations. Since we are the primary beneficiary of the SPV, we consolidate its assets and liabilities, which consist primarily of billed and unbilled accounts receivable of $629.3 million as of December 31, 2023. As of December 31, 2023, the AR Facility had a borrowing base of $404.2 million and there were $300.0 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. Borrowings under the AR Facility bear interest at the applicable SOFR plus a credit spread adjustment of 0.10%, plus a drawn fee in the amount of 0.90% at December 31, 2023. The SPV also pays a fee on the undrawn committed amount of the AR Facility. Interest and fees payable by the SPV under the AR Facility are due monthly.

The AR Facility is scheduled to terminate on August 1, 2025, unless extended or earlier terminated in accordance with its terms, at which time no further advances will be available and the obligations under the AR Facility must be repaid in full by no later than (i) the date that is ninety (90) days following such date or (ii) such earlier date on which the loans under the AR Facility become due and payable.

The AR Facility includes covenants, indemnification provisions, and events of default, including those providing for termination of the AR Facility and the acceleration of amounts owed by the SPV under the AR Facility if, among other things, a borrowing base deficiency exists, there is an event of default under the Revolving Credit Facility or certain other indebtedness, certain events negatively affecting the overall credit quality of the receivables held as collateral occur, a change in control occurs, or if the net consolidated leverage ratio of ENLC exceeds limits identical to those in the Revolving Credit Facility.

At December 31, 2023, we were in compliance with and expect to be in compliance with the financial covenants of the AR Facility for at least the next twelve months.

Senior Unsecured Notes Redemption Provisions

Each issuance of the senior unsecured notes may be fully or partially redeemed prior to an early redemption date (see "Early Redemption Date" in table below) at a redemption price equal to the greater of: (i) 100% of the principal amount of the notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the respective notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus a specified basis point premium (see "Basis Point Premium" in the table below); plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after the Early Redemption Date, the senior unsecured notes may be fully or partially redeemed at a redemption price equal to 100% of the principal amount of the applicable notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date. See applicable redemption provision terms below:

Issuance	Maturity Date of Notes	Early Redemption Date	Basis Point Premium
2024 Notes	April 1, 2024	Prior to January 1, 2024	25 Basis Points
2025 Notes	June 1, 2025	Prior to March 1, 2025	30 Basis Points
2026 Notes	July 15, 2026	Prior to April 15, 2026	50 Basis Points
2028 Notes	January 15, 2028	Prior to July 15, 2027	50 Basis Points
2029 Notes	June 1, 2029	Prior to March 1, 2029	50 Basis Points
2030 Notes	September 1, 2030	Prior to March 1, 2030	50 Basis Points
2044 Notes	April 1, 2044	Prior to October 1, 2043	30 Basis Points
2045 Notes	April 1, 2045	Prior to October 1, 2044	30 Basis Points
2047 Notes	June 1, 2047	Prior to December 1, 2046	40 Basis Points

Senior Unsecured Notes Indentures

The indentures governing the senior unsecured notes contain covenants that, among other things, limit ENLC's and ENLK's ability to create or incur certain liens or consolidate, merge, or transfer all or substantially all of ENLC's and ENLK's assets.

The indentures governing the 2028 Notes and the 2030 Notes provide that if a Change of Control Triggering Event (as defined in the indenture) occurs, ENLC must offer to repurchase the 2028 Notes and the 2030 Notes at a price equal to 101% of the principal amount of such notes, plus accrued and unpaid interest to, but excluding, the date of repurchase.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation, or other covenant in the indenture, subject to the cure periods for certain failures; and
- bankruptcy or other insolvency events involving ENLC and ENLK.

If an event of default relating to bankruptcy or other insolvency events occurs, the senior unsecured notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the senior unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies. At December 31, 2023, ENLC and ENLK were in compliance and expect to be in compliance with the covenants in the senior unsecured notes for at least the next twelve months. All interest payments for senior unsecured notes are due semi-annually, in arrears.

Issuances and Repurchases of Senior Unsecured Notes

On April 3, 2023, ENLC completed the sale of an additional $300.0 million aggregate principal amount of ENLC's 6.50% senior unsecured notes due 2030 (the "Additional Notes") at a price to the public of 99% of their face value. The Additional Notes were offered as an additional issuance of ENLC's existing 6.50% senior unsecured notes due 2030 that ENLC issued on

August 31, 2022 in an aggregate principal amount of $700.0 million. Related party debt includes borrowings under the Additional Notes. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the related party debt related to the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by us.

On August 31, 2022, ENLC completed the sale of the 2030 Notes at 100% of their face value. Interest on the 2030 Notes will be payable on March 1 and September 1 of each year beginning on March 1, 2023, until their maturity on September 1, 2030. The 2030 Notes are fully and unconditionally guaranteed by us. Related party debt includes borrowings under the 2030 Notes. We used the net proceeds of approximately $693.0 million and available cash to settle our debt tender offer to repurchase $700.0 million in aggregate principal amount of our senior unsecured notes. The repurchased notes consisted of $404.4 million of outstanding aggregate principal amount of our 4.40% senior unsecured notes due 2024 (the "2024 Notes") and $295.6 million of outstanding aggregate principal amount of our 4.15% senior unsecured notes due 2025 (the "2025 Notes"). Total consideration for the repurchased 2024 Notes and the 2025 Notes was $705.3 million, including $21.0 million of debt tender premium and $15.7 million of discount.

Activity related to the repurchases of our senior unsecured notes from the settled debt tender offer consisted of the following (in millions):

	Year Ended December 31, 2022
Debt repurchased	$ 700.0
Aggregate payments	(705.3)
Net discount on repurchased debt	(1.0)
Loss on extinguishment of debt	$ (6.3)

Additionally, for the year ended December 31, 2022, and prior to the tender offer, we repurchased a portion of the outstanding 2024 Notes and 2025 Notes in open market transactions. Activity related to the repurchases of our senior unsecured notes in open market transactions consisted of the following (in millions):

	Year Ended December 31, 2022
Debt repurchased	$ 23.1
Aggregate payments	(22.5)
Gain on extinguishment of debt	$ 0.6

(8) Partners' Capital

(a) Series B Preferred Units

As of December 31, 2023 and 2022, there were 54,575,638 and 54,168,359 Series B Preferred Units issued and outstanding, respectively.

Issuance

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"). On August 4, 2021, Enfield Holdings, L.P. ("Enfield") sold all of its Series B Preferred Units and ENLC Class C Common Units representing limited liability company interests in ENLC to Brookfield Infrastructure Partners L.P. and funds managed by Oaktree Capital Management, L.P.

Redemptions

In January 2022 and December 2021, we redeemed 3,333,334 and 3,300,330 Series B Preferred Units for total consideration of $50.5 million and $50.0 million plus accrued distributions, respectively. In addition, upon each such redemption, a corresponding number of ENLC Class C Common Units were automatically cancelled. The redemption price in each redemption represented 101% of the preferred units' par value. In connection with the Series B Preferred Unit redemption, we agreed with the holders of the Series B Preferred Units to pay cash in lieu of making a quarterly distribution in-kind of additional Series B Preferred Units (the "PIK Distribution") through the distribution declared for the fourth quarter of 2022.

Conversion and Distributions

Series B Preferred Units are exchangeable for ENLC common units in an amount equal to the number of outstanding Series B Preferred Units outstanding multiplied by the exchange ratio of 1.15, subject to certain adjustments (the “Series B Exchange Ratio”). The exchange is subject to ENLK’s option to pay cash instead of 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 than 150% of the Issue Price divided by the conversion ratio of 1.15.

The holder of the Series B Preferred Units is entitled to quarterly cash distributions and distributions in-kind of additional Series B Preferred Units. The PIK Distribution equals the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) the number of Series B Preferred Units equal to the quotient of (x) the excess (if any) of (1) the distribution that would have been payable by ENLC had the Series B Preferred Units been exchanged for ENLC common units but applying a one-to-one exchange ratio (subject to certain adjustments) instead of the Series B Exchange Ratio, over (2) $0.28125 per Series B Preferred Unit (the “Cash Distribution Component”), divided by (y) the Issue Price. Except as described above with respect to distributions made until the distribution declared for the fourth quarter of 2022, the quarterly cash distribution (the “Series B Cash Distribution”) consists of the Cash Distribution Component plus an amount in cash that will be determined based on a comparison of the value (applying the Issue Price) of (i) the PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

On September 8, 2023, in connection with ENLK’s qualification of the Series B Preferred Units to be eligible to be deposited through the Depository Trust Company, we amended and restated the limited partnership agreement of ENLK to, among other things, (i) reflect the cancellation of all outstanding ENLC Class C Common Units, which were non-economic equity interests previously held by the holders of the Series B Preferred Units and permitted such holders to participate in any vote of the holders of ENLC common units, (ii) provide for the termination of any rights of the holders of the Series B Preferred Units to PIK Distributions with respect to, and following, the earlier to occur of (x) any quarter in which the holders of the Series B Preferred Units give notice to our general partner of its election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024, and (iii) 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 ENLK’s limited partnership agreement).

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. A summary of the distribution activity relating to the Series B Preferred Units during the years ended December 31, 2023, 2022, and 2021 is provided below:

Declaration period	PIK Distribution	Cash distribution (in millions)	Date paid
2023			
First Quarter of 2023	135,421	$ 15.2	May 12, 2023
Second Quarter of 2023	135,759	$ 15.3	August 11, 2023
Third Quarter of 2023	136,099	$ 15.3	November 10, 2023
Fourth Quarter of 2023	136,439	$ 15.3	February 9, 2024
2022			
First Quarter of 2022	—	$ 17.5	May 13, 2022 (2)
Second Quarter of 2022	—	$ 17.3	August 12, 2022
Third Quarter of 2022	—	$ 17.3	November 14, 2022
Fourth Quarter of 2022	—	$ 17.3	February 13, 2023
2021			
First Quarter of 2021	150,871	$ 17	May 14, 2021
Second Quarter of 2021	151,248	$ 17	August 13, 2021
Third Quarter of 2021	151,626	$ 17.1	November 12, 2021
Fourth Quarter of 2021	—	$ 19.2	February 11, 2022 (1)

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

(2) In January 2022, we paid $0.3 million of accrued distributions related to the first quarter of 2022 on redeemed Series B Preferred Units. The remaining distribution of $17.2 million related to the first quarter of 2022 was paid on May 13, 2022.

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 us 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 December 31, 2023, due to the application of the Allocation Cap, the cumulative amount of distributions made in respect of each Series B Preferred Unit exceeded the cumulative amount of gross income allocated to each Series B Preferred Unit by $6.79 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 we generate positive net income.

(c) Series C Preferred Units

As of December 31, 2023 and 2022, there were 366,500 and 381,000 Series C Preferred Units issued and outstanding, respectively.

Issuance

In September 2017, we issued 400,000 Series C Preferred Units representing our limited partner interests at a price to the public of $1,000 per unit. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

Repurchases

A summary of the repurchase activity relating to the Series C Preferred Units is provided below:

Transaction date	Series C Preferred Units Repurchased	Total Consideration (in millions)	Percent Represented of Repurchased Preferred Units' Par Value
2023			
February 2023	4,500	$ 3.9	87 %
November 2023	3,000	$ 2.7	90 %
December 2023	7,000	$ 6.5	93 %
2022			
October 2022	19,000	$ 15.2	80 %

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
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
September 15, 2023 - December 14, 2023	9.782 %	$ 9.3	December 15, 2023
2022			
December 15, 2021 – June 14, 2022	6.000 %	$ 12.0	June 15, 2022
June 15, 2022 – December 14, 2022	6.000 %	$ 11.4	December 15, 2022
2021			
December 15, 2020 – June 14, 2021	6.000 %	$ 12.0	June 15, 2021
June 15, 2021 – December 14, 2021	6.000 %	$ 12.0	December 15, 2021

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

(2) The initial distribution rate for the Series C Preferred Units from the date of original issue through December 14, 2022 was 6.0% per year. Starting on December 15, 2022, distributions on the Series C Preferred Units accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to the floating rate of the three-month LIBOR plus a spread of 4.11%. . 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%.

(9) Investment in Unconsolidated Affiliates

As of December 31, 2023, our unconsolidated investments consisted of a 38.75% ownership in GCF, a 30% ownership in the Cedar Cove JV, and a 15% ownership in the Matterhorn JV. The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Year Ended December 31,		
	2023	2022	2021
GCF			
Contributions	$ 24.6	$ 1.5	$ —
Distributions	$ (2.0)	$ —	$ (3.5)
Equity in loss	$ (4.4)	$ (3.2)	$ (9.1)
Cedar Cove JV			
Distributions	$ (0.5)	$ (0.7)	$ (0.4)
Equity in loss	$ (2.4)	$ (1.9)	$ (2.4)
Matterhorn JV			
Contributions	$ 43.5	$ 64.4	$ —
Equity in loss	$ (1.4)	$ (0.5)	$ —
Total			
Contributions	$ 68.1	$ 65.9	$ —
Distributions	$ (2.5)	$ (0.7)	$ (3.9)
Equity in loss	$ (8.2)	$ (5.6)	$ (11.5)

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

	December 31, 2023	December 31, 2022
GCF	$ 44.5	$ 26.3
Cedar Cove JV (1)	(7.3)	(4.4)
Matterhorn JV	106.0	63.9
Total investment in unconsolidated affiliates	$ 143.2	$ 85.8

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

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

We account for unit-based compensation in accordance with ASC 718, which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is valued at fair value at the date of grant, and that grant date fair value is recognized as expense over each award's requisite service period with a corresponding increase to equity or liability based on the terms of each award and the appropriate accounting treatment under ASC 718. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to ENLC's directors, officers, and employees of our general partner is recorded by us since ENLC has no substantial or managed operating activities other than its interests in us.

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

	Year Ended December 31,		
	2023	2022	2021
Cost of unit-based compensation charged to operating expense	$ 3.7	$ 5.7	$ 6.6
Cost of unit-based compensation charged to general and administrative expense	15.5	24.7	18.7
Total unit-based compensation expense	$ 19.2	$ 30.4	$ 25.3

(b) Restricted Incentive Units

The restricted incentive units were valued at their fair value at the date of grant, which is equal to the market value of ENLC common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2023 is provided below:

	Year Ended December 31, 2023	
Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Unvested, beginning of period	6,775,186	$ 5.89
Granted (1)	1,587,965	11.03
Vested (1)(2)	(2,489,603)	5.96
Forfeited	(427,568)	6.98
Unvested, end of period	5,445,980	$ 7.27
Aggregate intrinsic value, end of period (in millions)	$ 66.2	

(1) Restricted incentive units typically vest at the end of three years.
(2) Vested units included 756,556 ENLC common units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the years ended December 31, 2023, 2022, and 2021 is provided below (in millions):

	Year Ended December 31,		
Restricted Incentive Units:	2023	2022	2021
Aggregate intrinsic value of units vested	$ 30.5	$ 24.4	$ 5.6
Fair value of units vested	$ 14.8	$ 19.0	$ 16.3

As of December 31, 2023, there were $16.7 million of unrecognized compensation costs that related to unvested restricted incentive units. These costs are expected to be recognized over a weighted average period of 1.8 years.

For restricted incentive unit awards granted to certain officers and employees (the "grantee"), such awards (the "Subject Grants") generally provide that, subject to the satisfaction of the conditions set forth in the agreement, the Subject Grants will vest on the third anniversary of the vesting commencement date (the "Regular Vesting Date"). The Subject Grants will be forfeited if the grantee's employment or service with ENLC and its affiliates terminates prior to the Regular Vesting Date except that the Subject Grants will vest in full or on a pro-rated basis for certain terminations of employment or service prior to the Regular Vesting Date. For instance, the Subject Grants will vest on a pro-rated basis for any terminations of the grantee's employment: (i) due to retirement, (ii) by ENLC or its affiliates without cause, or (iii) by the grantee for good reason (each, a "Covered Termination" and more particularly defined in the Subject Grants agreement) except that the Subject Grants will vest in full if the applicable Covered Termination is a "normal retirement" (as defined in the Subject Grants agreement) or the applicable Covered Termination occurs after a change in control (if any). The Subject Grants will vest in full if death or a qualifying disability occurs prior to the Regular Vesting Date.

(c) Performance Units

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

Performance Unit Awards Vesting

The vesting of performance units is dependent on (a) the grantee's continued employment or service with ENLC or its affiliates for all relevant periods and (b) the TSR performance of ENLC (the "ENLC TSR") and a performance goal based on cash flow ("Cash Flow"). At the time of grant, the Manager Board will determine the relative weighting of the two performance goals by including in the award agreement the number of units that will be eligible for vesting depending on the achievement of the TSR performance goals (the "Total TSR Units") versus the achievement of the Cash Flow performance goals (the "Total CF Units"). These performance awards have four separate performance periods: (i) three performance periods are each of the first, second, and third calendar years that occur following the vesting commencement date of the performance awards and (ii) the fourth performance period is the cumulative three-year period from the vesting commencement date through the third anniversary thereof (the "Cumulative Performance Period").

One-fourth of the Total TSR Units (the "Tranche TSR Units") relates to each of the four performance periods described above. Following the end date of a given performance period, the Governance and Compensation Committee (the "Manager Committee") of the Manager Board will measure and determine the ENLC TSR relative to the TSR performance of a designated group of peer companies (the "Designated Peer Companies") to determine the Tranche TSR Units that are eligible to vest, subject to the grantee's continued employment or service with ENLC or its affiliates through the end date of the Cumulative Performance Period. In short, the TSR for a given performance period is defined as (i)(A) the average closing price of a common equity security at the end of the relevant performance period minus (B) the average closing price of a common equity security at the beginning of the relevant performance period plus (C) reinvested dividends divided by (ii) the average closing price of a common equity security at the beginning of the relevant performance period.

The following table sets out the levels at which the Tranche TSR Units may vest (using linear interpolation) based on the ENLC TSR percentile ranking for the applicable performance period relative to the TSR achievement of the Designated Peer Companies:

Performance Level	Achieved ENLC TSR Position Relative to Designated Peer Companies	Vesting Percentage of the Tranche TSR Units
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 85% (1)	200%

(1) The performance awards granted prior to 2023 achieved the maximum performance level if the ENLC TSR position relative to designated peer companies was greater than or equal to 75%.

Approximately one-third of the Total CF Units (the "Tranche CF Units") relates to each of the first three performance periods described above (i.e., the Cash Flow performance goal does not have a Cumulative Performance Period). The Manager Board will establish the Cash Flow performance targets for each performance period no later than March 31 of the year in which the relevant performance period begins. Following the end date of a given performance period, the Manager Committee will measure and determine the Cash Flow performance of ENLC to determine the Tranche CF Units that are eligible to vest, subject to the grantee's continued employment or service with ENLC or its affiliates through the end of the Cumulative Performance Period.

In 2023, the Manager Board adopted the DCF metric as the Cash Flow performance goal in the Performance-Based Award Agreement for all periods beginning after January 1, 2023, rather than the previously used FCFAD metric. The following table sets out the levels at which the Tranche CF Units were eligible to vest (using linear interpolation):

		Performance Period Ended December 31,		
		2023	2022	2021
Performance Level	Vesting Percentage of the Tranche CF Units	Achieved DCF	Achieved FCFAD	Achieved FCFAD
Below Threshold	0%	Less than $801 million	Less than $154 million	Less than $205 million
Threshold	50%	Equal to $801 million	Equal to $154 million	Equal to $205 million
Target	100%	Equal to $932 million	Equal to $202 million	Equal to $256 million
Maximum	200%	Greater than or Equal to $1,123 million	Greater than or Equal to $241 million	Greater than or Equal to $300 million

The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the Designated Peer Companies' or Peer Companies' securities as applicable; (iii) an estimated ranking of ENLC among the Designated Peer Companies or Peer Companies, and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

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

Performance Units:	March 2023	June 2022	March 2022 (1)	January 2021
Grant-date fair value	$ 11.67	$ 11.71	$ 11.90	$ 4.70
Beginning TSR price	$ 10.40	$ 8.54	$ 8.83	$ 3.71
Risk-free interest rate	3.76 %	3.35 %	2.15 %	0.17 %
Volatility factor	64.00 %	76.00 %	75.00 %	71.00 %

(1) Excludes certain performance units awarded March 1, 2022 with vesting conditions based on performance metrics. The 88,863 performance units have a grant-date fair value of $8.90 and were scheduled to vest in February 2023. However, this award partially vested in October 2022 and is reflected in the "Vested" row of the summary of the performance units table below.

The following table presents a summary of the performance units:

	Year Ended December 31, 2023	
Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Unvested, beginning of period	2,979,154	$ 6.44
Granted	420,128	11.67
Vested (1)	(1,091,523)	8.30
Forfeited	(71,015)	10.97
Unvested, end of period	2,236,744	$ 6.37
Aggregate intrinsic value, end of period (in millions)	$ 27.2	

(1) Vested units included 811,114 ENLC common units withheld for payroll taxes paid on behalf of employees.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the years ended December 31, 2023, 2022, and 2021 is provided below (in millions).

	Year Ended December 31,		
Performance Units:	2023	2022	2021
Aggregate intrinsic value of units vested	$ 26.1	$ 20.4	$ 0.6
Fair value of units vested	$ 9.1	$ 26.2	$ 4.4

As of December 31, 2023, there were $8.7 million of unrecognized compensation costs that related to unvested performance units. These costs are expected to be recognized over a weighted-average period of 1.4 years.

(d) Benefit Plan

ENLK maintains a tax-qualified 401(k) plan whereby it matches 100% of every dollar contributed up to 6% of an employee's eligible compensation. Contributions of $8.4 million, $7.4 million, and $7.0 million were made to the plan for the years ended December 31, 2023, 2022, and 2021, respectively.

(11) Derivatives

Interest Rate Swaps

In January 2023, we entered into a $400.0 million interest rate swap with ENLC 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 this interest rate swap as a cash flow hedge in accordance with ASC 815. There is no ineffectiveness related to this hedge.

In April 2019, we entered into $850.0 million of interest rate swaps to manage the interest rate risk associated with our floating-rate, LIBOR-based borrowings. For the year ended December 31, 2021, we terminated $200.0 million of interest rate swaps, resulting in a $1.8 million payment, while the remaining $150.0 million of interest rate swaps expired on December 10, 2021.

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

	Year Ended December 31,		
	2023	2022	2021
Unrealized gain on designated cash flow hedge	$ 0.9	$ 1.9	$ 18.2

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

	Year Ended December 31,	
	2023	2022
Fair value of derivative assets—current	$ 3.3	$ —
Fair value of derivative liabilities—long-term	(2.4)	—
Net fair value of interest rate swaps	$ 0.9	$ —

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

	Year Ended December 31,		
	2023	2022	2021
Interest expense (income)	$ (4.5)	$ 1.9	$ 18.3

We expect to recognize an additional $3.3 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 OTC 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. 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):

	Year Ended December 31,		
	2023	2022	2021
Change in fair value of derivatives	$ (12.1)	$ 40.2	$ (12.4)
Realized gain (loss) on derivatives	32.8	(25.9)	(146.7)
Gain (loss) on derivative activity	$ 20.7	$ 14.3	$ (159.1)

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

	December 31, 2023	December 31, 2022
Fair value of derivative assets—current	$ 73.6	$ 68.4
Fair value of derivative assets—long-term	27.0	2.9
Fair value of derivative liabilities—current	(62.7)	(42.9)
Fair value of derivative liabilities—long-term	(24.3)	(2.7)
Net fair value of commodity derivatives	$ 13.6	$ 25.7

Set forth below are the summarized notional volumes and fair values of all instruments related to commodity derivatives that we held for price risk management purposes and the related physical offsets at December 31, 2023 (in millions, except volumes). The remaining term of the contracts extend no later than January 2028.

		December 31, 2023		
Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	MMgals	(111.8)	$ (0.8)
NGL (long contracts)	Swaps	MMgals	58.0	1.1
Natural gas (short contracts)	Swaps and futures	Bbtu	(145.8)	86.6
Natural gas (long contracts)	Swaps and futures	Bbtu	122.4	(75.5)
Crude and condensate (short contracts)	Swaps and futures	MMbbls	(7.4)	2.3
Crude and condensate (long contracts)	Swaps and futures	MMbbls	0.1	(0.1)
Total fair value of commodity derivatives				$ 13.6

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with financial institutions when entering into financial derivatives on commodities. We have entered into Master ISDAs that allow for netting of swap contract receivables and payables in the event of default by either party. Additionally, we have entered into FCDTCs that allow for netting of futures contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing commodity swap and futures contracts, the maximum loss on our gross receivable position of $100.6 million as of December 31, 2023 would be reduced to $15.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs and the FCDTCs.

(12) Fair Value Measurements

ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative contracts primarily consist of commodity swap and futures contracts, which are not traded on a public exchange. The fair values of commodity swap and futures contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly-quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate, and credit risk and are classified as Level 2 in hierarchy.

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

	Level 2	
	December 31, 2023	December 31, 2022
Interest rate swaps (1)	$ 0.9	$ —
Commodity derivatives (2)	$ 13.6	$ 25.7

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

Fair Value of Financial Instruments

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

	December 31, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,568.9	$ 4,427.0	$ 4,723.5	$ 4,385.9
Contingent consideration (2)(3)	$ 6.7	$ 6.7	$ 5.5	$ 5.5

(1) The carrying value of long-term debt, including current maturities of long-term debt, is reduced by debt issuance cost, net of accumulated amortization, of $32.1 million and $34.9 million as of December 31, 2023 and 2022, respectively. The respective fair values do not factor in debt issuance costs.
(2) Consideration for the Amarillo Rattler Acquisition included a contingent component capped at $15.0 million and payable, if at all, between 2024 and 2026 based on Diamondback E&P LLC's drilling activity above historical levels. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.
(3) Consideration for the Central Oklahoma Acquisition included a contingent component, which is payable, if at all, between 2024 and 2027 based on fee revenue earned on certain contractually specified volumes for the annual periods beginning January 1, 2023 through December 31, 2026. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.

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

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

(13) Commitments and Contingencies

(a) Change in Control and Severance Agreements

Certain members of our management are parties to severance and change in control agreements with the Operating Partnership. The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individuals from, among other things, competing with our general partner or its affiliates during his or her employment. In addition, the severance and change in control agreements prohibit subject individuals from, among other things, disclosing confidential information about our general partner or interfering with a client or customer of our general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person's employment.

(b) Environmental Issues

The operation of pipelines, plants, and other facilities for the gathering, processing, transmitting, stabilizing, fractionating, storing, or disposing of natural gas, NGLs, crude oil, condensate, brine, and other products is subject to stringent and complex laws and regulations pertaining to health, safety, and the environment. As an owner, partner, or operator of these facilities, we must comply with United States laws and regulations at the federal, state, and local levels that relate to air and water quality, hazardous and solid waste management and disposal, oil spill prevention, climate change, endangered species, and other environmental matters. The cost of planning, designing, constructing, and operating pipelines, plants, and other facilities must account for compliance with environmental laws and regulations and safety standards. Federal, state, or local administrative decisions, developments in the federal or state court systems, or other governmental or judicial actions may influence the interpretation and enforcement of environmental laws and regulations and may thereby increase compliance costs. Failure to comply with these laws and regulations may trigger a variety of administrative, civil, and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition, or cash flows. However, we cannot provide assurance that future events, such as changes in existing laws, regulations, or enforcement policies, the promulgation of new laws or regulations, or the discovery or development of new factual circumstances will not cause us to incur material costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

(c) Litigation 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 is between one of our subsidiaries, EnLink Gas Marketing, LP ("EnLink Gas"), and Koch Energy Services, LLC ("Koch") in the 162nd District Court in Dallas County, Texas. The dispute centers on whether EnLink Gas was excused from delivering natural gas or performing under certain delivery or purchase obligations during Winter Storm Uri, given our declaration of force majeure during the storm. Koch has invoiced us approximately $53.9 million (after subtracting amounts owed to EnLink Gas) and does not recognize the declaration of force majeure. We believe the declaration of force majeure was valid and appropriate and we intend to vigorously defend against Koch's claims.

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

(14) Segment Information

We manage and report our operations primarily according to the geography and the nature of the activity. We have five reportable segments:

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

We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. Adjusted gross margin is a non-GAAP financial measure. See “Item 1. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures” for additional information. Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2023						
Natural gas sales	$ 453.4	$ 444.7	$ 184.5	$ 76.6	$ —	$ 1,159.2
NGL sales	(12.0)	3,031.2	8.5	(6.2)	—	3,021.5
Crude oil and condensate sales	1,250.0	215.6	109.3	—	—	1,574.9
Product sales	1,691.4	3,691.5	302.3	70.4	—	5,755.6
NGL sales—related parties	927.9	22.4	465.6	295.9	(1,711.8)	—
Crude oil and condensate sales—related parties	—	—	—	10.5	(10.5)	—
Product sales—related parties	927.9	22.4	465.6	306.4	(1,722.3)	—
Gathering and transportation	114.6	79.9	236.8	203.9	—	635.2
Processing	60.1	1.6	144.4	123.4	—	329.5
NGL services	—	87.3	—	0.2	—	87.5
Crude services	23.9	19.6	17.5	0.7	—	61.7
Other services	7.3	1.3	0.5	0.8	—	9.9
Midstream services	205.9	189.7	399.2	329.0	—	1,123.8
NGL services—related parties	—	—	—	3.7	(3.7)	—
Midstream services—related parties	—	—	—	3.7	(3.7)	—
Revenue from contracts with customers	2,825.2	3,903.6	1,167.1	709.5	(1,726.0)	6,879.4
Realized gain on derivatives	3.0	2.6	6.5	20.7	—	32.8
Change in fair value of derivatives	(5.0)	4.1	(2.2)	(9.0)	—	(12.1)
Total revenues	2,823.2	3,910.3	1,171.4	721.2	(1,726.0)	6,900.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(2,205.5)	(3,388.4)	(645.6)	(342.6)	1,726.0	(4,856.1)
Adjusted gross margin	617.7	521.9	525.8	378.6	—	2,044.0
Operating expenses	(221.3)	(130.3)	(103.8)	(102.8)	—	(558.2)
Segment profit	396.4	391.6	422.0	275.8	—	1,485.8
Depreciation and amortization	(166.6)	(151.3)	(217.7)	(115.8)	(5.7)	(657.1)
Gross margin	229.8	240.3	204.3	160.0	(5.7)	828.7
Impairments	—	(20.7)	—	—	—	(20.7)
Gain (loss) on disposition of assets	0.2	(2.0)	0.9	1.2	—	0.3
General and administrative	—	—	—	—	(113.7)	(113.7)
Interest expense, net of interest income	—	—	—	—	(271.7)	(271.7)
Loss from unconsolidated affiliate investments	—	—	—	—	(8.2)	(8.2)
Income (loss) before non-controlling interest and income taxes	$ 230.0	$ 217.6	$ 205.2	$ 161.2	$ (399.3)	$ 414.7
Capital expenditures	$ 267.3	$ 68.6	$ 69.2	$ 75.5	$ 6.2	$ 486.8

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (continued)

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2022						
Natural gas sales	$ 1,078.7	$ 1,128.4	$ 367.5	$ 139.0	$ —	$ 2,713.6
NGL sales	(1.5)	4,196.6	10.8	1.4	—	4,207.3
Crude oil and condensate sales	1,158.6	350.0	135.4	—	—	1,644.0
Product sales	2,235.8	5,675.0	513.7	140.4	—	8,564.9
NGL sales—related parties	1,495.6	97.7	774.6	543.6	(2,911.5)	—
Crude oil and condensate sales—related parties	—	—	0.3	12.3	(12.6)	—
Product sales—related parties	1,495.6	97.7	774.9	555.9	(2,924.1)	—
Gathering and transportation	72.6	75.5	187.5	185.7	—	521.3
Processing	39.2	1.5	119.7	125.9	—	286.3
NGL services	—	82.0	—	0.2	—	82.2
Crude services	21.4	33.3	14.9	0.7	—	70.3
Other services	0.8	1.6	(0.3)	0.7	—	2.8
Midstream services	134.0	193.9	321.8	313.2	—	962.9
NGL services—related parties	—	—	—	1.6	(1.6)	—
Crude services—related parties	—	—	0.1	—	(0.1)	—
Other services—related parties	—	0.2	—	—	(0.2)	—
Midstream services—related parties	—	0.2	0.1	1.6	(1.9)	—
Revenue from contracts with customers	3,865.4	5,966.8	1,610.5	1,011.1	(2,926.0)	9,527.8
Realized gain (loss) on derivatives	(9.0)	2.9	(13.1)	(6.7)	—	(25.9)
Change in fair value of derivatives	9.6	7.7	5.6	17.3	—	40.2
Total revenues	3,866.0	5,977.4	1,603.0	1,021.7	(2,926.0)	9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(3,280.3)	(5,462.4)	(1,124.4)	(631.7)	2,926.0	(7,572.8)
Adjusted gross margin	585.7	515.0	478.6	390.0	—	1,969.3
Operating expenses	(200.2)	(140.7)	(90.9)	(93.1)	—	(524.9)
Segment profit	385.5	374.3	387.7	296.9	—	1,444.4
Depreciation and amortization	(154.5)	(156.5)	(201.8)	(121.1)	(5.5)	(639.4)
Gross margin	231.0	217.8	185.9	175.8	(5.5)	805.0
Gain (loss) on disposition of assets	0.1	(13.8)	0.5	(4.8)	—	(18.0)
General and administrative	—	—	—	—	(124.8)	(124.8)
Interest expense, net of interest income	—	—	—	—	(245.0)	(245.0)
Loss on extinguishment of debt	—	—	—	—	(6.2)	(6.2)
Loss from unconsolidated affiliate investments	—	—	—	—	(5.6)	(5.6)
Other income	—	—	—	—	0.8	0.8
Income (loss) before non-controlling interest and income taxes	$ 231.1	$ 204.0	$ 186.4	$ 171.0	$ (386.3)	$ 406.2
Capital expenditures	$ 210.2	$ 33.7	$ 63.8	$ 22.8	$ 7.1	$ 337.6

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2021						
Natural gas sales	$ 609.4	$ 693.5	$ 213.4	$ 150.0	$ —	$ 1,666.3
NGL sales	0.9	3,353.1	2.0	1.1	—	3,357.1
Crude oil and condensate sales	677.4	212.0	81.2	—	—	970.6
Product sales	1,287.7	4,258.6	296.6	151.1	—	5,994.0
NGL sales—related parties	1,008.4	129.7	630.8	447.0	(2,215.9)	—
Crude oil and condensate sales—related parties	—	—	0.1	7.1	(7.2)	—
Product sales—related parties	1,008.4	129.7	630.9	454.1	(2,223.1)	—
Gathering and transportation	46.8	64.7	186.9	157.0	—	455.4
Processing	29.1	2.4	98.7	108.3	—	238.5
NGL services	—	82.6	—	0.3	—	82.9
Crude services	18.4	39.3	12.8	0.7	—	71.2
Other services	0.2	1.7	0.6	0.5	—	3.0
Midstream services	94.5	190.7	299.0	266.8	—	851.0
Crude services—related parties	—	—	0.3	—	(0.3)	—
Other services—related parties	—	2.4	—	—	(2.4)	—
Midstream services—related parties	—	2.4	0.3	—	(2.7)	—
Revenue from contracts with customers	2,390.6	4,581.4	1,226.8	872.0	(2,225.8)	6,845.0
Realized loss on derivatives	(75.6)	(42.3)	(22.6)	(6.2)	—	(146.7)
Change in fair value of derivatives	(7.7)	0.7	—	(5.4)	—	(12.4)
Total revenues	2,307.3	4,539.8	1,204.2	860.4	(2,225.8)	6,685.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,996.1)	(4,091.2)	(796.6)	(531.8)	2,225.8	(5,189.9)
Adjusted gross margin	311.2	448.6	407.6	328.6	—	1,496.0
Operating expenses	(81.5)	(123.7)	(80.0)	(77.7)	—	(362.9)
Segment profit	229.7	324.9	327.6	250.9	—	1,133.1
Depreciation and amortization	(139.9)	(141.0)	(204.3)	(114.3)	(8.0)	(607.5)
Gross margin	89.8	183.9	123.3	136.6	(8.0)	525.6
Impairments	—	(0.6)	—	—	(0.2)	(0.8)
Gain on disposition of assets	—	1.2	—	0.3	—	1.5
General and administrative	—	—	—	—	(107.5)	(107.5)
Interest expense, net of interest income	—	—	—	—	(225.6)	(225.6)
Loss from unconsolidated affiliate investments	—	—	—	—	(11.5)	(11.5)
Other income	—	—	—	—	0.2	0.2
Income (loss) before non-controlling interest and income taxes	$ 89.8	$ 184.5	$ 123.3	$ 136.9	$ (352.6)	$ 181.9
Capital expenditures	$ 141.6	$ 9.3	$ 30.4	$ 11.9	$ 2.8	$ 196.0

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

Segment Identifiable Assets:	December 31, 2023	December 31, 2022
Permian	$ 2,813.6	$ 2,661.4
Louisiana	2,031.8	2,310.7
Oklahoma	2,275.8	2,420.4
North Texas	1,017.7	1,094.6
Corporate (1)	696.6	381.1
Total identifiable assets	$ 8,835.5	$ 8,868.2

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

(15) Supplemental Cash Flow Information

The following schedule summarizes cash paid for interest, cash paid (refunded) for income taxes, cash paid for operating leases included in cash flows from operating activities, non-cash investing activities, and non-cash financing activities for the periods presented (in millions):

	Year Ended December 31,		
Supplemental disclosures of cash flow information:	**2023**	**2022**	**2021**
Cash paid for interest (1)	$ 266.9	$ 221.1	$ 208.8
Cash paid for income taxes	$ 0.3	$ 0.7	$ 0.3
Cash paid for operating leases included in cash flows from operating activities	$ 35.1	$ 30.5	$ 24.6
Non-cash investing activities:			
Non-cash accrual of property and equipment	$ 41.1	$ 4.2	$ 12.0
Non-cash right-of-use assets obtained in exchange for operating lease liabilities	$ 36.5	$ 33.4	$ 18.7
Non-cash acquisitions	$ —	$ 1.3	$ 16.9
Non-cash financing activities:			
Redemption of mandatorily redeemable non-controlling interest	$ —	$ (6.5)	$ —

(1) Includes cash paid to ENLC for interest of $121.9 million, $66.3 million, and $53.2 million for the years ended December 31, 2023, 2022, 2021, respectively.

(16) 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:	December 31, 2023	December 31, 2022
Product inventory	$ 46.4	$ 147.1
Prepaid expenses and other	19.1	20.2
Other current assets	$ 65.5	$ 167.3

Other current liabilities:	December 31, 2023	December 31, 2022
Accrued interest	$ 26.5	$ 26.6
Accrued wages and benefits, including taxes	23.2	38.1
Accrued ad valorem taxes	33.3	32.0
Accrued settlement of mandatorily redeemable non-controlling interest (1)	—	10.5
Capital expenditure accruals	64.6	23.4
Short-term lease liability	28.2	26.2
Operating expense accruals	21.5	18.5
Other	41.9	23.3
Other current liabilities	$ 239.2	$ 198.6

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