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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

(Exact name of registrant as specified in its charter)	Commission file number	State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)
Crestwood Equity Partners LP	001-34664	Delaware	43-1918951
Crestwood Midstream Partners LP	001-35377	Delaware	20-1647837

811 Main Street	Suite 3400	Houston	Texas	77002
(Address of principal executive offices)				(Zip code)

(832) 519-2200
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

	Title of each class	Trading Symbol	Name of each exchange on which registered
Crestwood Equity Partners LP	Common Units representing limited partnership interests	CEQP	New York Stock Exchange
Crestwood Equity Partners LP	Preferred Units representing limited partner interests	CEQP-P	New York Stock Exchange
Crestwood Midstream Partners LP	None	None	None

Securities registered pursuant to Section 12(g) of the Act:

Crestwood Equity Partners LP	None
Crestwood Midstream Partners LP	None

Indicate by check mark if registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act.

Crestwood Equity Partners LP	Yes ☒ No ☐
Crestwood Midstream Partners LP	Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

Crestwood Equity Partners LP	Yes ☐ No ☒
Crestwood Midstream Partners LP	Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Crestwood Equity Partners LP	Yes ☒ No ☐
Crestwood Midstream Partners LP	Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Crestwood Equity Partners LP	Yes ☒ No ☐
Crestwood Midstream Partners LP	Yes ☒ No ☐

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

Crestwood Equity Partners LP	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Crestwood Midstream Partners LP	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

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

Crestwood Equity Partners LP	☐
Crestwood Midstream Partners LP	☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Crestwood Equity Partners LP	☒
Crestwood Midstream Partners LP	☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Crestwood Equity Partners LP	☐
Crestwood Midstream Partners LP	☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

Crestwood Equity Partners LP	☐
Crestwood Midstream Partners LP	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Crestwood Equity Partners LP	Yes ☐ No ☒
Crestwood Midstream Partners LP	Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2022).

Crestwood Equity Partners LP	$1.7 billion
Crestwood Midstream Partners LP	None

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (February 17, 2023).

Crestwood Equity Partners LP	105,356,560
Crestwood Midstream Partners LP	None

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents are incorporated by reference into the indicated parts of this report:

Crestwood Equity Partners LP	Portions of Crestwood Equity Partners LP's Proxy Statement for the 2023 Annual Meeting of Stockholders are incorporated by reference into Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K
Crestwood Midstream Partners LP	None

Crestwood Midstream Partners LP, as a wholly-owned subsidiary of a reporting company, meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this report with the reduced disclosure format as permitted by such instruction.

FILING FORMAT

This Annual Report on Form 10-K is a combined report being filed by two separate registrants: Crestwood Equity Partners LP and Crestwood Midstream Partners LP. Crestwood Midstream Partners LP is a wholly-owned subsidiary of Crestwood Equity Partners LP. Information contained herein related to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrant.

Item 15 of Part IV of this Annual Report includes separate financial statements (i.e., balance sheets, statements of operations, statements of comprehensive income, statements of partners' capital and statements of cash flows, as applicable) for Crestwood Equity Partners LP and Crestwood Midstream Partners LP. The notes accompanying the financial statements are presented on a combined basis for each registrant. Management's Discussion and Analysis of Financial Condition and Results of Operations included under Item 7 of Part II is presented for each registrant.

CRESTWOOD EQUITY PARTNERS LP
CRESTWOOD MIDSTREAM PARTNERS LP
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GLOSSARY

The terms below are common to our industry and used throughout this report.

/d	per day
AOD	Area of dedication, which means the acreage dedicated to a company by an oil and/or natural gas producer under one or more contracts.
ASU	Accounting Standards Update
Barrels (Bbls)	One barrel of petroleum products equal to 42 U.S. gallons.
Bcf	One billion cubic feet of natural gas. A standard volume measure of natural gas products.
Cycle	A complete withdrawal and injection of working gas. Cycling refers to the process of completing one cycle.
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
U.S. GAAP	Generally Accepted Accounting Principles in the United States
HP	Horsepower
Hub	Geographic location of a storage facility and multiple pipeline interconnections
Hub services	With respect to our natural gas storage and transportation operations, the following services: (i) interruptible storage services, (ii) firm and interruptible park and loan services, (iii) interruptible wheeling services, and (iv) balancing services.
Injection rate	The rate at which a customer is permitted to inject natural gas into a natural gas storage facility.
MBbls	One thousand barrels
MMBbls	One million barrels
MMcf	One million cubic feet of natural gas
Mscf	One thousand standard cubic feet
Natural gas	A gaseous mixture of hydrocarbon compounds, primarily methane together with varying quantities of ethane, propane, butane and other gases.
Natural Gas Act	Federal law enacted in 1938 that established the FERC's authority to regulate interstate pipelines.
Natural gas liquids (NGLs)	Those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. NGLs include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).
NYSE	New York Stock Exchange
SEC	Securities and Exchange Commission
Withdrawal rate	The rate at which a customer is permitted to withdraw gas from a natural gas storage facility.

FORWARD-LOOKING INFORMATION

This report, including information included or incorporated by reference herein, contains forward-looking statements concerning the financial condition, results of operations, plans, objectives, future performance and business of our company and its subsidiaries. These forward-looking statements include:

- statements that are not historical in nature, including, but not limited to: (i) our belief that anticipated cash from operations, cash distributions from entities that we control, and borrowing capacity under our credit facility will be sufficient to meet our anticipated liquidity needs for the foreseeable future; (ii) our belief that we do not have material potential liability in connection with legal proceedings that would have a significant financial impact on our consolidated financial condition, results of operations or cash flows; and (iii) our belief that our assets will continue to benefit from the development of unconventional shale plays as significant supply basins; and

- statements preceded by, followed by or that contain forward-looking terminology including the words “believe,” “expect,” “may,” “will,” “should,” “could,” “anticipate,” “estimate,” “intend” or the negation thereof, or similar expressions.

Forward-looking statements are not guarantees of future performance or results. They involve risks, uncertainties and assumptions. Actual results may differ materially from those contemplated by the forward-looking statements due to, among others, the following factors:

- our ability to successfully implement our business plan for our assets and operations;
- governmental legislation and regulations;
- industry and global factors that influence the supply of and demand for crude oil, natural gas and NGLs;
- industry factors that influence the demand for services in the markets (particularly unconventional shale plays) in which we provide services;
- weather conditions;
- outbreak of illness, pandemic or any other public health crisis, including the COVID-19 pandemic;
- the availability of crude oil, natural gas and NGLs, and the price of those commodities, to consumers relative to the price of alternative and competing fuels;
- the availability of storage and transportation infrastructure for hydrocarbons;
- the ability of members of the Organization of Petroleum Exporting Countries (OPEC) and other oil-producing countries to agree and maintain oil price and production controls;
- changes in global economic conditions, including capital and credit market conditions, inflation and interest rates;
- costs or difficulties related to the integration of acquisitions;
- environmental claims;
- operating hazards and other risks incidental to the provision of midstream services, including gathering, compressing, treating, processing, fractionating, transporting and storing energy products (i.e., crude oil, NGLs and natural gas) and related products (i.e., produced water);
- the price and availability of debt and equity financing, including our ability to raise capital through alternatives like joint ventures; and
- the ability to sell or monetize assets, to reduce indebtedness, to repurchase our equity securities, to make strategic investments, or for other general partnership purposes.

Additional discussion of factors that may affect our forward-looking statements appear elsewhere in this report, including Part I, Item 1A. Risk Factors and Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations. When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. These factors could cause our actual results to differ materially from those contained in any forward-looking statement. Except as required by applicable laws, we do not intend to update these forward-looking statements and information.

SUMMARY RISK FACTORS

Our business is subject to varying degrees of risk and uncertainty. Investors should consider the risks and uncertainties summarized below, as well as the risks and uncertainties discussed in Part I, Item 1A. Risk Factors of this Annual Report on Form 10-K. Additional risks not presently known to us or that we currently deem immaterial may also affect us. If any of these risks occur, our business, financial condition or results of operations could be materially and adversely affected.

Risks Inherent in Our Business

- Our business depends on hydrocarbon supply and demand fundamentals, which can be adversely affected by numerous factors outside of our control.
- The widespread outbreak of an illness, pandemic (like COVID-19) or any other public health crisis may have material adverse effects on our business, financial position, results of operations and/or cash flows.
- Our future growth may be limited if we are unable to complete successful, accretive growth projects.
- Our ability to finance new growth projects and make capital expenditures may be limited by our access to the capital markets or ability to raise investment capital at a cost of capital that allows for accretive midstream investments.
- The growth projects we complete may not perform as anticipated.
- We may rely upon third-party assets to operate our facilities, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such third-party assets.
- A substantial portion of our revenue is derived from our operations in the Williston Basin, and due to such geographic concentration, adverse developments in the Williston Basin could impact our financial condition and results of operations.
- Our gathering and processing operations depend, in part, on drilling and production decisions of others.
- We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flows and results of operations.
- Our storage and logistics operations are seasonal and generally have lower cash flows in certain periods during the year, which may require us to borrow money to fund our working capital needs of these businesses.
- Counterparties to our commodity derivative and physical purchase and sale contracts in our storage and logistics operations may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.
- Our storage and logistics operations and certain of our gathering and processing operations are subject to commodity risk, basis risk or risk of adverse market conditions, which can adversely affect our financial condition and results of operations.
- Changes in future business conditions could cause our long-lived assets and goodwill to become impaired, and our financial condition and results of operations could suffer if we record future impairments of long-lived assets and goodwill.
- Our level of indebtedness could adversely affect our ability to raise additional capital to fund operations, limit our ability to react to changes in our business or industry, and place us at a competitive disadvantage.
- Restrictions in our revolving credit facility and indentures governing our senior notes could adversely affect our business, financial condition, results of operations and ability to make distributions.
- A change of control could result in us facing substantial repayment obligations under our Crestwood Midstream revolving credit facility and indentures governing our senior notes.
- Our ability to make cash distributions may be diminished, and our financial leverage could increase, if we are not able to obtain needed capital or financing on satisfactory terms.
- A downgrade of our credit ratings could impact our and our subsidiaries' liquidity, access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.
- We operate joint ventures that may limit our operational flexibility.
- We may not be able to renew or replace expiring contracts.
- Inflation could adversely impact our ability to control operating expenses and capital costs, increase our level of indebtedness and adversely impact our customer base. The fees we charge to customers under our contracts may not escalate sufficiently to cover our cost increases, which could negatively impact our business, financial condition and results of operations.
- Our contracts may be suspended in some circumstances.

- We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and the inability to do so may disrupt our business and hinder our ability to grow.

Risks Related to Regulatory Matters

- Increasing attention to environmental, social and governance (ESG) matters may impact our business.
- Our operations are subject to extensive regulation, and regulatory measures adopted by regulatory authorities could have a material adverse effect on our business, financial condition and results of operations.
- A change in the jurisdictional characterization of our gathering assets may result in increased regulation, which could cause our revenues to decline and operating expenses to increase.
- Our operations are subject to compliance with environmental and operational health and safety laws and regulations that may expose us to significant costs and liabilities.

Risks Inherent to an Investment in our Equity

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses to enable us to pay quarterly distributions to our common and preferred unitholders.
- Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow given the current trends existing in the capital markets.
- We may issue additional common units without common unitholder approval, which would dilute existing common unitholder ownership interests.
- Common unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.
- The amount of cash we have available for distribution to common unitholders depends primarily on our cash flow (including distributions from joint ventures) and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.
- The control of our general partner may be transferred to a third party without unitholder consent.
- Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

Risks Related to our Tax Matters

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.
- The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly applied on a retroactive basis.
- If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.
- If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.
- Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.
- Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.
- Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.
- Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.
- We will treat each purchaser of our units as having the same tax benefits without regard to the specific units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our units.

PART I

Item 1. Business

Unless the context requires otherwise, references in this report to (i) “we,” “us,” “our,” “ours,” “our Company,” the “Company,” the “Partnership,” “Crestwood Equity,” “CEQP,” and similar terms refer to either Crestwood Equity Partners LP itself or Crestwood Equity Partners LP and its consolidated subsidiaries, as the context requires, and (ii) “Crestwood Midstream” and “CMLP” refers to Crestwood Midstream Partners LP itself or Crestwood Midstream Partners LP and its consolidated subsidiaries, as the context requires. Unless otherwise indicated, information contained herein is reported as of December 31, 2022.

Introduction

Crestwood Equity, a Delaware limited partnership formed in March 2001, is a master limited partnership (MLP) that develops, acquires, owns or controls, and operates primarily fee-based assets and operations within the energy midstream sector. Headquartered in Houston, Texas, we provide broad-ranging infrastructure solutions across the value chain to service premier liquids-rich natural gas and crude oil shale plays across the United States. We own and operate a diversified portfolio of NGL, crude oil, natural gas and produced water gathering, processing, storage, disposal and transportation assets that connect fundamental energy supply with energy demand across North America. Our primary business objective is to maximize the value of Crestwood Equity for our unitholders. Crestwood Equity’s common units representing limited partner interests are listed on the NYSE under the symbol “CEQP” and its preferred units representing limited partner interests are listed on the NYSE under the symbol “CEQP-P.”

Crestwood Equity is a holding company. All of our consolidated operating assets are owned by or through our wholly-owned subsidiary, Crestwood Midstream, a Delaware limited partnership. In addition, we have equity investments in joint ventures through which we operate certain of their respective assets.

Strategic Transactions

During 2022, we completed a number of strategic transactions that we believe will position the Company to become a stronger, better capitalized company, and we continued to execute on our strategy of maximizing unitholder value through portfolio optimization and the reinvestment of cash flow and divestiture proceeds into the balance sheet, common unit repurchases, common unit and preferred unit distributions, and high returning investment opportunities. These strategic transactions included: (i) the merger with Oasis Midstream Partners LP (Oasis Midstream); (ii) the acquisition of Sendero Midstream Partners; LP (Sendero); (iii) the acquisition of First Reserve Management, L.P.’s (First Reserve) 50% equity interest in Crestwood Permian Basin Holdings LLC (Crestwood Permian); (iv) the divestiture of our Barnett Shale assets; (v) the divestiture of our Marcellus Shale assets; and (vi) the anticipated divestiture of our Tres Palacios Holdings LLC (Tres Holdings) equity investment.

Oasis Merger

On February 1, 2022, we acquired Oasis Midstream in an equity and cash transaction valued at approximately $1.8 billion (Oasis Merger). Pursuant to the merger agreement, Oasis Petroleum Inc., now known as Chord Energy Corporation (Chord), received $150 million in cash plus 20.9 million newly issued CEQP common units in exchange for its 33.8 million common units held in Oasis Midstream. In addition, Oasis Midstream’s public unitholders received 12.9 million newly issued CEQP common units in exchange for the 14.8 million Oasis Midstream common units held by them. Additionally, under the merger agreement, Chord received a $10 million cash payment for its ownership of the general partner of Oasis Midstream. The assets acquired in the Oasis Merger consist of the Rough Rider system and the Panther system, which are described below in “*Description of Our Assets*.” This transaction further solidifies Crestwood’s competitive position in the Williston and Delaware Basins and expands the Company’s relationship with Chord. Additionally, the Rough Rider system is complementary with our Arrow system, which has provided and continues to provide opportunities to drive cost savings, commercial synergies and better utilization of available gas processing capacity.

Sendero and CPJV Acquisitions

On July 11, 2022, we acquired Sendero, a privately-held midstream company for cash consideration of approximately $631 million (Sendero Acquisition). The Sendero assets, which consist of the Carlsbad system, are located in Eddy County, New Mexico and provide natural gas gathering, compression and processing services to customers in the Delaware Basin. Also, on July 11, 2022, we acquired First Reserve's 50% equity interest in Crestwood Permian in exchange for approximately $6 million in cash and approximately 11.3 million newly issued CEQP common units (CPJV Acquisition). Prior to the CPJV Acquisition, we owned a 50% equity interest in Crestwood Permian, which we accounted for under the equity method of accounting. As a result of the CPJV Acquisition, we control and own 100% of the equity interests in Crestwood Permian. The assets acquired in the CPJV Acquisition consist of the Willow Lake, Orla and Desert Hills systems. The Sendero assets are complementary to Crestwood Permian's assets and are being integrated with minimal capital investment, which we expect will enable the Company to capture substantial cost and commercial synergies. The Sendero Acquisition and the CPJV Acquisition significantly increased the Company's position in the Delaware Basin. See *"Description of Our Assets"* below for further details on the Sendero and Crestwood Permian assets acquired.

Barnett and Marcellus Shale Divestitures

On July 1, 2022, we sold our assets in the Barnett Shale to EnLink Midstream, LLC (EnLink) for approximately $290 million, including working capital adjustments. The Barnett Shale assets consisted of our gathering and processing systems located in Hood, Somervell, Johnson, Tarrant and southern Denton Counties, Texas. On October 25, 2022, we sold our Marcellus Shale assets to Antero Midstream Corporation (Antero) for approximately $206 million. The Marcellus Shale assets consisted of gathering and compression systems in Harrison and Doddridge Counties, West Virginia. These divestitures represent a full exit of our gathering and processing operations in the Barnett and Marcellus Shales and allow the Company to focus on building and optimizing its assets in the Williston, Delaware and Powder River Basins, which best positions the Company to deliver long-term value to its unitholders.

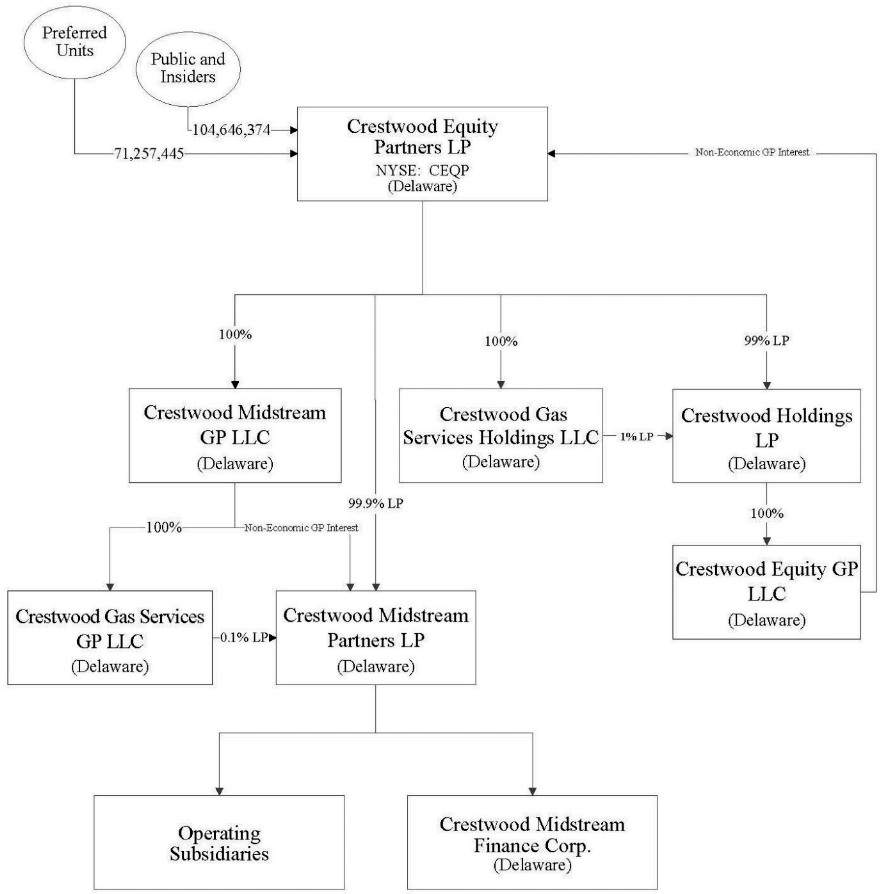
Tres Holdings Divestiture

On February 20, 2023, we and BIF II Tres Palacios Aggregator (Delaware) LLC (Brookfield) entered into an agreement with a third party to sell each of our respective interests in Tres Holdings for total consideration of approximately $335 million. The transaction is expected to close in the second quarter of 2023, subject to customary closing conditions.

For a further discussion of these strategic transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3 and Note 6.

Ownership Structure

The diagram below reflects a simplified version of our ownership structure as of December 31, 2022:



Description of Our Assets

We conduct our operations through Crestwood Midstream and its consolidated subsidiaries and our joint ventures. Our financial statements reflect three operating and reporting segments: (i) gathering and processing north operations (includes our Williston Basin and Powder River Basin operations); (ii) gathering and processing south operations (includes our Delaware Basin operations and an equity method investment); and (iii) storage and logistics operations (includes our crude oil, NGL and natural gas storage and logistics operations and two equity method investments).

Gathering and Processing North Segment

Our gathering and processing north operations provide natural gas gathering, compression, treating and processing services, crude oil gathering and storage services and produced water gathering and disposal services to producers in the Williston Basin and Powder River Basin. Our gathering and processing north segment's operating assets consist of: (i) natural gas facilities with approximately 818 MMcf/d of gathering capacity and approximately 775 MMcf/d of processing capacity; (ii) crude oil facilities with approximately 250 MBbls/d of gathering capacity and 496,000 Bbls of storage capacity; and (iii) produced water facilities with approximately 421 MBbls/d of gathering and disposal capacity.

Williston Basin

We own and operate the Arrow and Rough Rider systems which consist of integrated crude oil, rich natural gas and produced water gathering systems, natural gas processing facilities (Bear Den and Wild Basin), crude oil storage facilities and produced water disposal facilities. The Arrow and Rough Rider systems are located in the core of the Bakken Shale primarily in McKenzie and Dunn Counties, North Dakota, with the Arrow system primarily located on the Fort Berthold Indian Reservation.

The Rough Rider system connects to the Arrow crude oil system and is capable of transporting all of its crude oil volumes to the Arrow system. The Arrow system currently connects to the Dakota Access Pipeline (DAPL), Kinder Morgan Inc. (Kinder Morgan) Hiland, Tesoro High Plains Pipeline Company LLC (Tesoro) and True Companies' Bridger Four Bears pipelines, providing significant downstream delivery capacity for our Arrow and Rough Rider customers. Additionally, we can transport Arrow and Rough Rider crude oil volumes to our COLT Hub facility by pipeline or truck, which mitigates the impact of any potential pipeline shut-downs to our producers with the ability to access multiple markets out of the basin. In addition to the multiple pipeline take-away outlets, the Arrow and Rough Rider systems have 496,000 Bbls of crude oil working storage capacity.

Powder River Basin

We own and operate the Jackalope rich natural gas gathering system, the Continental Express high pressure pipeline and the Bucking Horse gas processing facility in Converse County, Wyoming.

The table below details certain information about our gathering and processing north segment as of December 31, 2022:

Basin (System)	**Gathering Capacity**	**2022 Average Gathering Volumes**	**Number of In-Service Processing Plants**	**Processing Capacity (MMcf/d)**	**Gross Acreage Dedication**
Williston Basin Arrow and Rough Rider	420 MMcf/d - natural gas 250 MBbls/d - crude oil 421 MBbls/d - produced water	247 MMcf/d - natural gas 78 MBbls/d - crude oil 165 MBbls/d - produced water	4	430	550,000
Powder River Basin Jackalope	398 MMcf/d - natural gas	106 MMcf/d - natural gas	2	345	400,000

The table below summarizes certain contract information of our gathering and processing north segment as of December 31, 2022:

Basin	**Type of Contracts**	**Weighted Average Remaining Contract Terms (in years)**	**Major Customers**
Williston Basin	Fixed-fee, percentage-of-proceeds	9	Chord Energy Corporation, Devon Energy Corporation, Enerplus Resources (USA) Corporation
Powder River Basin	Fixed-fee	13	Continental Resources, Inc., Occidental Petroleum Corporation (Oxy)

Our gathering and processing north segment provides services under a variety of contracts. Although the cash flows from these operations are predominantly fee-based under contracts with remaining terms ranging from 2 - 14 years, the results of our operations are significantly influenced by the volumes gathered and processed through our systems. The cash flows from these operations can also be impacted in the short term by changing commodity prices, seasonality, weather fluctuations and the financial condition of our customers. Our election to enter primarily into fixed-fee contracts subject to acreage dedication helps minimize our long-term exposure to commodity prices and its impact on the financial condition of our customers, and provides us more stable operating performance and cash flows.

Gathering and Processing South Segment

Our gathering and processing south operations provide natural gas gathering, compression and processing services, crude oil gathering services and produced water gathering and disposal services to producers in the Delaware Basin. Our gathering and processing south segment's operating assets consist of: (i) natural gas facilities with 1.1 Bcf/d of gathering capacity and 613 MMcf/d of processing capacity; (ii) crude oil facilities with approximately 90 MBbls/d of gathering capacity; and (iii) produced water facilities with approximately 354 MBbls/d of gathering and disposal capacity.

Delaware Basin

We own and operate the Willow Lake, Orla, Carlsbad, Desert Hills and Panther systems, which consist of rich natural gas gathering systems, natural gas processing facilities (Orla and Carlsbad), a produced water gathering and disposal system (Desert Hills), and a produced water gathering and disposal system and a crude oil gathering system (Panther). The Willow Lake and

Carlsbad systems' gathering operations are located in Eddy County, New Mexico and are highly complementary to each other. The Orla natural gas processing facility is located in Reeves County, Texas. Our Desert Hills and Panther systems' produced water and crude oil gathering operations are located in Culberson, Reeves, Winkler, Loving and Ward Counties, Texas.

We also own an undivided interest in 80,000 Bbls/d of capacity in a segment of the Epic Y-Grade Pipeline, LP (EPIC) pipeline from Orla, Texas to Benedum, Texas.

Crestwood Permian Basin Equity Investment

Our gathering and processing south segment also includes our 50% equity interest in Crestwood Permian Basin LLC (Crestwood Permian Basin). A subsidiary of Shell plc owns the remaining 50% equity interest. Crestwood Permian Basin owns the Nautilus natural gas gathering system, which is operated by subsidiaries of Crestwood Midstream. Crestwood Permian Basin has a long-term fixed-fee gathering agreement with a subsidiary of ConocoPhillips Company (ConocoPhillips), under which Permian Delaware Enterprise has dedicated the gathering rights for its gas production across a large acreage position in Loving, Reeves and Ward Counties, Texas to Crestwood Permian Basin.

The table below details certain information about our gathering and processing south segment (including our equity investment and its operations) as of December 31, 2022:

Delaware Basin (System)	Gathering Capacity	2022 Average Gathering Volumes	Number of In-Service Processing Plants	Processing Capacity(1) (MMcf/d)	Gross Acreage Dedication
Willow Lake/Orla	596 MMcf/d - natural gas	164 MMcf/d - natural gas	1	263	19,000
Carlsbad	326 MMcf/d - natural gas	186 MMcf/d - natural gas	2	350	80,000
Desert Hills	125 MBbls/d - produced water	68 MBbls/d - produced water	—	—	30,000
Panther	90 MBbls/d - crude oil 229 MBbls/d - produced water	21 MBbls/d - crude oil 63 MBbls/d - produced water	—	—	96,000
Nautilus	217 MMcf/d - natural gas	122 MMcf/d - natural gas	—	—	94,000

(1) Includes capacity of processing plants that are in service and not in service.

The table below summarizes certain contract information of our gathering and processing south segment (including our equity investment and its operations) as of December 31, 2022:

Delaware Basin (System)	Type of Contracts	Weighted Average Remaining Contract Terms (in years)	Major Customers
Willow Lake/Orla	Fixed-fee, percentage-of-proceeds	9	Novo Oil & Gas Northern Delaware LLC, Mewbourne Oil Company (Mewbourne), ConocoPhillips
Carlsbad	Fixed-fee, percentage-of-proceeds	4	Mewbourne, Marathon Oil Permian LLC, BTA Oil Producers LLC, Kaiser Francis Oil Company
Desert Hills	Fixed-fee	7	ConocoPhillips
Panther	Fixed-fee	12	Percussion Petroleum, LLC
Nautilus	Fixed-fee	14	ConocoPhillips, Battalion Oil Corporation

Our gathering and processing south segment provides services under a variety of contracts. Although the cash flows from these operations are predominantly fee-based under contracts with remaining terms ranging from 1 - 14 years, the results of our operations are significantly influenced by the volumes gathered and processed through our systems. The cash flows from these operations can also be impacted in the short term by changing commodity prices, seasonality, weather fluctuations and the financial condition of our customers. Our election to enter primarily into fixed-fee contracts subject to acreage dedications helps minimize our long-term exposure to commodity prices and their impact on the financial condition of our customers and provides us more stable operating performance and cash flows.

Storage and Logistics Segment

Our storage and logistics operations provide NGL, crude oil and natural gas storage, terminal, marketing and transportation (including rail, truck and pipeline) services to producers, refiners, marketers, utilities and other customers.

Below is a description of our storage and logistics operating assets, including those of our equity method investments.

- ***NGL Storage Facilities.*** Consists of approximately 10 MMBbls of NGL storage capacity located in Pennsylvania, South Carolina, Mississippi, Michigan, New York and Indiana, with receipts and deliveries that are supported by both rail cars and third party pipelines, allowing truck and rail access to local markets.
- ***NGL Terminals and Transportation.*** Includes a fleet of rail and rolling stock with approximately 1.6 MMBbls/d of NGL pipeline, terminal and transportation capacity, which also includes our rail-to-truck terminals located in Michigan, Indiana, Ohio, New Hampshire, Pennsylvania, New Jersey, New York, Rhode Island, North Carolina, South Carolina and Mississippi. We provide hauling services to customers primarily in the Central Mid-Continent and East Coast of the United States.
- ***COLT Hub.*** The COLT Hub consists of our integrated crude oil loading, storage and pipeline terminal located in the heart of the Williston Basin in Williams County, North Dakota. The COLT Hub has approximately 1.2 MMBbls of crude oil storage capacity and 160,000 Bbls/d of rail loading capacity. Customers can source crude oil for rail loading through interconnected gathering systems, a twelve-bay truck unloading rack and the COLT Connector, a 21-mile 10-inch bi-directional proprietary pipeline that connects the COLT terminal to our storage tank facility at Dry Fork (Beaver Lodge/Ramberg junction). The COLT Hub is connected to the Meadowlark Midstream Company, LLC crude oil pipeline, Kinder Morgan Hiland crude oil pipelines and the DAPL interstate pipeline system at the COLT terminal, and the Enbridge Energy Partners, L.P. and Marathon interstate pipeline systems at Dry Fork. The pipelines and truck unloading racks connected to the COLT Hub can deliver up to approximately 290,000 Bbls/d of crude oil to our terminal.
- ***Natural Gas Storage Facility.*** We own a 50.01% equity interest in Tres Holdings, a joint venture between CMLP Tres Manager LLC, our wholly-owned subsidiary, and Brookfield, which owns the remaining 49.99% equity interest in Tres Holdings. Tres Palacios Gas Storage LLC (Tres Palacios), a wholly-owned subsidiary of Tres Holdings, owns a FERC-certificated 34.9 Bcf multi-cycle salt dome natural gas storage facility located in Markham, Texas, with a FERC-certificated maximum injection rate of 1,000 MMcf/d and a maximum withdrawal rate of 2,500 MMcf/d. The Tres Palacios natural gas storage facility's 63-mile, 24-inch diameter header system (including a 38-mile dual 24-inch diameter system, a 20-mile north pipeline lateral and an approximate 5-mile south pipeline lateral) interconnects with 12 pipeline systems and can receive residue gas from the tailgate of Kinder Morgan's Houston central processing plant.
- ***Powder River Basin Crude Oil Facilities.*** We own a 50.01% equity interest in Powder River Basin Industrial Complex, LLC (PRBIC), a joint venture between Crestwood Crude Logistics LLC, our wholly-owned subsidiary and Twin Eagle Powder River Basin, LLC (Twin Eagle). PRBIC owns an integrated crude oil loading, storage and pipeline terminal located in Douglas County, Wyoming. PRBIC, which is operated by Twin Eagle, sources crude oil production from Powder River Basin producers through an eight-bay truck unloading rack. The PRBIC facility includes 20,000 Bbls/d of rail loading capacity and 380,000 Bbls of crude oil working storage capacity. The pipeline terminal includes connections to Kinder Morgan's Double H Pipeline system and Plains All American Pipeline, L.P.'s (Plains) Rocky Mountain Pipeline system.

The table below summarizes certain contract information about our COLT Hub operations, our Tres Holdings equity investment and our PRBIC equity investment as of December 31, 2022:

Facility	Type of Contracts[(1)]	Weighted Average Remaining Contract Terms	Major Customers
COLT	Fixed-Fee, Firm	Less than 1 year	BP Products North America, Inc (BP), Flint Hills Resources
Tres Palacios	Firm[(2)]	2 years	BP, Trafigura Trading LLC
PRBIC	Fixed-Fee, Firm	Less than 1 year	Texon L.P.

(1) Fixed-fee contracts represent contracts in which our customers agree to pay a flat rate based on the amount of crude oil transported or stored. Firm contracts represent contracts whereby our customers agree to pay for a specified amount of storage or transportation capacity, whether or not the capacity is utilized.

(2) Tres Palacios has approximately 29.2 Bcf of firm storage contracts at December 31, 2022.

The cash flows from our COLT Hub operations are predominantly fee-based under contracts with terms ranging from six months to one year. Our current cash flows from crude-by-rail facilities are supported by contracts with refiners and marketers. The rates and durations of the contracts associated with our crude oil terminals have eroded as pipelines have come on-line that make crude-by-rail options less economical, which impacts our cash flows from operations. The cash flows from our Tres

Palacios joint venture are predominantly fee-based under contracts with remaining terms ranging from one to six years. Cash flows from interruptible and other hub services provided by our Tres Palacios joint venture tend to increase during the peak winter season. The cash flows from our other storage and logistics operations represent sales to creditworthy customers typically under contracts with durations of one year or less, and tend to be seasonal in nature due to customer profiles and their tendencies to purchase NGLs during peak winter periods.

Major Customers

For the years ended December 31, 2022, 2021 and 2020, no customer accounted for more than 10% of our total consolidated revenues.

Competition

Our gathering and processing operations compete for customers based on reputation, operating reliability and flexibility, price, creditworthiness, and service offerings, including interconnectivity to producer-desired takeaway options (i.e., processing facilities and pipelines). We face strong competition in acquiring new supplies in the production basins in which we operate, and competition customarily is impacted by the level of drilling activity in a particular geographic region and fluctuations in commodity prices. Our primary competitors include other midstream companies with gathering and processing operations and producer-owned systems, and certain competitors enjoy first-mover advantages over us and may offer producers greater gathering and processing efficiencies, lower operating costs and more flexible commercial terms.

Natural gas storage and pipeline operators compete for customers primarily based on geographic location, which determines connectivity and proximity to supply sources and end-users, as well as price, operating reliability and flexibility, available capacity and service offerings. Our primary competitors in our natural gas storage market include other independent storage providers and major natural gas pipelines with storage capabilities embedded within their transmission systems. Our primary competitors in the natural gas transportation market include major natural gas pipelines and intrastate pipelines that can transport natural gas volumes between interstate systems. Long-haul pipelines often enjoy cost advantages over new pipeline projects with respect to options for delivering greater volumes to existing demand centers, and new projects and expansions proposed from time to time may serve the markets we serve and effectively displace the service we provide to customers.

Our crude oil rail terminals primarily compete with crude oil pipelines and other midstream companies that own and operate rail terminals in the markets we serve. The crude oil logistics business is characterized by strong competition for supplies, and competition is based largely on customer service quality, pricing, and geographic proximity to customers and other market hubs.

Our NGL marketing and logistics business competes primarily with integrated major oil companies, refiners and processors, and other energy companies that own or control transportation and storage assets that can be optimized for supply, marketing and logistics services.

Regulation

Our operations and investments are subject to extensive regulation by federal, state and local authorities. The regulatory burden on our operations increases our cost of doing business and, in turn, impacts our profitability. In general, midstream companies have experienced increased regulatory oversight over the past few years.

Pipeline and Underground Storage Safety

We are subject to pipeline safety regulations imposed by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline and storage facilities. All of our natural gas pipelines used in gathering, storage and transportation activities are subject to regulation by PHMSA under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), and all of our NGL and crude oil pipelines used in gathering, storage and transportation activities are subject to regulation by PHMSA under the Hazardous Liquid Pipeline Safety Act of 1979, as amended (HLPSA).

These federal statutes and PHMSA regulations collectively impose numerous safety requirements on pipeline operators, such as the development of a written qualification program for individuals performing covered tasks on pipeline facilities and the implementation of pipeline integrity management programs. For example, pursuant to the authority under the NGPSA and

HLPSA, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs to comprehensively evaluate certain high risk areas, known as high consequence areas (HCAs) and moderate consequence areas (MCAs) along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission lines, include Class 3 and 4 areas and, depending on the potential impacts of a risk event, may include Class 1 and 2 areas) whereas HCAs along crude oil and NGL pipelines are based on high-population density areas, in addition to certain drinking water sources and unusually sensitive ecological areas. MCAs are attributable to natural gas pipelines and are based on high-population areas as well as certain principal, high-capacity roadways, though they do not meet the definition of a natural gas pipeline HCA. Integrity management programs require more frequent inspections and other preventative measures to ensure pipeline safety in HCAs and MCAs.

We plan to continue testing under our pipeline integrity management programs to assess and maintain the integrity of our pipelines in accordance with PHMSA regulations. Notwithstanding our preventive and investigatory maintenance efforts, we may incur significant expenses if anomalous pipeline conditions are discovered or due to the implementation of more stringent pipeline safety standards resulting from new or amended legislation or agency rulemaking.

Legislation in the past decade has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. In particular, the NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act), the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (2016 Pipeline Safety Act) and, most recently, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 Pipeline Safety Act). Each of these laws imposed increased pipeline safety obligations on pipeline operators. The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2016 Pipeline Safety Act, among other things, required PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities. The 2020 Pipeline Safety Act reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory initiatives, including obligating operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those regulations.

With the adoption of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act and the 2020 Pipeline Safety Act, there exist mandates for PHMSA to make pipeline safety requirements more stringent, which further impose added pipeline safety requirements on operators.

- *Natural Gas Storage Facilities Rulemaking*. In February and July 2020, PHMSA published final rules that amended the minimum safety issues applicable to natural gas storage facilities, including wells, wellbore tubing and casing, and added applicable reporting requirements.
- *Natural Gas Pipeline Rulemaking*. In October 2019, PHMSA published a final rule for certain natural gas pipelines that imposes numerous requirements, including maximum allowable operating pressure (MAOP) reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage found in MCAs and Class 3 and Class 4 non-HCAs by 2033 unless the pipeline cannot be modified to permit such accommodation, and the consideration of seismicity as a risk factor in integrity management.
- *Hazardous Liquids Rulemaking*. In October 2019, PHMSA published a final rule that significantly extends and expands the reach of certain PHMSA integrity management requirements for hazardous liquid pipelines, including, for example, performance of periodic assessments and expanded use of leak detection systems, regardless of the pipeline's proximity to an HCA. Additionally, this final rule requires all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in line inspection tools by 2039 unless the pipeline cannot be modified to permit such accommodation. Moreover, this final rule extends annual, accident, and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure.
- *Natural Gas Gathering Lines Rulemaking*. In November 2021, PHMSA issued a final rule that will impose safety regulations on approximately 400,000 miles of previously unregulated onshore gas gathering lines that, among other things, provide criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures.

- *Natural Gas Pipeline Rulemaking*. In August 2022, PHMSA issued a final rule that adjusted the repair criteria for pipelines in HCAs, created new repair criteria for pipelines in non-HCAs, strengthened corrosion control requirements, mandated pipeline inspections following extreme weather events, strengthened integrity management assessment requirements, and codified a management of change process.

Separately, in June 2021, PHMSA issued an Advisory Bulletin advising pipeline and pipeline facility operators of the 2020 Pipeline Safety Act's mandate that they update their inspection and maintenance plans for the elimination of hazardous leaks and minimization of natural gas released from pipeline facilities by December 27, 2021. As required by the 2020 Pipeline Safety Act, PHMSA, together with state regulators, began their inspection of these plans in 2022 after holding a public information webinar in February 2022 that discussed key elements of the applicable regulations and provided a general overview of the review of such plans.

We are evaluating the operational and financial impact related to one or more of these laws and PHMSA rules. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act, and the 2020 Pipeline Safety Act, as well as any implementation of PHMSA regulations thereunder, or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto, could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

States are largely preempted by federal law from regulating pipeline safety for interstate pipelines, but most states are certified by the Department of Transportation to assume responsibility for enforcing intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate pipelines, states vary considerably in their authority and capacity to address pipeline safety. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements, and we do not anticipate any significant difficulty in complying with applicable state laws and regulations.

Natural Gas Gathering

Natural gas gathering facilities are exempt from FERC jurisdiction under Section 1(b) of the Natural Gas Act. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, we believe that our natural gas pipelines meet the traditional tests that the FERC has used to determine whether a pipeline is a gathering pipeline, and not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation. The FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided are not exempt from FERC regulation under the Natural Gas Act and the facility provides interstate services, the rates for, and terms and conditions of, the services provided by such facility would be subject to FERC regulation. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the Natural Gas Act or the Natural Gas Policy Act, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and complaint-based rate regulation. Our natural gas gathering operations may be subject to ratable take and common purchaser statutes in the states in which we operate. These statutes are designed to prohibit discrimination in favor of one producer over another producer, or one source of supply over another source of supply, and generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

The states in which we operate gathering systems have adopted a form of complaint-based regulation, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. To date, these regulations have not had an adverse effect on our systems. We cannot predict whether such a complaint will be filed against us in the future, however, a failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies.

Natural Gas Storage and Transportation

Our equity investments' natural gas pipelines used in gathering, storage and transportation activities are subject to regulation under the NGPSA. In response to the 2016 Pipeline Safety Act, PHMSA issued an interim final rule in December 2016 and a final rule in January 2020 imposing new safety-related requirements on downhole facilities (including wells, wellbore tubing and casing) of new and existing underground natural gas storage facilities. The final rule incorporates by reference two American Petroleum Institute Recommended Practices which address construction, maintenance, risk management and integrity management procedures for underground storage facilities. To the extent we operate or manage natural gas storage facilities owned by our equity investments, we have evaluated the final interim rules and do not anticipate any significant impact on our equity investments or any significant increase in the costs of operating and maintaining natural gas storage facilities.

The natural gas storage operations of Tres Palacios is subject to regulation by the FERC under the Natural Gas Act. Under the Natural Gas Act, the FERC has authority to regulate natural gas transportation services in interstate commerce, which includes natural gas storage services. The FERC exercises jurisdiction over (i) rates charged for services and the terms and conditions of service; (ii) the certification and construction of new facilities; (iii) the extension or abandonment of services and facilities; (iv) the maintenance of accounts and records; (v) the acquisition and disposition of facilities; (vi) standards of conduct between affiliated entities; and (vii) various other matters. Regulated natural gas companies are prohibited from charging rates determined by the FERC to be unjust, unreasonable or unduly discriminatory, and both the existing tariff rates and the proposed rates of regulated natural gas companies are subject to challenge.

The rates and terms and conditions of Tres Palacios' operations are found in its FERC-approved tariff. Tres Palacios is authorized to charge and collect market-based rates for storage services. Market-based authority allows companies to negotiate rates with individual customers based on market demand. A loss of market-based authority or any successful complaint or protest against the rates charged or provided by Tres Palacios could have an adverse impact on our results of operations.

In addition, the Energy Policy Act of 2005 amended the Natural Gas Act to (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for the sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978 and FERC rules, regulations or orders thereunder. As a result of the Energy Policy Act of 2005, the FERC has the authority to impose civil penalties for violations of these statutes and FERC rules, regulations and orders, up to approximately $1.5 million per day, per violation.

Subsurface Injection

Our produced and flowback water underground injection operations are subject to the federal Safe Drinking Water Act (SDWA) and analogous state laws and regulations. Pursuant to the SDWA, the EPA established the Underground Injection Control (UIC) program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require us to obtain a permit from the applicable regulatory agencies to operate our underground injection wells. States may add more stringent restrictions on the operation of injection wells when a permit is renewed or amended, which may result in material expenditures or impose significant restraints or financial assurances on our operations. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of UIC permits, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties claiming damage for alternative water supplies, property damages and personal injuries.

There exists a concern amongst certain public and federal and state agencies that the injection of produced and flowback water into below ground disposal wells may trigger seismic activity. In response to concerns identified by a 2016 United States Geological Survey, some federal and state agencies have investigated and continue to investigate whether such wells have caused increased seismic activity. Also, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety, including the permitting of disposal wells or otherwise to assess any relationship between seismicity and the use of such wells, which has resulted in some states restricting, suspending, or shutting down the use of such injection wells. For example, the Texas Railroad Commission (TRCC) has adopted rules governing the permitting or re-permitting of wells used to dispose of produced and flowback water and other fluids resulting from the production of crude oil and natural gas in order to address these seismic activity concerns with the state. Also, North Dakota agencies requires a map depicting the area around the location where the disposal well is proposed that depicts any known or suspected faults.

Freshwater Distribution

As freshwater availability becomes more limited, the regulatory restrictions on the use of freshwater may become more stringent. This could lead to increased flowback and produced water disposal costs. Some states have considered mandating the recycling of produced and flowback water. If such laws are passed, our producer customers may divert some produced and flowback water to recycling operations that may have otherwise been disposed of at our facilities, which could reduce the demand for our services. In addition, our sales of residual crude oil collected as part of the produced and flowback water injection process may impose liability on us in the event that the entity to which the crude oil was transferred fails to manage and dispose of residual crude oil in accordance with applicable environmental and occupational health and safety laws.

Crude Oil and NGL Transportation

The transportation of crude oil and natural gas liquids by common carrier pipelines on an interstate basis is subject to regulation by the FERC under the Interstate Commerce Act (ICA), the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. FERC regulations require interstate common carrier petroleum pipelines to file with the FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. The ICA and FERC regulations also require that such rates be just and reasonable, and to be applied in a non-discriminatory manner so as to not confer undue preference upon any shipper. Certain of our pipelines are considered common carrier pipelines subject to regulation by the FERC under the ICA.

The transportation of crude oil and natural gas liquids by common carrier pipelines on an intrastate basis is subject to regulation by state regulatory commissions. The basis for intrastate crude oil and natural gas liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil and natural gas liquids pipeline rates, varies from state to state. Intrastate common carriers must also offer service to all shippers requesting service on the same terms and under the same rates. Certain of our pipelines are intrastate common carriers under the laws of the state in which they are located. We believe that the regulation of our intrastate crude oil pipeline and natural gas liquids pipelines will not affect our operations in any materially different way than such regulation will affect the operation of our competitors.

Certain of our crude oil operations located in North Dakota are subject to state regulation by the North Dakota Industrial Commission (NDIC). For example, gas conditioning requirements established by the NDIC recently will require operators of crude by rail terminals to report to the NDIC any crude volumes received for loading that exceed federal vapor pressure limits. State legislation has been proposed that, if passed, would authorize and require the NDIC to promulgate regulations under which produced water pipelines would be required to, among other things, install leak detection facilities and post bonds to cover potential remediation costs associated with releases. Moreover, the regulation of our customers' production activities by the NDIC impacts our operations. For example, the NDIC approved additional requirements relating to site construction, underground gathering pipelines, spill containment, bonding for underground gathering pipelines and construction of berms around facilities. Additionally, the NDIC issued an order wherein the agency adopted legally enforceable "gas capture percentage goals" requiring our customers to capture certain percentages of natural gas produced by specified dates (the Gas Capture Order). The Gas Capture Order was subsequently modified in 2018. Exploration and production operators in the state may be required to install new equipment to satisfy these goals, and any failure by operators to meet these gas capture percentage goals would subject those operators to production restrictions, which could reduce the amount of commodities we gather on the Arrow system from our customers, and have a corresponding adverse impact on our business and results of operations.

Our assets in Texas include intrastate common carrier NGL pipelines subject to the regulation of the TRRC, which requires that our NGL pipelines file tariff publications containing all the rules and the regulations governing the rates and charges for services we perform. TRRC regulations also require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services.

We cannot, however, provide assurance that the FERC will not, at some point, either at the request of other entities or on its own initiative, assert that some or all of our crude oil or natural gas liquids pipelines are subject to FERC requirements for common carrier pipelines, or are otherwise not exempt from the FERC's filing or reporting requirements, or that such an assertion would not adversely affect our results of operations. In the event the FERC were to determine that our crude oil or natural gas liquids pipelines are subject to FERC requirements for common carrier pipelines, or otherwise would not qualify for a waiver from the FERC's applicable regulatory requirements, we would likely be required to (i) file a tariff with the FERC; (ii) provide a cost justification for the transportation charge; (iii) provide regulated services to all potential shippers without undue discrimination; and (iv) potentially be subject to fines, penalties or other sanctions for violations of the ICA and the FERC's regulations thereunder.

Portions of our Arrow gathering system, which is located on the Fort Berthold Indian Reservation, may be subject to applicable regulation by the Mandan, Hidatsa & Arikara Nation. An entirely separate and distinct set of laws and regulations may apply to operators and other parties within the boundaries of the Fort Berthold Indian Reservation. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and the Bureau of Land Management (BLM) promulgate and enforce regulations pertaining to oil and gas operations on Native American lands. These regulations include lease provisions, environmental standards, tribal employment preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and the BLM. However, Native American tribes possess certain inherent authorities to enact and enforce their own internal laws and regulations as long as such laws and regulations do not supersede or conflict with such federal statutes. These tribal laws and regulations may include various fees, taxes and requirements to extend preference in employment to tribal members or Indian owned businesses. Further, lessees and operators within a Native American reservation may be subject to the pertinent Native American judiciary system, or barred from litigating matters adverse to the pertinent tribe unless there is a specific waiver of the tribe's sovereign immunity. Therefore, we may be subject to various applicable laws and regulations pertaining to Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas operations within Native American reservations. One or more of these applicable regulatory requirements, or delays in obtaining necessary approvals or permits necessary to operate on tribal lands, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project within a Native American reservation. Additionally, we cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way in Native American lands without experiencing significant costs. For example, following a decision by the Federal Tenth Circuit Court of Appeals that relied, in part, on a previous Federal Eighth Circuit Court of Appeals decision, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Native American landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline's rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators.

In recent years, PHMSA and other federal agencies have reviewed the adequacy of transporting Bakken crude oil by rail transport and, as necessary, have pursued rules to better assure the safe transport of Bakken crude oil by rail. For example, PHMSA adopted a final rule that includes, among other things, providing new sampling and testing requirements to improve classification of Bakken crude oil transported. Additionally in 2016, PHMSA published a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029 and, more recently in February 2019, PHMSA published a final rule requiring railroads to develop and submit comprehensive oil spill response plans for specific route segments traveled by a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train. Additionally, that February 2019 final rule requires railroads to establish geographic response zones along various rail routes, ensure that both personnel and equipment are staged and prepared to respond in the event of an accident and share information about high-hazard flammable train operations with state and tribal emergency response commissions. We, as the owner of a Bakken crude oil loading terminal, may be adversely affected to the extent more stringent rail transport rules result in more significant operating costs in the shipment of Bakken crude oil by rail or as a result of delays or limitations of such shipments.

The transportation of NGLs by truck is subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations, which are administered by the United States Department of Transportation, cover the transportation of hazardous materials.

NGL Storage

Our NGL storage terminals are subject to federal, state and local regulation. For example, the Indiana Department of Natural Resources (INDNR), the New York State Department of Environmental Conservation (NYSDEC), Michigan Department of Environment, Great Lakes and Energy (EGLE) and the EPA have jurisdiction over the underground storage of NGLs and NGL related well drilling, well conversions and well plugging in Indiana, New York and Michigan, respectively. The INDNR regulates aspects of our Seymour facility, the NYSDEC and EPA regulate aspects of the Bath facility and the EGLE and EPA regulate aspects of our Alto facility. Additionally, NGL terminals have the potential to be subject to state and federal air compliance regulations. For example, the Pennsylvania Department of Environmental Protection (PADEP) and the EPA have jurisdiction over facilities with the potential to emit regulated air pollutants in Pennsylvania. The PADEP regulates those aspects of the Schaefferstown facility.

Environmental and Occupational Safety and Health Matters

Our operations and the operations of our equity investments are subject to stringent federal, tribal, regional, state and local laws and regulations governing the discharge and emission of pollutants into the environment, environmental protection or occupational health and safety. These laws and regulations may impose significant obligations on our operations, including (i) the need to obtain permits to conduct regulated activities; (ii) restrict the types, quantities and concentration of materials that can be released into the environment; (iii) apply workplace health and safety standards for the benefit of employees; (iv) require remedial activities or corrective actions to mitigate pollution from former or current operations; and (v) impose substantial liabilities on us for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the (i) assessment of sanctions, including administrative, civil and criminal penalties; (ii) imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; (iii) occurrence of restrictions, delays or cancellations in permitting or the development of projects; and (iv) issuance of injunctions restricting or prohibiting some or all of the activities in a particular area.

The following is a summary of the more significant existing federal environmental laws and regulations, each as amended from time to time, to which our business operations and the operations of our equity investments are subject:

- *The Comprehensive Environmental Response, Compensation and Liability Act*, a remedial statute that imposes strict liability on generators, transporters, disposers and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- *The Resource Conservation and Recovery Act*, which governs the generation, treatment, storage and disposal of non-hazardous and hazardous wastes;
- *The Clean Air Act*, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring and reporting requirements and that serves as a legal basis for the EPA to adopt climate change regulatory initiatives relating to greenhouse gas (GHG) emissions;
- *The Water Pollution Control Act*, also known as the federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- *The Safe Drinking Water Act*, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of substances into below-ground formations that may adversely affect drinking water sources;
- *The National Environmental Policy Act*, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments or detailed Environmental Impact Statements to be made available for public review and comment;
- *The Endangered Species Act*, which restricts activities that may affect federally identified endangered or threatened species, or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas; and
- *The Occupational Safety and Health Act*, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances and appropriate control measures.

Certain of these federal environmental laws, as well as their state counterparts, impose strict, joint and several liability for costs required to clean up and restore properties where pollutants have been released regardless of whom may have caused the harm or whether the activity was performed in compliance with all applicable laws. States also adopt and implement their own environmental laws and regulations, which may be more stringent than federal requirements. In the course of our operations, generated materials or wastes may have been spilled or released from properties owned or leased by us or on or under other locations where these materials or wastes have been taken for recycling or disposal. In addition, many of the properties owned or leased by us were previously operated by third parties whose management, disposal or release of materials and wastes was not under our control. Accordingly, we may be liable for the costs of cleaning up or remediating contamination arising out of our operations or as a result of activities by others who previously occupied or operated on properties now owned or leased by us. Private parties, including the owners of properties that we lease and facilities where our materials or wastes are taken for recycling or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. We may not be able to recover some or any of these additional costs from insurance.

It is also possible that adoption of stricter environmental laws and regulations or more stringent interpretation of existing environmental laws and regulations in the future could result in additional costs or liabilities to us as well as the industry in general or otherwise adversely affect demand for our services. For example, in 2015, the EPA issued a final rule under the Clean Air Act, making the National Ambient Air Quality Standard (NAAQS) for ground-level ozone more stringent. Since that time, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local, and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone and, in December 2020, published notice of a final action to retain the 2015 ozone NAAQS without revision on a going-forward basis. However, several groups have filed litigation over this December 2020 decision and, in January 2021, the Biden Administration announced plans to reconsider the December 2020 final action in favor of a more stringent ground-level ozone NAAQS. The Department of Justice has requested that any such legal challenges, therefore, be held in abeyance until the EPA completes its reconsideration. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of our or our customers' equipment, resulting in longer permitting timelines, and could significantly increase our or our customers' capital expenditures and operating costs.

In another example, there continues to be uncertainty on the federal government's applicable jurisdictional reach under the Clean Water Act over "waters of the United States," including wetlands. The EPA and the U.S. Army Corps of Engineers (Corps) under the Obama, Trump and Biden Administrations have pursued multiple rulemakings since 2015 in an attempt to determine the scope of such reach, and in several instances, federal courts have vacated these rulemakings. In the third quarter of 2021, two federal district courts in Arizona and New Mexico vacated the Trump Administration's 2020 rule, which resulted in a return to protections that were in place prior to the 2015 rulemaking revisions under the Obama Administration. In December 2022, the EPA and Corps released a final revised definition of "waters of the United States" founded upon the pre-2015 definition and including updates to incorporate existing Supreme Court decisions and agency guidance, and the new rule was officially published on January 18, 2023, to be effective on March 20, 2023. However, the new rule has already been challenged, with the State of Texas and industry groups filing separate suits in federal court in Texas on January 18, 2023. Moreover, in October 2022, the Supreme Court heard arguments in *Sackett v. EPA*, which involves issues relating to the legal tests used to determine whether wetlands are "waters of the United States." The Supreme Court is expected to release an opinion in this case in 2023, which could impact the regulatory definition and its implementation. The implementation of the final rule and the potential expansion of the scope of the Clean Water Act's jurisdiction in areas where we or our customers conduct operations could lead to project development delays, restrictions or cancellations, result in longer permitting timelines, or increased compliance expenditures or mitigation costs for our and our customers' operations, which may reduce the rate of production from operators.

Separately, Nationwide Permit (NWP) 12, one of the Corps' general permits that provides an avenue for streamlined authorization under the Clean Water Act Section 404 for certain oil and gas pipeline activities, has been subject to legal challenges and regulatory revision in recent years. The Corps reissued NWP 12 in January 2021 for a five-year period, but this permit is being challenged in federal court on the same grounds that were litigated in *Northern Plains Resource Council v. U.S. Army Corps of Engineers*. In that case, the U.S. District Court for the District of Montana previously found the permit unlawful and vacated it, though on appeal, the Supreme Court limited vacatur to only the pipeline at issue in the litigation. In addition, the Corps announced on March 28, 2022, that it was commencing a formal review of NWP 12 to ensure consistency with the Biden Administration's commitments on potential impacts to disadvantaged communities, climate change, and other issues. Although the full extent and impact of the ongoing litigation and agency action with respect to the issued NWP 12 is unclear at this time, any disruption in our ability to obtain coverage under NWP 12 or other similar general permits may result in increased costs and project delays if we are forced to seek individual permits from the Corps.

Another permitting and development constraint occurs as a result of the protections afforded under the Endangered Species Act (ESA) and comparable state laws, which restrict crude oil and natural gas-related activities that may affect endangered or threatened species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act (MBTA). The U.S. Fish and Wildlife Service (FWS) under the Trump Administration issued a final rule on January 7, 2021 which notably clarifies that criminal liability under the MBTA will apply only to actions "directed at" migratory birds, their nests, or their eggs; however, in October 2021, the FWS under the Biden Administration revoked the Trump Administration's rule on incidental take and published an advanced notice of proposed rulemaking to codify a general prohibition on incidental take while establishing a process to regulate or permit exceptions to such a prohibition. A notice of proposed rulemaking is scheduled for release in 2023. To the extent that protected species live in the areas where we operate, our ability to conduct or expand operations and construct facilities could be limited or could force us to incur significant additional costs. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for crude oil and natural gas development. In addition, the FWS may make new determinations on the listing of species as endangered or threatened under the ESA. The dunes sagebrush lizard and the lesser prairie chicken are examples of species where new protections could impact our operations. In August 2022, the FWS filed a stipulated settlement agreement in a case challenging its failure to timely make a twelve-month finding on a petition to list the dunes sagebrush lizard. Under the agreement, the FWS will submit a twelve-month finding on the petition no later than June 29, 2023. The FWS also published a final rule on November 22, 2022, listing one Distinct Population Segment of the lesser prairie chicken species as threatened, and a second Distinct Population Segment as endangered, with these new designations going into effect on March 27, 2023. The designation of previously undesignated species as endangered or threatened could cause us to incur additional costs or cause our operations to become subject to restrictions or bans or limit future development activity in affected areas, thereby reducing demand for our services.

Additionally, crude oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). The NEPA requires federal agencies, including the U.S. Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency may prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement. Such environmental assessments and environmental impact statements are made available for public review and comment. On July 16, 2020, the Council on Environmental Quality (CEQ) under the Trump Administration published a final rule modifying the NEPA, and that rule remains subject to ongoing litigation in several federal district courts. The CEQ, now under the Biden Administration, issued a final rule in April 2022 retreating from several of these changes, one of which focused on ensuring that agency analysis captures the direct, indirect and cumulative effects of major federal actions. The Biden Administration considered these initial changes to be only “Phase 1” of its two-phased approach to modifying the NEPA regulations. “Phase 2” of this process remains underway, and although no details are yet public, it is likely that these revisions will result in increased agency scrutiny of major federal actions, including those associated with development of oil and gas resources. Additionally, in January 2023, the CEQ released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under the NEPA. The CEQ’s interim guidance is effective immediately and encourages agencies to consider, among other things, effects from upstream and downstream GHG emissions of fossil fuel projects. Implementation of these changes may result in further permitting delays.

In addition to the laws and regulations described above, the potential impact of climate change continues to attract considerable attention in the United States and in other countries. President Biden has made action on climate change a priority of his administration’s agenda. At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act. Additionally, the Inflation Reduction Act of 2022 (IRA 2022) imposes fees on the emission of methane that exceed certain thresholds from sources rquired to report their GHG emissions to the EPA. Compliance with these rules or other initiatives could result in increased compliance expenditures or mitigation costs for our operations. Moreover, significant incentives for alternative clean energy investment could accelerate the transition away from fossil fuels to renewable and low carbon energy, which could in turn reduce demand for our products and services and adversely affect our business and results of operations. For more information on each of these climate change-related issues, see Item 1A. Risk Factors, *“Our and our customers’ operations are subject to various risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased costs, limit the areas in which oil and natural gas production may occur and reduced demand for our services.”*

Additionally, various states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, the United Nations has sponsored the Paris Agreement, which is a non-binding agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020. President Biden announced in April 2021 a new, more rigorous nationally determined emissions reduction level of 50-52% from 2005 levels in economy-wide net GHG emissions by 2030. Moreover, the international community has made a number of announcements at both the 26th Conference of the Parties (COP26) and the 27th Conference of the Parties (COP27) to include at the former, the launch of a Global Methane Pledge, an initiative which over 100 countries joined, committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including “all feasible reductions” in the energy sector. For more information on each of these climate change-related issues, see Item 1A. Risk Factors, *“Our and our customers’ operations are subject to various risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased costs, limit the areas in which oil and natural gas production may occur and reduced demand for our services.”*

Our access to capital may be impacted by climate change policies. Shareholders and bondholders currently invested in fossil fuel energy companies such as ours but concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices that favor “clean” power sources, such as wind and solar, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies. Many banks have made "net zero" carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions may be pressured or required to adopt policies that limit funding for fossil fuel energy companies. While we cannot predict what policies may result from these announcements, a material reduction in the capital available to the fossil fuel energy industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations. For more information on each of these climate change-related issues, see Item 1A. Risk Factors, *"Our and our customers' operations are subject to various risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased costs, limit the areas in which oil and natural gas production may occur and reduced demand for our services."* Furthermore, the SEC released a proposed rule in March 2022 that would establish a framework for the reporting of climate risks, targets and metrics. Although the final form and substance of this proposed rule and its requirement are not yet known, and the ultimate impacts upon our business is uncertain, the proposed rule, if finalized, may result in increased compliance costs and increased costs of and restrictions on access to capital. Separately, the SEC has also announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege that an issuer's existing climate disclosures are misleading or deficient.

Increasing attention to climate change, societal expectations for companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and customer demand for alternative forms of energy may result in increased costs, reduced demand for our services, reduced profits, increased risks of governmental investigations and private party litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts from oil and natural gas products and bias against companies operating in the sector. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors. For more information, see Item 1A. Risk Factors, *"Increasing attention to environmental, social and governance (ESG) matters may impact our business."*

Human Capital

As of December 31, 2022, we had 753 full-time employees, 280 of which were general and administrative employees and 473 of which were operational employees. Our ability to attract, develop, retain and keep our employees safe is critical to the operational performance and future sustainability of our company.

We believe our ability to attract employees is significantly influenced by our efforts to create a culture founded on respect and collaboration, and our ability to value the diverse backgrounds, skills and contributions that our employees offer. Our commitment to Diversity, Equity and Inclusion (DE&I) is advanced by our Chief Diversity Officer and our internal DE&I committee pursuant to our DE&I five-point plan with the key pillars of attracting talent for a diverse workforce, creating an inclusive and engaged workforce, focusing on sustainability and accountability, creating meaningful DE&I-related partnerships, and building the future pipeline of employees with DE&I in mind. During 2022, we demonstrated our commitment to DE&I by conducting indigenous cultural awareness training for a second consecutive year and granting internships and scholarships where 60% of the participants were from diverse backgrounds. Each of these DE&I accomplishments were factored into our employees' short-term incentive compensation for 2022 and 2021, and we were able to meet or exceed the targeted goals for each of those areas during both years.

We develop our employees through a comprehensive performance management program and through continuous training, especially as it relates to safety, operations, technology, human resources and ethics and compliance. During the years ended December 31, 2022 and 2021, 100% and 99.9% of our employees completed their assigned training in these areas.

We monitor our ability to retain our employees through our voluntary turnover rate (the percentage of employees who voluntarily leave our organization compared to our total employee population), which was 13% and 11% during the years ended December 31, 2022 and 2021.

We monitor our ability to keep our employees safe by setting company-wide goals each year as it relates to leading indicators (i.e., near miss reporting) and lagging indicators (i.e., incident and injury rates), certain of which are factored into our employees' short-term incentive compensation each year. During 2022 and 2021, we exceeded all of our core safety goals and targets, and achieved a total recordable incident rate of 1.03 and 1.10, respectively, a days away restricted transferred rate of

0.51 and 0.66, respectively, and a preventable vehicular incident rate of 0.89 and 0.66, respectively, for the years ended December 31, 2022 and 2021.

Available Information

Our website is located at *www.crestwoodlp.com*. We make available, free of charge, on or through our website our annual reports on Form 10-K, which include our audited financial statements, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as we electronically file such material with the SEC. These documents are also available, free of charge, at the SEC's website at *www.sec.gov*. In addition, copies of these documents, excluding exhibits, may be requested at no cost by contacting Investor Relations, Crestwood Equity Partners LP or Crestwood Midstream Partners LP, 811 Main Street, Suite 3400, Houston, Texas 77002, and our telephone number is (832) 519-2200.

In addition to its reports filed or furnished with the SEC, the Company publicly discloses information from time to time in its press releases, at annual meetings of unitholders, in publicly accessible conferences and investor presentations and through its website (principally within the "Investors" section of our website).

We also make available within the "Corporate Governance" section of our website our corporate governance guidelines, the charter of our Audit Committee and our Code of Business Conduct and Ethics. Requests for copies may be directed in writing to Crestwood Equity Partners LP, 811 Main Street, Suite 3400, Houston, Texas 77002, Attention: General Counsel. Interested parties may contact the chairperson of any of our Board committees, our Board's independent directors as a group or our full Board in writing by mail to Crestwood Equity Partners LP, 811 Main Street, Suite 3400, Houston, Texas 77002, Attention: General Counsel. All such communications will be delivered to the director or directors to whom they are addressed.

References to our website in this Form 10-K are provided as a convenience and do not constitute, and should not be deemed, an incorporation by reference of the information contained on, or available through, our website, and such information should not be considered part of this Form 10-K.

Item 1A. Risk Factors

Risks Inherent in Our Business

Our business depends on hydrocarbon supply and demand fundamentals, which can be adversely affected by numerous factors outside of our control.

Our success depends on the supply and demand for natural gas, NGLs and crude oil, which has historically generated the need for new or expanded midstream infrastructure. The degree to which our business is impacted by changes in supply or demand varies. Our business can be negatively impacted by sustained downturns in supply and demand for one or more commodities, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. For example, significantly lower commodity prices during the past few years have resulted in an industry-wide reduction in capital expenditures by producers and a slowdown in drilling, completion and supply development efforts. Notwithstanding this market downturn, production volumes of crude oil, natural gas and NGLs have continued to grow (or decline at a slower rate than expected). Similarly, major factors that impact natural gas demand domestically include the effects of the COVID-19 pandemic, the realization of potential liquefied natural gas exports and demand growth within the power generation market. Factors that impact crude oil demand include production cuts and freezes implemented by OPEC members and other large oil producers such as Russia. For example, during the first half of 2020, the combined effect of OPEC and Russia's failure to agree on a plan to cut production of oil and related commodities, the outbreak of the COVID-19 pandemic and the shortage in available storage for hydrocarbons in the United States contributed to a sharp drop in prices for crude oil. Subsequently, in 2022, Russia launched a military action against Ukraine. The conflict has caused, and could intensify, volatility in the prices of natural gas, oil and NGLs, and the extent and duration of the military action, sanctions and resulting market disruptions have been significant and could continue to have a substantial impact on the global economy and our business for an unknown period of time. There is evidence that the increase in crude oil prices during 2022 was partially due to the impact of the conflict between Russia and Ukraine on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Alternatively, a cessation of the hostilities between Russia and Ukraine as a result of a negotiated withdrawal or otherwise could cause commodity prices to decline. Further, in 2022, OPEC+ announced a 2 million barrel per day reduction in production quotas. This action was taken largely in response to the U.S. decision to continue releasing crude from its Strategic Petroleum Reserve. While actual OPEC+ production capabilities are difficult to discern, any return to previous targeted production levels could cause commodity prices to decline.

We cannot predict what actions OPEC and other oil-producing countries will take in the future or other geopolitical and domestic activities that may significantly influence commodity prices. In addition, the supply and demand for natural gas, NGLs and crude oil for our business will depend on many other factors outside of our control, some of which include:

- changes in general domestic and global economic and political conditions, including economic downturns or recessionary environments;
- disruptions of financial and credit markets, including inflation, which affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements;
- changes in domestic regulations that could impact the supply or demand for oil and gas;
- technological advancements that may drive further increases in production and reduction in costs of developing shale plays;
- competition from imported supplies and alternate fuels;
- commodity price changes that could negatively impact the supply of, or the demand for these products;
- outbreak of illness, pandemic or any other public health crisis, including the COVID-19 pandemic;
- the availability of hydrocarbon storage and transportation infrastructure;
- increased costs to explore for, develop, produce, gather, process or transport commodities;
- impact of interest rates on economic activity;
- shareholder activism and activities by non-governmental organizations to limit sources of funding for the energy sector or restrict the exploration, development and production of oil and gas;
- operational hazards, including terrorism, cyber-attacks or domestic vandalism;
- geopolitical events, such as the ongoing military conflict involving Russia and Ukraine;
- adoption of various energy efficiency and conservation measures; and
- perceptions of customers on the availability and price volatility of our services, particularly customers' perceptions on the volatility of commodity prices over the longer-term.

If volatility and seasonality in the oil and gas industry increase, because of increased production capacity, reduced demand for energy, or otherwise, the demand for our services and the fees that we will be able to charge for those services may decline. In addition to volatility and seasonality, an extended period of low commodity prices could adversely impact storage and transportation values for some period of time until market conditions adjust. For example, in response to low commodity prices experienced during early 2020, some of our customers reduced capital expenditures and curtailed production, which adversely affected our gathering and processing north and south segments' results. With West Texas Intermediate crude oil prices ranging from $71.05 to $123.64 per barrel in 2022, the sustainability of recent prices improvements and longer-term oil prices cannot be predicted. These commodity price impacts could have a negative impact on our business, financial condition and results of operations.

The widespread outbreak of an illness, pandemic (like COVID-19) or any other public health crisis may have material adverse effects on our business, financial position, results of operations and/or cash flows.

During the past few years, the global and U.S. economy was negatively impacted by the COVID-19 pandemic, which disrupted global supply chains, reduced consumer activity, disrupted travel and created significant volatility and disruption of financial and commodity markets. The effects of the COVID-19 pandemic resulted in a significant reduction in global demand for natural gas, NGLs and crude oil and a significant and persistent reduction in the market price of crude oil during 2020. As a result, many producers, including some of our customers, curtailed some of their short-term drilling and production activity and reduced or slowed down their plans for future drilling and production activity. This decrease in activity decreased the demand that certain of these customers had for our services in 2020, and may continue to impact demand for our services in the future if our customers continue to or further curtail drilling and production activity in the future. As COVID-19 vaccines have become more readily available and social distancing guidelines, travel restrictions and stay-at-home orders have eased, the pandemic's impact on the global economy and demand for natural gas, NGLs, and crude oil, and related commodity prices, has changed over time.

The extent of the impact of the COVID-19 pandemic or any other future public health crisis on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for oil and natural gas (including its impact on travel, manufacturing and consumer product demand have had and will have on the demand for commodities), the availability of personnel, equipment and services critical to our ability to operate our assets and the impact of potential governmental restrictions on travel, transportation and operations. There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will depend on future developments, which are highly uncertain and cannot be predicted. These developments include, but are not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. Additionally, the actions taken to contain the COVID-19 pandemic include actions implemented by governmental authorities, such as large-scale travel bans and restrictions, border closures, quarantines, shelter-in-place orders and business and government shutdowns, all of which affect the demand for crude oil, natural gas and NGLs. Due to these factors, we expect to see continued volatility in commodity prices for the foreseeable future. These potential impacts, while uncertain, could adversely affect our operating results.

Our future growth may be limited if we are unable to complete successful, accretive growth projects.

Our business strategy depends on our ability to provide increased services to our customers and develop growth projects that can be financed appropriately. We may be unable to complete successful, accretive growth projects for any of the following reasons, among others:

- we fail to identify (or we are outbid for) attractive expansion or development projects or acquisition candidates that satisfy our economic and other criteria;
- we fail to secure adequate customer commitments to use the facilities to be developed, expanded or acquired; or
- we cannot obtain governmental approvals or other rights, licenses or consents needed to complete such projects or acquisitions on time or on budget, if at all.

The development and construction of gathering, processing, storage and transportation facilities involves numerous regulatory, environmental, safety, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. When we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular growth project. For instance, if we build a new gathering system, processing plant or transmission pipeline, the construction may occur over an extended period of time and we will not receive material increases in revenues until the project is placed in service. Accordingly, if we do pursue growth projects, we can provide no assurances that our efforts will provide a platform for additional growth for our company.

Our ability to finance new growth projects and make capital expenditures may be limited by our access to the capital markets or ability to raise investment capital at a cost of capital that allows for accretive midstream investments.

There has been significant volatility in energy commodity prices in recent years and such volatility may increase the concerns of energy investors regarding the future outlook for the industry. This has resulted in historic increased trading volatility in the equity and debt securities of energy companies, as well as a negative impact on the ability of companies in the oil and gas industry to seek financing and access the capital markets on favorable terms or at all during such times of volatility. Our growth strategy depends on our ability to identify, develop and contract for new growth projects and raise the investment capital, at a reasonable cost of capital, required to generate accretive returns from the growth project. This trend may continue and could negatively impact our ability to grow for any of the following reasons:

- access to the public equity and debt markets for partnerships of similar size to us may limit our ability to raise new equity and debt capital to finance new growth projects;
- if market conditions deteriorate below current levels, it is unlikely that we could issue equity at costs of capital that would enable us to invest in new growth projects on an accretive basis; or
- we cannot raise financing for such projects or acquisitions on economically acceptable terms.

The growth projects we complete may not perform as anticipated.

Even if we complete growth projects that we believe will be strategic and accretive, such projects may nevertheless reduce our cash available for distribution due to the following factors, among others:

- mistaken assumptions about capacity, revenues, synergies, costs (including operating and administrative, capital, debt and equity costs), inflation, customer demand, growth potential, assumed liabilities and other factors;
- the failure to receive cash flows from a growth project or newly acquired asset due to delays in the commencement of operations for any reason;
- unforeseen operational issues or the realization of liabilities that were not known to us at the time the acquisition or growth project was completed;
- the inability to attract new customers or retain acquired customers to the extent assumed in connection with an acquisition or growth project;
- the failure to successfully integrate growth projects or acquired assets or businesses into our operations and/or the loss of key employees; or
- the impact of regulatory, environmental, political and legal uncertainties, or force majeure events, that are beyond our control.

In particular, we may construct facilities to capture anticipated future growth in production and/or demand in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our business, financial condition, results of operations and ability to make distributions.

If we complete future growth projects, our capitalization and results of operations may change significantly, and our investors may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources. If any growth projects we ultimately complete are not accretive to our cash available for distribution, our ability to make distributions may be reduced.

We may rely upon third-party assets to operate our facilities, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such third-party assets.

Certain of our operations and investments depend on assets owned and controlled by third parties to operate effectively. For example, (i) certain of our rich gas gathering systems depend on interconnections, compression facilities and processing plants owned by third parties for us to move gas off our systems; (ii) our crude oil gathering systems depend on third-party pipelines to move crude to demand markets or rail terminals and our crude oil rail terminals depend on railroad companies to move our customers' crude oil to market; and (iii) our natural gas storage facility relies on third-party interconnections and pipelines to receive and deliver natural gas. In addition, certain of our customers' operations rely on assets owned and controlled by them or other third parties to operate efficiently in order to deliver their commodities to us. Since we do not own or operate these third-party facilities, their continuing operation is outside of our control. If third-party facilities become unavailable or constrained, including due to force majeure events, or other downstream facilities utilized to move our customers' product to their end destination become unavailable, it could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. For example, in the fourth quarter of 2022, extreme winter weather events impacted our properties in the Williston Basin, Powder River Basin and Delaware Basin. The severity and duration of these weather events forced our customers to contend with surface equipment freezing, widespread power outages and limited road accessibility, which resulted in well shut-ins, facility downtime and delays in drilling and completion activity during the fourth quarter. These factors impacted gathering volumes for our properties in the affected areas during the fourth quarter of 2022, which impacted our results of operations during 2022.

In addition, the rates charged by processing plants, pipelines and other facilities interconnected to our assets affect the utilization and value of our services. Significant changes in the rates charged by these third parties, or the rates charged by the third parties that own downstream assets required to move commodities to their final destinations, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

A substantial portion of our revenue is derived from our operations in the Williston Basin, and due to such geographic concentration, adverse developments in the Williston Basin could impact our financial condition and results of operations.

A significant portion of our revenue is derived from our operations in the Williston Basin, which increased in concentration as a result of the acquisitions and divestitures that we completed during 2022. These operations accounted for approximately 61% of our total revenues, less of costs of product/services sold, during the year ended December 31, 2022. Due to this geographic concentration of our operations, adverse developments that affect customers, suppliers or operations in the Williston Basin, such as catastrophic events or weather, health pandemics, regional labor shortages, and changes in supply or demand of crude oil, natural gas and related commodities that impact regional commodity prices and availability of infrastructure, could have a significantly greater impact on our financial condition and results of operations than if we maintained operations in more diverse locations. For example, in the fourth quarter of 2022, extreme winter weather events impacted a number of our properties, including those in the Williston Basin, resulting in well shut-ins, facility downtime and delays in drilling and completion activity by our customers, which impacted gathering volumes for our properties in the Williston Basin and impacted our results of operations during the fourth quarter of 2022.

Our gathering and processing operations depend, in part, on drilling and production decisions of others.

Our gathering and processing operations are dependent on the continued availability of natural gas and crude oil production. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems, or the rate at which production from a well declines. Our gathering systems are connected to wells whose production will naturally decline over time, which means that our cash flows associated with these wells will decline over time. To maintain or increase throughput levels on our gathering systems and utilization rates at our natural gas processing plants, we must continually obtain new natural gas and crude oil supplies. Our ability to obtain additional sources of natural gas and crude oil primarily depends on the level of successful drilling activity near our systems, our ability to compete for volumes from successful new wells and our ability to expand our system capacity as needed. If we are not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering and processing facilities would decline, which could have a material adverse effect on our results of operations and distributable cash flow.

Although we have acreage dedications from customers that include certain producing and non-producing oil and gas properties, our customers are not contractually required to develop the reserves or properties they have dedicated to us. We have no control over producers or their drilling and production decisions in our areas of operations, which are affected by, among other things, (i) the availability and cost of capital; (ii) prevailing and projected commodity prices and fluctuations thereof; (iii) demand for natural gas, NGLs and crude oil; (iv) levels of reserves and geological considerations; (v) governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; (vi) the availability and cost of drilling rigs and other development services; (vii) the availability of storage of crude oil and other commodities; and (viii) the impact of illness, pandemics or any other public health crisis, including the COVID-19 pandemic and of force majeure events. As it relates to certain drilling methods, including hydraulic fracturing, the EPA has completed a study of potential adverse impacts that those drilling methods and fracturing activities may have on water quality and public health, concluding that water cycle activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Moreover, the Biden Administration may seek to pursue legislation, executive actions or regulatory initiatives that restrict hydraulic fracturing activities on federal lands. Drilling and production activity generally decreases as commodity prices decrease (such as what was experienced with the decline in commodity prices during 2020, as further described in "*Our business depends on hydrocarbon supply and demand fundamentals, which can be adversely affected by numerous factors outside of our control"*) and sustained declines in commodity prices could lead to a material decrease in such activity. Because of these factors, even if oil and gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. For example, due to the sharp decreases in commodity prices experienced in 2020, many of our customers announced reductions in their estimated capital expenditures. Reductions in exploration or production activity in our areas of operations could lead to reduced utilization of our systems.

Estimates of oil and gas reserves depend on many assumptions that may turn out to be inaccurate, and future volumes on our gathering systems may be less than anticipated.

We normally do not obtain independent evaluations of natural gas or crude oil reserves connected to our gathering systems. We therefore do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. It often takes producers longer periods of time to determine how to efficiently develop and produce hydrocarbons from unconventional shale plays than conventional basins, which can result in lower volumes becoming available as soon as expected in the shale plays in which we operate. If the total reserves or estimated life of the reserves connected to our gathering systems is less than anticipated and we are unable to secure additional sources of natural gas or crude oil, it could have a material adverse effect on our business, results of operations and financial condition.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flows and results of operations.

Many of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flows from operations, the incurrence of debt or the issuance of equity. The combination of the reduction of cash flows resulting from declines in commodity prices (such as experienced during 2020), inflation, a reduction in borrowing bases under a reserve-based credit facility, the lack of availability of debt or equity financing and declining economic conditions may result in a significant reduction of customers' liquidity and limit their ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

Our storage and logistics operations are seasonal and generally have lower cash flows in certain periods during the year, which may require us to borrow money to fund our working capital needs of these businesses.

The natural gas liquids inventory we pre-sell to our customers is higher during the second and third quarters of a given year, and our cash receipts during that period are lower. As a result, we may have to borrow money to fund the working capital needs of our storage and logistics operations during those periods. Any restrictions on our ability to borrow money could impact our ability to pay quarterly distributions to our unitholders.

Counterparties to our commodity derivative and physical purchase and sale contracts in our storage and logistics operations may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

We encounter risk of counterparty non-performance in our storage and logistics operations. Disruptions in the price or supply of NGLs, natural gas or crude oil for an extended or near term period of time could result in counterparty defaults on our derivative and physical purchase and sale contracts. This could impair our expected earnings from the derivative or physical sales contracts, our ability to obtain supply to fulfill our sales delivery commitments or our ability to obtain supply at reasonable prices, which could adversely affect our financial condition and results of operations.

Our storage and logistics operations and certain of our gathering and processing operations are subject to commodity risk, basis risk or risk of adverse market conditions, which can adversely affect our financial condition and results of operations.

We attempt to lock in a margin for a portion of the commodities we purchase by selling such commodities for physical delivery to our customers or by entering into future delivery obligations under contracts for forward sale. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, and sales or future delivery obligations. Any event that disrupts our anticipated physical supply of commodities could expose us to risk of loss resulting from the need to fulfill our obligations required under contracts for forward sale. Basis risk describes the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of a like commodity at a different time or place. Transportation costs and timing differentials are components of basis risk. In a backwardated market (when prices for future deliveries are lower than current prices), basis risk is created with respect to timing. In these instances, physical inventory generally loses value as the price of such physical inventory declines over time. Basis risk cannot be entirely eliminated, and basis exposure, particularly in backwardated or other adverse market conditions, can adversely affect our financial condition and results of operations.

Changes in future business conditions could cause our long-lived assets and goodwill to become impaired, and our financial condition and results of operations could suffer if we record future impairments of long-lived assets and goodwill.

We continually monitor our business, the business environment and the performance of our operations to determine if an event has occurred that indicates that a long-lived asset may be impaired. If an event occurs, which is a determination that involves judgment, we may be required to utilize cash flow projections to assess our ability to recover the carrying value of our assets based on our long-lived assets' ability to generate future cash flows on an undiscounted basis. This differs from our evaluation of goodwill, which is evaluated for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than the carrying amount. This evaluation requires us to compare the fair value of each of our reporting units primarily utilizing discounted cash flows, to its carrying value (including goodwill). If the fair value exceeds the carrying value amount, goodwill of the reporting unit is not considered impaired.

Our long-lived assets and goodwill impairment analyses are sensitive to changes in key assumptions used in our analysis, such as expected future cash flows, the degree of volatility in equity and debt markets and our unit price. If the assumptions used in our analysis are not realized, it is possible a material impairment charge may need to be recorded in the future. We cannot accurately predict the amount and timing of any impairment of long-lived assets or goodwill. Any additional impairment charges that we may take in the future could be material to our results of operations and financial condition. For a further discussion of our long-lived assets and goodwill impairments, see *Critical Accounting Policies and Estimates* discussed in Part II, Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations and Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Our industry is highly competitive, and increased competitive pressure could adversely affect our ability to execute our growth strategy.

We compete with other energy midstream enterprises, some of which are much larger and have significantly greater financial resources or operating experience, in our areas of operation. Furthermore, depressed commodity price environments may cause further consolidation within the energy industry, leading to combined companies with greater resources and better economies of scale. Our competitors may expand or construct infrastructure that creates additional competition for the services we provide to customers. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make distributions.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund operations, limit our ability to react to changes in our business or industry, and place us at a competitive disadvantage.

We had approximately $3.4 billion of long-term debt outstanding as of December 31, 2022. If we are unable to generate sufficient cash flow to satisfy debt obligations or to obtain alternative financing, our business, results of operations, financial condition and business prospects could be materially and adversely affected.

Our substantial debt could have adverse consequences to our unitholders. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future capital expenditures and working capital, to engage in development activities or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive covenants or terms of our debt;
- result in an event of default if we fail to satisfy debt obligations or fail to comply with the financial and other restrictive covenants contained in the agreements governing our indebtedness, which event of default could result in all of our debt becoming immediately due and payable and could permit our lenders to foreclose on any of the collateral securing such debt;
- increase our cost of borrowing;
- restrict us from making strategic acquisitions or investments, or cause us to make non-strategic divestitures;

- limit our flexibility in planning for, or reacting to, changes in our business or industry in which we operate, placing us at a competitive disadvantage compared to our peers who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploring; and
- impair our ability to obtain additional financing in the future.

Realization of any of these factors could adversely affect our financial condition, results of operations and cash flows.

Restrictions in our revolving credit facility and indentures governing our senior notes could adversely affect our business, financial condition, results of operations and ability to make distributions.

Our revolving credit facility and indentures governing our senior notes contain various covenants and restrictive provisions that will limit our ability to, among other things:

- incur additional debt;
- make distributions on or redeem or repurchase units;
- make investments and acquisitions;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company; and
- transfer or otherwise dispose of assets.

Furthermore, our Crestwood Midstream revolving credit facility contains covenants which requires us to maintain certain financial ratios such as (i) a net debt to consolidated EBITDA ratio (as defined in our credit agreement) of not more than 5.50 to 1.0; (ii) a consolidated EBITDA to consolidated interest expense ratio (as defined in our credit agreement) of not less than 2.50 to 1.0; and (iii) a senior secured leverage ratio (as defined in our credit agreement) of not more than 3.50 to 1.0.

Borrowings under our Crestwood Midstream revolving credit facility are secured by pledges of the equity interests of, and guarantees by, substantially all of our restricted domestic subsidiaries, and liens on substantially all of our real property (outside of New York) and personal property. None of our equity investments have guaranteed, and none of the assets of our equity investments secure, our obligations under our revolving credit facility.

The provisions of our credit agreement and indentures governing our senior notes may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility or indentures governing our senior notes could result in events of default, which could enable our lenders or holders of our senior notes, subject to the terms and conditions of our credit agreement or indentures, as applicable, to declare any outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If the payment of any such debt is accelerated, our assets may be insufficient to repay such debt in full, and the holders of our common units could experience a partial or total loss of their investment.

A change of control could result in us facing substantial repayment obligations under our Crestwood Midstream revolving credit facility and indentures governing our senior notes.

Crestwood Midstream's credit agreement and indentures governing our senior notes contain provisions relating to a change of control of Crestwood Equity's general partner. If these provisions are triggered, our outstanding indebtedness may become due. In the event our outstanding indebtedness became due, there is no assurance that we would be able to pay the indebtedness, in which case the lenders under the revolving credit facility would have the right to foreclose on our assets and holders of our senior notes would be entitled to require us to repurchase all or a portion of our notes at a purchase price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of such repurchase, which would have a material adverse effect on us. There is no restriction on our ability or the ability of Crestwood Equity's general partner to enter into a transaction which would trigger the change of control provision. In certain circumstances, the control of our general partner may be transferred to a third party without unitholder consent, and this may be considered a change in control under our revolving credit facility and senior notes. Please read *"The control of our general partner may be transferred to a third party without unitholder consent."*

Our ability to make cash distributions may be diminished, and our financial leverage could increase, if we are not able to obtain needed capital or financing on satisfactory terms.

Historically, we have used cash flow from operations, borrowings under our revolving credit facility, proceeds received from divestitures and issuances of debt or equity to fund our capital programs, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our operations to fund growth. If our cash flow from operations decreases or distributions from our equity investments decrease as a result of lower throughput volumes on their systems or otherwise, our ability to expend the capital necessary to expand our business or increase our future cash distributions may be limited. If our cash flow from operations and the distributions we receive from subsidiaries are insufficient to satisfy our financing needs, we cannot be certain that additional financing will be available to us on acceptable terms, if at all. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition or general economic conditions at the time of any such financing or offering. Even if we are successful in obtaining the necessary funds, the terms of such financings could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. Further, incurring additional debt may significantly increase our interest expense and financial leverage and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the cash distribution rate which could materially decrease our ability to pay distributions. If additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Increases in interest rates could adversely impact our unit price, ability to issue equity or incur debt for acquisitions or other purposes, and ability to make payments on our debt obligations.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Therefore, changes in interest rates either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make payments on our debt obligations.

A downgrade of our credit ratings could impact our and our subsidiaries' liquidity, access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit ratings may increase our and our subsidiaries' cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our and our subsidiaries' ability to access capital markets could also be limited by a downgrade of our credit ratings and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for crude oil, natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

The loss of key personnel could adversely affect our ability to operate.

Our success is dependent upon the efforts of our senior management team, as well as on our ability to attract and retain both executives and employees for our field operations. Our senior executives have significant experience in the oil and gas industry and have developed strong relationships with a broad range of industry participants. The loss of these executives, or the loss of key field employees operating in competitive markets, could prevent us from implementing our business strategy and could have a material adverse effect on our customer relationships, results of operations and ability to make distributions.

We operate joint ventures that may limit our operational flexibility.

We conduct a portion of our operations through joint ventures (including our Crestwood Permian Basin, Tres Holdings and PRBIC joint ventures), and we may enter into additional joint ventures in the future. In a joint venture arrangement, we could have less operational flexibility, as actions must be taken in accordance with the applicable governing provisions of the joint venture. In certain cases, we:

- could have limited ability to influence or control certain day to day activities affecting the operations;
- could have limited control on the amount of capital expenditures that we are required to fund with respect to these operations;
- could be dependent on third parties to fund their required share of capital expenditures;
- may be subject to restrictions or limitations on our ability to sell or transfer our interests in the jointly owned assets; and
- may be required to offer business opportunities to the joint venture, or rights of participation to other joint venture partners or participants in certain areas of mutual interest.

In addition, joint venture partners may have obligations that are important to the success of the joint venture, such as the obligation to pay substantial carried costs pertaining to the joint venture. The performance and ability of our joint venture partners to satisfy their obligations under joint venture arrangements is outside of our control. If these parties do not satisfy their obligations, our business may be adversely affected. Our joint venture partners may be in a position to take actions contrary to our instructions or requests contrary to our policies or objectives, and disputes between us and our joint venture partners may result in operational delays, litigation or operational impasses. The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to conduct business that is the subject of a joint venture, which could in turn negatively affect our financial condition and results of operations.

Moreover, our decision to operate aspects of our business through joint ventures could limit our ability to consummate strategic transactions. Similarly, due to the perceived challenges of existing joint ventures, companies like ours that fund a considerable portion of their operations through joint ventures may be less attractive merger or take-over candidates. We cannot provide any assurance that our operating model will not negatively affect the value of our common units.

We may not be able to renew or replace expiring contracts.

Our primary exposure to market risk occurs at the time contracts expire and are subject to renegotiation and renewal. As of December 31, 2022, the weighted average remaining term of our consolidated portfolio of natural gas gathering contracts is approximately eight years, our consolidated portfolio of crude oil gathering contracts is approximately nine years and our consolidated portfolio of produced water gathering contracts is approximately nine years. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the macroeconomic factors affecting natural gas, NGL and crude economics for our current and potential customers;
- the level of existing and new competition to provide services to our markets;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

Any failure to extend or replace a significant portion of our existing contracts, or extending or replacing them at unfavorable or lower rates, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Inflation could adversely impact our ability to control operating expenses and capital costs, increase our level of indebtedness and adversely impact our customer base. The fees we charge to customers under our contracts may not escalate sufficiently to cover our cost increases, which could negatively impact our business, financial condition and results of operations.

Although inflation in the United States has been relatively low in recent years, it rose to historically high levels in 2022. In addition, global and industry-wide supply chain disruptions caused by the COVID-19 pandemic have resulted in shortages in labor, materials and services. Such inflation and shortages have resulted in cost increases for labor, materials and services and could continue to cause costs to increase. Historically, we have been able to partially mitigate the impact that cost increases could have on our business, financial condition and results of operations through negotiated contractual rates and amounts authorized to be collected from our customers, and we intend to continue to do so. We cannot predict any future trends in the rate of inflation, and a significant increase in inflation, to the extent we are unable to recover higher costs through our commercial agreements or rates, would negatively impact our business, financial condition and results of operations.

Our contracts may be suspended in some circumstances.

Some third parties' obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of natural gas or crude oil is curtailed or cut off. Force majeure events generally include, without limitation, revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, winter storms, acts of God, explosions, mechanical or physical failures of our equipment or facilities or those of third parties. If any third party suspends or terminates its contracts with us, our business, financial condition, results of operations and ability to make distributions could be materially adversely affected.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and the inability to do so may disrupt our business and hinder our ability to grow.

We have completed a number of acquisitions in recent years, and we may continue to acquire businesses or assets that complement or expand our business. However, there is no guarantee that we will be able to identify attractive or suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets.

The success of any completed acquisition, including those that we have completed recently, will depend on our ability to effectively integrate the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Even if we are able to integrate acquired business operations successfully, there can be no assurance that the integration will result in the full realization of the anticipated benefits of such acquisitions, including cost savings or operational effectiveness, or that any such benefits may be achieved within an anticipated time frame.

Our failure to achieve consolidation savings, to successfully integrate the acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our business, financial condition and results of operations.

Our business involves many hazards and risks, some of which may not be fully covered by insurance.

Our operations are subject to many risks inherent in the energy midstream industry, such as:

- damage to pipelines and plants, related equipment and surrounding properties caused by natural disasters and acts of terrorism or domestic vandalism;
- subsidence of the geological structures where we store NGLs, or storage cavern collapses;
- operator error;
- inadvertent damage from construction, farm and utility equipment;
- leaks, migrations or losses of natural gas, NGLs, crude oil or produced water;
- fires and explosions;
- cyber intrusions; and
- other hazards that could also result in personal injury, including loss of life, property and natural resources damage, pollution of the environment or suspension of operations.

These risks could result in substantial losses due to breaches of contractual commitments, personal injury and/or loss of life, damage to and destruction of property and equipment and pollution or other environmental damage. For example, we have experienced releases on our Arrow water gathering system on the Fort Berthold Indian Reservation in North Dakota, the remediation and repair costs of which were covered by insurance, but nonetheless potential future water spills could subject us to substantial penalties, fines and damages from regulatory agencies and individual landowners. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. We are also not insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could result in a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities. Although we maintain insurance policies with insurers in such amounts and with such coverages and deductibles as we believe are reasonable and prudent, our insurance may not be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities (particularly our gathering and processing facilities) have been constructed, which subjects us to the possibility of more onerous terms or increased costs to obtain and maintain valid easements and rights-of-way. Easements and rights-of-way exists for varying periods of time. We obtain standard easement rights to construct and operate pipelines on land owned by third parties, and our rights frequently revert back to the landowner after we stop using the easement for its specified purpose. With regard to easements and rights-of-way on tribal lands, following a 2017 court decision issued by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land (that is, tribal land owned or at one time owned by an individual Indian landowner) bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted tribal lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way without experiencing significant costs. Our loss of easement rights could have a material adverse effect on our ability to operate our business, thereby resulting in a material reduction in our results of operations and ability to make distributions.

Terrorist attacks or "cyber security" events, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other assets might be specific targets for terrorist organizations or "cyber security" events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets or utilize our customer service systems. Also, destructive forms of protests and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas development and production or midstream processing or transportation activities could potentially result in damage or injury to persons, property or the environment or lead to extended interruptions of our or our customers' operations. Additionally, the oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain processing and operational activities. At the same time, companies in our industry have been the targets of cyber-attacks and ransomware demands, and it is possible that the attacks in our industry will continue and grow in number. In addition, to assist in conducting our business, we rely on information technology systems and data hosting facilities, including systems and facilities that are hosted by third parties and with respect to which we have limited visibility and control. These systems and facilities may be vulnerable to a variety of evolving cyber security risks or information security breaches, including unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions. These cyber security risks could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary, personal data and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as advanced persistent threats, may remain undetected for an extended period. The occurrence of any of these events, including any attack or threat targeted at our pipelines and other assets, could cause a substantial decrease in revenues, increased costs or other financial losses, exposure or loss of customer information, damage to our reputation or business relationships, increased regulation or litigation, disruption of our operations and/or inaccurate information reported from our operations. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition. Although we have adopted controls and systems, including updating our systems with recent patches and updates from our software providers and procuring limited insurance for certain cyber-related losses, that are designed to protect information and mitigate the risk of data loss and other cyber security events, such measures cannot entirely eliminate cyber security threats, particularly as these threats continue to evolve and grow. Furthermore the controls and systems we have installed may be breached or be inadequate to address a risk that arises. We are not aware of any cyber security events that impacted our company that have or could have resulted in a material loss; however there is no assurance that such a breach has not already occurred and we are unaware of it, and that we will not suffer such a loss in the future.

The risk of terrorism and political unrest in various energy producing regions may adversely affect the economy and price and availability of products.

An act of terror, or political unrest, in any of the major energy producing regions of the world could potentially result in disruptions in the supply of crude oil and natural gas, which could have a material impact on both availability and price. Since Russia's military invasion of Ukraine in 2022, prices for commodities produced in those countries, including crude oil and natural gas, have risen sharply and have been volatile due to market concerns of worldwide supply constraints. Terrorist attacks in the areas of our operations could negatively impact our ability to transport propane to our locations. These risks could potentially negatively impact our consolidated results of operations.

We are or may become subject to cyber security and data privacy laws, regulations, litigation and directives relating to our processing of personal data.

Several jurisdictions in which we operate throughout the United States may have laws governing how we must respond to a cyber incident that results in the unauthorized access, disclosure or loss of personal data. Additionally, new laws and regulations governing cybersecurity, data privacy and unauthorized disclosure of confidential information, including international comprehensive data privacy regulations and recent U.S. state legislation in California, Virginia and Colorado (some of which, among other things, provides for a private right of action), pose increasingly complex compliance challenges and could potentially elevate our costs over time. Our business involves collection, uses and other processing of personal data of our employees, contractors, suppliers and service providers. As legislation continues to develop and cyber incidents continue to evolve, we will likely be required to expend significant resources to continue to modify or enhance our protective measures to comply with such legislation and to detect, investigate and remediate vulnerabilities to cyber incidents and report any cyber incidents to the applicable regulatory authorities. In particular, in response to recent ransomware attacks, the Department of Homeland Security has issued a security directive to certain pipeline companies requiring the companies to appoint personnel, perform cybersecurity assessments, and report incidents and other information. Any failure by us, or a company we acquire, to comply with such laws and regulations could result in reputational harm, loss of goodwill, penalties, liabilities, and/or mandated changes in our business practices.

Risks Related to Regulatory Matters

Increasing attention to environmental, social and governance (ESG) matters may impact our business.

Increasing attention to climate change, societal expectations for companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and customer demand for alternative forms of energy may result in increased costs, reduced demand for our services, reduced profits, increased risks of governmental investigations and private party litigation, and negative impacts on our common unit price and access to capital markets. Additionally, there are organizations that provide information to investors on corporate governance, climate change, health and safety and other ESG-related factors and have developed ratings processes for evaluating companies on their approach to ESG matters. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us or our customers and to the diversion of investment to other industries which could have a negative impact on our unit price and/or our access to capital and costs of capital. Additionally, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations. Such ESG matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

Additionally, we have announced various voluntary ESG targets in our carbon management plan and may not be able to meet such targets in the manner or on such a timeline as initially contemplated, as a result of, but not limited to, unforeseen costs or technical difficulties associated with achieving such results. To the extent we do meet such targets, it may be achieved through various contractual arrangements, including the purchase of various credits that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. Also, despite these goals, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

Furthermore, public statements with respect to ESG matters, such as emissions reduction goals, other environmental goals, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," (i.e., misleading information or false claims overstating potential ESG benefits). For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private sectors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG statements, goals or standards were misleading, false, or otherwise deceptive. As a result, we may face increased litigation risk from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further regulatory ESG-related focus and scrutiny. See Item 1. Business, "*Regulation" and "Environmental and Occupational Safety and Health Matters*" for a further discussion of these matters.

Our operations are subject to extensive regulation, and regulatory measures adopted by regulatory authorities could have a material adverse effect on our business, financial condition and results of operations.

Our operations, including our Tres Holdings joint venture, are subject to extensive regulation by federal, state and local regulatory authorities. Federal regulation under the Natural Gas Act extends to such matters as:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;
- the types of services we may offer to our customers;
- the certification and construction of new, or the expansion of existing facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- contracts for service between storage and transportation providers and their customers;
- creditworthiness and credit support requirements;
- the maintenance of accounts and records;
- relationships among affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services; and
- various other matters.

The FERC issued a Notice of Inquiry (NOI) on April 19, 2018, thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999 (1999 Policy Statement), that is used to determine whether to grant certificates for new pipeline projects. On February 18, 2021, the FERC issued another NOI, reopening its review of the 1999 Policy Statement. On February 18, 2022, the FERC issued a Policy Statement on the Certificate of New Interstate Natural Gas Facilities and a Policy Statement on the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews (2022 Policy Statements), to be effective that same day. On March 24, 2022, the FERC issued an order converting the 2022 Policy Statements into draft policy statements, and requested further comments. The FERC will not apply the draft 2022 Policy Statements until it issues final guidance on these topics. We are unable to predict what, if any, changes may be proposed to the draft 2022 Policy Statements that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in these policy statements would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

There can be no assurance that the FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation and storage facilities. Failure to comply with applicable regulations under the Natural Gas Act, the Natural Gas Policy Act of 1978, the NGPSA and certain other laws, and with implementing regulations associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties of up to approximately $1.5 million per day, per violation.

A change in the jurisdictional characterization of our gathering assets may result in increased regulation, which could cause our revenues to decline and operating expenses to increase.

Our natural gas and crude oil gathering operations are generally exempt from the jurisdiction and regulation of the FERC, except for certain anti-market manipulation provisions. FERC regulation nonetheless affects our businesses and the markets for products derived from our gathering businesses. The FERC's policies and practices across the range of its oil and gas regulatory activities, including, for example, its policies on open access transportation, rate making, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we have no assurance that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has regularly been the subject of substantial, on-going litigation. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by the FERC, the courts or Congress. If our gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of certain gathering agreements.

State and municipal regulations also impact our business. Common purchaser statutes generally require gatherers to gather or provide services without undue discrimination as to source of supply or producer; as a result, these statutes restrict our right to decide whose production we gather or transport. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we currently operate have adopted complaint-based regulation of gathering activities, which allows oil and gas producers and shippers to file complaints with state regulators in an effort to resolve access and rate grievances. Other state and municipal regulations may not directly regulate our gathering business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the rates, terms and conditions of its gathering lines.

Our operations are subject to compliance with environmental and operational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our operations are subject to stringent federal, tribal, regional, state and local laws and regulations governing worker health and safety aspects of our operations, the discharge of materials into the environment and otherwise relating to environmental protection. These requirements may take the form of laws, regulations, executive actions and various other legal initiatives. See Item 1. Business, "*Regulation" and "Environmental and Occupational Safety and Health Matters*" for a further discussion on these matters. Compliance with these regulations and other regulatory initiatives or any other new environmental laws and regulations could, among other things, require us or our customers to install new or modified emission controls on equipment or processes and incur significantly increased capital or operating expenditures and operating delays, restrictions or cancellations with respect to our operations, which costs may be significant. Additionally, one or more of these developments that impact our customers involved in oil and natural gas exploration and production could reduce demand for our services. These developments could have a material adverse effect on our business, results of operations and financial condition.

Our and our customers' operations are subject to various risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased costs, limit the areas in which oil and natural gas production may occur and reduced demand for our services.

The threat of climate change continues to attract considerable attention in the U.S. and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions, which makes our and our customers' operations subject to a number of regulatory, political, litigation and financial risks arising out of the threat of climate change, energy conservation measures, or initiatives that stimulate demand for alternative forms of energy that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce the demand for the crude oil and natural gas. Risks arising out of the threat of climate change, energy conservation measures, governmental requirements for renewable energy resources, increasing customer demand for alternative forms of energy, and technological advances in fuel economy and energy generation devices may create new competitive conditions that result in reduced demand for the crude oil and natural gas our customers produce and our services. The potential impact of changing demand for crude oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

In the U.S., no comprehensive climate change legislation has been implemented at the federal level, though the IRA 2022 advances numerous climate-related objectives, including a federal fee on excess methane emissions from certain facilities. However, with the EPA's determination that GHG emissions present a danger to public health and the environment as a pollutant under the CAA, the EPA has adopted several rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., implement New Source Performance Standards directing the reduction of methane from certain new, modified or reconstructed facilities, and together with the U.S. Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the U.S. In November 2021, the EPA issued a proposed rule that would make methane emissions from the crude oil and natural gas sources category more stringent, by establishing Quad Ob new source and Quad Oc first time existing source standards of performance for methane and volatile organic compound emissions. The EPA published a supplemental proposal in November 2022 for public comment. Among other items, the proposal sets forth specific revisions strengthening the first nationwide emissions guidelines for states to limit methane from existing crude oil and natural gas facilities. The proposal also revises requirements for fugitive emissions monitoring and repair as well as equipment leaks and the frequency of monitoring surveys, establishes a “super emitter” response program to timely mitigate emissions events, and provides additional options for the use of advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions. The proposal is expected to be finalized in 2023, though it may be challenged in court. We are unable to predict at this time the scope of any final regulatory requirements and the expected cost to comply with such requirements. Any increase in regulatory scope and oversight may increase compliance expenditure or mitigation costs for our operations. Additionally, the IRA 2022 imposes fees on the emission of methane that exceed certain thresholds from sources required to report their GHG emissions to the EPA. The methane emissions fees would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 per ton in 2025, and be set at $1,500 per ton for 2026 and each year thereafter.

The methane emissions fee and renewable and low-carbon energy funding provisions of the law could increase our and our customers' operating costs and accelerate the transition away from fossil fuels, which could in turn reduce demand for our products and services and adversely affect our business and results of operations.

Various states and groups of states have also adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs and restriction of emissions. At the international level, the Paris Agreement requires nations to submit non-binding GHG emissions reduction goals every five years after 2020. In April 2021, the Biden Administration announced nationwide emissions reduction targets that would reduce GHG emissions by 50-52% from their 2005 levels by 2030. The international community gathered again in November 2021 at COP26, during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies, amongst other measures. Relatedly, the United States and European Union jointly announced at COP26 the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector. At COP27 in November 2022, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase-out of inefficient fossil fuel subsidies. The United States has also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, COP26, COP27, or other international conventions cannot be predicted at this time and it is unclear what additional initiatives may be adopted or implemented that may have a negative impact to our financial condition or results of operations.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the U.S. that may limit fracturing of oil and natural gas wells or result in restrictions of leases or other authorizations for oil and gas development on federal lands and offshore waters. Other actions to restrict oil and natural gas activities that could be pursued by the Biden Administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. Litigation risks are also increasing, as a number of parties have sought to bring suit against fossil fuel companies in state or federal court, alleging that such companies created public nuisances by producing fuels that contributed to global warming or that such companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts to their investors or customers.

There are also increasing financial risks for fossil fuel energy companies, as various investors become increasingly concerned about the potential effects of climate change and may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices that favor "clean" power sources such as wind and solar photovoltaic, making those sources more attractive for investment, and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (GFANZ) announced that commitments from over 450 firms across 45 countries had resulted in substantial capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero by 2050. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding for fossil fuel energy companies. In late 2020, the Federal Reserve joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector, and in September 2022, announced that six of the U.S.' largest banks will participate in a pilot climate scenario analysis exercise, expected to be launched in early 2023, to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. The Federal Reserve released its pilot exercise in January 2023, which is designed to analyze the impact of both physical and transition risks related to climate change on specific assets of the banks’ portfolios. While we cannot predict what policies may result from these developments, such efforts could make it more difficult to secure funding for exploration and production or midstream energy business activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce fossil fuels or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for fossil fuels, which could reduce demand for our transportation and storage services. Political, litigation and financial risks may result in our customers restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services. Moreover, the increased competitiveness of alternative energy sources (such as wind, solar, geothermal, tidal and biofuels) could reduce demand for hydrocarbons and for our services. For more information, see our regulatory disclosure in Item 1. *Business, "Regulation" and "Environmental and Occupational Safety and Health Matters*."

Finally, climatic events in the areas in which we operate, whether from climate change or otherwise, can cause disruptions and in some cases delays in, or suspension of, our services. These events, including, but not limited to, drought, winter storms, wildfire, extreme temperatures or flooding, may become more intense or more frequent as a result of climate change and could have an adverse effect on our continued operations as well as the operations of our oil and natural gas customers on whom we rely upon for throughput and our third party vendors whom supply us with products and services. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we transport, which may impact demand for our services. While our consideration of changing climatic conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

We may incur higher costs as a result of pipeline integrity management program testing and additional safety legislation.

Pursuant to authority under the NGPSA and HLPSA, PHMSA has established rules requiring pipeline operators to develop and implement integrity management programs for certain natural gas and hazardous liquid pipelines located where a leak or rupture could harm HCAs, MCAs, Class 3 and 4 areas, as well as areas unusually sensitive to environmental damage and commercially navigable waterways. Among other things, these regulations require operators of covered pipelines like us to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a HCA, MCA or Class 3 and 4 area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Additionally, certain states where we conduct operations, including New Mexico, North Dakota and Wyoming, have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas pipelines, and New Mexico and Texas have also adopted regulations similar to existing PHMSA regulations for certain intrastate hazardous liquid pipelines. We estimate that the total future costs to complete the testing required by existing PHMSA or any applicable state regulations will not have a material impact to our results. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program itself, which costs could be substantial. The results of this testing could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Moreover, federal legislation or implementing regulations adopted in recent years may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital costs, operational delays and costs of operations. See Item 1. Business, "*Regulation" and "Environmental and Occupational Safety and Health Matters*" for a further discussion on pipeline safety matters.

Risks Inherent in an Investment in Our Equity

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses to enable us to pay quarterly distributions to our common and preferred unitholders.

We may not have sufficient cash each quarter to pay quarterly distributions to our common unitholders or, alternatively, we may reallocate a portion of our available cash to debt repayments or capital investments. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, distributions received from our joint ventures, and payments of fees and expenses as well as decisions the board of directors makes regarding acceptable levels of debt or the desire to invest in new growth projects. Our board typically reviews these factors on a quarterly basis. Before we pay any cash distributions on our preferred and common units, we will establish reserves and pay fees and expenses, including reimbursements to our general partner and its affiliates, for all expenses they incur and payments they make on our behalf. These costs will reduce the amount of cash available to pay distributions to our common unitholders and, to the extent we are unable to declare and pay fixed cash distributions on our preferred units, we cannot make cash distributions to our common unitholders until all payments accruing on the preferred units have been paid.

The amount of cash we have available to distribute on our preferred and common units will fluctuate from quarter to quarter based on, among other things:

- the rates charged for services and the amount of services customers purchase, which will be affected by, among other things, the overall balance between the supply of and demand for commodities, governmental regulation of our rates and services and our ability to obtain permits for growth projects;
- force majeure events that damage our or third-party pipelines, facilities, related equipment and surrounding properties;
- prevailing economic and market conditions;
- governmental regulation, including changes in governmental regulation in our industry;
- changes in tax laws;
- the level of competition from other midstream companies;
- the level of our operations and maintenance and general and administrative costs;
- the level of capital expenditures we make;
- our ability to make borrowings under our revolving credit facility;
- our ability to access the capital markets for additional investment capital; and
- acceptable levels of debt, liquidity and/or leverage.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including: the level and timing of our capital expenditures; our debt service requirements and other liabilities; fluctuations in our working capital needs; our ability to borrow funds and access capital markets; restrictions contained in our debt agreements; and the amount of cash reserves established by our general partner.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow given the current trends existing in the capital markets.

Decreases in commodity prices can negatively impact the equity and debt markets resulting in limitations on our ability to access the capital markets for new growth capital at a reasonable cost of capital. Historically, we have distributed all of our available cash to our preferred and common unitholders on a quarterly basis and relied upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. If the current capital market trends persist, we may be unable to finance growth externally by accessing the capital markets, and may have to depend on a reallocation of our cash distributions to reduce debt and/or invest in new growth projects. In addition, we may dispose of assets to reduce debt and/or invest in new growth projects, which can impact the level of our cash distributions.

In the event we continue to distribute all of our available cash or decide to reallocate cash to debt reduction, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we decide to reallocate cash to debt reduction or invest in new capital projects, we may be unable to maintain or increase our per unit distribution level. Subject to certain restrictions that apply if we are not able to pay cash distributions to our preferred unitholders, there are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

We may issue additional common units without common unitholder approval, which would dilute existing common unitholder ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests we may issue at any time without the approval of our existing common unitholders. The issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- our existing common unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of the common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units and has other governance differences from typical corporations.

Unitholders' voting rights are restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership due to the absence of a takeover premium in the trading price or other governance differences.

Common unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the Delaware Act), we may not make a distribution to our common unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

It may be determined that the right, or the exercise of the right by the limited partners as a group, to (i) remove or replace our general partner; (ii) approve some amendments to our partnership agreement; or (iii) take other action under our partnership agreement constitutes "participation in the control" of our business. A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner.

The amount of cash we have available for distribution to common unitholders depends primarily on our cash flow (including distributions from joint ventures) and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from reserves and working capital or other borrowings and cash distributions received from our joint ventures, and not solely on profitability, which will be affected by non-cash items. As a result, we may pay cash distributions during periods when we record net losses for financial accounting purposes and may not pay cash distributions during periods when we record net income.

Our preferred units contain covenants that may limit our business flexibility.

Our preferred units contain covenants preventing us from taking certain actions without the approval of the holders of a majority or a super-majority of the preferred units, depending on the action as described below. The need to obtain the approval of holders of the preferred units before taking these actions could impede our ability to take certain actions that management or our board of directors may consider to be in the best interests of its unitholders. The affirmative vote of the then-applicable voting threshold of the outstanding preferred units, voting separately as a class with one vote per preferred unit, shall be necessary to amend our partnership agreement in any manner that (i) alters or changes the rights, powers, privileges or preferences or duties and obligations of the preferred units in any material respect; (ii) except as contemplated in the partnership agreement, increases or decreases the authorized number of preferred units; or (iii) otherwise adversely affects the preferred units, including without limitation the creation (by reclassification or otherwise) of any class of senior securities (or amending the provisions of any existing class of partnership interests to make such class of partnership interests a class of senior securities). In addition, our partnership agreement provides certain rights to the preferred unitholders that could impair our ability to consummate (or increase the cost of consummating) a change-in-control transaction, which could result in less economic benefits accruing to our common unitholders.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. The new owner of our general partner would then be in a position, subject to obtaining any approvals or consents required under the applicable governing documents, to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by our board of directors and officers. This effectively permits a “change of control” without the vote or consent of the common unitholders. In addition, such a change of control could result in our indebtedness becoming due. Please read risk factor “*A change of control could result in us facing substantial repayment obligations under our revolving credit facility and senior notes.”*

Our partnership agreement limits our general partner’s fiduciary duties to us and restricts the remedies available for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- provides that our general partner is entitled to make decisions in “good faith” if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of our outstanding units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

Risks Related to our Tax Matters

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstances and other proposals have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impair our ability to qualify as a publicly traded partnership in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our units. Unitholders are urged to consult with their own tax advisors with respect to the status of regulatory or administrative developments and proposals and their potential effect on their investment in our units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our units, and the costs of any such contest would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under these rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustments into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, a unitholder may be allocated taxable income and gain resulting from the sale and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" being allocated to our unitholders as taxable income without any increase in our cash available for distribution. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our units could be more or less than expected.

If our unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those units. Because distributions in excess of our unitholders' allocable share of our total net taxable income result in a reduction in their tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if they sell their units they may incur a tax liability in excess of the amount of cash received from the sale.

Furthermore, a substantial portion of the amount realized from the sale of our units, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation deductions. Thus, our unitholders may recognize both ordinary income and capital loss from the sale of their units if the amount realized on a sale of their units is less than their adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which our unitholders sell their units, they may recognize ordinary income from our allocations of income and gain to them prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for business interest is limited to the sum of our business interest income and a certain percentage of our adjusted taxable income. For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income. If our business interest is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Additionally, all or part of any gain recognized by such tax-exempt organization upon a sale or other disposition of our units may be unrelated business taxable income and may be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit. In addition to the withholding tax imposed on distributions of effectively connected income, distributions to a non-U.S. unitholder will also be subject to a 10% withholding tax on the amount of any distribution in excess of our cumulative net income. As we do not compute our cumulative net income for such purposes due to the complexity of the calculation and lack of clarity in how it would apply to us, we intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to such 10% withholding tax. Accordingly, distributions to a non-U.S. unitholder will be subject to a combined withholding tax rate equal to the sum of the highest applicable effective tax rate and 10%.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a non-U.S. person. While the determination of a partner's amount realized generally includes any decrease of a partner's share of the partnership's liabilities, the Treasury regulations provide that the amount realized on a transfer of an interest in a publicly traded partnership, such as our units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. For a transfer of interests in a publicly traded partnership that is effected through a broker on or after January 1, 2023, the obligation to withhold is imposed on the transferor's broker. Current and prospective non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our units.

We will treat each purchaser of our units as having the same tax benefits without regard to the specific units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our units.

Because we cannot match transferors and transferees of units and because of other reasons, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of our units and could have a negative impact on the value of our units or result in audit adjustments to our unitholders' tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (i.e., a loan to a "short seller" to cover a short sale of units) may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, they may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Our unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes, estate, inheritance or intangible taxes and non-U.S. taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders' responsibility to file all required U.S. federal, state, local and non-U.S. tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

The tax treatment of distributions on our preferred units is uncertain and the IRS may determine that preferred distributions are guaranteed payments, which may result in less favorable tax treatment to the holder of such preferred units.

The tax treatment of distributions on our preferred units is uncertain. We will treat each of the holders of the preferred units as partners for tax purposes and will not treat preferred distributions as guaranteed payments for the use of capital. However, if the IRS were to determine that such preferred distributions were guaranteed payments, the preferred distributions would generally be taxable to each of the holders of preferred units as ordinary income and the holders of preferred units would recognize taxable income from the accrual of such a guaranteed payment (even in the absence of a contemporaneous cash distribution). Although we expect that much of our income will be eligible for the 20% deduction for qualified publicly traded partnership income, the Treasury Regulations provide that income attributable to a guaranteed payment for the use of capital is not eligible for the 20% deduction for qualified business income. As a result, if the IRS treated the preferred distributions as guaranteed payments, income attributable to a guaranteed payment for use of capital recognized by holders of our preferred units would not eligible for the 20% deduction for qualified business income. In addition, if the preferred units were treated as indebtedness for tax purposes, preferred distributions likely would be treated as payments of interest by us to each of the holders of preferred units. All holders of our preferred units are urged to consult a tax advisor with respect to the consequences of owning our preferred units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in Item 1. Business, and is incorporated herein by reference. We also lease office space for our corporate offices in Houston, Texas and Kansas City, Missouri.

We own or lease the property rights necessary to conduct our operations and we also lease and rely upon our customers' property rights to conduct a substantial part of our operations. We believe that we have satisfactory title to our assets. Title to property may be subject to encumbrances. For example, we have granted to the lenders of our revolving credit facility security interests in substantially all of our real property interests. We believe that none of these encumbrances will materially detract from the value of our properties or from our interest in these properties, nor will they materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

A description of our legal proceedings is included in Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 10, and is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Crestwood Equity's common units representing limited partner interests are traded on the NYSE under the symbol "CEQP."

At the close of business on February 17, 2023, Crestwood Equity had 105,356,560 common units issued and outstanding, which were held by 227 unitholders of record.

Issuer Purchases of Equity Securities

On March 25, 2021, CEQP's board of directors approved a plan to repurchase common and preferred units in one or more open-market transactions or in privately negotiated transactions, with an aggregate purchase price not to exceed $175 million, exclusive of any fees, commissions or other expenses. The repurchase program expired on December 31, 2022. No units were purchased under the program during the years ended December 31, 2022 and 2021.

Equity Compensation Plan Information

For information on our equity compensation plans, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 13.

Item 6. Selected Financial Data

This information has been omitted from this report pursuant to the final SEC rules in Release No. 34-90459 which permits the elimination of Item 301 of Regulation S-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Our Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our consolidated financial statements and the accompanying footnotes, and Part I, Item 1. Business.

A comparative discussion of our 2021 operating results to our 2020 operating results can be found in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K for the year ended December 31, 2021 filed with the SEC on February 25, 2022.

Overview

We own and operate crude oil, natural gas and NGL midstream assets and operations. Headquartered in Houston, Texas, we are a fully-integrated midstream solution provider that specializes in connecting shale-based energy supplies to key demand markets. We conduct our operations through our wholly-owned subsidiary, Crestwood Midstream, a limited partnership that owns and operates gathering, processing, storage, disposal and transportation assets in the most prolific shale plays across the United States.

Our Company

We provide broad-ranging services to customers across the crude oil, natural gas and NGL sectors of the energy value chain. Our midstream infrastructure is geographically located in or near significant supply basins, especially developed and emerging liquids-rich and crude oil shale plays, across the United States. We believe that our strategy of focusing on prolific, low-cost shale plays positions us well to generate greater returns in varying commodity price environments and capture greater upside economics when development activity occurs.

Our financial statements reflect three operating and reporting segments: (i) gathering and processing north operations (includes our Williston Basin and Powder River Basin operations); (ii) gathering and processing south operations (includes our Delaware Basin operations and our Crestwood Permian Basin equity method investment); and (iii) storage and logistics (includes our crude oil, NGL and natural gas storage and logistics operations and our Tres Holdings and PRBIC equity method investments).

Below is a summary of our operating and reporting segments. For a detailed description of the assets included in our operating and reporting segments, see Part I, Item 1. Business.

- *Gathering and Processing North*. Our gathering and processing north operations provide natural gas gathering, compression, treating and processing services, crude oil gathering and storage services and produced water gathering and disposal services to producers in the Williston Basin and Powder River Basin.

- *Gathering and Processing South*. Our gathering and processing south operations provide natural gas gathering, compression, treating and processing services, crude oil gathering services and produced water gathering and disposal services to producers in the Delaware Basin.

- *Storage and Logistics*. Our storage and logistics operations provide NGLs, crude oil and natural gas storage, terminal, marketing and transportation (including rail, truck and pipeline) services to producers, refiners, marketers, utilities and other customers.

Outlook and Trends

Our business objective is to create long-term value for our unitholders. We expect to create value for our investors by generating stable operating margins and improving cash flows from our diversified midstream operations by prudently financing investments in our assets and expansions of our portfolio, maximizing throughput and optimizing services on our assets, and effectively controlling our capital expenditures, operating and administrative costs.

Throughout 2022, we have taken a number of strategic steps to better position the Company to increase cash flows and our operating scale in our core basins to create a stronger, better capitalized company that can accretively grow cash flows and volumes, while being a high-quality midstream operator and an industry leader in ESG efforts.

In 2022, we successfully executed on our long-term growth strategy through disciplined capital investments utilizing our current financial flexibility. On February 1, 2022, we acquired Oasis Midstream in an equity and cash transaction valued at approximately $1.8 billion. Pursuant to the merger agreement, Chord received $150 million in cash plus 20.9 million newly issued CEQP common units in exchange for its 33.8 million common units held in Oasis Midstream. In addition, Oasis Midstream's public unitholders received 12.9 million newly issued CEQP common units in exchange for the 14.8 million Oasis Midstream common units held by them. Additionally, under the merger agreement, Chord received a $10 million cash payment for its ownership of the general partner of Oasis Midstream. This transaction further solidifies Crestwood's competitive position in the Williston Basin and expands the Company's relationship with Chord. Additionally, the Rough Rider system acquired in the merger with Oasis Midstream is complementary with our Arrow system, which has provided and continues to provide opportunities to drive cost savings and commercial synergies and better utilization of available gas processing capacity.

During 2022, we also completed a series of strategic transactions including (i) the acquisition of Sendero for approximately $631 million, (ii) the acquisition of First Reserve's 50% equity interest in Crestwood Permian in exchange for approximately $6 million in cash and approximately 11.3 million newly issued CEQP common units, and (iii) the divestitures of our Barnett and Marcellus Shale assets for approximately $290 million and $206 million, respectively. The acquisitions of Sendero and First Reserve's 50% equity interest in the Crestwood Permian joint venture have significantly increased the Company's position in the Delaware Basin.

The divestitures of our Barnett and Marcellus natural gas assets represents a full exit of our gathering and processing operations in the Barnett and Marcellus Shales. These divestitures allow the Company to focus on building and optimizing its gathering and processing positions in the Williston, Delaware and Powder River Basins, which we believe will best position the Company to deliver long-term value to its unitholders.

On February 20, 2023, we and Brookfield entered into an agreement with a third party to sell each of our respective interests in Tres Palacios Holdings LLC (Tres Holdings) for total consideration of approximately $335 million. The transaction is expected to close in the second quarter of 2023, subject to customary closing conditions.

Following the strategic transactions discussed above, we are focusing our near-term strategy on optimizing and integrating the acquired assets into our legacy gathering and processing operations. To accomplish this strategy, we have also taken steps to (i) minimize capital expenditures to better align with development activity by our gathering and processing customers; (ii) realign our organization to reduce operating and administrative expenses; (iii) engage with our customers to maintain volumes across our asset portfolio; (iv) optimize our storage, transportation and marketing assets to take advantage of regional commodity price volatility; and (v) evaluate our debt and equity structure to preserve liquidity and ensure balance sheet strength. Given our efforts over the past few years to improve the Partnership's competitive position in the businesses we operate, manage costs and improve margins and create a stronger balance sheet, we believe we are well positioned to execute our business plan.

Other Developments

Bakken DAPL Matter. In July 2020, a U.S. District Court (District Court) ordered the Dakota Access Pipeline (DAPL) to cease operation based on an alleged procedural permitting failure. On August 5, 2020, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) stayed the DAPL shutdown, and subsequently issued an opinion upholding the District Court's decision on the merits, but not prohibiting DAPL's continued operation. The plaintiffs sought another injunction against DAPL's operation, which was denied by the District Court in May 2021. As required by the District Court, the U.S. Army Corps of Engineers is currently conducting an environmental impact statement, which is currently expected to be complete in 2023. We expect DAPL will remain in operation while the environmental impact statement is being completed.

The Rough Rider gathering system connects to the Arrow crude oil system and is capable of transporting all of its crude oil volumes to the Arrow system. The Arrow system currently connects to the DAPL, Kinder Morgan Hiland, Tesoro and True Companies' Bridger Four Bears pipelines, providing significant downstream delivery capacity for our Arrow and Rough Rider customers. Additionally, we can transport Arrow and Rough Rider crude volumes to our COLT Hub facility by pipeline or truck, which mitigates the impact of any potential pipeline shut-downs to our producers with the ability to access multiple markets out of the basin.

Carbon Management. One of the core initiatives related to our ESG efforts surrounds our focus on managing the intensity of our emissions in order to reduce climate-related risk to our business.

In January 2022, we published our first carbon management plan (CMP), which outlines near-term emissions reduction and management activities that we intend to implement over the next three years. The CMP includes several core objectives, including (i) reducing emissions intensity of our assets; (ii) evaluating opportunities to reduce Scope 2 greenhouse gas (GHG) emissions while managing our operations' energy efficiency; (iii) enhancing our process by which we manage GHG emissions; (iv) piloting methane emission monitoring devices at certain of our facilities; (v) participating in the development of responsibly sourced gas standards for the midstream sector; (vi) investing in technology to better inventory and calculate emissions data and integrating the technology into our operations; and (vii) participating in and providing leadership to trade associations focused on climate-related risks. We have made progress on several of the key objectives of our CMP in 2022, including installing methane detection devices at 13% of our facilities during 2022. With respect to our approach to acquisitions and divestitures, we also published a carbon protocol that incorporates the evaluation of GHG emissions during the due diligence process and related onsite inspections prior to close of any such transactions.

Our emissions-related metrics are included in our executives' and employees' short-term incentive compensation program. During 2022, our methane intensity target (which includes of the operations acquired during 2022) was 0.046% (measured as metric tons per Mscf of throughput on our assets), compared to our actual 2021 methane intensity statistic of 0.036%. We have included a methane intensity target of 0.040% in our executives' and employees' short-term incentive compensation program for 2023.

We currently believe that our carbon management efforts will help to mitigate the potential impact that emissions may have on our capital expenditures or results of operations in the future.

Critical Accounting Estimates and Policies

The preparation of financial statements in conformity with U.S. GAAP requires management to select appropriate accounting estimates and to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those that require difficult, complex or subjective judgment necessary in accounting for inherently uncertain matters and those that could significantly influence our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. We have discussed the development and selection of the following critical accounting estimates and related disclosures with the Audit Committee of the board of directors of our general partner.

For a complete discussion of our significant accounting policies, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2.

Goodwill

Our goodwill represents the excess of the amount we paid for a business over the fair value of the net identifiable assets acquired. We evaluate goodwill for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount. This evaluation requires us to compare the fair value of each of our reporting units to its carrying value (including goodwill). If the fair value exceeds the carrying amount, goodwill of the reporting unit is not considered impaired.

We estimate the fair value of our reporting units based on a number of factors, including discount rates, projected cash flows and the potential value we would receive if we sold the reporting unit. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our reporting units (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates. If the assumptions embodied in the projections prove inaccurate, we could incur a future impairment charge. In addition, the use of the income approach to determine the fair value of our reporting units (see further discussion of the use of the income approach below) could result in a different fair value if we had utilized a market approach, or a combination thereof.

Upon acquisition, we are required to record the assets, liabilities and goodwill of a reporting unit at its fair value on the date of acquisition. As a result, any level of decrease in the forecasted cash flows of these businesses or increases in the discount rates utilized to value those businesses from their respective acquisition dates would likely result in the fair value of the reporting unit falling below the carrying value of the reporting unit, and could result in an assessment of whether that reporting unit's goodwill is impaired.

At December 31, 2022, our goodwill consisted of approximately $94.7 million associated with our gathering and processing north Williston reporting unit, $35.6 million associated with our gathering and processing south Permian reporting unit and $92.7 million associated with our storage and logistics NGL Marketing and Logistics reporting unit. We continue to monitor our goodwill, and we could experience impairments of goodwill in the future if we experience a significant sustained decrease in the market value of our common or preferred units or if we receive additional negative information about market conditions or the intent of our customers on our operations with goodwill, which could negatively impact the forecasted cash flows or discount rates utilized to determine the fair value of those businesses. A 5% decrease in the forecasted cash flows or a 1% increase in the discount rates utilized to determine the fair value of each of our reporting units would not have resulted in a goodwill impairment at December 31, 2022.

Long-Lived Assets

Our long-lived assets consist of property, plant and equipment and intangible assets that have been obtained through multiple business combinations and property, plant and equipment that has been constructed in recent years. The initial recording of a majority of these long-lived assets was at fair value, which is estimated by management primarily utilizing market-related information, asset specific information and other projections on the performance of the assets acquired (including an analysis of discounted cash flows which can involve assumptions on discount rates and projected cash flows of the assets acquired). Management reviews this information to determine its reasonableness in comparison to the assumptions utilized in determining the purchase price of the assets in addition to other market-based information that was received through the purchase process and other sources. These projections also include projections on potential and contractual obligations assumed in these acquisitions. Due to the imprecise nature of the projections and assumptions utilized in determining fair value, actual results can, and often do, differ from our estimates.

We utilize assumptions related to the useful lives and related salvage value of our property, plant and equipment in order to determine depreciation and amortization expense each period. Due to the imprecise nature of the projections and assumptions utilized in determining useful lives, actual results can, and often do, differ from our estimates.

To estimate the useful life of our finite lived intangible assets we utilize assumptions of the period over which the assets are expected to contribute directly or indirectly to our future cash flows. Generally this requires us to amortize our intangible assets based on the expected future cash flows (to the extent they are readily determinable) or on a straight-line basis (if they are not readily determinable) of the acquired contracts or customer relationships. Due to the imprecise nature of the projections and assumptions utilized in determining future cash flows, actual results can, and often do, differ from our estimates.

We continually monitor our business, the business environment and the performance of our operations to determine if an event has occurred that indicates that a long-lived asset may be impaired. If an event occurs, which is a determination that involves judgment, we may be required to utilize cash flow projections to assess our ability to recover the carrying value of our assets based on our long-lived assets' ability to generate future cash flows on an undiscounted basis. This differs from our evaluation of goodwill, for which we perform an assessment of the recoverability of goodwill utilizing fair value estimates that primarily utilize discounted cash flows in the estimation process (as described above), and accordingly a reporting unit that has experienced a goodwill impairment may not experience a similar impairment of the underlying long-lived assets included in that reporting unit.

Projected cash flows of our long-lived assets are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, construction costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. If those cash flow projections indicate that the long-lived asset's carrying value is not recoverable, we record an impairment charge for the excess of the carrying value of the asset over its fair value. The estimate of fair value considers a number of factors, including the potential value we would receive if we sold the asset, discount rates and projected cash flows. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

During 2022, 2021 and 2020, we recorded losses and impairments related to our property, plant and equipment as described below. For a further discussion of these matters, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 2, Note 3 and Note 11.

- During 2022, we recorded a loss on long-lived assets of approximately $250 million related to the sale of our Marcellus Shale assets. In addition, during 2022, Crestwood Midstream recorded a loss on long-lived assets of approximately $53 million related to the sale of the Barnett Shale assets. We also recorded a loss on long-lived assets of approximately $7 million related to the anticipated sale of parts inventory related to our legacy Granite Wash operations and a loss on long-lived assets of approximately $4 million due to a buyout of leases related to our exiting the crude oil railcar business during 2022.

- During 2021, we recorded approximately $40 million of impairments of our property, plant and equipment related to our gathering and processing south segment's compressor stations in our Marcellus operations based on the actual or anticipated dismantlement and redeployment of those assets to other areas.

- During 2020, we sold our Fayetteville assets and recorded a loss on long-lived assets of approximately $20 million. In addition, during 2020, we recorded approximately $3 million of impairments of our property, plant and equipment primarily related to the removal and retirement of certain of our water gathering facilities in our Arrow operations.

We continue to monitor our long-lived assets, and we could experience additional impairments of the remaining carrying value of these long-lived assets in the future if we receive negative information about market conditions or the intent of our long-lived assets' customers, which could negatively impact the forecasted cash flows or discount rates utilized to determine the fair value of those investments.

Equity Method Investments

We evaluate our equity method investments for impairment when events or circumstances indicate that the carrying value of the equity method investment may be impaired and that impairment is other than temporary. If an event occurs, we evaluate the recoverability of our carrying value based on the fair value of the investment. If an impairment is indicated, we adjust the carrying values of the investment downward, if necessary, to their estimated fair values.

We estimate the fair value of our equity method investments based on a number of factors, including discount rates, projected cash flows, enterprise value and the potential value we would receive if we sold the equity method investment. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our equity method investments (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our equity method investments' customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

We continue to monitor our equity method investments, and if we receive negative information about market conditions or the intent of our equity method investments' customers to curtail production in the future that negatively impacts the forecasted cash flows or discount rates utilized to determine the fair value of those investments, we could experience impairments to the carrying value of these investments.

Our equity method investments have long-lived assets in their underlying financial statements, and our equity investees apply similar accounting policies and have similar critical accounting estimates in assessing those assets for impairment as we do. During 2021, we recorded a $158.7 million reduction to the equity earnings from our Stagecoach Gas equity method investment primarily as a result of the sale (through a series of transactions) of Stagecoach Gas to a subsidiary of Kinder Morgan. For a further discussion of the Stagecoach Gas divestiture, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6. During 2020, we recorded a $4.5 million reduction to the equity earnings from our PRBIC equity method investment as a result of us recording our proportionate share of a long-lived asset impairment recorded by the equity method investee.

Revenue Recognition

We recognize revenues for services and products under our revenue contracts as our obligations to perform services or deliver/sell products under the contracts are satisfied. A contract's transaction price is allocated to each performance obligation in the contract and recognized as revenue when, or as, the performance obligation is satisfied. Under certain contracts, we may be entitled to receive payments in advance of satisfying our performance obligations under the contract. We recognize a liability for these payments in excess of revenue recognized and present this deferred revenue as contract liabilities on our consolidated balance sheets. At December 31, 2022 and 2021, we had deferred revenues of approximately $224.0 million and $197.8 million. Our deferred revenues primarily relate to:

- *Capital Reimbursements.* Certain of our contracts require that our customers reimburse us for capital expenditures related to the construction of long-lived assets utilized to provide services to them under the revenue contracts. Because we consider these amounts as consideration from customers associated with ongoing services to be provided to customers, we defer these upfront payments in deferred revenue and recognize the amounts in revenue over the life of the associated revenue contract as the performance obligations are satisfied under the contract.

- *Contracts with Increasing (Decreasing) Rates per Unit.* Certain of our contracts have fixed rates per volume that increase and/or decrease over the life of the contract once certain time periods or thresholds are met. We record revenues on these contracts ratably per unit over the life of the contract based on the remaining performance obligations to be performed, which can result in the deferral of revenue for the difference between the consideration received and the ratable revenue recognized.

The evaluation of when performance obligations have been satisfied and the transaction price that is allocated to our performance obligations requires significant judgments and assumptions, including our evaluation of the timing of when control of the underlying good or service has transferred to our customers, estimating the revenue to be generated per unit over the life of the contracts, and determining the relative standalone selling price of goods and services provided to customers under contracts with multiple performance obligations. Actual results can significantly vary from those judgments and assumptions.

How We Evaluate Our Operations

We evaluate our overall business performance based primarily on EBITDA and Adjusted EBITDA. We do not utilize depreciation, amortization and accretion expense in our key measures because we focus our performance management on cash flow generation and our assets have long useful lives.

EBITDA and Adjusted EBITDA - We believe that EBITDA and Adjusted EBITDA are widely accepted financial indicators of a company's operational performance and its ability to incur and service debt, fund capital expenditures and make distributions. We believe that EBITDA and Adjusted EBITDA are useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. EBITDA is defined as income before income taxes, plus debt-related costs (interest and debt expense, net, and gain (loss) on modification/extinguishment of debt) and depreciation, amortization and accretion expense. Adjusted EBITDA considers the adjusted earnings impact of our unconsolidated affiliates by adjusting our equity earnings or losses from our unconsolidated affiliates to reflect our proportionate share (based on the distribution percentage) of their EBITDA, excluding gains and losses on long-lived assets and other impairments. Adjusted EBITDA also considers the impact of certain significant items, such as unit-based compensation charges, gains or losses and impairments on long-lived assets, impairments of goodwill, third party costs incurred related to potential and completed acquisitions, certain environmental remediation costs, the change in fair value of commodity inventory-related derivative contracts, costs associated with the realignment and restructuring of our operations and corporate structure, and other transactions identified in a specific reporting period. The change in fair value of commodity inventory-related derivative contracts is considered in determining Adjusted EBITDA given that the timing of recognizing gains and losses on these derivative contracts differs from the recognition of revenue for the related underlying sale of inventory to which these derivatives relate. Changes in the fair value of other derivative contracts are not considered in determining Adjusted EBITDA given the relatively short-term nature of those derivative contracts. EBITDA and Adjusted EBITDA are not measures calculated in accordance with U.S. GAAP, as they do not include deductions for items such as depreciation, amortization and accretion, interest and income taxes, which are necessary to maintain our business. EBITDA and Adjusted EBITDA should not be considered as alternatives to net income, operating cash flow or any other measure of financial performance presented in accordance with U.S. GAAP. EBITDA and Adjusted EBITDA calculations may vary among entities, so our computation may not be comparable to measures used by other companies. See our reconciliation of net income to EBITDA and Adjusted EBITDA in "*Results of Operations*" below.

Results of Operations

The following table summarizes our results of operations (*in millions*).

	Crestwood Equity			Crestwood Midstream	
	Year Ended December 31,			Year Ended December 31,	
	2022	2021	2020	2022	2021
Revenues	$ 6,000.7	$ 4,569.0	$ 2,254.3	$ 6,000.7	$ 4,569.0
Costs of product/services sold	4,997.1	3,843.9	1,600.5	4,997.1	3,843.9
Operations and maintenance expense	196.1	121.0	131.8	196.1	121.0
General and administrative expense	130.4	97.6	91.5	124.4	90.2
Depreciation, amortization and accretion	328.9	244.2	237.4	334.6	258.4
Loss on long-lived assets, net	187.7	39.6	26.0	312.7	39.4
Goodwill impairment	—	—	80.3	—	—
Gain on acquisition	(75.3)	—	—	(75.3)	—
Operating income	235.8	222.7	86.8	111.1	216.1
Earnings (loss) from unconsolidated affiliates, net	15.7	(120.4)	32.5	15.7	(120.4)
Interest and debt expense, net	(177.4)	(132.1)	(133.6)	(177.4)	(132.1)
Gain (loss) on modification/extinguishment of debt	—	(7.5)	0.1	—	(7.5)
Other income (expense), net	0.3	0.1	(0.7)	0.1	—
Provision for income taxes	(1.9)	(0.2)	(0.4)	(1.7)	(0.1)
Net income (loss)	72.5	(37.4)	(15.3)	(52.2)	(44.0)
Add:					
Interest and debt expense, net	177.4	132.1	133.6	177.4	132.1
(Gain) loss on modification/extinguishment of debt	—	7.5	(0.1)	—	7.5
Provision for income taxes	1.9	0.2	0.4	1.7	0.1
Depreciation, amortization and accretion	328.9	244.2	237.4	334.6	258.4
EBITDA	580.7	346.6	356.0	461.5	354.1
Unit-based compensation charges	37.2	34.9	30.7	37.2	34.9
Loss on long-lived assets, net	187.7	39.6	26.0	312.7	39.4
Goodwill impairment	—	—	80.3	—	—
Gain on acquisition	(75.3)	—	—	(75.3)	—
(Earnings) loss from unconsolidated affiliates, net	(15.7)	120.4	(32.5)	(15.7)	120.4
Adjusted EBITDA from unconsolidated affiliates, net	30.0	67.0	75.4	30.0	67.0
Change in fair value of commodity inventory-related derivative contracts	(14.4)	(13.5)	33.6	(14.4)	(13.5)
Significant transaction and environmental related costs and other items	31.9	5.1	10.8	31.9	2.5
Adjusted EBITDA	$ 762.1	$ 600.1	$ 580.3	$ 767.9	$ 604.8

	Crestwood Equity			Crestwood Midstream	
	Year Ended December 31,			Year Ended December 31,	
	2022	2021	2020	2022	2021
Net cash provided by operating activities	$ 439.2	$ 426.7	$ 408.1	$ 445.2	$ 434.4
Net changes in operating assets and liabilities	114.3	6.7	(36.1)	114.4	6.8
Amortization of debt-related deferred costs	(2.2)	(6.7)	(6.5)	(2.2)	(6.7)
Interest and debt expense, net	177.4	132.1	133.6	177.4	132.1
Unit-based compensation charges	(37.2)	(34.9)	(30.7)	(37.2)	(34.9)
Loss on long-lived assets, net	(187.7)	(39.6)	(26.0)	(312.7)	(39.4)
Goodwill impairment	—	—	(80.3)	—	—
Gain on acquisition	75.3	—	—	75.3	—
Earnings (loss) from unconsolidated affiliates, net, adjusted for cash distributions received	0.7	(138.0)	(6.5)	0.7	(138.0)
Deferred income taxes	(1.1)	0.4	(0.1)	(1.2)	—
Provision for income taxes	1.9	0.2	0.4	1.7	0.1
Other non-cash income (expense)	0.1	(0.3)	0.1	0.1	(0.3)
EBITDA	580.7	346.6	356.0	461.5	354.1
Unit-based compensation charges	37.2	34.9	30.7	37.2	34.9
Loss on long-lived assets, net	187.7	39.6	26.0	312.7	39.4
Goodwill impairment	—	—	80.3	—	—
Gain on acquisition	(75.3)	—	—	(75.3)	—
(Earnings) loss from unconsolidated affiliates, net	(15.7)	120.4	(32.5)	(15.7)	120.4
Adjusted EBITDA from unconsolidated affiliates, net	30.0	67.0	75.4	30.0	67.0
Change in fair value of commodity inventory-related derivative contracts	(14.4)	(13.5)	33.6	(14.4)	(13.5)
Significant transaction and environmental related costs and other items	31.9	5.1	10.8	31.9	2.5
Adjusted EBITDA	$ 762.1	$ 600.1	$ 580.3	$ 767.9	$ 604.8

Segment Results

The following tables summarize the EBITDA of our segments (*in millions*):

	Gathering and Processing North	Gathering and Processing South	Storage and Logistics
Revenues	$ 1,010.7	$ 381.4	$ 4,608.6
Intersegment revenues	527.2	207.5	(734.7)
Costs of product/services sold	848.6	399.5	3,749.0
Operations and maintenance expense	105.3	43.0	47.8
Loss on long-lived assets, net	—	(308.9)	(4.1)
Gain on acquisition	—	75.3	—
Earnings from unconsolidated affiliates, net	—	11.1	4.6
Crestwood Midstream EBITDA for the year ended December 31, 2022	$ 584.0	$ (76.1)	$ 77.6
Gain on long-lived assets[(1)]	—	125.0	—
Crestwood Equity EBITDA for the year ended December 31, 2022	$ 584.0	$ 48.9	$ 77.6
Revenues	$ 574.7	$ 105.9	$ 3,888.4
Intersegment revenues	459.3	—	(459.3)
Costs of product/services sold	553.2	0.9	3,289.8
Operations and maintenance expense	51.1	22.9	47.0
Gain (loss) on long-lived assets, net	0.4	(40.6)	0.7
Earnings (loss) from unconsolidated affiliates, net	—	9.6	(130.0)
EBITDA for the year ended December 31, 2021	$ 430.1	$ 51.1	$ (37.0)
Revenues	$ 510.4	$ 121.0	$ 1,622.9
Intersegment revenues	160.5	(0.7)	(159.8)
Costs of product/services sold	261.0	0.5	1,339.0
Operations and maintenance expense	55.7	29.2	46.9
Loss on long-lived assets, net	(3.8)	(20.0)	(2.4)
Goodwill impairment	(80.3)	—	—
Earnings (loss) from unconsolidated affiliates, net	—	(1.0)	33.5
EBITDA for the year ended December 31, 2020	$ 270.1	$ 69.6	$ 108.3

(1) Represents the elimination of the loss on long-lived assets of approximately $53 million recorded by CMLP and the gain on long-lived assets of approximately $72 million recorded by CEQP related to the sale of our assets in the Barnett Shale. For a further discussion of the sale of our assets in the Barnett Shale, see Note 3.

Below is a discussion of the factors that impacted EBITDA by segment for the year ended December 31, 2022 compared to the year ended December 31, 2021.

Gathering and Processing North

EBITDA for our gathering and processing north segment increased by approximately $153.9 million during the year ended December 31, 2022 compared to 2021. On February 1, 2022, we completed the merger with Oasis Midstream, and as a result, we began reflecting the financial results of the Williston Basin operations acquired in the Oasis Merger in our gathering and processing north segment. For a further discussion of this merger, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3.

Our gathering and processing north segment's revenues increased by approximately $503.9 million during the year ended December 31, 2022 compared to 2021, while our costs of product/services sold increased by approximately $295.4 million during 2022 compared to 2021. During the year ended December 31, 2022, we recognized revenues of approximately $348.6 million and product costs of approximately $105.2 million, related to the Williston Basin operations acquired in the Oasis Merger. The remaining increases in our gathering and processing north segment's revenues and costs of product/services sold were primarily driven by our Arrow operations which experienced higher average commodity prices on its agreements under which it purchases and sells crude oil and natural gas. Arrow's realized prices on its commodity sales increased by more than 50% during 2022 compared to 2021. Arrow's costs of product/services sold increased more than its revenues as a result of a decrease in its natural gas gathering and processing volumes and crude oil gathering volumes, which decreased by 14%, 13% and 31%, respectively, during 2022 compared to 2021. These volume decreases primarily resulted from lower activity by our producer customers due to natural production declines and the impact that supply chain and other operational issues had on our customers during 2022, and unusual winter weather conditions experienced during 2022 that unfavorably impacted our operations and our customers' operations.

Our gathering and processing north segment's operations and maintenance expenses increased by approximately $54.2 million during the year ended December 31, 2022 compared to 2021, primarily due to the Williston Basin operations acquired in the Oasis Merger.

Gathering and Processing South

EBITDA for CMLP's gathering and processing south segment decreased by approximately $127.2 million during the year ended December 31, 2022 compared to 2021. CMLP's gathering and processing south segment's EBITDA was impacted by the Delaware Basin operations acquired in the Oasis Merger, the Sendero Acquisition and the CPJV Acquisition as well as the divestitures of our operations in the Barnett and Marcellus Shales during 2022. For a further discussion of these strategic transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3.

Our gathering and processing south segment's revenues, costs of product/services sold and operations and maintenance expenses increased by approximately $483.0 million, $398.6 million, and $20.1 million, respectively, during the year ended December 31, 2022 compared to 2021.

The Sendero Acquisition and CPJV Acquisition on July 11, 2022 increased our gathering and processing south segment's revenues, cost of product/services sold and operations and maintenance expenses by approximately $519.3 million, $419.6 million and $23.4 million, respectively, during the year ended December 31, 2022 compared to 2021. In addition, we recognized a gain of approximately $75.3 million during 2022 related to the CPJV Acquisition.

In addition to the contributions from the acquisitions described above, the Delaware Basin operations acquired in the Oasis Merger on February 1, 2022 also increased our gathering and processing south segment's revenues, cost of product/services sold and operations and maintenance expenses by approximately $19.6 million, $0.8 million and $5.0 million, respectively, during the year ended December 31, 2022.

Partially offsetting the increases described above were the divestitures of our Barnett and Marcellus operations during 2022, which decreased our gathering and processing south segment's revenues, costs of product/services sold and operations and maintenance expenses by approximately $34.8 million, $1.4 million and $7.7 million, respectively, during the year ended December 31, 2022 compared to 2021. During the year ended December 31, 2022, CMLP recognized a loss on long-lived assets related to the Barnett and Marcellus divestitures of approximately $53 million and $250 million, respectively.

Also impacting our gathering and processing south segment's EBITDA during the year ended December 31, 2022 was a loss on long-lived assets of approximately $7.0 million related to the anticipated sale of parts inventory related to our legacy Granite Wash operations. In addition, during the year ended December 31, 2021, we recorded an impairment of approximately $40.1 million of our property, plant and equipment related to the compressor stations in our Marcellus operations based on the actual or anticipated dismantlement and redeployment of those assets to other areas.

Our gathering and processing south segment's EBITDA was also impacted by a net increase in earnings from unconsolidated affiliates of approximately $1.5 million during the year ended December 31, 2022 compared to 2021, due to an increase in equity earnings of approximately $2.4 million related to the Crestwood Permian Basin equity investment acquired in conjunction with the CPJV Acquisition, partially offset by a decrease in equity earnings of approximately $0.9 million due to the consolidation of our Crestwood Permian equity investment as a result of the acquisition of the remaining 50% equity interest in July 2022.

EBITDA for CEQP's gathering and processing south segment decreased by approximately $2.2 million during the year ended December 31, 2022 compared to 2021. The change in CEQP's gathering and processing south segment's EBITDA year over year was due to all of the factors discussed above for CMLP. However, CEQP did not record a loss on long-lived assets during 2022 related to the divestiture of the Barnett operations due to historical impairments previously recorded by CEQP on Barnett's long-lived assets. During 2022, CEQP recorded a gain on the Barnett divestiture of approximately $72 million.

Storage and Logistics

EBITDA for our storage and logistics segment increased by approximately $114.6 million during the year ended December, 2022 compared to 2021. Our storage and logistics segment's EBITDA for the year ended December 31, 2021 was impacted by a reduction to the equity earnings from our Stagecoach Gas Services LLC (Stagecoach Gas) equity method investment as a result of recording our proportionate share of a loss on long-lived assets (including goodwill) recorded by the equity method investee as further discussed below.

Our storage and logistics segment's revenues increased by approximately $444.8 million during the year ended December 31, 2022 compared to 2021, and our costs of product/services sold increased by approximately $459.2 million during 2022 compared to 2021.

Our NGL marketing and logistics operations experienced an increase in revenues of approximately $151.8 million and an increase in costs of product/services sold of approximately $160.1 million during the year ended December 31, 2022 compared to 2021. These increases were primarily driven by higher NGL prices as a result of overall increases in commodity prices during 2022 compared to 2021. In addition, our NGL marketing and logistics operations were impacted by lower demand for its storage, terminalling and marketing services during 2022 compared to 2021 as a result of warmer weather primarily in the East Coast, which resulted in costs of product/services sold increasing more than revenues during the year ended December 31, 2022 compared to 2021. Our NGL marketing and logistics operations' costs of product/services sold was also impacted by the effect of increasing commodity prices on our assets and liabilities from price risk management activities that manage our company-wide crude oil, natural gas and NGL commodity price exposures. Included in our costs of product/services sold was a gain of $9.4 million during the year ended December 31, 2022 and a loss of $44.5 million during the year ended December 31, 2021 related to our price risk management activities.

Our crude oil and natural gas marketing operations experienced an increase in revenues of approximately $300.0 million during the year ended December 31, 2022 compared to 2021, and an increase in product costs of approximately $298.3 million during 2022 compared to 2021. These increases were primarily driven by higher crude oil purchases and sales as a result of increases in commodity prices during 2022 compared to 2021, as well as an increase in marketing activity surrounding our natural gas-related operations driven by higher natural gas prices.

During the year ended December 31, 2022, our COLT Hub operations experienced a 68% decrease in its crude oil rail loading volumes compared to 2021 due to lower demand for its rail loading services as a result of lower basis differentials in the Bakken, which resulted in a decrease in revenues of approximately $7 million compared to 2021.

Our storage and logistics segment's EBITDA was impacted by a loss on long-lived assets of approximately $4.1 million during the year ended December 31, 2022, primarily due to the buyout of leases related to our exiting the crude oil railcar leasing business. For a further discussion of this matter, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 11.
Our storage and logistics segment's EBITDA was also impacted by a net increase in earnings from unconsolidated affiliates of approximately $134.6 million during the year ended December 31, 2022 compared to 2021. During 2021, our results included a loss from unconsolidated affiliates of approximately $139.2 million from our Stagecoach Gas equity investment that was sold in 2021 to a subsidiary of Kinder Morgan through a series of transactions. This loss primarily related to a $158.7 million reduction to the equity earnings from our Stagecoach Gas equity investment during the year ended December 31, 2021 primarily as a result of recording our proportionate share of a loss on long-lived assets (including goodwill) recorded by the equity method investee. For a further discussion of this transaction, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 5.
During the year ended December 31, 2022, earnings from our Tres Holdings equity investment decreased by $4.1 million compared to 2021, primarily due to the unusual cold weather experienced in early 2021 which resulted in higher revenues from natural gas inventory sales and an increase in demand for its storage and transportation services during the year ended December 31, 2021.

Other Items Affecting EBITDA Results

General and Administrative Expenses. During the year ended December 31, 2022, our general and administrative expenses increased compared to 2021, primarily due to transaction costs incurred in connection with our strategic transactions executed during 2022 as further discussed in Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3.

Items not affecting EBITDA include the following:

Depreciation, Amortization and Accretion Expense. During the year ended December 31, 2022, our depreciation, amortization and accretion expense increased compared to 2021, primarily due to our acquisitions during 2022, partially offset by the divestitures of our operations in the Barnett and Marcellus Shales during 2022. For a further discussion of these transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3.

Interest and Debt Expense, Net. During the year ended December 31, 2022, our interest and debt expense, net increased primarily due to the senior notes acquired in conjunction with the merger with Oasis Midstream and the Crestwood Permian credit facility acquired in conjunction with the acquisition of the 50% equity interest in Crestwood Permian. In addition, our interest and debt expense increased due to (i) additional borrowings under the Crestwood Midstream credit facility to fund the cash consideration in conjunction with our acquisitions during 2022; (ii) borrowings to fund the repayment of the Oasis Midstream credit facility acquired in conjunction with the Oasis Merger; and (iii) higher interest rates during the year ended December 31, 2022 compared to 2021. These increases in borrowings were partially offset by the proceeds received from the sale of our Barnett and Marcellus assets during 2022. For a further discussion of the long-term debt assumed in conjunction with our acquisitions during 2022, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9.

The following table provides a summary of our interest and debt expense, net (*in millions*):

	Year Ended December 31,		
	2022	**2021**	**2020**
Credit facilities	$ 40.2	$ 14.4	$ 23.3
Senior notes	137.5	109.1	106.1
Other, net	2.7	9.0	6.9
Gross interest and debt expense	180.4	132.5	136.3
Less: capitalized interest	3.0	0.4	2.7
Interest and debt expense, net	$ 177.4	$ 132.1	$ 133.6

Loss on Extinguishment of Debt. During the year ended December 31, 2021, we recognized a loss on extinguishment of debt of approximately $7.5 million primarily due to the redemption of our 2023 Senior Notes and the amendment of the Crestwood Midstream credit facility in December 2021.

Liquidity and Sources of Capital

Crestwood Equity is a holding company that derives all of its operating cash flow from its operating subsidiaries. Our principal sources of liquidity include cash generated by operating activities from our subsidiaries, distributions from our joint ventures, borrowings under our credit facilities, and sales of equity and debt securities. Our equity investments use cash from their respective operations and contributions from us to fund their operating activities and maintenance and growth capital expenditures. We believe our liquidity sources and operating cash flows are sufficient to address our future operating, debt service and capital requirements.

We make quarterly cash distributions to our common unitholders within approximately 45 days after the end of each fiscal quarter in an aggregate amount equal to our available cash for such quarter. We also pay quarterly cash distributions of approximately $15 million to our preferred unitholders and quarterly cash distributions of approximately $10 million to Crestwood Niobrara's non-controlling partner. The $434 million of preferred securities issued to Crestwood Niobrara's non-controlling partner are redeemable by the non-controlling partner beginning in January 2024, and we believe we have adequate borrowing capacity under the Crestwood Midstream credit facility along with adequate other potential sources of capital to fund any such potential redemption.

On January 19, 2023, we declared a quarterly cash distribution of $0.655 per unit to our common unitholders with respect to the fourth quarter of 2022, which was paid on February 14, 2023. Our Board of Directors evaluates the level of distributions to our common and preferred unitholders every quarter and considers a wide range of strategic, commercial, operational and financial factors, including current and projected operating cash flows. We believe our operating cash flows will exceed cash distributions to our partners, preferred unitholders and non-controlling partner, and as a result, we will have adequate operating cash flows as a source of liquidity for our growth capital expenditures.

The Crestwood Midstream credit agreement provides for a five-year $1.75 billion revolving credit facility that is available to fund acquisitions, working capital and internal growth projects and for general partnership purposes and allows Crestwood Midstream to increase its available borrowings under the facility by $100 million, subject to lender approval and the satisfaction of certain other conditions, as described in the credit agreement. As of December 31, 2022, we had $819.5 million of available capacity under the Crestwood Midstream credit facility, considering the most restrictive debt covenants in the credit agreement. As of December 31, 2022, we were in compliance with all of our debt covenants applicable to our credit facilities and our senior notes. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9 for a more detailed description of the covenants related to our credit facilities and senior notes.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions, tender offers or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. In January 2023, Crestwood Midstream issued $600 million of 7.375% unsecured senior notes due 2031 (the 2031 Senior Notes). We used the proceeds from the issuance of the 2031 Senior Notes to repay borrowings under the Crestwood Midstream credit facility and to repay all outstanding borrowings under the Crestwood Permian credit facility, which was terminated in January 2023. On February 20, 2023, we and Brookfield entered into an agreement with a third party to sell each of our respective interests in Tres Holdings for approximately $335 million. We intend to use our 50% share of the net proceeds to reduce borrowings under the Crestwood Midstream credit facility. The transaction is expected to close in the second quarter of 2023, subject to customary closing conditions.

Cash Flows

The following table provides a summary of Crestwood Equity's cash flows by category (*in millions*):

	Year Ended December 31,		
	2022	**2021**	**2020**
Net cash provided by operating activities	$ 439.2	$ 426.7	$ 408.1
Net cash provided by (used in) investing activities	$ (391.1)	$ 568.9	$ (273.3)
Net cash used in financing activities	$ (53.9)	$ (996.3)	$ (146.5)

Operating Activities

Our cash flows from operating activities increased by approximately $12.5 million during the year ended December 31, 2022 compared to 2021. The net increase was primarily driven by the operations acquired in the Oasis Merger, the Sendero Acquisition and the CPJV Acquisition, which are described in *Results of Operations* above. This net increase was partially offset by a reduction in operation cash flows from the operations divested during the Barnett and Marcellus divestitures during 2022, which are discussed above in *Results of Operations*.

Investing Activities

Capital Expenditures. The energy midstream business is capital intensive, requiring significant investments for the acquisition or development of new facilities. We categorize our capital expenditures as either:

- growth capital expenditures, which are made to construct additional assets, expand and upgrade existing systems, or acquire additional assets; or
- maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets, extend their useful lives or comply with regulatory requirements.

During 2023, we anticipate growth capital expenditures of approximately $135 million to $155 million, maintenance capital expenditures of approximately $25 million to $30 million, and approximately $10 million to $20 million on capital expenditures that are directly reimbursable by our customers. We anticipate that our growth and reimbursable capital expenditures in 2023 will increase the services we can provide to our customers and the operating efficiencies of our systems. We expect to finance our capital expenditures with a combination of cash generated by our operating subsidiaries, distributions received from our equity investments and borrowings under our credit facility. Additional commitments or expenditures will be made at our discretion, and any discontinuation of the construction of these projects could result in less future operating cash flows and earnings.

The following table summarizes our capital expenditures for the year ended December 31, 2022 (*in millions*):

Growth capital(1)	$	191.6
Maintenance capital		28.7
Other(2)		9.0
Purchases of property, plant and equipment	$	229.3

(1) Includes $3.2 million paid related to outstanding litigation on the construction of the Bear Den II cryogenic processing plant.
(2) Represents purchases of property, plant and equipment that are reimbursable by third parties.

Acquisitions and Divestitures. Below is a summary of the acquisition and divestiture activities that impacted our investing activities during the years ended December 31, 2022 and 2021. For a further discussion of these transactions, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 3, Note 6 and Note 11.

- *Oasis Merger*. In February 2022, we acquired Oasis Midstream, which included cash consideration of $160 million, net of cash acquired of approximately $14.9 million.
- *Sendero Acquisition*. In July 2022, we acquired Sendero for cash consideration of approximately $631.2 million, net of cash acquired of approximately $28.5 million.
- *CPJV Acquisition*. In July 2022, we acquired First Reserve's 50% equity interest in Crestwood Permian, which included cash consideration of approximately $5.9 million, net of acquired cash of approximately $149.4 million.
- *Crude Oil Railcars Sale*. In April 2022, we sold our crude oil railcars for approximately $24.7 million primarily as a result of the exit of our crude railcar operations.
- *Barnett Divestiture*. In July 2022, we sold our assets in the Barnett Shale for approximately $290 million, including working capital adjustments.
- *Marcellus Divestiture*. In October 2022, we sold our assets in the Marcellus Shale for approximately $206 million.
- *Stagecoach Gas Divestiture*. In conjunction with the second closing, in November 2021, we sold our remaining Stagecoach Gas equity investment for approximately $15 million.

Investments in/Capital Distributions from Unconsolidated Affiliates. Pursuant to our joint venture agreements with our respective equity investments, we periodically make contributions to our equity investments to fund their expansion projects and for other operating purposes. During the years ended December 31, 2022 and 2021, we contributed approximately $90.9 million and $17.6 million to our equity investments.

During the year ended December 31, 2021, we received a distribution from Stagecoach Gas of approximately $614 million, which represented our proportionate share of the gross proceeds received by Stagecoach Gas related to the first closing of its sale of certain of its assets. For further discussion of this distribution, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 6.

Financing Activities

The following equity and debt transactions impacted our financing activities during the year ended December 31, 2022 compared to 2021.

Equity and Debt Transactions

- During the year ended December 31, 2022, CEQP acquired 4.6 million CEQP common units from OMS Holdings LLC, a subsidiary of Chord, for approximately $123.7 million;
- During the year ended December 31, 2022, distributions to our partners increased by approximately $100.9 million compared to 2021, primarily due to an increase in common units outstanding as a result of the units issued in conjunction with the Oasis Merger and the CPJV Acquisition, as well as an increase in our distribution per limited partner unit from $0.625 per unit to $0.655 per unit;
- During the year ended December 31, 2022, our taxes paid for unit-based compensation vesting increased by approximately $7.5 million compared to 2021, primarily due to higher vesting of unit-based compensation awards;

- During the year ended December 31, 2022, our payments for finance leases increased by approximately $29.2 million primarily due to an option we exercised under our leases to purchase crude oil rail cars;
- During the year ended December 31, 2022, we borrowed amounts under the Crestwood Midstream credit facility to (i) fund cash consideration of approximately $631.2 million to acquire Sendero; (ii) fund approximately $5.9 million of cash consideration to acquire the remaining 50% equity interest in Crestwood Permian; (iii) fund $160.0 million of cash consideration paid in conjunction with the Oasis Merger; and (iv) repay approximately $218.4 million outstanding under the credit facility acquired in conjunction with the Oasis Merger;
- During the year ended December 31, 2021, we paid approximately $690.5 million to repurchase and cancel approximately $687.2 million of senior notes that were due in 2023;
- During the year ended December 31, 2021, we received net proceeds of approximately $691 million from the issuance of senior notes due February 2029; and
- During the year ended December 31, 2022, our other debt-related transactions resulted in net repayments under our credit facilities of approximately $435.8 million compared to net repayments of approximately $446.4 million during 2021.

Guarantor Summarized Financial Information

Crestwood Midstream and Crestwood Midstream Finance Corp. are issuers of our debt securities (the Issuers). Crestwood Midstream is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Crestwood Midstream Finance Corp. is Crestwood Midstream's 100% owned subsidiary and has no material assets or operations other than those related to its service as co-issuer of our senior notes. Obligations under Crestwood Midstream's senior notes and its credit facility are jointly and severally guaranteed by substantially all of its subsidiaries (collectively, the Guarantor Subsidiaries), except for Crestwood Infrastructure Holdings LLC, Crestwood Niobrara LLC, Crestwood Pipeline and Storage Northeast LLC, Powder River Basin Industrial Complex LLC, and Tres Palacios Holdings LLC and their respective subsidiaries (collectively, Non-Guarantor Subsidiaries). The assets and credit of our Non-Guarantor Subsidiaries are not available to satisfy the debts of the Issuers or Guarantor Subsidiaries, and the liabilities of our Non-Guarantor Subsidiaries do not constitute obligations of the Issuers or Guarantor Subsidiaries. In January 2023, Crestwood Permian and certain of its subsidiaries were designated as Guarantor Subsidiaries of Crestwood Midstream's senior notes and its credit facility. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9 for additional information regarding the Crestwood Midstream credit facility and senior notes and related guarantees.

The following tables provide summarized financial information for the Issuers and Guarantor Subsidiaries (collectively, the Obligor Group) on a combined basis after elimination of significant intercompany balances and transactions between entities in the Obligor Group. The investment balances in the Non-Guarantor Subsidiaries have been excluded from the supplemental summarized combined financial information. Transactions with other related parties, including the Non-Guarantor Subsidiaries, represent affiliate transactions and are presented separately in the summarized combined financial information below.

Summarized Combined Balance Sheet Information (in millions)

	December 31, 2022	
Current assets	$	588.4
Current assets - affiliates	$	1.3
Property, plant and equipment, net	$	3,295.8
Non-current assets	$	1,012.9
Current liabilities	$	466.1
Current liabilities - affiliates	$	41.5
Long-term debt, less current portion	$	3,171.5
Non-current liabilities	$	147.6

Summarized Combined Income Statement Information (in millions)

		Year Ended December 31, 2022
Revenues	$	5,410.1
Revenues - affiliates	$	384.4
Cost of products/services sold	$	4,288.8
Cost of products/services sold - affiliates	$	431.2
Operations and maintenance expenses(1)	$	161.7
General and administrative expenses(2)	$	124.4
Operating income	$	213.7
Net income	$	39.0

(1) We have operating agreements with certain of our affiliates pursuant to which we charge them operations and maintenance expenses in accordance with their respective agreements, and these charges are reflected as a reduction of operations and maintenance expenses in our consolidated statements of operations. During the year ended December 31, 2022, we charged $27.5 million to our affiliates under these agreements. See Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 19 for a further description of our related party operating agreements.

(2) Includes $32.8 million of net general and administrative expenses that were charged by our affiliates to us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in the interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows.

As of December 31, 2022, the carrying value and fair value of our fixed rate debt instruments was approximately $2.3 billion and $2.1 billion, respectively. As of December 31, 2021, the carrying value and fair value of our fixed rate debt instruments was approximately $1.8 billion and $1.9 billion, respectively. In January 2023, Crestwood Midstream issued $0.6 billion of 7.375% unsecured senior notes due 2031. For a further discussion of our fixed rate debt, see Part IV, Item 15. Exhibits, Financial Statement Schedules, Note 9.

We are subject to the risk of loss associated with changes in interest rates on our credit facilities. At December 31, 2022, we had obligations totaling $922.3 million and $206.8 million outstanding under the Crestwood Midstream credit facility and Crestwood Permian credit facility, respectively. These floating rate obligations expose us to the risk of increased interest payments in the event of increases in short-term interest rates. If the interest rate on our credit facilities were to fluctuate by 1% from the rate as of December 31, 2022, our annual interest expense would have changed by approximately $11.3 million. In January 2023, we repaid and terminated the Crestwood Permian credit facility.

Commodity Price, Market and Credit Risk

Inherent in our business are certain business risks, including market risk and credit risk.

Market Risk

We typically do not take title to the natural gas, NGLs or crude oil that we gather, store, or transport for our customers. However, we do take title to crude oil, natural gas and NGLs under certain purchase and sale agreements and percentage-of-proceeds contracts related to our gathering and processing services, and to NGLs and crude oil marketed or supplied by our NGL and crude oil storage and logistics operations. Our current business model is designed to minimize our exposure to fluctuations in commodity prices, although we are willing to assume commodity price risk in certain processing and marketing activities. We remain subject to volumetric risk under contracts without minimum volume commitments or take-or-pay pricing terms, for which market conditions can negatively influence our producer customers' decisions to develop or produce hydrocarbons.

In our storage and logistics operations, we consider market risk to be the risk that the value of our NGL and crude services portfolio will change, either favorably or unfavorably, in response to changing market conditions. We take an active role in managing and controlling market risk and have established control procedures, which are reviewed on an ongoing basis. We monitor market risk through a variety of techniques, including daily reporting of the portfolio's position to senior management. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with our price risk management activities are energy marketers, propane retailers, resellers, and dealers.

We engage in hedging and risk management transactions, including various types of forward contracts, options, swaps and futures contracts, to reduce the effect of price volatility on our product costs, protect the value of our inventory positions and to help ensure the availability of propane during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes only when we have a matching purchase commitment from our marketing customers. However, we may experience net unbalanced positions from time to time, which we believe to be immaterial in amount. In addition to our ongoing policy to maintain a balanced position, for accounting purposes we are required, on an ongoing basis, to track and report the market value of our derivative portfolio. We also utilize hedging and risk management transactions to reduce the impact of price risk under certain contracts in our gathering and processing operations. Our derivatives are not designated as hedges for accounting purposes.

The fair value of the derivatives contracts related to price risk management activities as of December 31, 2022 were assets of $72.8 million and liabilities of $23.9 million. We use observable market values for determining the fair value of these derivative contracts. In cases where actively quoted prices are not available, other external sources are used that incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis. Our risk management function regularly compares valuations to independent sources and models on a quarterly basis. The following table represents the impact that a 10% change in market prices would have on the underlying fair value of our commodity-based derivative instruments, along with the net unbalanced position of those commodity-based derivatives at December 31, 2022 and the inventory position that would substantially offset that theoretical change at December 31, 2022:

	December 31, 2022		
	Change in Fair Value of Commodity-Based Derivatives ***(in millions)***	**Net Unbalanced Derivative Position**	**Inventory Position**
Natural gas	$ 1.1	2.5 Bcf	0.8 Bcf
NGLs	$ 9.4	2.9 MMBbls	2.9 MMBbls
Crude oil	$ 2.0	0.2 MMBbls	0.2 MMBbls

Credit Risk

Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing and controlling credit risk and have established control procedures, which are reviewed on an ongoing basis. We have diversified our credit risk through having long-term contracts with many investment grade customers and creditworthy producers. Additionally, we perform credit analyses of our customers on a regular basis pursuant to our corporate credit policy. We have not had any significant losses due to failures to perform by our counterparties.

Under a number of our customer contracts, there are provisions that provide for our right to request or demand credit assurances from our customers including the posting of letters of credit, surety bonds, cash margin or collateral held in escrow for varying levels of future revenues. We continue to closely monitor our producer customer base since a majority of our customers for our gathering and processing services are either not rated by the major rating agencies or had below investment grade credit ratings. At December 31, 2022 and 2021, our allowance for doubtful accounts was $0.5 million and $0.6 million.

Item 8. Financial Statements and Supplementary Data

Reference is made to the financial statements and report of independent registered public accounting firm included later in this report under Part IV, Item 15. Exhibits, Financial Statement Schedules.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As of December 31, 2022, Crestwood Equity and Crestwood Midstream carried out an evaluation under the supervision and with the participation of their respective management, including the Chief Executive Officer and Chief Financial Officer of their General Partners, as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in the Securities Exchange Act of 1934, as amended (Exchange Act) Rules 13a-15(e) and 15d-15(e)). Crestwood Equity and Crestwood Midstream maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in their respective reports that are filed or submitted under the Exchange Act of 1934, as amended, are recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC, and that information is accumulated and communicated to their respective management, including the Chief Executive Officer and Chief Financial Officer of their General Partners, as appropriate, to allow timely decisions regarding required disclosure. Such management, including the Chief Executive Officer and Chief Financial Officer of their General Partners, does not expect that the disclosure controls and procedures or the internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Crestwood Equity's and Crestwood Midstream's disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and the Chief Executive Officer and Chief Financial Officer of their General Partners concluded that such disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2022.

Changes in Internal Control over Financial Reporting

There have been no changes in Crestwood Equity's or Crestwood Midstream's internal control over financial reporting during the fourth quarter of 2022 that have materially affected, or are reasonably likely to materially affect Crestwood Equity's or Crestwood Midstream's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Crestwood Equity's and Crestwood Midstream's management is responsible for establishing and maintaining adequate internal control over financial reporting, pursuant to Exchange Act Rules 13a-15(f). Crestwood Equity's and Crestwood Midstream's internal control systems were designed to provide reasonable assurance to their respective management and board of directors regarding the preparation and fair presentation of published financial statements in accordance with U.S. GAAP.

Management recognizes that there are inherent limitations in the effectiveness of any system of internal control, and accordingly, even effective internal control can provide only reasonable assurance with respect to financial statement preparation and fair presentation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

During 2022, we completed the Oasis Merger, Sendero Acquisition and the CPJV Acquisition. Management's assessment of and conclusion on the effectiveness of internal control over financial reporting as of December 31, 2022 excluded Oasis Midstream, Sendero and Crestwood Permian and their respective financial reporting systems were not fully integrated into our financial reporting systems throughout 2022. Therefore, we did not have the practical ability to perform an assessment of their internal controls prior to the conclusion of management's evaluation. We expect to include Oasis Midstream, Sendero and Crestwood Permian in next year's assessment. Oasis Midstream, Sendero and Crestwood Permian constituted a total of $3,192.6 million and $900.0 million in total assets and revenues, respectively, in our consolidated financial statements.

Under the supervision and with the participation of Crestwood Equity's and Crestwood Midstream's management, including the Chief Executive Officers and Chief Financial Officers of their General Partners, Crestwood Equity and Crestwood Midstream assessed the effectiveness of their respective internal control over financial reporting as of December 31, 2022. In making this assessment, Crestwood Equity and Crestwood Midstream used the criteria set forth in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based upon such assessment, Crestwood Equity and Crestwood Midstream concluded that, as of December 31, 2022, their respective internal control over financial reporting is effective, based upon those criteria.

Crestwood Equity's independent registered public accounting firm, Ernst & Young LLP, issued an attestation report dated February 24, 2023, on the effectiveness of our internal control over financial reporting, which is included herein.

Item 9B. Other Information

None.

PART III

Item 10, “Directors, Executive Officers and Corporate Governance;” Item 11, “Executive Compensation;” Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters;” and Item 13, “Certain Relationships and Related Transactions, and Director Independence” have been omitted from this report for Crestwood Midstream pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Item 10. Directors, Executive Officers and Corporate Governance

The information required to be disclosed under this item will be presented in our definitive proxy statement for the 2023 annual meeting of unitholders, which is expected to be filed pursuant to Regulation 14A within 120 days after the end of the fiscal year covered by this Form 10-K.

Item 11. Executive Compensation

The information required to be disclosed under this item will be presented in our definitive proxy statement for the 2023 annual meeting of unitholders, which is expected to be filed pursuant to Regulation 14A within 120 days after the end of the fiscal year covered by this Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The information required to be disclosed under this item will be presented in our definitive proxy statement for the 2023 annual meeting of unitholders, which is expected to be filed pursuant to Regulation 14A within 120 days after the end of the fiscal year covered by this Form 10-K.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required to be disclosed under this item will be presented in our definitive proxy statement for the 2023 annual meeting of unitholders, which is expected to be filed pursuant to Regulation 14A within 120 days after the end of the fiscal year covered by this Form 10-K.

Item 14. Principal Accountant Fees and Services

The information required to be disclosed under this item will be presented in our definitive proxy statement for the 2023 annual meeting of unitholders, which is expected to be filed pursuant to Regulation 14A within 120 days after the end of the fiscal year covered by this Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Exhibits, Financial Statements and Financial Statement Schedules:

1. Financial Statements:

   See Index Page for Financial Statements

2. Financial Statement Schedules:
   Schedule I: Parent Only Condensed Financial Statements
   Schedule II: Valuation and Qualifying Accounts

   Other financial statement schedules have been omitted because they are either not required, are immaterial or are not applicable or because equivalent information has been included in the financial statements, the notes thereto or elsewhere herein.

3. Exhibits:

Exhibit Number	Description
2.1	Contribution Agreement, dated as of April 20, 2016, by and between Crestwood Pipeline and Storage Northeast LLC and Con Edison Gas Pipeline and Storage Northeast, LLC (incorporated herein by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on April 22, 2016).
2.2	Purchase Agreement dated as of April 9, 2019 by and between Crestwood Niobrara LLC and Williams MLP Operating LLC (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on April 10, 2019).
2.3	Purchase Agreement, dated as of March 25, 2021, by and among Crestwood Holdings LLC, as the seller, and Crestwood Equity Partners LP, as the purchaser, and, for the limited purposes set forth therein, Crestwood Equity GP LLC (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on March 26, 2021).
2.4	Purchase and Sale Agreement, dated as of May 31, 2021 among Con Edison Gas Pipeline and Storage Northeast, LLC, Crestwood Pipeline and Storage Northeast LLC, as the Sellers, Stagecoach Gas Services LLC as the Company, Kinder Morgan Operating LLC "A" as Buyer, Con Edison Transmission, Inc. (solely for the limited purposes set forth therein) and Crestwood Midstream Partners LP (solely for the limited purposes set forth therein) (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on June 1, 2021).
2.5	Agreement and Plan of Merger, dated as of October 25, 2021, by and among Oasis Midstream Partners LP, OMP GP LLC, Crestwood Equity Partners LP, Project Falcon Merger Sub LLC, Project Phantom Merger Sub LLC, and, solely for the purposes of Section 2.1(a)(i) thereof, Crestwood Equity GP LLC (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on October 28, 2021).
2.6	Equity Purchase Agreement, dated as of May 25, 2022, by and among Sendero Midstream Partners, LP, Energy Capital Partners III, LP, Energy Capital Partners III-A, LP, Energy Capital Partners III-B (Sendero IP), LP, Energy Capital Partners III-C (Sendero IP), LP, Carlsbad Co-Invest, LP, ECP III (Sendero Co-Invest) Corp, Sendero Midstream Management, LLC, Sendero Midstream GP, LLC, Crestwood Midstream Partners LP, Crestwood Sendero GP LLC, and Crestwood Equity Partners LP (solely for the limited purposes set forth therein) (incorporated by reference to Exhibit 2.1 to Crestwood Equity Partners LP's Form 8-K filed on May 26, 2022).
2.7	Contribution Agreement, dated as of May 25, 2022, by and between FR XIII Crestwood Permian Basin Holdings LLC and Crestwood Equity Partners LP (incorporated by reference to Exhibit 2.2 to Crestwood Equity Partners LP's Form 8-K filed on May 26, 2022).
3.1	Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P.'s Registration Statement on Form S-1 (Registration No. 333-56976) filed on March 14, 2001).
3.2	Certificate of Correction of Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P.'s Form 10-Q filed on May 12, 2003).

Exhibit Number	Description
3.3	Amendment to the Certificate of Limited Partnership of Crestwood Equity Partners LP (f/k/a Inergy, L.P.) (the "Partnership") dated as of October 7, 2013 (incorporated herein by reference to Exhibit 3.2 to Crestwood Equity Partners LP's Form 8-K filed on October 10, 2013).
3.4	Sixth Amended and Restated Agreement of Limited Partnership of Crestwood Equity Partners LP dated August 20, 2021 (incorporated by reference to Exhibit 3.1 to Crestwood Equity Partners LP's Form 8-K filed on August 20, 2021).
3.5	Certificate of Formation of Inergy GP, LLC (incorporated herein by reference to Exhibit 3.5 to Inergy, L.P.'s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001)
3.6	Certificate of Amendment of Crestwood Equity GP LLC (f/k/a Inergy GP, LLC) dated October 7, 2013 (incorporated herein by reference to Exhibit 3.3A to Crestwood Equity Partners LP's Form 10-Q filed on November 8, 2013)
3.7	Second Amended and Restated Limited Liability Company Agreement of Crestwood Equity GP LLC dated August 20, 2021 (incorporated by reference to Exhibit 3.2 to Crestwood Equity Partners LP's Form 8-K filed on August 20, 2021).
3.8	Certificate of Limited Partnership of Inergy Midstream, L.P. (incorporated herein by reference to Exhibit 3.4 to Inergy Midstream, L.P.'s Form S-1/A filed on November 21, 2011)
3.9	Amendment to the Certificate of Limited Partnership of Crestwood Midstream Partners LP (f/k/a Inergy Midstream, L.P.) (incorporated herein by reference to Exhibit 3.2 to Inergy Midstream, L.P.'s Form 8-K filed on October 10, 2013)
3.10	Second Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP, dated as of September 30, 2015 (incorporated by reference to Exhibit 3.1 to Crestwood Midstream Partners LP's Form 8-K filed on October 1, 2015).
3.11	Certificate of Formation of NRGM GP, LLC (incorporated herein by reference to Exhibit 3.7 to Inergy Midstream, L.P.'s Form S-1/A filed on November 21, 2011)
3.12	Certificate of Amendment of Crestwood Midstream GP LLC (f/k/a NRGM GP, LLC) (incorporated herein by reference to Exhibit 3.37 to Crestwood Midstream Partners LP's Form S-4/A filed on October 28, 2013)
3.13	Amended and Restated Limited Liability Company Agreement of NRGM GP, LLC, dated December 21, 2011 (incorporated herein by reference to Exhibit 3.2 to Inergy Midstream, L.P.'s Form 8-K filed on December 22, 2011)
3.14	Amendment No. 1 to the Amended and Restated Limited Liability Company Agreement of Crestwood Midstream GP LLC (f/k/a NRGM GP, LLC) (incorporated herein by reference to Exhibit 3.39 to Crestwood Midstream Partners LP's Form S-4/A filed on October 28, 2013)
4.1	Specimen Unit Certificate for Common Units (incorporated herein by reference to Exhibit 4.3 to Inergy L.P.'s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001)
4.2	Indenture, dated as of March 14, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on March 15, 2017)
4.3	Supplemental Indenture dated as of June 5, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-Q filed on August 4, 2017)
4.4	Supplemental Indenture dated as of December 1, 2017, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018)
4.5	Indenture, dated as of April 15, 2019, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on April 16, 2019).

Exhibit Number	Description
4.6	Third Amended and Restated Limited Liability Company Agreement for Crestwood Niobrara LLC, dated between Crestwood Midstream Partners LP and CN Jackalope Holdings, LLC (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-Q filed on May 2, 2019).
4.7	First Amendment to the Third Amended and Restated Limited Liability Company Agreement of Crestwood Niobrara LLC dated as of April 9, 2019 (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on August 20, 2021).
4.8	Registration Rights Agreement, dated December 28, 2017, by and among Crestwood Equity Partners LP and CN Jackalope Holdings, LLC (incorporated herein by reference to Exhibit 4.10 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018).
4.9	First Amendment to Registration Rights Agreement dated as of April 9, 2019 by and between Crestwood Equity Partners LP and CN Jackalope Holdings, LLC (incorporated herein by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on April 10, 2019).
4.10	Registration Rights Agreement, dated March 14, 2017, by and among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and J.P. Morgan Securities LLC, as representative of the several initial purchasers, with respect to the 5.72% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on March 15, 2017).
4.11	Registration Rights Agreement, dated as of September 30, 2015, by and among Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015).
4.12	Supplemental Indenture dated as of October 22, 2018, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, each existing Guarantor and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.13 to Crestwood Equity Partners LP's Form 10-K filed on February 22, 2019).
4.13	Indenture, dated January 21, 2021, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on January 21, 2021).
4.14	First Supplemental Indenture, dated as of February 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and Regions Bank (incorporated herein by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
4.15	Fourth Supplemental Indenture, dated as of February 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, the guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.2 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
4.16	First Supplemental Indenture, dated as of February 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, the guarantors named therein and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.3 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
4.17	First Supplemental Indenture, dated as of February 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corporation, the guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
4.18	Registration Rights Agreement, dated as of February 1, 2022 by and among Crestwood Equity Partners LP, Oasis Petroleum Inc., OMS Holdings LLC and Oasis Investment Holdings LLC (incorporated herein by reference to Exhibit 4.6 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
4.19	Supplemental Indenture, dated as of July 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank Trust Company, National Association, as successor in interest to U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).

Exhibit Number	Description
4.20	Supplemental Indenture, dated as of July 1, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and Regions Bank as trustee (incorporated by reference to Exhibit 4.2 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).
4.21	Registration Rights Agreement, dated July 11, 2022, by and between Crestwood Equity Partners LP and FR XIII Crestwood Permian Basin Holdings LLC (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on July 15, 2022).
4.22	Fifth Supplemental Indenture, dated as of July 20, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank Trust Company, National Association, as successor in interest to U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).
4.23	Second Supplemental Indenture, dated as of July 20, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank Trust Company, National Association, as successor in interest to U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.4 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).
4.24	Second Supplemental Indenture, dated as of July 20, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank Trust Company, National Association, as successor in interest to U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.5 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).
4.25	Second Supplemental Indenture, dated as of July 20, 2022, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and Regions Bank, as trustee (incorporated by reference to Exhibit 4.6 to Crestwood Equity Partners LP's Form 10-Q filed on July 28, 2022).
4.26	Indenture, dated as of January 19, 2023, among Crestwood Midstream Partners LP, Crestwood Midstream Finance Corp., the guarantors named therein and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Crestwood Equity Partners LP's Form 8-K filed on January 19, 2023).
**4.27	Description of Securities
*10.1	Omnibus Amendment to Employment Agreements dated February 22, 2018 by and between Crestwood Operations LLC and each of Robert G. Phillips, Robert Halpin, Steven Dougherty, Joel Lambert and William H. Moore (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-K filed on February 26, 2018).
*10.2	Employment Agreement between Robert G. Phillips and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 27, 2014).
*10.3	Employment Agreement between Joel Lambert and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on February 28, 2014).
*10.4	Employment Agreement between William H. Moore and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on March 2, 2015).
*10.5	Employment Agreement between Steven M. Dougherty and Crestwood Operations LLC dated as of January 21, 2014 (incorporated herein by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 10-K filed on February 29, 2016).
*10.6	Amended and Restated Employee Agreement between Robert T. Halpin and Crestwood Operations LLC dated as of April 1, 2015 (incorporated herein by reference to Exhibit 10.5 to Crestwood Equity Partners LP's Form 10-K filed on February 29, 2016).
*10.7	Crestwood Equity Partners LP Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.7 to Crestwood Equity Partners LP's Form 10-K filed on February 28, 2014).
*10.8	Form of Crestwood Equity Partners LP's Restricted Unit Award Agreement (incorporated herein by reference to Exhibit 4.12 to Crestwood Equity Partner LP's Form S-8 filed on January 16, 2015).

Exhibit Number	Description
*10.9	Form of Crestwood Equity Partners LP's Phantom Unit Award Agreement (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 23, 2015).
*10.10	Form of Crestwood Equity Partners LP's Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 10-Q filed on May 4, 2017).
*10.11	Crestwood Equity Partners Non-Qualified Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on November 15, 2016).
10.12	Guaranty, dated as of April 20, 2016, made by Crestwood Equity Partners LP in favor of Con Edison Gas Pipeline and Storage Northeast, LLC (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on April 22, 2016).
10.13	Amended and Restated Limited Liability Company Agreement of Stagecoach Gas Services LLC dated as of June 3, 2016. (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on June 8, 2016).
10.14	Registration Rights Agreement, dated as of September 30, 2015, by and among Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015).
10.15	Board Representation and Standstill Agreement, dated as of September 30, 2015, by and among Crestwood Equity GP LLC, Crestwood Equity Partners LP and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on October 1, 2015).
*10.16	Crestwood Equity Partners LP 2018 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed with the Commission on May 16, 2018).
*10.17	First Amendment to the Crestwood Equity Partners LP 2018 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on August 20, 2021).
*10.18	Crestwood Equity Partners LP Employee Unit Purchase Plan. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K, filed with the Commission on August 24, 2018).
*10.19	Form of Crestwood Equity Partners LP's Executive Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 10-Q filed November 1, 2018).
*10.20	Form of Crestwood Equity Partners LP's Non-Executive Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018).
*10.21	Form of Crestwood Equity Partners LP's Director Restricted Unit Award Grant Notice (incorporated by reference to Exhibit 10.3 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018).
*10.22	Form of Crestwood Equity Partners LP's Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 10-Q filed on November 1, 2018).
*10.23	Form of Director and Officer Indemnification Agreement filed as Exhibit 10.1 to Crestwood Equity Partners LP's Form 10-Q filed on August 6, 2020.
10.24	Common Unit Purchase Agreement, dated as of March 25, 2021, by and among Crestwood Equity Partners LP, Crestwood Gas Services Holdings LLC and the Purchasers named therein (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on March 26, 2021).
10.25	Registration Rights Agreement, dated March 30, 2021, by and between Crestwood Equity Partners LP and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on March 31, 2021).
10.26	Support Agreement, dated as of October 25, 2021, by and among Crestwood Equity Partners LP, Oasis Midstream Partners LP, OMP GP LLC, Oasis Petroleum Inc. and OMS Holdings LLC (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on October 28, 2021).
10.27	Third Amended and Restated Credit Agreement, dated as of December 20, 2021, by and among Crestwood Midstream Partners LP, as borrower, the lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on December 21, 2021).

Exhibit Number	Description
*10.28	Employment Agreement between Diaco Aviki and Crestwood Operations LLC dated as of January 18, 2022 (incorporated herein by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 18, 2022).
10.29	Master Amendment to Commercial Agreements, dated as of February 1, 2022, by and among Oasis Petroleum North America LLC, Oasis Petroleum Marketing LLC, Oasis Midstream Services LLC, Oasis Midstream Partners LP, OMP Operating LLC and Bighorn Devco LLC (incorporated herein by reference to Exhibit 10.3 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
*10.30	Form of Director and Officer Indemnification Agreement (incorporated herein by reference to Exhibit 10.4 to Crestwood Equity Partners LP's Form 8-K filed on February 3, 2022).
*10.31	Director Nomination and Voting Support Agreement, dated July 11, 2022, by and among Crestwood Equity Partners LP, Crestwood Equity GP LLC, and FR XIII Crestwood Permian Basin Holdings LLC (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on July 15, 2022).
*10.32	Employment Agreement between John Black and Crestwood Operations LLC, dated August 15, 2022 (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on August 16, 2022).
*10.33	Second Amendment to the Crestwood Equity Partners LP Long Term Incentive Plan dated as of January 6, 2023 (incorporated by reference to Exhibit 10.1 to Crestwood Equity Partners LP's Form 8-K filed on January 10, 2023).
*10.34	2023 Omnibus Amendment to 2023 Employment Agreement dated as of January 6, 2023 (incorporated by reference to Exhibit 10.2 to Crestwood Equity Partners LP's Form 8-K filed on January 10, 2023).
**10.35	Form of 2023 Restricted Unit Award Agreement (Executive)
**10.36	Form of 2023 Performance Unit Award Agreement
**21.1	List of subsidiaries of Crestwood Equity Partners LP
**22.1	List of Issuers of Guarantor Subsidiaries of Crestwood Midstream Partners LP
**23.1	Consent of Ernst & Young LLP - Crestwood Equity Partners LP
**23.2	Consent of Ernst & Young LLP - Stagecoach Gas Services LLC
**31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Equity Partners LP
**31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Equity Partners LP
**31.3	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Midstream Partners LP
**31.4	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended - Crestwood Midstream Partners LP
**32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Equity Partners LP
**32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Equity Partners LP
**32.3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Midstream Partners LP
**32.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Crestwood Midstream Partners LP
**97.1	Crestwood Equity Partners LP Clawback Policy effective as of November 10, 2022
**99.1	Financial Statements for Stagecoach Gas Services LLC as of November 24, 2021 (unaudited) and December 31, 2020 (audited) and for the period ended November 24, 2021 (unaudited) and the year ended December 31, 2020 (audited) pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09)

Exhibit Number	Description
**101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
**101.SCH	Inline XBRL Taxonomy Extension Schema Document
**101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
**101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
**101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (contained in Exhibit 101)

* Management contracts or compensatory plans or arrangements

** Filed herewith

(b) Exhibits.

See exhibits identified above under Item 15(a)3.

(c) Financial Statement Schedules.

Financial Statements for Stagecoach Gas Services LLC as of November 24, 2021 (unaudited) and December 31, 2020 (audited) and for the period ended November 24, 2021 (unaudited) and the year ended December 31, 2020 (audited) pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09) and is filed herein as Exhibit 99.1.

Crestwood Equity Partners LP
Crestwood Midstream Partners LP

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors of Crestwood Equity GP LLC and Unitholders of Crestwood Equity Partners LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Crestwood Equity Partners LP (the Partnership) as of December 31, 2022 and 2021, the related consolidated statements of operations, partners' capital and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and financial statement schedules listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 24, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the 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 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of the critical audit matters 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 matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

	Revenue recognition – Measuring variable consideration
Description of the Matter	As described in Note 2 to the consolidated financial statements, the Partnership recognizes revenues for services and products under revenue contracts as obligations to perform services or deliver/sell products under the contracts are satisfied. For a significant customer contract within the Partnership's Gathering and Processing North operating segment, consideration to be received under the contact is estimated over the life of the contract and the contract's transaction price is allocated to each performance obligation in the contract and recognized as revenue when, or as, the performance obligation is satisfied.

Auditing the Partnership's measurement of variable consideration under this contract involved especially challenging judgment because the calculation involves subjective management assumptions about estimates of future revenues including forecasted production of its customer over the life of the contract. For example, the estimates of future revenues reflect management's assumptions about future economic conditions and expected volumes to be gathered and processed, and changes in those assumptions can have a material effect on the amount of revenue recognized

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Partnership's process to calculate the variable consideration, including the underlying assumptions about estimates of expected volumes. Our audit procedures included, among others, evaluating the significant assumptions and the accuracy and completeness of the underlying data used in management's calculation. This included testing management's forecasted volumes through comparison to the forecasted production of the customer, forecasted commodity prices and historical data and the recalculation of the transaction price. In addition, we performed sensitivity analyses to evaluate the changes in variable consideration that would result from changes in the Partnership's forecasted volumes included in the calculation of the transaction price.
	Purchase price allocation – Measuring intangible assets
Description of the Matter	As described in Note 2 to the consolidated financial statements, the Partnership completed the acquisitions of Oasis Midstream Partners LP (Oasis Midstream) and Sendero Midstream Partners, LP (Sendero Midstream) for total purchase consideration of $1.8 billion and $631.2 million, respectively, in the year ended December 31, 2022. The acquisitions have been accounted as business combinations. The Partnership's accounting for these acquisitions included determining the fair value of the intangible assets acquired, which primarily included customer relationships of $464.0 million and $41.5 million for Oasis Midstream and Sendero Midstream, respectively. Auditing the Partnership's accounting for its acquisitions of Oasis Midstream and Sendero Midstream was complex due to the significant estimation uncertainty in determining the fair value of customer relationships. The estimation uncertainty was primarily due to the sensitivity of the fair value of the customer relationships to underlying assumptions about future volume projections for each of the acquired businesses and the discount rate for Oasis Midstream. These significant assumptions are forward-looking and could be affected by future economic and market conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Partnership's accounting for the acquisitions. For example, we tested controls over the estimation of the fair value of the customer relationship intangible assets, including the valuation models and underlying assumptions used to develop such estimates. Our audit procedures included, among others, assessing the appropriateness of the valuation methodologies used, evaluating the significant assumptions, and evaluating the completeness and accuracy of underlying data supporting the significant assumptions. For example, we compared the significant assumptions to current industry, market and economic data. We performed sensitivity analyses of the significant assumptions to evaluate the change in the fair value resulting from changes in the assumptions. We involved our valuation specialists to assist with our evaluation of the methodologies used by the Partnership and significant assumptions used in the valuation of the intangible assets acquired.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2013.
Houston, Texas
February 24, 2023

Report of Independent Registered Public Accounting Firm on Internal Controls Over Financial Reporting

The Board of Directors of Crestwood Equity GP LLC and Unitholders of Crestwood Equity Partners LP

Opinion on Internal Control over Financial Reporting

We have audited Crestwood Equity Partners LP's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Crestwood Equity Partners LP (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Oasis Midstream Partners LP (Oasis Midstream), Sendero Midstream Partners, LP (Sendero Midstream), and Crestwood Permian Basin Holdings LLC (CPBH), which are included in the 2022 consolidated financial statements of the Partnership and constituted $3,192.6 million of total assets as of December 31, 2022 and $900.0 million of revenues for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of Oasis Midstream, Sendero Midstream, and CPBH.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets as of December 31, 2022 and 2021 and related consolidated statements of operations, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and financial statement schedules listed in the Index at Item 15(a) of the Partnership and our report dated February 24, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Houston, Texas
February 24, 2023

CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(in millions, except unit information)

	December 31,	
	2022	2021
Assets		
Current assets:		
Cash	$ 7.5	$ 13.3
Accounts receivable, less allowance for doubtful accounts of $0.5 and $0.6 at December 31, 2022 and 2021	432.2	378.0
Inventory	122.6	156.5
Assets from price risk management activities	72.8	42.1
Prepaid expenses and other current assets	18.7	14.8
Total current assets	653.8	604.7
Property, plant and equipment	5,353.2	3,771.5
Less: accumulated depreciation	822.8	992.1
Property, plant and equipment, net	4,530.4	2,779.4
Intangible assets	1,306.3	1,126.1
Less: accumulated amortization	300.7	393.2
Intangible assets, net	1,005.6	732.9
Goodwill	223.0	138.6
Operating lease right-of-use assets, net	24.4	27.4
Investments in unconsolidated affiliates	119.5	155.8
Other non-current assets	10.3	6.9
Total assets	$ 6,567.0	$ 4,445.7
Liabilities and capital		
Current liabilities:		
Accounts payable	$ 305.5	$ 336.5
Accrued expenses and other liabilities	180.8	147.1
Liabilities from price risk management activities	23.9	114.6
Current portion of long-term debt	—	0.2
Total current liabilities	510.2	598.4
Long-term debt, less current portion	3,378.3	2,052.1
Other long-term liabilities	333.4	258.7
Deferred income taxes	3.5	2.3
Total liabilities	4,225.4	2,911.5
Commitments and contingencies (*Note 10*)		
Interest of non-controlling partner in subsidiary	434.4	434.6
Partners' capital:		
Crestwood Equity Partners LP partners' capital (104,646,374 and 62,991,511 common units issued and outstanding at December 31, 2022 and 2021)	1,295.2	487.6
Preferred units (71,257,445 units issued and outstanding at both December 31, 2022 and 2021)	612.0	612.0
Total partners' capital	1,907.2	1,099.6
Total liabilities and capital	$ 6,567.0	$ 4,445.7

See accompanying notes.

CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues:			
Product revenues	$ 5,198.4	$ 4,145.4	$ 1,793.0
Product revenues - related party (*Note 19*)	222.6	25.8	27.3
Service revenues	430.4	396.4	433.5
Service revenues - related party (*Note 19*)	149.3	1.4	0.5
Total revenues	6,000.7	4,569.0	2,254.3
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	4,730.4	3,688.8	1,558.8
Product costs - related party (*Note 19*)	240.9	136.8	21.0
Service costs	25.8	18.3	20.7
Total costs of products/services sold	4,997.1	3,843.9	1,600.5
Operating expenses and other:			
Operations and maintenance	196.1	121.0	131.8
General and administrative	130.4	97.6	91.5
Depreciation, amortization and accretion	328.9	244.2	237.4
Loss on long-lived assets, net	187.7	39.6	26.0
Goodwill impairment	—	—	80.3
Gain on acquisition	(75.3)	—	—
	767.8	502.4	567.0
Operating income	235.8	222.7	86.8
Earnings (loss) from unconsolidated affiliates, net	15.7	(120.4)	32.5
Interest and debt expense, net	(177.4)	(132.1)	(133.6)
Gain (loss) on modification/extinguishment of debt	—	(7.5)	0.1
Other income (expense), net	0.3	0.1	(0.7)
Income (loss) before income taxes	74.4	(37.2)	(14.9)
Provision for income taxes	(1.9)	(0.2)	(0.4)
Net income (loss)	72.5	(37.4)	(15.3)
Net income attributable to non-controlling partner	41.2	41.1	40.8
Net income (loss) attributable to Crestwood Equity Partners LP	31.3	(78.5)	(56.1)
Net income attributable to preferred units	60.1	60.1	60.1
Net loss attributable to partners	$ (28.8)	$ (138.6)	$ (116.2)
Net loss per limited partner unit: *(Note 14)*			
Basic and Diluted	$ (0.29)	$ (2.11)	$ (1.59)
Weighted-average limited partners' units outstanding:			
Basic and Diluted	99.0	65.6	73.2

See accompanying notes.

CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in millions)

	Preferred		Partners			
	Units	Capital	Common Units	Subordinated Units	Capital	Total Partners' Capital
Balance at December 31, 2019	71.3	$ 612.0	71.9	0.4	$ 1,320.8	$ 1,932.8
Distributions to partners	—	(60.1)	—	—	(182.7)	(242.8)
Unit-based compensation charges	—	—	2.1	—	34.0	34.0
Taxes paid for unit-based compensation vesting	—	—	(0.6)	—	(15.6)	(15.6)
Other	—	—	0.2	—	3.1	3.1
Net income (loss)	—	60.1	—	—	(116.2)	(56.1)
Balance at December 31, 2020	71.3	612.0	73.6	0.4	1,043.4	1,655.4
Crestwood Holdings Transactions *(Note 12)*	—	—	—	—	(273.2)	(273.2)
Retirement of units *(Note 12)*	—	—	(11.5)	(0.4)	—	—
Distributions to partners	—	(60.1)	—	—	(164.3)	(224.4)
Unit-based compensation charges	—	—	1.3	—	32.0	32.0
Taxes paid for unit-based compensation vesting	—	—	(0.4)	—	(8.4)	(8.4)
Other	—	—	—	—	(3.3)	(3.3)
Net income (loss)	—	60.1	—	—	(138.6)	(78.5)
Balance at December 31, 2021	71.3	612.0	63.0	—	487.6	1,099.6
Distributions to partners	—	(60.1)	—	—	(265.2)	(325.3)
Issuance of common units *(Note 3)*	—	—	45.1	—	1,200.8	1,200.8
Purchase of common units *(Note 12)*	—	—	—	—	(123.7)	(123.7)
Retirement of common units *(Note 12)*	—	—	(4.6)	—	—	—
Unit-based compensation charges	—	—	1.6	—	39.8	39.8
Taxes paid for unit-based compensation vesting	—	—	(0.6)	—	(15.9)	(15.9)
Other	—	—	0.1	—	0.6	0.6
Net income (loss)	—	60.1	—	—	(28.8)	31.3
Balance at December 31, 2022	71.3	$ 612.0	104.6	—	$ 1,295.2	$ 1,907.2

See accompanying notes.

CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Operating activities			
Net income (loss)	$ 72.5	$ (37.4)	$ (15.3)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	328.9	244.2	237.4
Amortization of debt-related deferred costs and fair value adjustment	2.2	6.7	6.5
Unit-based compensation charges	37.2	34.9	30.7
Loss on long-lived assets, net	187.7	39.6	26.0
Goodwill impairment	—	—	80.3
Gain on acquisition	(75.3)	—	—
(Gain) loss on modification/extinguishment of debt	—	7.5	(0.1)
(Earnings) loss from unconsolidated affiliates, net, adjusted for cash distributions received	(0.7)	138.0	6.5
Deferred income taxes	1.1	(0.4)	0.1
Other	(0.1)	0.3	(0.1)
Changes in operating assets and liabilities:			
Accounts receivable	149.4	(114.3)	(27.5)
Inventory	34.3	(67.4)	(33.7)
Prepaid expenses and other current assets	(2.4)	(1.0)	(3.7)
Accounts payable, accrued expenses and other liabilities	(181.3)	148.3	(1.2)
Reimbursements of property, plant and equipment	7.1	4.3	15.7
Change in price risk management activities, net	(121.4)	23.4	86.5
Net cash provided by operating activities	439.2	426.7	408.1
Investing activities			
Acquisitions, net of cash acquired *(Note 3)*	(604.3)	—	(162.3)
Purchases of property, plant and equipment	(229.3)	(83.2)	(168.3)
Investments in unconsolidated affiliates	(90.9)	(17.6)	(9.4)
Capital distributions from unconsolidated affiliates	11.8	652.0	39.4
Net proceeds from sale of assets, including equity investments	521.6	17.7	27.3
Net cash provided by (used in) investing activities	(391.1)	568.9	(273.3)

CRESTWOOD EQUITY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(in millions)

	Year Ended December 31,		
	2022	2021	2020
Financing activities			
Proceeds from the issuance of long-term debt	3,743.0	2,859.5	1,125.1
Payments on long-term debt	(3,254.3)	(3,287.5)	(975.8)
Payments on finance leases	(32.0)	(2.8)	(3.1)
Payments for deferred financing costs	(3.7)	(17.9)	—
Net proceeds from issuance of non-controlling interest	—	1.0	2.8
Payments for Crestwood Holdings Transactions	—	(275.6)	—
Purchase of common units	(123.7)	—	—
Distributions to partners	(265.2)	(164.3)	(182.7)
Distributions to non-controlling partner	(41.4)	(40.2)	(37.1)
Distributions to preferred unitholders	(60.1)	(60.1)	(60.1)
Taxes paid for unit-based compensation vesting	(15.9)	(8.4)	(15.6)
Other	(0.6)	—	—
Net cash used in financing activities	(53.9)	(996.3)	(146.5)
Net change in cash	(5.8)	(0.7)	(11.7)
Cash at beginning of period	13.3	14.0	25.7
Cash at end of period	$ 7.5	$ 13.3	$ 14.0
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 178.2	$ 125.9	$ 129.8
Cash paid for income taxes	$ 1.8	$ 0.8	$ 0.6
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$ 7.4	$ (5.8)	$ 40.0

See accompanying notes.

Report of Independent Registered Public Accounting Firm

The Board of Directors of Crestwood Equity GP LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Crestwood Midstream Partners (the Partnership) as of December 31, 2022 and 2021, and the related consolidated statements of operations, partners' capital and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's 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 financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of the critical audit matters 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 matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

	Revenue recognition – Measuring variable consideration
Description of the Matter	As described in Note 2 to the consolidated financial statements, the Partnership recognizes revenues for services and products under revenue contracts as obligations to perform services or deliver/sell products under the contracts are satisfied. For a significant customer contract within the Partnership's Gathering and Processing North operating segment, consideration to be received under the contact is estimated over the life of the contract and the contract's transaction price is allocated to each performance obligation in the contract and recognized as revenue when, or as, the performance obligation is satisfied.

Auditing the Partnership’s measurement of variable consideration under this contract involved especially challenging judgment because the calculation involves subjective management assumptions about estimates of future revenues including forecasted production of its customer over the life of the contract. For example, the estimates of future revenues reflect management's assumptions about future economic conditions and expected volumes to be gathered and processed, and changes in those assumptions can have a material effect on the amount of revenue recognized

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Partnership’s process to calculate the variable consideration, including the underlying assumptions about estimates of expected volumes.

Our audit procedures included, among others, evaluating the significant assumptions and the accuracy and completeness of the underlying data used in management’s calculation. This included testing management’s forecasted volumes through comparison to the forecasted production of the customer, forecasted commodity prices and historical data and the recalculation of the transaction price. In addition, we performed sensitivity analyses to evaluate the changes in variable consideration that would result from changes in the Partnership’s forecasted volumes included in the calculation of the transaction price.

Purchase price allocation – Measuring intangible assets

Description of the Matter

As described in Note 2 to the consolidated financial statements, the Partnership completed the acquisitions of Oasis Midstream Partners LP (Oasis Midstream) and Sendero Midstream Partners, LP (Sendero Midstream) for total purchase consideration of $1.8 billion and $631.2 million, respectively, in the year ended December 31, 2022. The acquisitions have been accounted as business combinations. The Partnership’s accounting for these acquisitions included determining the fair value of the intangible assets acquired, which primarily included customer relationships of $464.0 million and $41.5 million for Oasis Midstream and Sendero Midstream, respectively.

Auditing the Partnership’s accounting for its acquisitions of Oasis Midstream and Sendero Midstream was complex due to the significant estimation uncertainty in determining the fair value of customer relationships. The estimation uncertainty was primarily due to the sensitivity of the fair value of the customer relationships to underlying assumptions about future volume projections for each of the acquired businesses and the discount rate for Oasis Midstream. These significant assumptions are forward-looking and could be affected by future economic and market conditions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Partnership’s accounting for the acquisitions. For example, we tested controls over the estimation of the fair value of the customer relationship intangible assets, including the valuation models and underlying assumptions used to develop such estimates.

Our audit procedures included, among others, assessing the appropriateness of the valuation methodologies used, evaluating the significant assumptions, and evaluating the completeness and accuracy of underlying data supporting the significant assumptions. For example, we compared the significant assumptions to current industry, market and economic data. We performed sensitivity analyses of the significant assumptions to evaluate the change in the fair value resulting from changes in the assumptions. We involved our valuation specialists to assist with our evaluation of the methodologies used by the Partnership and significant assumptions used in the valuation of the intangible assets acquired

/s/ Ernst & Young LLP

We have served as the Partnership’s auditor since 2013.
Houston, Texas
February 24, 2023

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31,	
	2022	**2021**
Assets		
Current assets:		
Cash	$ 7.1	$ 12.9
Accounts receivable, less allowance for doubtful accounts of $0.5 and $0.6 at December 31, 2022 and 2021	432.2	378.0
Inventory	122.6	156.5
Assets from price risk management activities	72.8	42.1
Prepaid expenses and other current assets	18.7	14.4
Total current assets	653.4	603.9
Property, plant and equipment	5,350.0	4,100.8
Less: accumulated depreciation	822.6	1,193.0
Property, plant and equipment, net	4,527.4	2,907.8
Intangible assets	1,306.3	1,126.1
Less: accumulated amortization	300.7	393.2
Intangible assets, net	1,005.6	732.9
Goodwill	223.0	138.6
Operating lease right-of-use assets, net	24.4	27.4
Investments in unconsolidated affiliates	119.5	155.8
Other non-current assets	8.1	4.8
Total assets	$ 6,561.4	$ 4,571.2
Liabilities and capital		
Current liabilities:		
Accounts payable	$ 305.4	$ 336.4
Accrued expenses and other liabilities	179.5	146.1
Liabilities from price risk management activities	23.9	114.6
Current portion of long-term debt	—	0.2
Total current liabilities	508.8	597.3
Long-term debt, less current portion	3,378.3	2,052.1
Other long-term liabilities	330.3	254.1
Deferred income taxes	2.3	0.8
Total liabilities	4,219.7	2,904.3
Commitments and contingencies (*Note 10*)		
Interest of non-controlling partner in subsidiary	434.4	434.6
Partners’ capital	1,907.3	1,232.3
Total liabilities and capital	$ 6,561.4	$ 4,571.2

See accompanying notes.

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues:			
Product revenues	$ 5,198.4	$ 4,145.4	$ 1,793.0
Product revenues - related party (*Note 19*)	222.6	25.8	27.3
Service revenues	430.4	396.4	433.5
Service revenues - related party (*Note 19*)	149.3	1.4	0.5
Total revenues	6,000.7	4,569.0	2,254.3
Costs of product/services sold (exclusive of items shown separately below):			
Product costs	4,730.4	3,688.8	1,558.8
Product costs - related party (*Note 19*)	240.9	136.8	21.0
Service costs	25.8	18.3	20.7
Total costs of products/services sold	4,997.1	3,843.9	1,600.5
Operating expenses and other:			
Operations and maintenance	196.1	121.0	131.8
General and administrative	124.4	90.2	86.7
Depreciation, amortization and accretion	334.6	258.4	251.5
Loss on long-lived assets, net	312.7	39.4	26.0
Goodwill impairment	—	—	80.3
Gain on acquisition	(75.3)	—	—
	892.5	509.0	576.3
Operating income	111.1	216.1	77.5
Earnings (loss) from unconsolidated affiliates, net	15.7	(120.4)	32.5
Interest and debt expense, net	(177.4)	(132.1)	(133.6)
Gain (loss) on modification/extinguishment of debt	—	(7.5)	0.1
Other income, net	0.1	—	—
Loss before income taxes	(50.5)	(43.9)	(23.5)
(Provision) benefit for income taxes	(1.7)	(0.1)	0.1
Net loss	(52.2)	(44.0)	(23.4)
Net income attributable to non-controlling partner	41.2	41.1	40.8
Net loss attributable to Crestwood Midstream Partners LP	$ (93.4)	$ (85.1)	$ (64.2)

See accompanying notes.

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in millions)

	Total Partners' Capital
Balance at December 31, 2019	$ 2,099.3
Distributions to partner	(242.6)
Unit-based compensation charges	29.3
Taxes paid for unit-based compensation vesting	(15.6)
Other	(1.1)
Net loss	(64.2)
Balance at December 31, 2020	1,805.1
Distributions to partner	(509.7)
Unit-based compensation charges	30.5
Taxes paid for unit-based compensation vesting	(8.4)
Other	(0.1)
Net loss	(85.1)
Balance at December 31, 2021	1,232.3
Non-cash contributions from partner *(Note 12)*	1,202.4
Cash contributions from partner *(Note 12)*	164.3
Distributions to partners	(622.2)
Unit-based compensation charges	39.8
Taxes paid for unit-based compensation vesting	(15.9)
Net loss	(93.4)
Balance at December 31, 2022	$ 1,907.3

See accompanying notes.

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Operating activities			
Net loss	$ (52.2)	$ (44.0)	$ (23.4)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, amortization and accretion	334.6	258.4	251.5
Amortization of debt-related deferred costs and fair value adjustment	2.2	6.7	6.5
Unit-based compensation charges	37.2	34.9	30.7
Loss on long-lived assets, net	312.7	39.4	26.0
Goodwill impairment	—	—	80.3
Gain on acquisition	(75.3)	—	—
(Gain) loss on modification/extinguishment of debt	—	7.5	(0.1)
(Earnings) loss from unconsolidated affiliates, net, adjusted for cash distributions received	(0.7)	138.0	6.5
Deferred income taxes	1.2	—	—
Other	(0.1)	0.3	(0.1)
Changes in operating assets and liabilities:			
Accounts receivable	149.4	(114.3)	(27.8)
Inventory	34.3	(67.4)	(33.7)
Prepaid expenses and other current assets	(2.5)	(0.6)	(4.6)
Accounts payable, accrued expenses and other liabilities	(181.3)	147.8	(6.1)
Reimbursements of property, plant and equipment	7.1	4.3	15.7
Change in price risk management activities, net	(121.4)	23.4	86.5
Net cash provided by operating activities	445.2	434.4	407.9
Investing activities			
Acquisitions, net of cash acquired *(Note 3)*	(602.7)	—	(162.3)
Purchases of property, plant and equipment	(228.6)	(81.3)	(168.3)
Investments in unconsolidated affiliates	(90.9)	(17.6)	(9.4)
Capital distributions from unconsolidated affiliates	11.8	652.0	39.4
Net proceeds from sale of assets, including equity investments	521.6	17.7	27.3
Net cash provided by (used in) investing activities	(388.8)	570.8	(273.3)

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(in millions)

	Year Ended December 31,		
	2022	2021	2020
Financing activities			
Proceeds from the issuance of long-term debt	3,743.0	2,859.5	1,125.1
Payments on long-term debt	(3,254.3)	(3,287.5)	(975.8)
Payments on finance leases	(32.0)	(2.8)	(3.1)
Payments for deferred financing costs	(3.7)	(17.9)	—
Net proceeds from issuance of non-controlling interest	—	1.0	2.8
Contributions from partner	164.3	—	—
Distributions to partner	(622.2)	(509.7)	(242.6)
Distributions to non-controlling partner	(41.4)	(40.2)	(37.1)
Taxes paid for unit-based compensation vesting	(15.9)	(8.4)	(15.6)
Net cash used in financing activities	(62.2)	(1,006.0)	(146.3)
Net change in cash	(5.8)	(0.8)	(11.7)
Cash at beginning of period	12.9	13.7	25.4
Cash at end of period	$ 7.1	$ 12.9	$ 13.7
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 178.2	$ 125.9	$ 129.8
Cash paid for income taxes	$ 1.3	$ 0.5	$ 0.5
Supplemental schedule of noncash investing activities			
Net change to property, plant and equipment through accounts payable and accrued expenses	$ 7.4	$ (5.8)	$ 40.0

See accompanying notes.

Note 1 – Organization and Business Description

The accompanying notes to the consolidated financial statements apply to Crestwood Equity Partners LP (the Company, Crestwood Equity or CEQP) and Crestwood Midstream Partners LP (Crestwood Midstream or CMLP) unless otherwise indicated.

Organization

Crestwood Equity Partners LP. CEQP is a publicly-traded (NYSE: CEQP) Delaware limited partnership formed in March 2001. Crestwood Equity GP LLC (Crestwood Equity GP), our wholly-owned subsidiary, owns our non-economic general partnership interest.

Crestwood Midstream Partners LP. Crestwood Equity owns a 99.9% limited partnership interest in Crestwood Midstream and Crestwood Gas Services GP LLC (CGS GP), a wholly-owned subsidiary of Crestwood Equity, owns a 0.1% limited partnership interest in Crestwood Midstream. Crestwood Midstream GP LLC, a wholly-owned subsidiary of Crestwood Equity, owns the non-economic general partnership interest of Crestwood Midstream.

Unless otherwise indicated, references in this report to “we,” “us,” “our,” “ours,” “our company,” the “partnership,” the “Company,” “Crestwood Equity,” “CEQP,” and similar terms refer to either Crestwood Equity Partners LP itself or Crestwood Equity Partners LP and its consolidated subsidiaries, as the context requires. Unless otherwise indicated, references to “Crestwood Midstream” and “CMLP” refer to Crestwood Midstream Partners LP and its consolidated subsidiaries.

Description of Business

Crestwood Equity develops, acquires, owns or controls, and operates primarily fee-based assets and operations within the energy midstream sector. We provide broad-ranging infrastructure solutions across the value chain to service premier liquids-rich natural gas and crude oil shale plays across the United States. We own and operate a diversified portfolio of NGL, crude oil, natural gas and produced water gathering, processing, storage, disposal and transportation assets that connect fundamental energy supply with energy demand across the United States. Crestwood Equity is a holding company and all of its consolidated operating assets are owned by or through its wholly-owned subsidiary, Crestwood Midstream.

See Note 16 for information regarding our operating and reporting segments.

Note 2 – Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements are prepared in accordance with U.S. GAAP and include the accounts of all consolidated subsidiaries after the elimination of all intercompany accounts and transactions. Certain footnote disclosures in the prior periods have been reclassified to conform to the current year presentation, none of which impacted our previously reported net income, earnings per unit or partners’ capital. In management’s opinion, all necessary adjustments to fairly present our results of operations, financial position and cash flows for the periods presented have been made and all such adjustments are of a normal and recurring nature.

Significant Accounting Policies

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination to consolidate or apply the equity method of accounting to an entity can also require us to evaluate whether that entity is considered a variable interest entity. This evaluation, along with the determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control or direct the policies, decisions or activities of an entity. We use the cost method of accounting where we are unable to exert significant influence over the entity.

Use of Estimates

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these consolidated financial statements. Actual results can differ from those estimates.

Cash

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

Accounts Receivable

We record accounts receivable when products or services are delivered and it is probable that payment will be received for those products or services, and we do not record any interest or penalties on accounts receivable that are past due under the terms of the related arrangement or invoice until those amounts are received. We estimate the allowance for doubtful accounts using a method that considers both the aging of our accounts receivable and the projected loss rate of our receivables. We write off accounts receivable, and the related allowance for doubtful accounts, when it becomes remote that payment for products or services will be received.

Inventory

Our inventory, which is stated at the lower of cost or net realizable value and cost is computed predominantly using the average cost method, consisted of the following (*in millions*):

	December 31,	
	2022	**2021**
NGLs, crude oil and natural gas	$ 121.8	$ 155.6
Spare parts	0.8	0.9
Total inventory	$ 122.6	$ 156.5

Property, Plant and Equipment

Property, plant and equipment is recorded at is original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and interest. We capitalize major units of property replacements or improvement and expense minor items. Depreciation is computed using the straight-line method over the estimated useful lives of the assets, as follows:

	Years
Gathering systems and pipelines	20
Facilities and equipment	3 - 20
Buildings, rights-of-way and easements	5 - 50
Office furniture and fixtures	5 - 10
Vehicles	5

We evaluate our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such events or changes in circumstances are present, a loss is recognized if the carrying value of the asset is in excess of the sum of the undiscounted cash flows expected to result from the use of the asset and its eventual disposition. An impairment loss is measured as the amount by which the carrying amount of the asset exceeds the fair value of the asset, which is typically based on discounted cash flow projections using assumptions as to revenues, costs and discount rates typical of third party market participants, which is a Level 3 fair value measurement.

Projected cash flows of our property, plant and equipment are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, constructions costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

During 2022, we recorded a loss on long-lived assets of approximately $7.0 million related to the anticipated sale of parts inventory related to our gathering and processing south segment's legacy Granite Wash operations. During 2021, we recorded $40.1 million of impairments of our property, plant and equipment to reflect our gathering and processing south segment's compressor stations in our Marcellus operations at fair value based on the actual or anticipated dismantlement and redeployment of those assets to other areas. During 2020, we recorded $3.1 million of impairments of our property, plant and equipment primarily related to the removal and retirement of certain water gathering facilities in our gathering and processing north segment in response to several produced water releases on our Arrow system over the past few years. During 2022 and 2020, we sold several of our legacy assets and we recorded gains and losses on long-lived assets related to each of these divestitures. For a further discussion of these asset sales, see Note 3 and Note 11.

Identifiable Intangible Assets and Liabilities

Our identifiable intangible assets consist of customer relationships, trademarks and certain revenue contracts. These intangible assets have arisen primarily from acquisitions. We amortize certain of our revenue contracts based on the projected cash flows associated with these contracts if the projected cash flows are readily determinable, otherwise we amortize our revenue contracts on a straight-line basis. We recognize acquired intangible assets separately if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer's intent to do so.

Projected cash flows of our intangible assets are generally based on current and anticipated future market conditions, which require significant judgment to make projections and assumptions about pricing, demand, competition, operating costs, construction costs, legal and regulatory issues and other factors that may extend many years into the future and are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates.

We did not record any impairments of our intangible assets during the years ended December 31, 2022, 2021 or 2020.

We amortize our intangible assets on a straight-line basis over their estimated economic lives. The weighted average amortization period of our intangible assets are as follows:

	Years
Customer relationships	21
Revenue contracts	18
Trademarks	10

Our identifiable intangible liabilities primarily consist of revenue contracts and are amortized over the life of the respective revenue contract. These intangible liabilities primarily relate to our Sendero Acquisition and CPJV Acquisition (as defined in Note 3) during 2022. We reflect our intangible liabilities as other long-term liabilities on our consolidated balance sheet.

Goodwill

Our goodwill represents the excess of the amount we paid for a business over the fair value of the net identifiable assets acquired. We evaluate goodwill for impairment annually on December 31, and whenever events indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount. This evaluation requires us to compare the fair value of each of our reporting units to its carrying value (including goodwill). If the fair value exceeds the carrying amount, goodwill of the reporting unit is not considered impaired.

We estimate the fair value of our reporting units based on a number of factors, including discount rates, projected cash flows and the potential value we would receive if we sold the reporting unit. Estimating projected cash flows requires us to make certain assumptions as it relates to the future operating performance of each of our reporting units (which includes assumptions, among others, about estimating future operating margins and related future growth in those margins, contracting efforts and the cost and timing of facility expansions) and assumptions related to our customers, such as their future capital and operating plans and their financial condition. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates. If the assumptions embodied in the projections prove inaccurate, we could incur a future impairment charge. In addition, the use of the income approach to determine the fair value of our reporting units (see further discussion of the use of the income approach below) could result in a different fair value if we had utilized a market approach, or a combination thereof.

Upon acquisition, we are required to record the assets, liabilities and goodwill of a reporting unit at its fair value on the date of acquisition. As a result, any level of decrease in the forecasted cash flows of these businesses or increases in the discount rates utilized to value those businesses from their respective acquisition dates would likely result in the fair value of the reporting unit falling below the carrying value of the reporting unit, and could result in an assessment of whether that reporting unit's goodwill is impaired.

We acquired our Powder River Basin reporting unit in 2019 and recorded it at fair value at that time. During 2020, current and forward commodity prices significantly declined from their levels at December 31, 2019 due primarily to the decreases in energy demand as a result of the outbreak of the COVID-19 pandemic and actions taken by the Organization of the Petroleum Exporting Countries, Russia, the United States and other oil-producing countries relating to the oversupply of oil. Based on these events, we determined that the forecasted cash flows, and therefore the fair value, of our Powder River Basin reporting unit significantly decreased during 2020, and accordingly performed a quantitative impairment assessment of the goodwill related to that reporting unit during that period. Based on our quantitative assessment, which utilized the income approach, we determined that the goodwill associated with the Powder River Basin reporting unit should be fully impaired, and accordingly we recorded an $80.3 million impairment of the goodwill attributed to that reporting unit in the gathering and processing north segment during the year ended December 31, 2020.

During 2022, we completed several acquisitions (which are further described in Note 3) that resulted in the modification of our reporting units. As a result of this modification, we have three reporting units with goodwill as of December 31, 2022: (i) Williston (includes our gathering and processing north segment's Williston Basin operations acquired in the Oasis Merger as described in Note 3 and its Arrow operations); (ii) Permian (includes our gathering and processing south segment's Permian operations acquired in the Oasis Merger, Sendero Acquisition and CPJV Acquisition, each of which are defined in Note 3); and (iii) NGL Marketing and Logistics (included in our storage and logistics segment's operations). In conjunction with these acquisitions, we combined our historical Arrow reporting unit into the Williston reporting unit and aggregated the acquired Permian operations into our Permian reporting unit for the purpose of evaluating goodwill for impairment on an ongoing basis. Upon modification of our reporting units and at December 31, 2022, we performed an assessment of our goodwill and based on our analysis, we did not record any impairment of goodwill for the year ended December 31, 2022.

The following table summarizes the goodwill of our reporting units (in millions). We did not record any impairments of goodwill during the years ended December 31, 2022 and 2021. At December 31, 2022, our accumulated goodwill impairments at CEQP and CMLP were approximately $1,736.8 million and $1,479.6 million, respectively.

	Goodwill at December 31, 2021	Additions during the Year Ended December 31, 2022	Goodwill at December 31, 2022
Gathering and Processing North			
Williston	$ 45.9	$ 48.8	$ 94.7
Gathering and Processing South			
Permian	—	35.6	35.6
Storage and Logistics			
NGL Marketing and Logistics	92.7	—	92.7
Total	$ 138.6	$ 84.4	$ 223.0

Leases

We enter into leases with third parties for the right to utilize certain office buildings, vehicles and other operating facilities and equipment. For contracts that extend for a period greater than 12 months, we recognize a right-of-use asset and a corresponding lease liability on our consolidated balance sheets based on the present value of each lease, which is based on the future minimum lease payments and is determined by discounting these payments using our incremental borrowing rate. We recognize operating lease expense on our consolidated statements of operations as either costs of product/services sold, operations and maintenance expenses or general and administrative expenses on a straight-line basis over the lease term. We do not have any material leases where we are considered to be the lessor. Our lease agreements do not contain any material residual value guarantees or material restrictive covenants. We do not have any material revenue contracts that are considered leases.

Investments in Unconsolidated Affiliates

Equity method investments in which we exercise significant influence, but do not control and are not the primary beneficiary, are accounted for using the equity method of accounting. Differences in the basis of investments and the separate net asset values of the investees, if any, are amortized into net income or loss over the remaining useful lives of the underlying assets and liabilities, except for the excess related to goodwill. We evaluate our equity method investments for impairment when events or circumstances indicate that the carrying value of the equity method investment may be impaired and that impairment is other than temporary. If an event occurs, we evaluate the recoverability of our carrying value based on the fair value of the investment. If an impairment is indicated, or if we decide to sell an investment in an unconsolidated affiliate, we adjust the carrying values of the asset downward, if necessary, to their estimated fair values. We did not record impairments of our equity method investments during the years ended December 31, 2022, 2021 and 2020. During the year ended December 31, 2021, we recorded our proportionate share of the impairments recorded by our Stagecoach Gas Services LLC equity method investment related to the sale of its assets, which we recorded as a reduction to our earnings from unconsolidated affiliates. During the year ended December 31, 2020, we recorded a reduction in equity earnings from our Powder River Basin Industrial Complex, LLC equity method investment as a result of us recording our proportionate share of a long-lived asset impairment recorded by the equity method investee. See Note 6 for a further discussion of these impairments recorded by our equity method investments.

Asset Retirement Obligations

An asset retirement obligation (ARO) is an estimated liability for the cost to retire a tangible asset. We record a liability for legal or contractual obligations to retire our long-lived assets associated with our facilities and right-of-way contracts we hold. We record a liability in the period the obligation is incurred and estimable. An ARO is initially recorded at its estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the asset to which that liability relates. An ongoing expense is recognized for changes in the fair value of the liability as a result of the passage of time, which we record as depreciation, amortization and accretion expense on our consolidated statements of operations.

We have various obligations to remove property, plant and equipment on rights-of-way and leases for which we cannot currently estimate the fair value of those obligations because the associated assets have indeterminate lives. An asset retirement obligation liability (and related assets), if any, will be recorded for these obligations once sufficient information is available to reasonably estimate the fair value of the obligations. Our current AROs are reflected in accrued expenses and other liabilities and our long-term AROs are reflected in other long-term liabilities on our consolidated balance sheets.

Deferred Financing Costs

Deferred financing costs represent costs associated with obtaining long-term financing and are amortized over the term of the related debt using a method which approximates the effective interest method and has a weighted average remaining life of five years. Our net deferred financing costs are reflected as a reduction of long-term debt on our consolidated balance sheets.

Environmental Costs and Other Contingencies

We recognize liabilities for environmental and other contingencies when there is an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

We record liabilities for environmental contingencies at their undiscounted amounts on our consolidated balance sheets as accrued expenses and other liabilities when environmental assessments indicate that remediation efforts are probable and costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts and presently enacted laws and regulations, taking into consideration the likely effects of other societal and economic factors. These estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and recognize a current period charge in operations and maintenance expenses when clean-up efforts do not benefit future periods.

We evaluate potential recoveries of amounts from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our consolidated balance sheet.

Revenue Recognition

We provide gathering, processing, compression, storage, fractionation, and transportation (consisting of pipelines, truck and rail terminals, truck/trailer units and rail cars) services and we sell commodities (including crude oil, natural gas and NGLs) under various contracts, which are described below.

- *Fixed-fee contracts*. Under these contracts, we do not take title to the underlying crude oil, natural gas, NGLs and water but charge our customers a fixed-fee for the services we provide, which can be a firm reservation charge and/or a charge per volume gathered, processed, compressed, stored, loaded and/or transported (which, in certain contracts, can be subject to a minimum level of volumes).
- *Percentage-of-proceeds service contracts*. Under these contracts, we take title to crude oil, natural gas or NGLs after the commodity leaves our gathering and processing facilities. We often market and sell those commodities to third parties after they leave our facilities and we will remit a portion of the sales proceeds to our producers.
- *Percentage-of-proceeds product contracts.* Under these contracts, we take title to crude oil, natural gas or NGLs before the commodity enters our facilities. We market and sell those commodities to third parties and we will remit a portion of the sales proceeds to our producers.
- *Purchase and sale contracts*. Under these contracts, we purchase crude oil, natural gas or NGLs before the commodity enters our facilities, and we market and sell those commodities to third parties.

We recognize revenues for services and products under revenue contracts as our obligations to perform services or deliver/sell products under the contracts are satisfied. A contract's transaction price is allocated to each performance obligation in the contract and recognized as revenue when, or as, the performance obligation is satisfied. Our fixed-fee contracts and our percentage-of-proceeds service contracts primarily have a single performance obligation to deliver a series of distinct goods or services that are substantially the same and have the same pattern of transfer to our customers. For performance obligations associated with these contracts, we recognize revenues over time utilizing the output method based on the actual volumes of products delivered/sold or services performed, because the single performance obligation is satisfied over time using the same performance measure of progress toward satisfaction of the performance obligation. The transaction price under certain of our fixed-fee contracts and percentage-of-proceeds service contracts includes variable consideration that varies primarily based on actual volumes that are delivered under the contracts. Because the variable consideration specifically relates to our efforts to transfer the services and/or products under the contracts, we allocate the variable consideration entirely to the distinct service, and accordingly recognize the variable consideration as revenues at the time the good or service is transferred to the customer.

Certain of our fixed-fee contracts contain minimum volume features under which the customers must utilize our services to gather, compress or load a specified quantity of crude oil or natural gas or pay a deficiency fee based on the difference between actual volumes and the contractual minimum volume. We recognize revenues from these contracts when actual volumes are gathered, compressed or loaded and the likelihood of a customer exercising its remaining rights to make up the deficient volumes under minimum volume commitments becomes remote.

We recognize revenues at a point in time for performance obligations associated with our percentage-of proceeds product contracts and purchase and sale contracts, and these revenues are recognized because control of the underlying product is transferred to the customer when the distinct good is provided to the customer.

The evaluation of when performance obligations have been satisfied and the transaction price that is allocated to our performance obligations requires significant judgments and assumptions, including our evaluation of the timing of when control of the underlying good or service has transferred to our customers and the relative standalone selling price of goods and services provided to customers under contracts with multiple performance obligations. Actual results can significantly vary from those judgments and assumptions. We did not have any material contracts with multiple performance obligations or under which we received material amounts of non-cash consideration during the years ended December 31, 2022, 2021 and 2020.

Amounts due from our customers under our revenue contracts are typically billed as the service is being provided or on a weekly, bi-weekly or monthly basis and are due within 30 days of billing. Under certain of our contracts, we recognize revenues in excess of billings which we present as contract assets on our consolidated balance sheets.

Under certain contracts, we are entitled to receive payments in advance of satisfying our performance obligations under the contracts. We recognize a liability for these payments in excess of revenue recognized and present it as deferred revenue or contract liabilities on our consolidated balance sheets. Our deferred revenue primarily relates to:

- *Capital Reimbursements.* Certain of our contracts require that our customers reimburse us for capital expenditures related to the construction of long-lived assets utilized to provide services to them under the respective revenue contracts. Because we consider these amounts as consideration from customers associated with ongoing services to be provided to customers, we defer these upfront payments in deferred revenue and recognize the amounts in revenue over the life of the associated revenue contract as the performance obligations are satisfied under the contract.

- *Contracts with Increasing (Decreasing) Rates per Unit.* Certain of our contracts have fixed rates per volume that increase and/or decrease over the life of the contract once certain time periods or thresholds are met. We record revenues on these contracts ratably per unit over the life of the contract based on estimated volumes and the remaining performance obligations to be performed, which can result in the deferral of revenue for the difference between the consideration received and the ratable revenue recognized.

Credit Risk and Concentrations

Inherent in our contractual portfolio are certain credit risks. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing credit risk and have established control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate.

Income Taxes

Crestwood Equity is a master limited partnership and Crestwood Midstream is a limited partnership. Partnerships are generally not subject to federal income tax, although publicly-traded partnerships are treated as corporations for federal income tax purposes and therefore are subject to federal income tax, unless the partnership generates at least 90% of its gross income from qualifying sources. If the qualifying income requirement is satisfied, the publicly-traded partnership will be treated as a partnership for federal income tax purposes. We satisfy the qualifying income requirement and are treated as a partnership for federal and state income tax purposes. Our consolidated earnings are included in the federal and state income tax returns of our partners. However, legislation in certain states allows for taxation of partnerships, and as such, certain state taxes have been included in our accompanying financial statements as income taxes due to the nature of the tax in those particular states as discussed below. In addition, federal and state income taxes are provided on the earnings of the subsidiaries incorporated as taxable entities. We are required to recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial reporting and tax basis of assets and liabilities using expected rates in effect for the year in which the differences are expected to reverse.

We are responsible for the Texas Margin tax included in our Texas franchise tax returns. The margin tax qualifies as an income tax under U.S. GAAP, which requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis attributable to such tax.

Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and the financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

Price Risk Management Activities

We utilize certain derivative financial instruments to (i) manage our exposure to commodity price risk, specifically, the related change in the fair value of inventory, as well as the variability of cash flows related to forecasted transactions; and (ii) ensure the availability of adequate physical supply of commodity. We record all derivative instruments as either assets or liabilities on our consolidated balance sheets at their fair values. Changes in the fair value of these derivative financial instruments are recorded through current earnings. We do not have any derivatives designated as fair value hedges or cash flow hedges for accounting purposes.

Unit-Based Compensation

Long-term incentive awards are granted under the Crestwood Equity Partners LP Long Term Incentive Plan (Crestwood LTIP). Unit-based compensation awards consist of restricted units and performance units that are recognized in our consolidated statements of operations based on their grant date at fair value. For restricted units, we generally recognize the expense over the vesting period on a straight line basis. For performance units, we remeasure compensation expense at each balance sheet date because the vesting is subject to the attainment of certain performance and market goals over a three-year period. For those awards that are reflected in liabilities, we remeasure the associated liability at every balance sheet date through settlement, such that the vested portion of the liability is adjusted to reflect its revised fair value through compensation expense.

Note 3 – Acquisitions and Divestitures

Acquisitions

During the years ended December 31, 2022 and 2020, we completed several acquisitions which are further described below. We accounted for each of these acquisitions as business combinations using the acquisition method of accounting. In addition, the purchase accounting for our acquisitions during 2022 reflects the adoption of Accounting Standards Update (ASU) 2021-08, *Business Combinations (Topic 805)* during the year ended December 31, 2022.

Oasis Merger

On October 25, 2021, we entered into a merger agreement to acquire Oasis Midstream Partners LP (Oasis Midstream) in an equity and cash transaction (the Oasis Merger). Oasis Midstream operated a diversified portfolio of midstream assets located in the Williston and Delaware Basins and its operations included natural gas services (gathering, compression, processing and gas lift supply), crude oil services (gathering, terminalling and transportation), and water services (gathering and disposal of produced and flowback water and freshwater distribution).

On February 1, 2022, we completed the merger with Oasis Midstream, which was valued at approximately $1.8 billion. Pursuant to the merger agreement, Oasis Petroleum Inc., now known as Chord Energy Corporation (Chord), received $150 million in cash plus approximately 20.9 million newly issued CEQP common units in exchange for its 33.8 million common units held in Oasis Midstream. In addition, Oasis Midstream's public unitholders received approximately 12.9 million newly issued CEQP common units in exchange for the approximately 14.8 million Oasis Midstream common units held by them. Additionally, under the merger agreement Oasis Petroleum received a $10 million cash payment in exchange for its ownership of the general partner of Oasis Midstream.

The fair value of the assets acquired and liabilities assumed were determined primarily utilizing market related information and other projections on the performance of the assets acquired, including an analysis of discounted cash flows at a discount rate of approximately 12%. Certain fair values are Level 3 fair value measurements and were developed by management with the assistance of a third-party valuation firm. We estimated the fair value of the senior notes assumed based on quoted market prices for similar issuances which are considered Level 2 fair value measurements.

The following table summarizes the final valuation of the assets acquired and liabilities assumed at the acquisition date *(in millions)*:

Cash	$	14.9
Other current assets		63.2
Property, plant and equipment		1,264.4
Intangible assets		464.0
Total assets acquired		1,806.5
Current liabilities		48.2
Long-term debt(1)		698.7
Other long-term liabilities(2)		25.8
Total liabilities assumed		772.7
Net assets acquired excluding goodwill		1,033.8
Goodwill		56.2
Net assets acquired	$	1,090.0

(1) Consists of approximately $218 million outstanding borrowings under the Oasis Midstream credit facility, which was immediately repaid upon the closing of the Oasis Merger and approximately $450 million of unsecured senior notes and the related fair value adjustment of approximately $30.7 million. For a further discussion of the long-term debt assumed in conjunction with the Oasis Merger, see Note 8.

(2) Consists primarily of liabilities for asset retirement obligations of approximately $16.1 million.

The identifiable intangible assets primarily consist of customer relationships with Oasis Petroleum and other customers with a weighted-average life of 20 years. The goodwill recognized relates primarily to the anticipated operating synergies between the assets acquired and our existing operations. We reflected approximately $48.8 million of goodwill in our gathering and processing north segment and approximately $7.4 million in our gathering and processing south segment.

The financial results of the Williston Basin operations are included in our gathering and processing north segment and the financial results of the Delaware Basin operations are included in our gathering and processing south segment from the date of acquisition. During the year ended December 31, 2022, we recognized approximately $21.8 million of transaction costs related to the Oasis Merger, which are included in general and administrative expenses in our consolidated statements of operations. During the year ended December 31, 2022, we recognized approximately $368.2 million of revenues and $127.4 million of net income related to the operations acquired from Oasis Midstream.

Sendero Acquisition

On July 11, 2022, we acquired Sendero Midstream Partners, LP (Sendero), a privately-held midstream company, for cash consideration of approximately $631.2 million (Sendero Acquisition). Sendero's assets are located in Eddy County, New Mexico and its operations include natural gas gathering, compression and processing services.

The fair values of the assets acquired and liabilities assumed were determined primarily utilizing market related information and other projections on the performance of the assets acquired, including an analysis of discounted cash flows at a discount rate of approximately 13%. Certain fair values are Level 3 fair value measurements and were developed by management with the assistance of a third-party valuation firm.

The following table summarizes the final valuation of the assets acquired and liabilities assumed at the acquisition date *(in millions)*. The final valuation primarily resulted in an increase to the fair value of property, plant and equipment of approximately $97 million with a corresponding decrease to intangible assets from the amounts recorded in the initial preliminary purchase price allocation recorded earlier in 2022. The impact of this change to our depreciation, amortization and accretion expense for the year ended December 31, 2022 was not material.

Cash	$	28.5
Other current assets		77.3
Property, plant and equipment		537.5
Intangible assets		41.5
Other non-current assets		0.1
Total assets acquired		684.9
Current liabilities		63.9
Long-term liabilities(1)		18.0
Total liabilities assumed		81.9
Net assets acquired excluding goodwill		603.0
Goodwill		28.2
Total purchase price	$	631.2

(1) Includes intangible liabilities of approximately $14.0 million which are further described below.

The identifiable intangible assets primarily consist of customer relationships with a weighted-average life of 20 years and the identifiable intangible liabilities primarily consist of revenue contracts with a weighted-average life of 10 years. The goodwill recognized relates primarily to the anticipated operating synergies between the assets acquired and the operations acquired in conjunction with the CPJV Acquisition discussed below.

The financial results of the operations acquired from Sendero are included in our gathering and processing south segment from the date of acquisition. During the year ended December 31, 2022, we recognized approximately $9.6 million of transaction costs related to the Sendero Acquisition, which are included in general and administrative expenses in our consolidated statements of operations. During the year ended December 31, 2022, we recognized approximately $261.8 million of revenues and $31.0 million of net income related to the operations acquired from Sendero.

CPJV Acquisition

On July 11, 2022, we acquired First Reserve Management, L.P.'s (First Reserve) 50% equity interest in Crestwood Permian Basin Holdings LLC (Crestwood Permian) in exchange for approximately $5.9 million in cash and approximately 11.3 million newly issued CEQP common units (CPJV Acquisition). Prior to the CPJV Acquisition, we owned a 50% equity interest in Crestwood Permian, which we accounted for under the equity method of accounting and we reflected this equity investment in our gathering and processing south segment. As a result of this transaction, we control and own 100% of the equity interests in Crestwood Permian.

The fair values of the assets acquired and liabilities assumed were determined primarily utilizing market related information and other projections on the performance of the assets acquired, including an analysis of discounted cash flows at a discount rate of approximately 15%. Certain fair values are Level 3 fair value measurements and were developed by management with the assistance of a third-party valuation firm.

The following table summarizes the final valuation of the assets acquired and liabilities assumed at the acquisition date *(in millions)*. The final valuation primarily resulted in an increase to the fair value of property, plant and equipment of approximately $47 million, an increase to other long-term liabilities of approximately $2 million, and other working capital adjustments, and the elimination of intangible assets and goodwill of approximately $16 million and $29 million, respectively, from the amounts recorded in the initial preliminary purchase price allocation recorded earlier in 2022. The impact of this change to our depreciation, amortization and accretion expense for the year ended December 31, 2022 was not material.

Cash	$	149.4
Other current assets[3]		44.0
Property, plant and equipment		500.8
Investment in unconsolidated affiliate		78.6
Other non-current assets		4.9
Total assets acquired		777.7
Current liabilities[3]		75.1
Long-term debt[1]		140.2
Other long-term liabilities[2]		49.7
Total liabilities assumed		265.0
Fair value of 100% of interest in Crestwood Permian		512.7
Less:		
Elimination of equity interest in Crestwood Permian[3]		177.7
Gain on acquisition of Crestwood Permian		75.3
Total purchase price[3]	$	259.7

(1) Consists of a revolving credit facility, which was repaid in January 2023. See Note 9 for a further discussion of this credit facility.

(2) Includes intangible liabilities of approximately $38.9 million which are further described below.

(3) In conjunction with the CPJV Acquisition, we eliminated approximately $34.0 million of net accounts payable that were due to Crestwood Permian from a subsidiary of CMLP, which are reflected as a $17.0 million reduction of our equity investment in Crestwood Permian and a $17.0 million reduction of the total purchase price in the table above.

The identifiable intangible liabilities primarily consist of revenue contracts with a weighted-average life of eight years. As shown in the table above, the fair value of the assets acquired and liabilities assumed in the CPJV Acquisition exceeded the sum of the cash consideration paid, the fair value of the common units issued and the historical book value of our 50% equity interest in Crestwood Permian (which was derecognized) and, as a result, we recognized a gain of approximately $75.3 million, which is included in gain on acquisition in our consolidated statements of operations.

The consolidated financial results of Crestwood Permian are included in our gathering and processing south segment from the date of acquisition. During the year ended December 31, 2022, we recognized approximately $0.5 million of transaction costs related to the CPJV Acquisition, which are included in general and administrative expenses in our consolidated statements of operations. During the year ended December 31, 2022, we recognized approximately $270.0 million of revenues and $14.8 million of net income related to Crestwood Permian's operations.

The tables below present selected unaudited pro forma information related to the Oasis Merger, Sendero Acquisition and CPJV Acquisition as if these acquisitions had occurred on January 1, 2020 (*in millions*). The pro forma information is not necessarily indicative of the financial results that would have occurred if the acquisitions had been completed as of the date indicated. The pro forma amounts were calculated after applying our accounting policies and adjusting the results to reflect the depreciation, amortization and accretion expense that would have been charged assuming the fair value adjustments to property, plant and equipment and intangible assets and liabilities had been made at the beginning of the reporting period. The pro forma net income (loss) also includes the net effects of interest expense on incremental borrowings, repayments of long-term debt and amortization of the fair value adjustment to long-term debt.

Crestwood Equity

	Year Ended December 31,		
	2022	2021	2020
Revenues	$ 6,234.9	$ 5,197.9	$ 2,688.9
Net income (loss)	$ 93.4	$ 21.9	$ (116.0)
Net loss attributable to partners	$ (7.9)	$ (79.3)	$ (216.9)
Net loss per limited partner unit:			
Basic and Diluted	$ (0.07)	$ (0.72)	$ (1.83)

Crestwood Midstream

	Year Ended December 31,		
	2022	2021	2020
Revenues	$ 6,234.9	$ 5,197.9	$ 2,688.9
Net income (loss)	$ (31.3)	$ 15.3	$ (124.1)

NGL Asset Acquisition

In April 2020, we acquired several NGL storage and rail-to-truck terminals from Plains All American Pipeline, L.P. for approximately $162 million (NGL Asset Acquisition). The acquired assets include 7 MMBbls of NGL storage and seven terminals, and resulted in an increase of approximately $110 million to our property, plant and equipment, $50 million to our intangible assets and $2 million to our other assets and liabilities, net. The identifiable intangible assets primarily consist of customer accounts with a weighted-average remaining life of 20 years on the date of acquisition. We allocated the purchase price to these assets and liabilities based on their fair values, which are Level 3 fair value measurements and were developed by management with the assistance of a third-party valuation firm utilizing market-related information about the property, plant and equipment and customer relationships acquired. These assets are included in our storage and logistics segment. The transaction costs related to this acquisition were not material during the year ended December 31, 2020.

Divestitures

Barnett

In July 2022, we sold our assets in the Barnett Shale to EnLink Midstream, LLC (EnLink) for approximately $290 million, including working capital adjustments. During the year ended December 31, 2022, Crestwood Midstream recorded a loss on the sale of approximately $53 million, which is included in loss on long-lived assets, net on its consolidated statement of operations. Crestwood Equity's historical carrying value of the property, plant and equipment related to the Barnett Shale assets was less than the sales proceeds due to historical impairments previously recorded on the property, plant and equipment by Crestwood Equity and as a result, during the year ended December 31, 2022, Crestwood Equity recorded a gain on the sale of approximately $72 million, which is included in (gain) loss on long-lived assets, net on its consolidated statement of operations. The sale of the Barnett assets resulted in a decrease of approximately $346.9 million and $221.9 million of property, plant and equipment, net at CMLP and CEQP, respectively, and a decrease of approximately $18.9 million in liabilities for asset retirement obligations at both CMLP and CEQP. Our assets in the Barnett Shale were previously included in our gathering and processing south segment and included our Cowtown, Lake Arlington and Alliance systems which consisted of natural gas processing units, gathering systems and related dehydration, compression and amine treating facilities located in Texas.

Marcellus

In October 2022, we sold our assets in the Marcellus Shale to Antero Midstream Corporation for approximately $206 million, and during the year ended December 31, 2022, we recorded a loss on long-lived assets of approximately $250 million, which is included in loss on long-lived assets, net on our consolidated statement of operations. The sale of our Marcellus assets resulted in a decrease of approximately $311.7 million of property, plant and equipment, net, $153.8 million of intangible assets, net, $7.0 million of asset retirement obligation liabilities and $5.3 million of other long-term liabilities. Our assets in the Marcellus Shale were previously included in our gathering and processing south segment and consisted of natural gas gathering systems and related compression and dehydration facilities located in West Virginia.

Fayetteville

In October 2020, we sold our gathering systems in the Fayetteville Shale to a third party for approximately $23 million, and during the year ended December 31, 2020, we recognized a loss on the sale of approximately $19.9 million, which is included in loss on long-lived assets, net on our consolidated statement of operations. Our Fayetteville assets were previously included in our gathering and processing south segment and consisted of five natural gas gathering systems and related compression, dehydration and treating facilities located in Arkansas.

Note 4 – Certain Balance Sheet Information

Property, Plant and Equipment

Property, plant and equipment consisted of the following (*in millions*):

	CEQP		CMLP	
	December 31,		December 31,	
	2022	2021	2022	2021
Gathering systems and pipelines and related assets	$ 1,616.1	$ 1,052.5	$ 1,616.1	$ 1,195.2
Facilities and equipment	2,893.9	2,200.6	2,893.9	2,385.8
Buildings, land, rights-of-way, storage rights and easements	637.1	391.8	637.1	395.5
Vehicles	22.7	17.0	19.5	14.5
Construction in process	135.0	64.7	135.0	64.7
Finance leases	13.6	12.3	13.6	12.3
Office furniture and fixtures	34.8	32.6	34.8	32.8
	5,353.2	3,771.5	5,350.0	4,100.8
Less: accumulated depreciation	822.8	992.1	822.6	1,193.0
Total property, plant and equipment, net	$ 4,530.4	$ 2,779.4	$ 4,527.4	$ 2,907.8

Depreciation. CEQP’s depreciation expense totaled $250.8 million, $180.9 million and $174.8 million for the years ended December 31, 2022, 2021 and 2020. CMLP’s depreciation expense totaled $256.5 million, $195.1 million and $188.9 million for the years ended December 31, 2022, 2021 and 2020.

Capitalized Interest. During the years ended December 31, 2022, 2021 and 2020, we capitalized interest of $3.0 million, $0.4 million and $2.7 million related to certain expansion projects.

Intangible Assets

Our intangible assets consisted of the following (*in millions*):

	December 31,	
	2022	2021
Customer relationships(1)	$ 994.1	$ 488.7
Revenue contracts(1)	306.0	631.2
Trademarks	6.2	6.2
	1,306.3	1,126.1
Less: accumulated amortization	300.7	393.2
Total intangible assets, net	$ 1,005.6	$ 732.9

(1) The change in our intangible assets during the year ended December 31, 2022 primarily relates to our acquisitions and divestitures which are further discussed in Note 3.

The following table summarizes total accumulated amortization of our intangible assets (*in millions*):

	December 31,	
	2022	2021
Customer relationships[(1)]	$ 230.2	$ 183.2
Revenue contracts[(1)]	64.6	204.6
Trademarks	5.9	5.4
Total accumulated amortization	$ 300.7	$ 393.2

(1) The change in our intangible assets' accumulated amortization during the year ended December 31, 2022 primarily relates to our acquisitions and divestitures which are further discussed in Note 3.

Amortization expense related to our intangible assets for the years ended December 31, 2022, 2021 and 2020, was approximately $78.9 million, $61.4 million and $60.7 million.

Estimated amortization of our intangible assets for the next five years is as follows (*in millions*):

Year Ending December 31,	
2023	$ 64.0
2024	$ 60.7
2025	$ 60.7
2026	$ 60.7
2027	$ 60.7

Accrued Expenses and Other Liabilities

Accrued expenses and other liabilities consisted of the following (*in millions*):

	December 31,	
	2022	2021
CMLP		
Accrued expenses	$ 66.5	$ 66.2
Accrued property taxes	8.4	4.5
Income tax payable	0.9	0.4
Interest payable	43.2	30.6
Accrued additions to property, plant and equipment	35.6	17.4
Operating leases	10.9	13.2
Finance leases	1.9	1.7
Contract liabilities	11.7	10.7
Asset retirement obligations	0.4	1.4
Total CMLP accrued expenses and other liabilities	$ 179.5	$ 146.1
CEQP		
Accrued expenses	1.2	0.9
Income tax payable	0.1	0.1
Total CEQP accrued expenses and other liabilities	$ 180.8	$ 147.1

Other Long-Term Liabilities

Other long-term liabilities consisted of the following (*in millions*):

	December 31,	
	2022	2021
CMLP		
Contract liabilities	$ 212.3	$ 187.1
Operating leases	17.4	19.4
Asset retirement obligations	36.4	34.8
Intangible liabilities, net(1)	50.0	—
Other	14.2	12.8
Total CMLP other long-term liabilities	$ 330.3	$ 254.1
CEQP		
Other	3.1	4.6
Total CEQP other long-term liabilities	$ 333.4	$ 258.7

(1) Intangible liabilities primarily consist of revenue contracts acquired in conjunction with the Sendero Acquisition and CPJV Acquisition during the year ended December 31, 2022. As of and during the year ended December 31, 2022, accumulated amortization and amortization expenses related to these intangible liabilities was approximately $2.8 million. The estimated amortization of our intangible liabilities for the next 5 years is approximately $6.0 million in each year. See Note 3 for a further discussion of these intangible liabilities.

Note 5 - Asset Retirement Obligations

We have legal obligations to retire certain of our assets associated with our facilities and right-of-way contracts we hold. Where we can reasonably estimate the ARO, we accrue a liability based on an estimate of the timing and amount of settlement. We record changes in these estimates based on changes in the expected amount and timing of payments to settle our obligations. We did not have any material assets that were legally restricted for use in settling asset retirement obligations as of December 31, 2022 and 2021.

The following table presents the changes in our net asset retirement obligations (*in millions*):

	December 31,	
	2022	2021
Net asset retirement obligations at January 1	$ 36.2	$ 35.1
Liabilities acquired(1)	23.6	—
Liabilities incurred	2.3	—
Liabilities settled	(0.6)	(0.4)
Accretion expense	2.0	1.9
Other(2)	(26.7)	(0.4)
Net asset retirement obligations at December 31(3)	$ 36.8	$ 36.2

(1) Relates to obligations associated with acquisitions during 2022 as further discussed in Note 3.

(2) Relates primarily to obligations associated with the divestitures of our Barnett and Marcellus assets during 2022, as further discussed in Note 3.

(3) Includes $0.4 million and $1.4 million of current ARO liabilities at December 31, 2022 and 2021.

Note 6 - Investments in Unconsolidated Affiliates

Net Investments and Earnings (Loss)

We account for each of our investments in unconsolidated affiliates under the equity method of accounting. Our Crestwood Permian Basin LLC (Crestwood Permian Basin) equity investment is included in our gathering and processing south segment. Our Tres Palacios Holdings LLC (Tres Holdings) and Powder River Basin Industrial Complex, LLC (PRBIC) equity investments are included in our storage and logistics segment.

Our net investments in and earnings (loss) from our unconsolidated affiliates are as follows (*in millions, unless otherwise stated):*

	Ownership Percentage	Investment		Earnings (Loss) from Unconsolidated Affiliates		
	December 31,	December 31,		Year Ended December 31,		
	2022	2022	2021	2022	2021	2020
Crestwood Permian Basin LLC(1)	50.00 %	$ 76.5	$ —	$ 2.4	$ —	$ —
Tres Palacios Holdings LLC(2)	50.01 %	39.8	36.2	5.2	9.3	—
Powder River Basin Industrial Complex, LLC(3)	50.01 %	3.2	3.5	(0.6)	(0.1)	(4.3)
Crestwood Permian Basin Holdings LLC	— %	—	116.1	8.7	9.6	(1.0)
Stagecoach Gas Services LLC	— %	—	—	—	(139.2)	37.8
Total		$ 119.5	$ 155.8	$ 15.7	$ (120.4)	$ 32.5

(1) As of December 31, 2022, our equity in the underlying net assets of Crestwood Permian Basin was less than our carrying value of our investment balance by approximately $2.3 million. During the year ended December 31, 2022, we recorded amortization of less than $0.1 million related to this basis difference, which we amortize over the life of Crestwood Permian Basin's property, plant and equipment.

(2) As of December 31, 2022, our equity in the underlying net assets of Tres Palacios Holdings LLC (Tres Holdings) exceeded the carrying value of our investment balance by approximately $20.2 million. During each of the years ended December 31, 2022, 2021 and 2020, we recorded amortization of approximately $1.3 million related to this excess basis, which we amortize over the life of Tres Palacios' sublease agreement.

(3) As of December 31, 2022, our equity in the underlying net assets of Powder River Basin Industrial Complex, LLC (PRBIC) approximates the carrying value of our investment balance. During the year ended December 31, 2020, we recorded a $4.5 million reduction to the equity earnings from our PRBIC equity method investment as a result of recording our proportionate share of a long-lived asset impairment recorded by the equity method investee.

Crestwood Permian Basin Holdings LLC Acquisition

In July 2022, we acquired the remaining 50% equity interest in Crestwood Permian Basin Holdings LLC (Crestwood Permian) and as a result, we control and own 100% of the equity interests in Crestwood Permian. As a result of this transaction, we eliminated our historical equity investment in Crestwood Permian of approximately $177.7 million as of the acquisition date and began consolidating Crestwood Permian's operations. Our Crestwood Permian equity investment was previously included in our gathering and processing south segment. Crestwood Permian's operations includes its 50% equity interest in Crestwood Permian Basin, which owns a natural gas gathering system and related assets. Shell Midstream Partners, L.P., a subsidiary of Royal Dutch Shell plc, owns the remaining 50% equity interest in Crestwood Permian Basin.

Stagecoach Gas Services LLC Divestiture

In July 2021, Stagecoach Gas Services LLC (Stagecoach Gas) sold certain of its wholly-owned subsidiaries to a subsidiary of Kinder Morgan, Inc. (Kinder Morgan) for approximately $1.195 billion plus certain purchase price adjustments (Initial Closing) pursuant to a purchase and sale agreement dated as of May 31, 2021 between our wholly-owned subsidiary, Crestwood Pipeline and Storage Northeast LLC (Crestwood Northeast), Con Edison Gas Pipeline and Storage Northeast, LLC (CEGP), a wholly-owned subsidiary of Consolidated Edison, Inc., Stagecoach Gas and Kinder Morgan. Following the Initial Closing, in November 2021 Crestwood Northeast and CEGP sold each of their equity interests in Stagecoach Gas and its wholly-owned subsidiary, Twin Tier Pipeline LLC, (Second Closing) to Kinder Morgan. We received cash proceeds of approximately $15.4 million related to the Second Closing.

In conjunction with the Initial Closing and Second Closing, we recorded a $155.6 million reduction in our equity earnings from unconsolidated affiliates during the year ended December 31, 2021 related to losses recorded by us and our Stagecoach equity investment associated with the sale, which also eliminated our $51.3 million historical basis difference between our investment balance and the equity in the underlying net assets of Stagecoach Gas. In addition, our earnings from unconsolidated affiliates during the year ended December 31, 2021 were also reduced by our proportionate share of transaction costs of approximately

$3.1 million related to the sale, which were paid by us during 2021 on behalf of Stagecoach Gas. Our Stagecoach Gas equity investment was previously included in our storage and logistics segment.

Tres Holdings Divestiture

On February 20, 2023, we and Brookfield Infrastructure Group entered into an agreement with a third party to sell each of our respective interests in Tres Holdings for net proceeds of approximately $335 million. The transaction is expected to close in the second quarter of 2023, subject to customary closing conditions.

Distributions and Contributions

The following table summarizes our distributions from and contributions to our unconsolidated affiliates *(in millions)*:

	Distributions[(1)]			Contributions[(2)]		
	Year Ended December 31,			Year Ended December 31,		
	2022	2021	2020	2022	2021	2020
Crestwood Permian Basin	$ 4.5	$ —	$ —	$ —	$ —	$ —
Tres Holdings	8.7	15.5	6.4	7.1	6.9	6.0
PRBIC	—	—	0.4	0.3	—	—
Crestwood Permian	13.6	16.3	11.9	83.5	10.7	3.4
Stagecoach Gas	—	640.9	59.7	—	—	—
Total	$ 26.8	$ 672.7	$ 78.4	$ 90.9	$ 17.6	$ 9.4

(1) In July 2021, Stagecoach Gas closed on the sale of certain of its wholly-owned subsidiaries to a subsidiary of Kinder Morgan and distributed to us approximately $613.9 million as our proportionate share of the gross proceeds received from the sale. We utilized approximately $3 million of these proceeds to pay transaction costs related to the sale described above, $40 million of these proceeds to pay our remaining contingent consideration obligation and related accrued interest described below, and the remaining proceeds to repay a portion of the amounts outstanding under the Crestwood Midstream credit facility.

(2) In January 2023, we made a cash contribution of approximately $5.1 million to our Tres Holdings equity investment.

Note 7 – Risk Management

We are exposed to certain market risks related to our ongoing business operations. These risks include exposure to changing commodity prices. We utilize derivative instruments to manage our exposure to fluctuations in commodity prices, which is discussed below. Additional information related to our derivatives is discussed in Note 2 and Note 8.

Risk Management Activities

We sell NGLs (such as propane, ethane, butane and heating oil), crude oil and natural gas to energy-related businesses and may use a variety of financial and other instruments including forward contracts involving physical delivery of NGLs, crude oil and natural gas. We periodically enter into offsetting positions to economically hedge against the exposure our customer contracts create. Certain of these contracts and positions are derivative instruments. We do not designate any of our commodity-based derivatives as hedging instruments for accounting purposes. Our commodity-based derivatives are reflected at fair value in our consolidated balance sheets, and changes in the fair value of these derivatives that impact our consolidated statements of operations are reflected in costs of product/services sold. Our commodity-based derivatives that are settled with physical commodities are reflected as an increase to product revenues, and the commodity inventory that is utilized to satisfy those physical obligations is reflected as an increase to product costs in our consolidated statements of operations. Our commodity-based derivatives that are settled financially are also reflected in product costs in our consolidated statements of operations. The following table summarizes the increase (decrease) in our product revenues and product costs, net, in our consolidated statements of operations related to our commodity-based derivatives (*in millions*):

	Year Ended December 31,		
	2022	2021	2020
Product revenues	$ 548.6	$ 486.7	$ 214.3
Product costs, net	$ (9.4)	$ 44.5	$ 20.7

We attempt to balance our contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. This balance in the contractual portfolio significantly reduces the volatility in product costs related to these instruments.

Notional Amounts and Terms

The notional amounts of our derivative financial instruments include the following:

	December 31, 2022		December 31, 2021	
	Fixed Price Payor	Fixed Price Receiver	Fixed Price Payor	Fixed Price Receiver
Propane, ethane, butane, heating oil and crude oil (MMBbls)	67.2	70.2	71.6	75.8
Natural gas (Bcf)	44.2	48.4	31.9	43.4

Notional amounts reflect the volume of transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not reflect our monetary exposure to market or credit risks. All contracts subject to price risk had a maturity of 36 months or less; however, 92% of the contracted volumes will be delivered or settled within 12 months.

Credit Risk

Inherent in our contractual portfolio are certain credit risks. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing credit risk and have established control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with our price risk management activities are energy marketers and propane retailers, resellers and dealers.

Certain of our derivative instruments have credit limits that require us to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as our established credit limit with the respective counterparty. If our credit rating were to change, the counterparties could require us to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in our credit rating as well as the requirements of the individual counterparty. All collateral amounts have been netted against the asset or liability with the respective counterparty and are reflected in our consolidated balance sheets as assets and liabilities from price risk management activities. For a summary of the fair value of our commodity derivative instruments with credit-risk-related contingent features and their associated collateral, see Note 8.

Note 8 – Fair Value Measurements

The accounting standard for fair value measurement establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and US government treasury securities.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Instruments in this category include non-exchange-traded derivatives such as over the counter (OTC) forwards, options and physical exchanges.

- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial Assets and Liabilities

As of December 31, 2022 and 2021, we held certain assets and liabilities that are required to be measured at fair value on a recurring basis, which include our derivative instruments related to crude oil, NGLs and natural gas. Our derivative instruments consist of forwards, swaps, futures, physical exchanges and options.

Our derivative instruments that are traded on the NYMEX have been categorized as Level 1.

Our derivative instruments also include OTC contracts, which are not traded on a public exchange. The fair values of these derivative instruments are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. These instruments have been categorized as Level 2.

Our OTC options are valued based on the Black Scholes option pricing model that considers time value and volatility of the underlying commodity. The inputs utilized in the model are based on publicly available information as well as broker quotes. These options have been categorized as Level 2.

Our financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth by level within the fair value hierarchy, our financial instruments that were accounted for at fair value on a recurring basis at December 31, 2022 and 2021 (*in millions*):

	December 31, 2022						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/ Margin Received or Paid	Fair Value
Assets							
Assets from price risk management	$ 62.8	$ 474.3	$ —	$ 537.1	$ (452.1)	$ (12.2)	$ 72.8
Other investments[2]	2.6	—	—	2.6	—	—	2.6
Total assets at fair value	$ 65.4	$ 474.3	$ —	$ 539.7	$ (452.1)	$ (12.2)	$ 75.4
Liabilities							
Liabilities from price risk management with credit-risk-related contingent features	$ 65.7	$ 420.1	$ —	$ 485.8	$ (452.1)	$ (25.6)	$ 8.1
Liabilities from price risk management without credit-risk-related contingent features	—	11.9	—	11.9	—	3.9	15.8
Total liabilities at fair value	$ 65.7	$ 432.0	$ —	$ 497.7	$ (452.1)	$ (21.7)	$ 23.9

	December 31, 2021						
	Level 1	Level 2	Level 3	Gross Fair Value	Contract Netting[1]	Collateral/ Margin Received or Paid	Fair Value
Assets							
Assets from price risk management	$ 33.3	$ 695.6	$ —	$ 728.9	$ (607.4)	$ (79.4)	$ 42.1
Other investments[2]	2.2	—	—	2.2	—	—	2.2
Total assets at fair value	$ 35.5	$ 695.6	$ —	$ 731.1	$ (607.4)	$ (79.4)	$ 44.3
Liabilities							
Liabilities from price risk management with credit-risk-related contingent features	$ 26.9	$ 635.1	$ —	$ 662.0	$ (607.4)	$ 2.8	$ 57.4
Liabilities from price risk management without credit-risk-related contingent features	—	51.2	—	51.2	—	6.0	57.2
Total liabilities at fair value	$ 26.9	$ 686.3	$ —	$ 713.2	$ (607.4)	$ 8.8	$ 114.6

(1) Amounts represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

(2) Amount primarily relates to our investment in Suburban Propane Partners, L.P. units which is reflected in other non-current assets on CEQP's consolidated balance sheets.

Cash, Accounts Receivable and Accounts Payable

As of December 31, 2022 and 2021, the carrying amounts of cash, accounts receivable and accounts payable approximate fair value based on the short-term nature of these instruments.

Credit Facilities

The fair value of the amounts outstanding under our credit facilities approximates the respective carrying amounts as of December 31, 2022 and 2021, due primarily to the variable nature of the interest rates of the instruments, which is considered a Level 2 fair value measurement. See Note 9 for a further discussion of our credit facilities.

Senior Notes

We estimate the fair value of our senior notes primarily based on quoted market prices for the same or similar issuances (representing a Level 2 fair value measurement). The following table represents the carrying amount (reduced for deferred financing costs associated with the respective notes) and fair value of our senior notes (*in millions*):

	December 31, 2022		December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
2025 Senior Notes	$ 497.6	$ 486.7	$ 496.5	$ 511.9
2027 Senior Notes	$ 595.3	$ 556.9	$ 594.2	$ 615.0
February 2029 Senior Notes	$ 692.1	$ 642.1	$ 690.8	$ 727.3
April 2029 Senior Notes[1]	$ 476.7	$ 450.0	$ —	$ —

(1) Represents $450 million of unsecured senior notes assumed in conjunction with the merger with Oasis Midstream discussed in Note 3, and the related net fair value adjustment which is further described in Note 9.

Note 9 – Long-Term Debt

Long-term debt consisted of the following (*in millions*):

	December 31, 2022	December 31, 2021
CMLP Credit Facility	$ 922.3	$ 282.0
CPBH Credit Facility	206.8	—
2025 Senior Notes	500.0	500.0
2027 Senior Notes	600.0	600.0
February 2029 Senior Notes	700.0	700.0
April 2029 Senior Notes	450.0	—
April 2029 Senior Notes fair value adjustment, net	26.7	—
Other	—	0.2
Less: deferred financing costs, net	27.5	29.9
Total debt	3,378.3	2,052.3
Less: current portion	—	0.2
Total long-term debt, less current portion	$ 3,378.3	$ 2,052.1

Credit Facilities

CMLP Credit Facility. The CMLP credit agreement provides for a five-year $1.75 billion revolving credit facility (the CMLP Credit Facility), which matures in December 2026 and is available to fund acquisitions, working capital and internal growth projects and for general partnership purposes. The CMLP Credit Facility allows Crestwood Midstream to increase its available borrowings under the facility by $100 million, subject to lender approval and the satisfaction of certain other conditions, as described in the CMLP Credit Facility. The CMLP Credit Facility also includes a sub-limit of up to $25 million for same-day swing line advances and a sub-limit up to $350 million for letters of credit. In conjunction with the closing of the Oasis Merger in February 2022, the CMLP Credit Facility was refinanced and increased from $1.25 billion to $1.5 billion. In October 2022, we amended the CMLP credit facility to increase the capacity from $1.5 billion to $1.75 billion under the terms of the credit agreement. Subject to limited exception, the CMLP Credit Facility is guaranteed and secured by substantially all of the equity interests and assets of Crestwood Midstream's subsidiaries, except for Crestwood Infrastructure Holdings LLC, Crestwood Niobrara, PRBIC and Tres Holdings and their respective subsidiaries. Crestwood Equity also guarantees Crestwood Midstream's payment obligations under its $1.75 billion Credit Facility. In January 2023, Crestwood Permian and certain of its subsidiaries were designated as guarantor subsidiaries of Crestwood Midstream's senior notes and its credit facility.

In December 2021, Crestwood Midstream amended and restated the CMLP Credit Facility and we recognized a loss on extinguishment of debt of approximately $0.8 million for the year ended December 31, 2021 in conjunction with this amendment.

The CMLP Credit Facility contains various covenants and restrictive provisions that limit our ability to, among other things, (i) incur additional debt; (ii) make distributions on or redeem or repurchase units; (iii) make certain investments and acquisitions; (iv) incur or permit certain liens to exist; (v) merge, consolidate or amalgamate with another company; (vi) transfer or dispose of assets; and (vii) incur a change in control at either Crestwood Equity or Crestwood Midstream.

Borrowings under the CMLP Credit Facility bear interest at either:

- the Alternate Base Rate, which is defined as the highest of (i) the federal funds rate plus 0.50%; (ii) Wells Fargo Bank's prime rate; or (iii) the Adjusted Term SOFR (as defined in the credit agreement) for a one-month tenor plus 1% per annum; plus a margin varying from 0.50% to 1.50% depending on Crestwood Midstream's most recent consolidated total leverage ratio; or

- Adjusted Term SOFR plus a margin varying from 1.50% to 2.50% depending on Crestwood Midstream's most recent consolidated total leverage ratio.

The unused portion of the CMLP Credit Facility is subject to a commitment fee ranging from 0.30% to 0.50% according to CMLP's most recent consolidated total leverage ratio. Interest on the Alternate Base Rate loans is payable quarterly, or if the Adjusted Term SOFR applies, interest is payable at certain intervals selected by Crestwood Midstream.

Crestwood Midstream is required under its credit agreement to maintain a net debt to consolidated EBITDA ratio (as defined in its credit agreement) of not more than 5.50 to 1.0, a consolidated EBITDA to consolidated interest expense ratio (as defined in its credit agreement) of not less than 2.50 to 1.0, and a senior secured leverage ratio (as defined in its credit agreement) of not more than 3.50 to 1.0. At December 31, 2022, the net debt to consolidated EBITDA ratio was approximately 3.96 to 1.0, the consolidated EBITDA to consolidated interest expense ratio was approximately 4.56 to 1.0, and the senior secured leverage ratio was 1.15 to 1.0.

At December 31, 2022, Crestwood Midstream had $819.5 million of available capacity under its credit facility considering the most restrictive covenants in its credit agreement. At December 31, 2022 and 2021, Crestwood Midstream's outstanding standby letters of credit were $8.2 million and $6.3 million. The interest rates on borrowings under the credit facility were between 6.28% and 8.50% at December 31, 2022 and 1.90% and 4.00% at December 31, 2021. The weighted-average interest rates on outstanding borrowings as of December 31, 2022 and 2021 was 6.40% and 1.91%.

If Crestwood Midstream fails to perform its obligations under these and other covenants, the lenders' credit commitment could be terminated and any outstanding borrowings, together with accrued interest, under the CMLP Credit Facility could be declared immediately due and payable. The CMLP Credit Facility also has cross default provisions that apply to any of its other material indebtedness.

CPBH Credit Facility. In conjunction with the CPJV Acquisition in July 2022, we assumed a credit agreement entered into by CPB Subsidiary Holdings LLC (CPB Holdings), a wholly-owned subsidiary of Crestwood Permian. The credit agreement allowed for revolving loans, letters of credit and swing line loans of up to $230 million (the CPBH Credit Facility). In January 2023, we repaid and terminated the CPBH Credit Facility.

The CPBH Credit Facility contained various covenants and restrictive provisions that limited Crestwood Permian's ability to, among other things, (i) incur additional debt; (ii) make distributions on or redeem or repurchase units; (iii) make certain investments and acquisitions; (iv) incur or permit certain liens to exist; (v) merge, consolidate or amalgamate with another company; and (vi) transfer or dispose of assets.

We recorded interest under the CPBH Credit Facility at either:

- the Alternate Base Rate, which is defined as the highest of (i) the federal funds rate plus 0.50%; (ii) Wells Fargo Bank's prime rate; or (iii) the Adjusted Term SOFR (as defined in the credit agreement) for a one-month tenor plus 1% per annum; plus a margin varying from 1.50% to 2.50% depending on our most recent consolidated total leverage ratio; or

- the Adjusted Term SOFR plus a margin varying from 2.50% to 3.50% depending on our most recent consolidated total leverage ratio.

The interest rates on borrowings under the CPBH Credit Facility were between 7.03% and 9.25% at December 31, 2022. The weighted average interest rate on outstanding borrowings as of December 31, 2022 was 7.37%.

Senior Notes

2025 Senior Notes. The 5.75% Senior Notes due 2025 (the 2025 Senior Notes) mature on April 1, 2025, and interest is payable semi-annually in arrears on April 1 and October 1 of each year.

2027 Senior Notes. The 5.625% Senior Notes due 2027 (the 2027 Senior Notes) mature on May 1, 2027, and interest is payable semi-annually in arrears on May 1 and November 1 of each year.

February 2029 Senior Notes. In January 2021, Crestwood Midstream issued $700 million of 6.00% unsecured senior notes due 2029 (the February 2029 Senior Notes). The February 2029 Senior Notes mature on February 1, 2029, and interest is payable semiannually in arrears on February 1 and August 1 of each year, beginning on August 1, 2021. The net proceeds from this offering of approximately $691.0 million were used to repay a portion of the 2023 Senior Notes and to repay indebtedness under the 2023 Credit Facility.

April 2029 Senior Notes. In February 2022, in conjunction with the Oasis Merger, we assumed $450 million of 8.00% unsecured senior notes due 2029 (the April 2029 Senior Notes) and we recorded a fair value adjustment of approximately $30.7 million related to the senior notes. During the year ended December 31, 2022, we recorded a reduction of our interest and debt expense of approximately $3.9 million related to the amortization of the fair value adjustment. The April 2029 Senior Notes will mature on April 1, 2029, and interest is payable semi-annually on April 1 and October 1 of each year.

2031 Senior Notes. In January 2023, Crestwood Midstream issued $600 million of 7.375% unsecured senior notes due 2031 (the 2031 Senior Notes). The 2031 Senior Notes mature on February 1, 2031, and interest is payable semiannually in arrears on February 1 and August 1 of each year, beginning on August 1, 2023. The net proceeds from this offering of approximately $592.5 million were used to repay a portion of amounts outstanding under the CMLP Credit Facility.

In general, each series of Crestwood Midstream's senior notes are fully and unconditionally guaranteed, joint and severally, on a senior unsecured basis by Crestwood Midstream's domestic restricted subsidiaries (other than Crestwood Midstream Finance Corp., which has no assets). The indentures contain customary release provisions, such as (i) disposition of all or substantially all the assets of, or the capital stock of, a guarantor subsidiary to a third person if the disposition complies with the indentures; (ii) designation of a guarantor subsidiary as an unrestricted subsidiary in accordance with its indentures; (iii) legal or covenant defeasance of a series of senior notes, or satisfaction and discharge of the related indenture; and (iv) guarantor subsidiary ceases to guarantee any other indebtedness of Crestwood Midstream or any other guarantor subsidiary, provided it no longer guarantees indebtedness under the CMLP Credit Facility.

The indentures restrict the ability of Crestwood Midstream and its restricted subsidiaries to, among other things, sell assets; redeem or repurchase subordinated debt; make investments; incur or guarantee additional indebtedness or issue preferred units; create or incur certain liens; enter into agreements that restrict distributions or other payments to Crestwood Midstream from its restricted subsidiaries; consolidate, merge or transfer all or substantially all of their assets; engage in affiliate transactions; create unrestricted subsidiaries; and incur a change in control at either Crestwood Equity or Crestwood Midstream. These restrictions are subject to a number of exceptions and qualifications, and many of these restrictions will terminate when the senior notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Rating Services and no default or event of default (each as defined in the respective indentures) under the indentures has occurred and is continuing.

At December 31, 2022, we were in compliance with our debt covenants and restrictions in each of the credit agreements discussed above.

The CMLP Credit Facility and senior notes are secured by the net assets of its guarantor subsidiaries. Accordingly, such assets are only available to the creditors of Crestwood Midstream. Crestwood Equity had restricted net assets of approximately $1,907.3 million as of December 31, 2022.

Maturities

The aggregate maturities of principal amounts on our outstanding long-term debt as of December 31, 2022 for the next five years and in total thereafter are as follows (*in millions*):

2023	$	—
2024		—
2025		706.8 (1)
2026		922.3
2027		600.0
Thereafter		1,150.0
Total debt	$	3,379.1

(1) Includes amounts outstanding on the CPBH Credit Facility at December 31, 2022, which was repaid in January 2023.

Note 10 – Commitments and Contingencies

Legal Proceedings

Linde Lawsuit. On December 23, 2019, Linde Engineering North America Inc. (Linde) filed a lawsuit in the District Court of Harris County, Texas alleging that Arrow Field Services, LLC, our consolidated subsidiary, and Crestwood Midstream breached a contract entered into in March 2018 under which Linde was to provide engineering, procurement and construction services to us related to the completion of the construction of the Bear Den II cryogenic processing plant. Since the lawsuit was filed, we have paid Linde approximately $22.7 million related to this matter (including approximately $3.2 million paid during the year ended December 31, 2022).

A jury trial concluded on June 17, 2022, and a final judgement was entered on October 24, 2022. The final judgment includes an award of damages of approximately $20.7 million, a pre-judgement interest award of approximately $17.7 million and attorney fees and other costs of approximately $4.7 million. We have insurance coverage related to certain pre-judgement interest awards but have not recorded a receivable related to any potential insurance recovery at December 31, 2022. On January 9, 2023, we paid approximately $21.2 million into the Court Registry under protest to mitigate the impact of post-judgment interest. We filed a Notice of Appeal on January 13, 2023, and we are unable to predict the ultimate outcome on the appeal related to this matter.

General. We are periodically involved in litigation proceedings. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, then we accrue the estimated amount. The results of litigation proceedings cannot be predicted with certainty. We could incur judgments, enter into settlements or revise our expectations regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations or cash flows in the period in which the amounts are paid and/or accrued. As of December 31, 2022 and 2021, we had approximately $35.0 million and $16.8 million accrued for outstanding legal matters. Certain of our outstanding legal matters are insurable events under our policies and at December 31, 2022, we recorded insurance receivables of approximately $3.8 million. Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures for which we can estimate will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures.

Any loss estimates are inherently subjective, based on currently available information, and are subject to management's judgment and various assumptions. Due to the inherently subjective nature of these estimates and the uncertainty and unpredictability surrounding the outcome of legal proceedings, actual results may differ materially from any amounts that have been accrued.

Regulatory Compliance

In the ordinary course of our business, we are subject to various laws and regulations. In the opinion of our management, compliance with current laws and regulations will not have a material effect on our results of operations, cash flows or financial condition.

Environmental Compliance

Our operations are subject to stringent and complex laws and regulations pertaining to worker health, safety, and the environment. We are subject to laws and regulations at the federal, state, regional and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating our facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures.

At December 31, 2022 and 2021, our accrual of approximately $0.8 million and $1.0 million was based on our undiscounted estimate of amounts we will spend on compliance with environmental and other regulations, and any associated fines or penalties. We estimate that our potential liability for reasonably possible outcomes related to our environmental exposures could range from approximately $0.8 million to $1.1 million at December 31, 2022. We did not record any insurance receivables at December 31, 2021.

Self-Insurance

We utilize third-party insurance subject to varying retention levels of self-insurance, which management considers prudent. Such self-insurance relates to losses and liabilities primarily associated with medical claims, workers' compensation claims and general, product, vehicle and environmental liability. Losses are accrued based upon management's estimates of the aggregate liability for claims incurred using certain assumptions followed in the insurance industry and based on past experience. The primary assumption utilized is actuarially determined loss development factors. The loss development factors are based primarily on historical data. Our self-insurance reserves could be affected if future claim developments differ from the historical trends. We believe changes in health care costs, trends in health care claims of our employee base, accident frequency and severity and other factors could materially affect the estimate for these liabilities. We continually monitor changes in employee demographics, incident and claim type and evaluate our insurance accruals and adjust our accruals based on our evaluation of these qualitative data points. We are liable for the development of claims for our previously disposed of retail propane operations, provided they were reported prior to August 1, 2012. The following table summarizes CEQP's and CMLP's self-insurance reserves *(in millions)*:

	CEQP		CMLP	
	December 31,		December 31,	
	2022	2021	2022	2021
Self-insurance reserves[1]	$ 5.6	$ 5.5	$ 4.8	$ 4.7

(1) At December 31, 2022, CEQP and CMLP classified approximately $3.2 million and $2.7 million, respectively, of these reserves as other long-term liabilities on their consolidated balance sheets.

Indemnifications

We periodically provide indemnification arrangements related to assets or businesses we have sold. Our potential exposure under indemnification arrangements can range from a specified amount to an unlimited amount, depending on the nature of the claim, specificity as to duration, and the particular transaction. As of December 31, 2022 and 2021, we have no amounts accrued for these indemnifications.

Note 11 - Leases

The following table summarizes the balance sheet information related to our operating and finance leases (*in millions*):

	December 31,	
	2022	2021
Operating leases		
Operating lease right-of-use assets, net	$ 24.4	$ 27.4
Accrued expenses and other liabilities	$ 10.9	$ 13.2
Other long-term liabilities	17.4	19.4
Total operating lease liabilities	$ 28.3	$ 32.6
Finance leases		
Property, plant and equipment	$ 13.6	$ 12.3
Less: accumulated depreciation	8.9	9.2
Property, plant and equipment, net	$ 4.7	$ 3.1
Accrued expenses and other liabilities	$ 1.9	$ 1.7
Other long-term liabilities	2.7	1.2
Total finance lease liabilities	$ 4.6	$ 2.9

The following table presents the weighted-average remaining lease term and the weighted-average discount rate associated with our operating and finance leases:

	December 31,	
	2022	2021
Weighted-average remaining lease term *(in years)*		
Operating leases[(1)]	5.6	3.9
Finance leases[(2)]	2.9	2.6
Weighted-average discount rate		
Operating leases[(3)]	6.3 %	5.9 %
Finance leases[(3)]	6.2 %	5.5 %

(1) Remaining terms vary from one year to 17 years as of December 31, 2022.
(2) Remaining terms vary from one year to four years as of December 31, 2022.
(3) As of December 31, 2022 and 2021, we utilized discount rates ranging from 2.2% to 9.2% and 1.5% to 8.3%, respectively, to estimate the discounted cash flows used in estimating our right-of-use assets and lease liabilities, which were primarily based on our credit-adjusted collateralized incremental borrowing rate.

The estimation of our right-of-use assets and lease liabilities requires us to make significant assumptions and judgments about the terms of the leases, variable payments, and discount rates. Certain of our operating leases have renewal options to extend the leases from one year to 10 years at the end of each lease term, or terminate the leases at our sole discretion. In addition, certain of our finance leases have options to purchase the leased property by the end of the lease term. We make significant assumptions on the likelihood on whether we will renew our leases or purchase the property at the end of the lease terms in determining the discounted cash flows to measure our right-of-use assets and lease liabilities. The estimation of variable lease payments in determining discounted cash flows, including those with usage-based costs, also requires us to make significant assumptions on the timing and nature of the variability of those payments based on the lease terms.

We recognize operating lease expense and amortize our right-of-use assets for our finance leases on a straight-line basis over the term of the respective leases. We have applied the practical expedient of not separating the lease and non-lease components for our leases where the predominant consideration paid related to the underlying operating and finance lease contracts relate to the lease component. The following table presents the costs and income associated with our operating and finance leases (*in millions*):

	Year Ended December 31,		
	2022	2021	2020
Operating leases			
Operating lease expense[(1)(2)]	$ 15.8	$ 20.0	$ 27.2
Lease income[(3)]	(3.2)	(3.7)	(1.7)
Total operating lease expense, net	$ 12.6	$ 16.3	$ 25.5
Finance leases			
Amortization of right-of-use assets[(4)]	$ 3.3	$ 3.0	$ 3.5
Interest on lease liabilities[(5)]	0.2	0.3	0.5
Total finance lease expense	$ 3.5	$ 3.3	$ 4.0

(1) Approximately $9.4 million, $13.4 million and $17.6 million is included in costs of product/services sold, $3.6 million, $3.9 million and $6.7 million is included in operations and maintenance expense and $2.8 million, $2.7 million and $2.9 million is included in general and administrative expense on our consolidated statements of operations for the years ended December 31, 2022, 2021 and 2020, respectively.
(2) Includes short-term and variable lease costs of approximately $1.6 million, $2.2 million and $5.5 million for the years ended December 31, 2022, 2021 and 2020.
(3) Include lessor and sublease income which is reflected in service revenues on our consolidated statements of operations.
(4) Included in depreciation, amortization and accretion expense on our consolidated statements of operations.
(5) Included in interest and debt expense, net on our consolidated statements of operations.

The following table presents supplemental cash flow information for our operating and finance leases (*in millions*):

	Year Ended December 31,		
	2022	2021	2020
Cash paid for lease liabilities			
Operating cash flows from operating leases	$ 15.2	$ 19.0	$ 21.3
Operating cash flows from finance leases	$ 0.2	$ 0.3	$ 0.5
Financing cash flows from finance leases	$ 32.0	$ 2.8	$ 3.1
Right-of-use assets obtained in exchange for lease obligations			
Operating leases	$ 2.3	$ —	$ 2.1
Finance leases	$ 4.0	$ 1.5	$ 0.4

Other. During March 2022, we exercised an option to purchase crude oil railcars under certain of our finance leases as a result of our plan to exit our crude oil railcar operations. In April 2022, we sold the crude oil railcars to a third party for proceeds of approximately $24.7 million and recognized a loss on the sale of approximately $4.1 million during the year ended December 31, 2022.

The following table presents the future minimum lease liabilities for our leases as of December 31, 2022 for the next five years and in total thereafter (*in millions*):

Year Ending December 31,	Operating Leases	Finance Leases	Total
2023	$ 11.9	$ 2.1	$ 14.0
2024	8.4	1.2	9.6
2025	5.6	1.1	6.7
2026	3.6	0.6	4.2
2027	0.7	—	0.7
Thereafter	1.8	—	1.8
Total lease payments	32.0	5.0	37.0
Less: interest	3.7	0.4	4.1
Present value of lease liabilities	$ 28.3	$ 4.6	$ 32.9

Note 12 – Partners' Capital and Non-Controlling Partner

Preferred Units

Subject to certain conditions, the holders of the preferred units will have the right to convert preferred units into (i) common units on a 10-for-1 basis, or (ii) a number of common units determined pursuant to a conversion ratio set forth in Crestwood Equity's partnership agreement upon the occurrence of certain events, such as a change in control. The preferred units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class, with each preferred units entitled to one vote for each common unit into which such preferred unit is convertible, except that the preferred units are entitled to vote as a separate class on any matter on which all unitholders are entitled to vote that adversely affects the rights, powers, privileges or preferences of the preferred units in relation to CEQP's other securities outstanding.

Common and Subordinated Units

On February 1, 2022, we completed the merger with Oasis Midstream. Pursuant to the merger agreement, Chord (formerly Oasis Petroleum) received cash and approximately 20.9 million newly issued CEQP common units in exchange for its common units held in Oasis Midstream. In addition, Oasis Midstream's public unitholders received approximately 12.9 million newly issued CEQP common units in exchange for the Oasis Midstream common units held by them. For a further discussion of the merger with Oasis Midstream, see Note 3. On September 15, 2022, CEQP acquired 4.6 million CEQP common units from a subsidiary of Chord, for approximately $123.7 million. This transaction resulted in CEQP retiring the common units acquired from Chord.

On July 11, 2022, we acquired First Reserve's 50% equity interest in Crestwood Permian in exchange for approximately $5.9 million in cash and approximately 11.3 million newly issued CEQP common units. For a further discussion of the CPJV Acquisition, see Note 3.

In March 2021, CEQP acquired approximately 11.5 million CEQP common units and 0.4 million subordinated units of CEQP from Crestwood Holdings LLC (Crestwood Holdings) for approximately $268 million (the Crestwood Holdings Transaction). CEQP reflected the purchase price as a reduction to its common unitholders' partners' capital in its consolidated statement of partners' capital during the year ended December 31, 2021. This transaction resulted in CEQP retiring the common and subordinated units acquired from Crestwood Holdings. In addition, in conjunction with this transaction, CEQP eliminated approximately $2.4 million of accounts payable to Crestwood Holdings which is reflected as an increase to CEQP's common unitholders' partners' capital in its consolidated statements of partners' capital during the year ended December 31, 2021. Transaction costs related to this transaction of approximately $7.6 million are reflected as a reduction of CEQP's common unitholders' partners' capital in its consolidated statement of partners' capital during the year ended December 31, 2021.

Distributions

Crestwood Equity

Limited Partners. Crestwood Equity makes quarterly distributions to its partners within approximately 45 days after the end of each quarter in an aggregate amount equal to its available cash for such quarter. Available cash generally means, with respect to each quarter, all cash on hand at the end of the quarter less the amount of cash that the general partner determines in its reasonable discretion is necessary or appropriate to:

- provide for the proper conduct of its business;
- comply with applicable law, any of its debt instruments, or other agreements; or
- provide funds for distributions to unitholders for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. The amount of cash CEQP has available for distribution depends primarily upon its cash flow (which consists of the cash distributions it receives in connection with its ownership of Crestwood Midstream).

A summary of CEQP's limited partner quarterly cash distributions for the years ended December 31, 2022, 2021 and 2020 is presented below:

Record Date	Payment Date	Per Unit Rate	Cash Distributions (*in millions*)
2022			
February 7, 2022	February 14, 2022	$ 0.625	$ 60.9
May 6, 2022	May 13, 2022	$ 0.655	64.2
August 5, 2022	August 12, 2022	$ 0.655	71.6
November 7, 2022	November 14, 2022	$ 0.655	68.5
			$ 265.2
2021			
February 5, 2021	February 12, 2021	$ 0.625	$ 46.4
May 7, 2021	May 14, 2021	$ 0.625	39.3
August 6, 2021	August 13, 2021	$ 0.625	39.3
November 5, 2021	November 12, 2021	$ 0.625	39.3
			$ 164.3
2020			
February 7, 2020	February 14, 2020	$ 0.625	$ 45.3
May 8, 2020	May 15, 2020	$ 0.625	45.7
August 7, 2020	August 14, 2020	$ 0.625	45.7
November 6, 2020	November 13, 2020	$ 0.625	46.0
			$ 182.7

On February 14, 2023, we paid a distribution of $0.655 per limited partner unit to unitholders of record on February 7, 2023 with respect to the fourth quarter of 2022.

Preferred Unitholders. The holders of our preferred units are entitled to receive fixed quarterly distributions of $0.2111 per unit. Distributions on the preferred units are paid in cash unless, subject to certain exceptions, (i) there is no distribution being paid on our common units; and (ii) our available cash (as defined in our partnership agreement) is insufficient to make a cash distribution to our preferred unitholders. If we fail to pay the full amount payable to our preferred unitholders in cash, then (x) the fixed quarterly distribution on the preferred units will increase to $0.2567 per unit, and (y) we will not be permitted to declare or make any distributions to our common unitholders until such time as all accrued and unpaid distributions on the preferred units have been paid in full in cash. In addition, if we fail to pay in full any preferred distribution (as defined in our partnership agreement), the amount of such unpaid distribution will accrue and accumulate from the last day of the quarter for which such distribution is due until paid in full, and any accrued and unpaid distributions will be increased at a rate of 2.8125% per quarter.

During each of the years ended December 31, 2022, 2021 and 2020, we paid cash distributions to our preferred unitholders of approximately $60.1 million. On February 14, 2023, we made a cash distribution of approximately $15.0 million to our preferred unitholders with respect to the fourth quarter of 2022.

Crestwood Midstream

In accordance with the partnership agreement, Crestwood Midstream's general partner may, from time to time, cause Crestwood Midstream to make cash distributions at the sole discretion of the general partner. During the years ended December 31, 2022, 2021 and 2020, Crestwood Midstream paid cash distributions of $622.2 million, $509.7 million and $242.6 million, which represented net amounts due to Crestwood Midstream related to cash advances to CEQP for its general corporate activities.

On February 1, 2022, Crestwood Midstream received a non-cash contribution of approximately $1,075.1 million from Crestwood Equity related to net assets it acquired in conjunction with the merger with Oasis Midstream. In addition, on February 1, 2022, Crestwood Equity contributed cash acquired in conjunction with the merger with Oasis Midstream of approximately $14.9 million to Crestwood Midstream.

On July 11, 2022, Crestwood Midstream received a non-cash contribution of approximately $127.3 million from Crestwood Equity related to the acquisition of an additional 50% equity interest in Crestwood Permian. In addition, on July 11, 2022, Crestwood Equity contributed cash acquired in conjunction with this acquisition of approximately $149.4 million to Crestwood Midstream.

For a further discussion of these acquisitions, see Note 3.

Non-Controlling Partner

Crestwood Niobrara issued $175 million of Series A-2 Preferred Units and $235 million of Series A-3 Preferred Units (collectively defined as the Crestwood Niobrara Preferred Units) to CN Jackalope Holdings LLC (Jackalope Holdings) in conjunction with its equity interest in Jackalope Gas Gathering Services L.L.C. (Jackalope). In connection with the issuance of the Series A-3 Preferred Units, we entered into a Third Amended and Restated Limited Liability Company Agreement (Crestwood Niobrara Amended Agreement) with Jackalope Holdings, pursuant to which we serve as managing member of Crestwood Niobrara. The Crestwood Niobrara Amended Agreement modified certain provisions under the previous limited liability company agreement related to the conversion and redemption of the Series A-2 Preferred Units, as follows:

- The Crestwood Niobrara Preferred Units are convertible by the preferred interest holder starting on January 1, 2021 into Crestwood Niobrara common units. The preferred interest holder has the option to contribute additional capital to Crestwood Niobrara to increase their common ownership percentage in Crestwood Niobrara to 50% upon the conversion.

- The Crestwood Niobrara Preferred Units are redeemable by the preferred interest holder starting in January 2024 for an amount equal to the Liquidation Preference (as defined in the Crestwood Niobrara Amended Agreement). If redemption is elected by the preferred interest holder, we have the option to elect to give consideration equal to the Liquidation Preference in either (i) unregistered CEQP common units (subject to a Registration Rights Agreement) with a total value of up to $100 million and/or cash; or (ii) proceeds from a full liquidation of Crestwood Niobrara's assets and unregistered CEQP common units (subject to a Registration Rights Agreement).

- The Crestwood Niobrara Preferred Units are redeemable by us starting on January 1, 2023 for either (i) unregistered CEQP common units (subject to a Registration Rights Agreement) with a total value of up to $100 million and/or cash; or (ii) proceeds from a full liquidation of Crestwood Niobrara's assets and registered CEQP common units (subject to a Registration Rights Agreement).

As a result of the modification of the conversion and redemption provisions of the Crestwood Niobrara Preferred Units, we continue to consolidate Crestwood Niobrara and have reflected the preferred interests as a non-controlling interest in subsidiary apart from partners' capital (i.e., temporary equity) on our consolidated balance sheets at December 31, 2022 and 2021. We adjust the carrying amount of the non-controlling interest to its redemption value each period through net income attributable to non-controlling partner.

The following table shows the change in the interest of our non-controlling partner in subsidiary during the years ended December 31, 2022, 2021 and 2020 *(in millions)*:

Balance at December 31, 2019	$	426.2
Contributions from non-controlling partner		2.8
Distributions to non-controlling partner		(37.1)
Net income attributable to non-controlling partner		40.8
Balance at December 31, 2020		432.7
Contributions from non-controlling partner		1.0
Distributions to non-controlling partner		(40.2)
Net income attributable to non-controlling partner		41.1
Balance at December 31, 2021		434.6
Distributions to non-controlling partner		(41.4)
Net income attributable to non-controlling partner		41.2
Balance at December 31, 2022	$	434.4

Crestwood Niobrara is required to make quarterly cash distributions on its preferred interests within 30 days after the end of each quarter. In January 2023, Crestwood Niobrara paid a cash distribution of $10.3 million to Jackalope Holdings with respect to the fourth quarter of 2022.

Note 13 - Equity Plans

Long-term incentive awards are granted under the Crestwood LTIP in order to align the economic interests of key employees and directors with those of CEQP's common unitholders and to provide an incentive for continuous employment. Long-term incentive compensation consist of grants of restricted, phantom and performance units which vest based upon continued service.

As of December 31, 2022 and 2021, we had total unamortized compensation expense of approximately $29.5 million and $33.2 million related to restricted, phantom, and performance units, which will be amortized during the next three years (or sooner in certain cases, which generally represents the original vesting period of these instruments), except for grants to non-employee directors of our general partner, which vest over one year. We recognized compensation expense of approximately $37.2 million, $39.5 million and $35.1 million under the Crestwood LTIP during the years ended December 31, 2022, 2021 and 2020, which is included in general and administrative expenses on our consolidated statements of operations. During the years ended December 31, 2022 and 2021, compensation expense includes approximately $1.8 million and $4.4 million related to equity awards under the Crestwood LTIP that was included in accrued expenses and other liabilities on our consolidated balance sheets. As of February 17, 2023, we had 1,516,305 units available for issuance under the Crestwood LTIP.

Restricted Units. The Crestwood LTIP permits grants of restricted units that are designed to provide an incentive for continuous employment to certain key employees. Restricted units vest over a three-year period following the grant date or, if earlier, upon change of control of Crestwood Equity's general partner or due to death or disability of the employee.

Performance and Phantom Units. The Crestwood LTIP permits grants of performance and phantom units that are designed to provide an incentive for continuous employment to certain key employees. The vesting of performance and phantom units are subject to the attainment of certain performance and market goals over a three-year period and entitle a participant to receive common units of Crestwood Equity without payment of an exercise price upon vesting. The number of units issued are based on a performance multiplier ranging between 50% and 200%, determined based on the actual performance in the third year of the performance period compared to pre-established performance goals. The performance goals are based on achieving a specified level of distributable cash flow per unit, Adjusted EBITDA and three-year relative total shareholder return, and for certain awards, return on invested capital. In February 2022 and February 2020, our performance and phantom units vested at 196.8% and 196.0% of the targeted performance goals. We had no performance units vest during the year ended December 31, 2021.

The following table summarizes information regarding restricted, phantom and performance unit activity during the years ended December 31, 2022, 2021 and 2020.

	Units	Weighted-Average Grant Date Fair Value
Unvested - January 1, 2020	2,355,949	$ 28.94
Granted - restricted units	1,569,451	$ 25.42
Granted - performance and phantom units	733,400	$ 28.46
Vested - restricted units	(906,275)	$ 28.75
Vested - performance and phantom units	(848,424)	$ 29.84
Forfeited - restricted units	(149,001)	$ 28.24
Forfeited - performance and phantom units	(31,244)	$ 27.60
Unvested - December 31, 2020	2,723,856	$ 26.62
Granted - restricted units	1,399,781	$ 20.51
Granted - performance and phantom units	77,081	$ 25.09
Vested - restricted units	(1,148,928)	$ 27.65
Vested - phantom units	(2,117)	$ 26.63
Forfeited - restricted units	(48,565)	$ 21.67
Unvested - December 31, 2021	3,001,108	$ 23.42
Granted - restricted units	1,167,597	$ 27.86
Granted - performance and phantom units	538,627	$ 18.58
Vested - restricted units	(1,019,011)	$ 25.04
Vested - performance and phantom units	(554,525)	$ 23.47
Forfeited - restricted units	(31,539)	$ 25.53
Unvested - December 31, 2022	3,102,257	$ 23.69

Under the Crestwood LTIP, participants who have been granted restricted units and/or performance units may elect to have us withhold common units to satisfy minimum statutory tax withholding obligations arising in connection with the vesting of non-vested common units. Any such common units withheld are returned to the Crestwood LTIP on the applicable vesting dates, which correspond to the times at which income is recognized by the employee. When we withhold these common units, we are required to remit to the appropriate taxing authorities the fair value of the units withheld as of the vesting date. The number of units withheld is determined based on the closing price per common unit as reported on the NYSE on such dates. During the years ended December 31, 2022, 2021, and 2020, we withheld 562,317, 423,330 and 581,608 common units to satisfy employee tax withholding obligations for the restricted and performance units.

Employee Unit Purchase Plan

In August 2018, the board of directors of our general partner approved an employee unit purchase plan under which employees of the general partner may purchase our common units through payroll deductions up to a maximum of 10% of the employees' eligible compensation, not to exceed $25,000 for any calendar year. Under the plan, we anticipate purchasing our common units on the open market for the benefit of participating employees based on their payroll deductions. In addition, we may match up to 10% of participating employees' payroll deductions to purchase additional Crestwood common units for participating employees. The board of directors of our general partner authorized 1,500,000 common units (subject to adjustment as provided in the employee unit purchase plan) to be available for purchase. During the years ended December 31, 2022, 2021 and 2020, 9,934, 9,932 and 29,784 common units were purchased under the plan.

Note 14 - Earnings Per Limited Partner Unit

We calculate the dilutive effect of the preferred units and Crestwood Niobrara preferred units using the if-converted method which assumes units are converted at the beginning of the period (beginning with their respective issuance date), and the resulting common units are included in the denominator of the diluted net income per common unit calculation for the period being presented. Distributions declared in the period and undeclared distributions that accumulated during the period are added back to the numerator for purposes of the if-converted calculation. The dilutive effect of the unit-based compensation performance units is calculated using the treasury stock method which considers the impact to net income or loss attributable to Crestwood Equity Partners and limited partner units from the potential issuance of limited partner units. Prior to the Crestwood Holdings transactions in March 2021, we calculated basic net income per limited partner unit using the two-class method. Our income (loss) was allocated to our common units and other participating securities (i.e., subordinated units) based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in income (loss) or excess distributions over income (loss).

We exclude potentially dilutive securities from the determination of diluted earnings per unit (as well as their related income statement impacts) when their impact is anti-dilutive. The following table summarizes information regarding the weighted-average of common units excluded during the years ended December 31, 2022, 2021 and 2020 *(in millions)*:

	Year Ended December 31,		
	2022	**2021**	**2020**
Preferred units(1)	7.1	7.1	7.1
Crestwood Niobrara's preferred units(1)	4.1	4.2	5.7
Unit-based compensation performance units(2)	0.2	0.2	0.1
Subordinated units(3)	—	0.1	0.4

(1) See Note 12 for additional information regarding the potential conversion of our preferred units and Crestwood Niobrara's preferred units to common units.

(2) For a description of our unit-based compensation performance units, see Note 13.

(3) In March 2021, CEQP retired the subordinated units. For additional information regarding the retirement of the subordinated units, see Note 12.

Note 15 - Employee Benefit Plan

A 401(k) plan is available to all of our employees after meeting certain requirements. The plan permits employees to make contributions of up to 90% of their salary, subject to statutory limits, which was $20,500 in 2022, $19,500 in 2021 and $19,500 in 2020. We match 100% of participants' basic contributions up to 6% of eligible compensation. Employees may participate in the plan immediately and certain employees are not eligible for matching contributions until after a 90-day waiting period. During the years ended December 31, 2022, 2021 and 2020, aggregate matching contributions made by us were $4.3 million, $4.0 million and $4.2 million.

Note 16 – Segments

Our financial statements reflect three operating and reporting segments: (i) gathering and processing north operations (includes our Arrow, Jackalope and Oasis Midstream Williston operations); (ii) gathering and processing south operations (includes our Crestwood Permian, Sendero and Oasis Midstream Delaware operations and our Crestwood Permian Basin LLC equity method investment); and (iii) storage and logistics operations (includes our crude oil, NGL and natural gas storage and logistics operations, and our Tres Holdings and PRBIC equity method investments). During 2022, we completed a number of strategic transactions, including the Oasis Merger, the Sendero Acquisition and the CPJV Acquisition. In addition, during 2022, we sold our Barnett and Marcellus assets, which were previously included in our gathering and processing south segment. For a further discussion of these acquisitions and divestitures and the impact to our segments, see Note 3.

Below is a description of our operating and reporting segments.

- *Gathering and Processing North*. Our gathering and processing north operations provide natural gas gathering, compression, treating and processing services, crude oil gathering and storage services and produced water gathering and disposal services to producers in the Williston Basin and Powder River Basin.

- *Gathering and Processing South*. Our gathering and processing south operations provide natural gas gathering, compression, treating and processing services, crude oil gathering services and produced water gathering and disposal services to producers in the Delaware Basin.

- *Storage and Logistics*. Our storage and logistics operations provide NGLs, crude oil and natural gas storage, terminal, marketing and transportation (including rail, truck and pipeline) services to producers, refiners, marketers, utilities and other customers.

We assess the performance of our operating segments based on EBITDA, which is defined as income before income taxes, plus debt-related costs (net interest and debt expense and gain (loss) on modification/extinguishment of debt) and depreciation, amortization and accretion expense.

Below is a reconciliation of CEQP's and CMLP's net income (loss) to EBITDA (*in millions*):

	CEQP			CMLP		
	Year Ended December 31,			Year Ended December 31,		
	2022	2021	2020	2022	2021	2020
Net income (loss)	$ 72.5	$ (37.4)	$ (15.3)	$ (52.2)	$ (44.0)	$ (23.4)
Add:						
Interest and debt expense, net	177.4	132.1	133.6	177.4	132.1	133.6
(Gain) loss on modification/extinguishment of debt	—	7.5	(0.1)	—	7.5	(0.1)
Provision (benefit) for income taxes	1.9	0.2	0.4	1.7	0.1	(0.1)
Depreciation, amortization and accretion	328.9	244.2	237.4	334.6	258.4	251.5
EBITDA	$ 580.7	$ 346.6	$ 356.0	$ 461.5	$ 354.1	$ 361.5

The following tables summarize CEQP's and CMLP's reportable segment data for the years ended December 31, 2022, 2021 and 2020 (*in millions*). Intersegment revenues included in the following tables are accounted for as arms-length transactions that apply our revenue recognition policy described in Note 2. Included in earnings (loss) from unconsolidated affiliates, net reflected in the tables below was approximately $14.3 million, $187.4 million and $42.9 million of our proportionate share of interest expense, depreciation and amortization expense, goodwill impairments and gains (losses) on long-lived assets, net recorded by our equity investments for the years ended December 31, 2022, 2021 and 2020, respectively.

Segment EBITDA Information

	Year Ended December 31, 2022				
	Gathering and Processing North	Gathering and Processing South	Storage and Logistics	Corporate	Total
Crestwood Midstream					
Revenues	$ 1,010.7	$ 381.4	$ 4,608.6	$ —	$ 6,000.7
Intersegment revenues	527.2	207.5	(734.7)	—	—
Costs of product/services sold	848.6	399.5	3,749.0	—	4,997.1
Operations and maintenance expense	105.3	43.0	47.8	—	196.1
General and administrative expense	—	—	—	124.4	124.4
Gain (loss) on long-lived assets, net	—	(308.9)	(4.1)	0.3	(312.7)
Gain on acquisition	—	75.3	—	—	75.3
Earnings from unconsolidated affiliates, net	—	11.1	4.6	—	15.7
Other income	—	—	—	0.1	0.1
Crestwood Midstream EBITDA	$ 584.0	$ (76.1)	$ 77.6	$ (124.0)	$ 461.5
Crestwood Equity					
General and administrative expense	—	—	—	6.0	6.0
Gain on long-lived assets, net(1)	—	125.0	—	—	125.0
Other income	—	—	—	0.2	0.2
Crestwood Equity EBITDA	$ 584.0	$ 48.9	$ 77.6	$ (129.8)	$ 580.7

(1) Represents the elimination of the loss on long-lived assets of approximately $53 million recorded by CMLP related to the sale of assets in the Barnett Shale and the gain on long-lived assets of approximately $72 million recorded by CEQP related to this sale. For a further discussion of this transaction, see Note 3.

	Year Ended December 31, 2021				
	Gathering and Processing North	Gathering and Processing South	Storage and Logistics	Corporate	Total
Crestwood Midstream					
Revenues	$ 574.7	$ 105.9	$ 3,888.4	$ —	$ 4,569.0
Intersegment revenues	459.3	—	(459.3)	—	—
Costs of product/services sold	553.2	0.9	3,289.8	—	3,843.9
Operations and maintenance expense	51.1	22.9	47.0	—	121.0
General and administrative expense	—	—	—	90.2	90.2
Gain (loss) on long-lived assets, net	0.4	(40.6)	0.7	0.1	(39.4)
Earnings (loss) from unconsolidated affiliates, net	—	9.6	(130.0)	—	(120.4)
Crestwood Midstream EBITDA	$ 430.1	$ 51.1	$ (37.0)	$ (90.1)	$ 354.1
Crestwood Equity					
General and administrative expense	—	—	—	7.4	7.4
Loss on long-lived assets, net	—	—	—	(0.2)	(0.2)
Other income	—	—	—	0.1	0.1
Crestwood Equity EBITDA	$ 430.1	$ 51.1	$ (37.0)	$ (97.6)	$ 346.6

	Year Ended December 31, 2020				
	Gathering and Processing North	Gathering and Processing South	Storage and Logistics	Corporate	Total
Crestwood Midstream					
Revenues	$ 510.4	$ 121.0	$ 1,622.9	$ —	$ 2,254.3
Intersegment revenues	160.5	(0.7)	(159.8)	—	—
Costs of product/services sold	261.0	0.5	1,339.0	—	1,600.5
Operations and maintenance expense	55.7	29.2	46.9	—	131.8
General and administrative expense	—	—	—	86.7	86.7
Gain (loss) on long-lived assets, net	(3.8)	(20.0)	(2.4)	0.2	(26.0)
Goodwill impairment	(80.3)	—	—	—	(80.3)
Earnings (loss) from unconsolidated affiliates, net	—	(1.0)	33.5	—	32.5
Crestwood Midstream EBITDA	$ 270.1	$ 69.6	$ 108.3	$ (86.5)	$ 361.5
Crestwood Equity					
General and administrative expense	—	—	—	4.8	4.8
Other expense	—	—	—	(0.7)	(0.7)
Crestwood Equity EBITDA	$ 270.1	$ 69.6	$ 108.3	$ (92.0)	$ 356.0

Other Segment Information

	CEQP		CMLP	
	Year Ended December 31,		Year Ended December 31,	
	2022	2021	2022	2021
Total Assets				
Gathering and Processing North	$ 4,003.6	$ 2,408.0	$ 4,003.6	$ 2,408.0
Gathering and Processing South	1,473.0	886.5	1,473.0	1,017.4
Storage and Logistics	1,057.6	1,125.1	1,057.6	1,125.1
Corporate	32.8	26.1	27.2	20.7
Total assets	$ 6,567.0	$ 4,445.7	$ 6,561.4	$ 4,571.2

	Year Ended December 31,		
	2022	2021	2020
Purchases of property, plant and equipment			
Crestwood Midstream			
Gathering and Processing North	$ 129.7	$ 66.1	$ 156.5
Gathering and Processing South	84.0	7.9	3.2
Storage and Logistics	11.3	6.6	7.5
Corporate	3.6	0.7	1.1
Total Crestwood Midstream purchases of property, plant and equipment	$ 228.6	$ 81.3	$ 168.3
Crestwood Equity			
Corporate	0.7	1.9	—
Total Crestwood Equity purchases of property, plant and equipment	$ 229.3	$ 83.2	$ 168.3

Major Customers

No customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2022, 2021 and 2020 at CEQP or CMLP.

Note 17 - Revenues

Contract Assets and Contract Liabilities

Our contract assets and contract liabilities are reported in a net position on a contract-by-contract basis at the end of each reporting period. Our receivables related to our revenue contracts accounted for under ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* totaled $368.2 million and $331.0 million at December 31, 2022 and 2021, and are included in accounts receivable on our consolidated balance sheets. Our contract assets are included in other non-current assets on our consolidated balance sheets. Our contract liabilities primarily consist of current and non-current deferred revenues. On our consolidated balance sheets, our current deferred revenues are included in accrued expenses and other liabilities and our non-current deferred revenues are included in other long-term liabilities. The majority of revenues associated with our deferred revenues is expected to be recognized as the performance obligations under the related contracts are satisfied over the next 14 years.

The following table summarizes our contract assets and contract liabilities *(in millions)*:

	December 31, 2022	December 31, 2021
Contract assets (non-current)[(1)]	$ 5.4	$ 1.3
Contract liabilities (current)[(2)]	$ 11.7	$ 10.7
Contract liabilities (non-current)[(2)]	$ 212.3	$ 187.1

(1) Includes approximately $4.9 million acquired in conjunction with the CPJV Acquisition.
(2) During the year ended December 31, 2022, we recognized revenues of approximately $15.6 million that were previously included in contract liabilities at December 31, 2021. The remaining change in our contract liabilities during the year ended December 31, 2022 related to capital reimbursements associated with our revenue contracts and revenue deferrals associated with our contracts with increasing (decreasing) rates.

The following table summarizes the transaction price allocated to our remaining performance obligations under certain contracts that have not been recognized as of December 31, 2022 *(in millions)*:

2023	$ 62.6
2024	42.4
2025	2.2
2026	0.5
2027	0.5
Thereafter	0.7
Total	$ 108.9

Our remaining performance obligations presented in the table above exclude estimates of variable rate escalation clauses in our contracts with customers, and is generally limited to fixed-fee and percentage-of-proceeds service contracts which have fixed pricing and minimum volume terms and conditions. Our remaining performance obligations generally exclude, based on the following practical expedients that we elected to apply, disclosures for (i) variable consideration allocated to a wholly-unsatisfied promise to transfer a distinct service that forms part of the identified single performance obligation; (ii) unsatisfied performance obligations where the contract term is one year or less; and (iii) contracts for which we recognize revenues as amounts are invoiced.

Disaggregation of Revenues

The following tables summarize our revenues from contracts with customers disaggregated by type of product/service sold and by commodity type for each of our segments for the years ended December 31, 2022, 2021 and 2020 (*in millions*). In addition, the revenues from contracts with customers are presented in the three operating and reporting segments that are further discussed in Note 16 for all periods presented. We believe this summary best depicts how the nature, amount, timing and uncertainty of our revenues and cash flows are affected by economic factors. Our non-*Topic 606* revenues presented in the tables below primarily represent revenues related to our commodity-based derivatives.

	Year Ended December 31, 2022				
	Gathering and Processing North	**Gathering and Processing South**	**Storage and Logistics**	**Intersegment Elimination**	**Total**
Topic 606 revenues					
Gathering					
Natural gas	$ 124.9	$ 63.0	$ —	$ —	$ 187.9
Crude oil	57.7	6.5	—	—	64.2
Water	159.1	22.6	—	—	181.7
Processing					
Natural gas	73.8	11.9	—	—	85.7
Compression					
Natural gas	—	12.2	—	—	12.2
Storage					
Crude oil	2.4	—	0.3	(0.3)	2.4
NGLs	—	—	8.9	—	8.9
Pipeline					
Crude oil	5.8	0.7	1.9	(0.1)	8.3
NGLs	—	11.5	0.3	(5.1)	6.7
Transportation					
NGLs	—	—	22.6	—	22.6
Rail Loading					
Crude oil	—	—	0.4	—	0.4
Product Sales					
Natural gas	338.7	220.8	652.9	(455.9)	756.5
Crude oil	493.9	0.3	1,475.0	(50.4)	1,918.8
NGLs	271.1	239.4	1,895.2	(222.2)	2,183.5
Water	7.2	—	—	—	7.2
Other	1.9	—	0.7	(0.7)	1.9
Total Topic 606 revenues	1,536.5	588.9	4,058.2	(734.7)	5,448.9
Non-Topic 606 revenues	1.4	—	550.4	—	551.8
Total revenues	$ 1,537.9	$ 588.9	$ 4,608.6	$ (734.7)	$ 6,000.7

	Year Ended December 31, 2021				
	Gathering and Processing North	Gathering and Processing South	Storage and Logistics	Intersegment Elimination	Total
Topic 606 revenues					
Gathering					
Natural gas	$ 56.3	$ 83.2	$ —	$ —	$ 139.5
Crude oil	73.1	—	—	—	73.1
Water	94.0	—	—	—	94.0
Processing					
Natural gas	24.4	5.0	—	—	29.4
Compression					
Natural gas	—	17.1	—	—	17.1
Storage					
Crude oil	0.3	—	0.5	(0.3)	0.5
NGLs	—	—	11.5	—	11.5
Pipeline					
Crude oil	2.7	—	2.6	(0.1)	5.2
NGLs	—	—	0.2	—	0.2
Transportation					
NGLs	—	—	17.3	—	17.3
Rail Loading					
Crude oil	—	—	4.6	—	4.6
Product Sales					
Natural gas	171.4	0.6	326.2	(171.1)	327.1
Crude oil	401.5	—	1,237.7	(82.6)	1,556.6
NGLs	209.4	—	1,796.6	(205.2)	1,800.8
Other	—	—	1.7	—	1.7
Total Topic 606 revenues	1,033.1	105.9	3,398.9	(459.3)	4,078.6
Non-Topic 606 revenues	0.9	—	489.5	—	490.4
Total revenues	$ 1,034.0	$ 105.9	$ 3,888.4	$ (459.3)	$ 4,569.0

	Year Ended December 31, 2020				
	Gathering and Processing North	Gathering and Processing South	Storage and Logistics	Intersegment Elimination	Total
Topic 606 revenues					
Gathering					
Natural gas	$ 53.4	$ 87.2	$ —	$ —	$ 140.6
Crude oil	95.3	—	—	—	95.3
Water	92.6	—	—	—	92.6
Processing					
Natural gas	22.4	9.5	—	—	31.9
Compression					
Natural gas	—	23.9	—	—	23.9
Storage					
Crude oil	1.1	—	1.9	(0.3)	2.7
NGLs	—	—	13.1	—	13.1
Pipeline					
Crude oil	6.2	—	4.1	(0.1)	10.2
NGLs	—	—	0.3	—	0.3
Transportation					
Crude oil	—	—	1.9	—	1.9
NGLs	—	—	10.9	—	10.9
Rail Loading					
Crude oil	—	—	7.4	—	7.4
Product Sales					
Natural gas	53.7	(0.3)	90.9	(52.8)	91.5
Crude oil	292.2	—	660.7	(53.0)	899.9
NGLs	54.0	—	614.2	(53.6)	614.6
Other	—	—	1.5	—	1.5
Total Topic 606 revenues	670.9	120.3	1,406.9	(159.8)	2,038.3
Non-Topic 606 revenues	—	—	216.0	—	216.0
Total revenues	$ 670.9	$ 120.3	$ 1,622.9	$ (159.8)	$ 2,254.3

Note 18 - Income Taxes

The (provision) benefit for income taxes consisted of the following *(in millions)*:

	CEQP			CMLP		
	Year Ended December 31,			Year Ended December 31,		
	2022	2021	2020	2022	2021	2020
Current:						
Federal	$ (0.4)	$ (0.4)	$ (0.2)	$ —	$ —	$ 0.1
State	(0.8)	(0.2)	(0.1)	(0.7)	(0.1)	—
Total current	(1.2)	(0.6)	(0.3)	(0.7)	(0.1)	0.1
Deferred:						
Federal	0.3	0.3	(0.1)	—	—	—
State	(1.0)	0.1	—	(1.0)	—	—
Total deferred	(0.7)	0.4	(0.1)	(1.0)	—	—
(Provision) benefit for income taxes	$ (1.9)	$ (0.2)	$ (0.4)	$ (1.7)	$ (0.1)	$ 0.1

The effective rate differs from the statutory rate for the years ended December 31, 2022, 2021 and 2020, primarily due to the partnerships not being treated as a corporation for federal income tax purposes as discussed in Note 2.

Deferred income taxes related to the operations of CEQP's wholly-owned taxable subsidiaries, IPCH Acquisition Corp. and Crestwood Gas Services GP LLC, and the impact of Texas Margin tax on our operations, and reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

Components of our deferred income taxes are as follows *(in millions)*.

	CEQP		CMLP	
	December 31,		December 31,	
	2022	2021	2022	2021
Total deferred tax asset[1]	$ 0.1	$ 0.2	$ —	$ —
Total deferred tax liability[1]	(3.6)	(2.5)	(2.3)	(0.8)
Net deferred tax liability	$ (3.5)	$ (2.3)	$ (2.3)	$ (0.8)

(1) Relates to the basis difference in the stock of a company.

Uncertain Tax Positions. We evaluate the uncertainty in tax positions taken or expected to be taken in the course of preparing our consolidated financial statements to determine whether the tax positions are more likely than not of being sustained by the applicable tax authority. Such tax positions, if any, would be recorded as a tax benefit or expense in the current year. We believe that there were no uncertain tax positions that would impact our results of operations for the years ended December 31, 2022, 2021 and 2020 and that no provision for income tax was required for these consolidated financial statements. However, our conclusions regarding the evaluation of uncertain tax positions are subject to review and may change based on factors including, but not limited to, ongoing analyses of tax laws, regulations and interpretations thereof.

Note 19 – Related Party Transactions

We enter into transactions with our affiliates within the ordinary course of business, including product purchases, marketing services and various operating agreements, including operating leases. We also enter into transactions with our affiliates related to services provided on our expansion projects.

On July 11, 2022, we acquired First Reserve's 50% equity interest in Crestwood Permian. As a result of this transaction, we control and own 100% of the equity interests of Crestwood Permian and include their results in our consolidated financial statements. Prior to July 11, 2022, we owned a 50% equity interest in Crestwood Permian, which we accounted for under the equity method of accounting, and reflected transactions with Crestwood Permian as transactions with affiliates in the tables below.

As discussed above, in conjunction with our acquisition of First Reserve's 50% equity interest in Crestwood Permian, we issued 11.3 million newly issued CEQP common units to First Reserve and as a result, First Reserve is considered a related party of CEQP and CMLP. During the year ended December 31, 2022 we paid approximately $0.8 million of capital expenditures to Applied Consultants, Inc., an affiliate of First Reserve.

On February 1, 2022, we completed the merger with Oasis Midstream. Pursuant to the merger agreement, Chord received approximately 20.9 million newly issued CEQP common units in exchange for its common units held in Oasis Midstream and as a result was considered a related party. In September 2022, we acquired 4.6 million CEQP common units from a subsidiary of Chord and as a result of this transaction and other transactions Chord executed with third parties related to its ownership of CEQP common units, Chord is no longer considered a related party of CEQP and CMLP.

Prior to August 2021, Crestwood Holdings indirectly owned our general partner and the affiliates of Crestwood Holdings and its owners were considered CEQP's and CMLP's related parties. With the completion of the Crestwood Holdings Transactions in August 2021, Crestwood Holdings and its affiliates are no longer considered related parties of CEQP and CMLP. During the years ended December 31, 2021 and 2020 and we paid approximately $0.6 million, and $3.5 million of capital expenditures to Applied Consultants, Inc., an affiliate of Crestwood Holdings. In addition, during the years ended December 31, 2021 and 2020, Crestwood Holdings allocated a $4.6 million and $4.4 million reduction of unit-based compensation charges to CEQP and CMLP. Also, CEQP allocated approximately $0.2 million and $2.1 million of its general and administrative costs to Crestwood Holdings during the years ended December 31, 2021 and 2020.

Below is a discussion of certain of our related party services and agreements.

Shared Services. CMLP shares common management, general and administrative and overhead costs with CEQP, and as such, CMLP allocates a portion of its costs to CEQP. CEQP grants long-term incentive awards under the Crestwood LTIP as discussed in Note 13 and, as such, CEQP allocates certain of its unit-based compensation costs to CMLP.

Tres Holdings Operating Agreement. CMLP Tres Manager, LLC, a consolidated subsidiary of Crestwood Midstream, entered into an operating agreement with Tres Holdings, pursuant to which we operate and maintain their facilities as well as provide certain administrative and other general services identified in the agreement. Under the operating agreement, Tres Holdings reimburses us for all costs incurred on its behalf. These reimbursements are reflected as a reduction of operations and maintenance expenses in our consolidated statements of operations.

Crestwood Permian Basin Operating Agreement. Crestwood Midstream Operations entered into an operating agreement with Crestwood Permian Basin, pursuant to which we provide operating services for Crestwood Permian Basin's facilities, as well as certain administrative and other general services identified in the agreement. Under the operating agreement, Crestwood Permian Basin reimburses us for all costs incurred on its behalf. These reimbursements are reflected as a reduction of operations and maintenance expenses in our consolidated statements of operations.

Crestwood Permian Operating Agreement. Prior to the acquisition of the remaining interest in Crestwood Permian as further discussed in Note 3, Crestwood Midstream Operations, LLC (Crestwood Midstream Operations) entered into an operating agreement with Crestwood Permian, pursuant to which we provided operating services for Crestwood Permian's facilities, as well as certain administrative and other general services identified in the agreement. Under the operating agreement, Crestwood Permian reimbursed us for all costs incurred on its behalf. These reimbursements are reflected as a reduction of operations and maintenance expenses in our consolidated statements of operations.

Stagecoach Gas Management Agreement. Prior to the sale of our equity interest in Stagecoach Gas as further discussed in Note 6, Crestwood Midstream Operations, our wholly-owned subsidiary, provided management and operating services to Stagecoach Gas under a management agreement pursuant to which we operated and maintained Stagecoach Gas's facilities. Reimbursements received from Stagecoach Gas under this agreement were reflected as a reduction of operations and maintenance expenses in our consolidated statements of operations.

The following table shows transactions with our affiliates which are reflected in our consolidated statements of operations for the years December 31, 2022, 2021 and 2020 (*in millions*):

	Year Ended December 31,		
	2022	2021	2020
Revenues at CEQP and CMLP[(1)]	$ 371.9	$ 27.2	$ 27.8
Costs of product/services sold at CEQP and CMLP[(2)]	$ 240.9	$ 136.8	$ 21.0
Operations and maintenance expenses at CEQP and CMLP charged to our unconsolidated affiliates[(3)]	$ 14.7	$ 22.2	$ 21.8
General and administrative expenses charged by CEQP to CMLP, net[(4)]	$ 32.8	$ 35.5	$ 31.1
General and administrative expenses at CEQP and CMLP[(5)]	$ 1.3	$ —	$ —

(1) Includes (i) $218.7 million during the year ended December 31, 2022 related to the sale of crude oil and NGLs to a subsidiary of Chord; (ii) $147.7 million during the year ended December 31, 2022 primarily related to gathering and processing services under agreements with a subsidiary of Chord; (iii) $3.9 million, $26.2 million and $27.8 million during the years ended December 31, 2022, 2021 and 2020 related to the sale of NGLs to a subsidiary of Crestwood Permian; (iv) $1.3 million and $1.0 million during the years ended December 31, 2022 and 2021 related to compressor leases with a subsidiary of Crestwood Permian; and (v) $0.3 million during the year ended December 31, 2022 related to gathering and processing services under agreements with Lucero Energy Corp, an affiliate of First Reserve.

(2) Includes (i) $114.1 million during the year ended December 31, 2022 primarily related to purchases of NGLs from a subsidiary of Chord; (ii) $116.8 million, $110.7 million and $20.0 million during the years ended December 31, 2022, 2021 and 2020 related to purchases of natural gas and NGLs from a subsidiary of Crestwood Permian; (iii) $2.0 million, $11.6 million and $0.6 million during the years ended December 31, 2022, 2021 and 2020 related to purchases of natural gas from a subsidiary of Tres Holdings; (iii) $0.3 million related to gathering services under agreements with Crestwood Permian Basin during the year ended December 31, 2022; (iv) $5.6 million, $14.5 million and $0.4 million during the years ended December 31, 2022, 2021 and 2020 related to purchases of NGLs from Ascent Resources - Utica, LLC (Ascent), an affiliate of First Reserve and Crestwood Holdings; and (v) $2.1 million during the year ended December 31, 2022 related to purchases of NGLs from Lucero Energy Corp, an affiliate of First Reserve.

(3) We have operating agreements with certain of our unconsolidated affiliates pursuant to which we charge them operations and maintenance expenses in accordance with their respective agreements described above. During the year ended December 31, 2022, we charged $4.9 million to Tres Holdings, $2.0 million to Crestwood Permian Basin and $7.8 million to Crestwood Permian under these agreements. During the year ended December 31, 2021, we charged $3.4 million to Stagecoach Gas, $4.9 million to Tres Holdings and $13.9 million to Crestwood Permian under these agreements. During the year ended December 31, 2020, we charged $6.6 million to Stagecoach Gas, $4.1 million to Tres Holdings and $11.1 million to Crestwood Permian under these agreements.

(4) Includes $37.2 million, $39.5 million and $35.1 million of unit-based compensation charges allocated from CEQP to CMLP during the years ended December 31, 2022, 2021 and 2020. In addition, includes $4.4 million, $4.0 million and $4.0 million of CMLP's general and administrative costs allocated to CEQP during the years ended December 31, 2022, 2021 and 2020.

(5) Represents general and administrative expenses related to a transition services agreement with a subsidiary of Chord.

The following table shows accounts receivable and accounts payable from our affiliates as of December 31, 2022 and 2021 (*in millions*):

	December 31,	
	2022	2021
Accounts receivable at CEQP and CMLP	$ 1.6	$ 8.2
Accounts payable at CEQP and CMLP	$ 3.0	$ 12.0

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CRESTWOOD EQUITY PARTNERS LP

By Crestwood Equity GP, LLC
(its general partner)

CRESTWOOD MIDSTREAM PARTNERS LP

By Crestwood Midstream GP LLC
(its general partner)

Dated: February 24, 2023

By /s/ ROBERT G. PHILLIPS
Robert G. Phillips
Founder, Chairman, Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following officers of Crestwood Equity GP, LLC, as general partner of Crestwood Equity Partners LP, and Crestwood Midstream GP LLC, as general partner of Crestwood Midstream Partners LP, and the following directors of Crestwood Equity GP LLC in the capacities and on the dates indicated.

Date	Signature and Title
February 24, 2023	/s/ ROBERT G. PHILLIPS **Robert G. Phillips,** **Founder, Chairman, Chief Executive Officer and Director** **(Principal Executive Officer)**
February 24, 2023	/s/ JOHN BLACK **John Black,** **Executive Vice President and Chief Financial Officer** **(Principal Financial Officer)**
February 24, 2023	/s/ STEVEN M. DOUGHERTY **Steven M. Dougherty,** **Executive Vice President and Chief Accounting Officer** **(Principal Accounting Officer)**
February 24, 2023	/s/ WARREN H. GFELLER **Warren H. Gfeller, Director**
February 24, 2023	/s/ JANEEN S. JUDAH **Janeen S. Judah, Director**
February 24, 2023	/s/ DAVID LUMPKINS **David Lumpkins, Director**
February 24, 2023	/s/ ANGELA A. MINAS **Angela A. Minas, Director**
February 24, 2023	/s/ GARY D. REAVES **Gary D. Reaves, Director**
February 24, 2023	/s/ JOHN J. SHERMAN **John J. Sherman, Director**
February 24, 2023	/s/ FRANCES M. VALLEJO **Frances M. Vallejo, Director**
February 24, 2023	/s/ CLAY C. WILLIAMS **Clay C. Williams, Director**

Crestwood Equity Partners LP
Parent Only
Condensed Balance Sheets
(in millions)

	December 31,	
	2022	2021
Assets		
Current assets:		
Cash	$ 0.2	$ 0.2
Prepaid expenses and other current assets	—	0.4
Total current assets	0.2	0.6
Property, plant and equipment, net	3.0	2.5
Investments in subsidiaries	1,906.2	1,100.1
Other assets	2.2	2.1
Total assets	$ 1,911.6	$ 1,105.3
Liabilities and partners' capital		
Current liabilities:		
Accounts payable	$ 0.1	$ 0.1
Accrued expenses	1.2	1.0
Total current liabilities	1.3	1.1
Other long-term liabilities	3.1	4.6
Total partners' capital	1,907.2	1,099.6
Total liabilities and partners' capital	$ 1,911.6	$ 1,105.3

See accompanying notes.

Crestwood Equity Partners LP
Parent Only
Condensed Statements of Income
(in millions)

	Year Ended December 31,		
	2022	2021	2020
Revenues	$ —	$ —	$ —
Expenses	6.2	7.7	4.9
Operating loss	(6.2)	(7.7)	(4.9)
Equity in net income (loss) of subsidiaries	37.3	(70.9)	(50.5)
Other income (expense), net	0.2	0.1	(0.7)
Net income (loss) attributable to Crestwood Equity Partners LP	$ 31.3	$ (78.5)	$ (56.1)

See accompanying notes.

Crestwood Equity Partners LP
Parent Only
Condensed Statements of Cash Flows
(in millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Cash flows from operating activities	$ 67.8	$ (5.5)	$ (9.4)
Cash flows from investing activities	455.6	507.8	242.6
Cash flows from financing activities:			
Payments for Crestwood Holdings Transactions	—	(275.6)	—
Purchase of common units	(123.7)	—	—
Distributions paid to partners	(325.3)	(224.4)	(242.8)
Change in intercompany balances	(74.4)	(2.3)	9.6
Net cash used in financing activities	(523.4)	(502.3)	(233.2)
Net change in cash	—	—	—
Cash at beginning of period	0.2	0.2	0.2
Cash at end of period	$ 0.2	$ 0.2	$ 0.2

See accompanying notes.

Crestwood Equity Partners LP
Parent Only
Notes to Condensed Financial Statements

Note 1. Basis of Presentation

In the parent-only financial statements, our investment in subsidiaries is stated at cost plus equity in undistributed earnings of subsidiaries since the date of acquisition. Our share of net income of our unconsolidated subsidiaries is included in consolidated income using the equity method. The parent-only financial statements should be read in conjunction with our consolidated financial statements.

Note 2. Distributions

During the years ended December 31, 2022, 2021 and 2020, we received cash distributions from Crestwood Midstream Partners LP of approximately $622.2 million, $509.7 million and $242.6 million.

Crestwood Equity Partners LP
Crestwood Midstream Partners LP
Valuation and Qualifying Accounts
For the Years Ended December 31, 2022, 2021 and 2020
(in millions)

	Balance at beginning of period	Charged to costs and expenses	Other additions	Deductions (write-offs)	Balance at end of period
Allowance for doubtful accounts					
2022	$ 0.6	$ (0.1)	$ —	$ —	$ 0.5
2021	$ 0.9	$ 0.6	$ —	$ (0.9)	$ 0.6
2020	$ 0.3	$ 0.5	$ 0.7 (1)	$ (0.6)	$ 0.9

(1) Amount represents the cumulative effect of adopting the provisions of ASU 2016-13, *Financial Instruments - Credit Losses (Topic 326)* on January 1, 2020.