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**

Commission file number 1-12295

GENESIS ENERGY, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0513049**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

811 Louisiana, Suite 1200,	
Houston , TX	**77002**
(Address of principal executive offices)	**(Zip code)**

Registrant's telephone number, including area code: (713) 860-2500

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Units	GEL	NYSE

Securities registered pursuant to Section 12(g) of the Act:
NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. 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. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

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

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

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

Indicate by check mark whether the registrant 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 (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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. ☐

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). ☐

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

The aggregate market value of the Class A common units held by non-affiliates of the Registrant on June 30, 2022 (the last business day of Registrant's most recently completed second fiscal quarter) was approximately $837.3 million based on $8.02 per unit, the closing price of the common units as reported on the NYSE. For purposes of this computation, all executive officers and directors are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers and directors are affiliates. On February 23, 2023, the Registrant had 122,539,221 Class A Common Units and 39,997 Class B Common Units outstanding.

GENESIS ENERGY, L.P.
2022 FORM 10-K ANNUAL REPORT
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Definitions

Unless the context otherwise requires, references in this annual report to "Genesis Energy, L.P.," "Genesis," "we," "our," "us," "the Company" or like terms refer to Genesis Energy, L.P. and its operating subsidiaries. As generally used within the energy industry and in this annual report, the identified terms have the following meanings:

Bbl or Barrel: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.

Bbls/day: Barrels per day.

Bcf: Billion cubic feet of gas.

CO_2: Carbon dioxide.

DST: Dry short tons (2,000 pounds), a unit of weight measurement.

FERC: Federal Energy Regulatory Commission.

Gal: Gallon.

MBbls: Thousand Bbls.

MBbls/day: Thousand Bbls per day.

Mcf: Thousand cubic feet of gas.

MMBtu: One million British thermal units, an energy measurement.

MMcf: Thousand Mcf.

MMcf/day: Thousand Mcf per day.

NaHS: (commonly pronounced as "nash") Sodium hydrosulfide.

NaOH or Caustic Soda: Sodium hydroxide.

Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.

Wellhead: The point at which the hydrocarbons and water exit the ground.

FORWARD-LOOKING INFORMATION

The statements in this Annual Report on Form 10-K that are not historical information may be "forward looking statements" as defined under federal law. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions, estimated or projected future financial performance, and other such references are forward-looking statements, and historical performance is not necessarily indicative of future performance. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "goal," "intend," "may," "could," "plan," "position," "projection," "strategy," "should" or "will," or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include, among others:

- *demand for, the supply of, our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas, NaHS, soda ash, and caustic soda, all of which may be affected by economic activity,* *capital expenditures by energy producers, weather, alternative energy sources, international events (including the war in Ukraine), global pandemics, inflation, the actions of OPEC (as defined below) and other oil exporting nations, conservation and technological advances;*

- *our ability to successfully execute our business and financial strategies;*
- *our ability to continue to realize cost savings from our cost saving measures;*
- *throughput levels and rates;*
- *changes in, or challenges to, our tariff rates;*
- *our ability to successfully identify and close strategic acquisitions on acceptable terms (including obtaining third-party consents and waivers of preferential rights), develop or construct infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;*
- *service interruptions in our pipeline transportation systems, processing operations or mining facilities;*
- *shutdowns or cutbacks at refineries, petrochemical plants, utilities, individual plants or other businesses for which we transport crude oil, petroleum, natural gas or other products or to whom we sell soda ash, petroleum or other products;*
- *risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;*
- *changes in laws and regulations to which we are subject, including tax withholding issues, regulations regarding qualifying income, accounting pronouncements, and safety, environmental and employment laws and regulations;*
- *the effects of production declines resulting from a suspension of drilling in the Gulf of Mexico or otherwise;*
- *the effects of future laws and regulations;*
- *planned capital expenditures and availability of capital resources to fund capital expenditures, and our ability to access the credit and capital markets to obtain financing on terms we deem acceptable;*
- *our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indentures governing our notes, which contain various affirmative and negative covenants;*
- *loss of key personnel;*
- *cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions (common and preferred) at the current level or to increase quarterly cash distributions in the future;*
- *an increase in the competition that our operations encounter;*
- *cost and availability of insurance;*
- *hazards and operating risks that may not be covered fully by insurance;*
- *our financial and commodity hedging arrangements, which may reduce our earnings, profitability and cash flow;*
- *changes in global economic conditions, including capital and credit markets conditions, inflation and interest rates, including the result of any economic recession or depression that has occurred or may occur in the future;*
- *the impact of natural disasters, international military conflicts (such as the conflict in Ukraine), pandemics (including Covid-19), epidemics, accidents or terrorism, and actions taken by governmental authorities and other third parties in response thereto, on our business financial condition and results of operations;*
- *reduction in demand for our services resulting in impairments of our assets;*
- *changes in the financial condition of customers or counterparties;*
- *adverse rulings, judgments, or settlements in litigation or other legal or tax matters;*
- *the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes;*
- *the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price; and*
- *a cyberattack involving our information systems and related infrastructure, or that of our business associates.*

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A. These risks may also be specifically *described in our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.*

PART I

Item 1. Business

General

We are a growth-oriented master limited partnership ("MLP") formed in Delaware in 1996. Our common units are traded on the New York Stock Exchange, or NYSE, under the ticker symbol "GEL." We are (i) a provider of an integrated suite of midstream services (primarily transportation, storage, sulfur removal, blending, terminaling and processing) for a large area of the Gulf of Mexico and the Gulf Coast region of the crude oil and natural gas industry and (ii) one of the leading producers in the world of natural soda ash. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, refinery-related plants, storage tanks and terminals, railcars, barges and other vessels, and trucks. The other core focus of our business is our trona and trona-based exploring, mining, processing, producing, marketing and selling business based in Wyoming (our "Alkali Business"). Our Alkali Business mines and processes trona from which it produces natural soda ash, also known as sodium carbonate (Na_2CO_3), a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products, including lithium batteries, and has been operating for over 70 years.

We currently manage our businesses through four divisions that constitute our reportable segments: offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. For additional information, please review the section entitled "Financial Measures." Our operations include, among others, the following diversified businesses, each of which is one of the leaders in its market, has a long commercial life and has significant barriers to entry:

- one of the largest pipeline networks (based on throughput capacity) in the Deepwater area of the Gulf of Mexico, an area that produced approximately 15% of the oil produced in the U.S. during 2022;
- one of the leading producers (based on tons produced) of natural soda ash in the world;
- one of the largest producers and marketers (based on tons produced) of sodium hydrosulfide (or NaHS, pronounced "nash") in North and South America; and
- one of the leading providers of crude oil and petroleum transportation, storage, and other handling services for two of the largest refinery complexes in the U.S., one located in Baton Rouge, Louisiana and one in Baytown, Texas, both of which have been operational for over 100 years;

We conduct our operations and own our operating assets through our subsidiaries and joint ventures. Our general partner, Genesis Energy, LLC, a wholly-owned subsidiary that owns a non-economic general partner interest in us, has sole responsibility for conducting our business and managing our operations. Our outstanding common units (including our Class B common units), and our outstanding Class A convertible preferred units (our "Class A Convertible Preferred Units"), representing limited partner interests, constitute all of the economic equity interests in us.

Offshore Pipeline Transportation Segment

We conduct our offshore crude oil and natural gas pipeline transportation and handling operations in the Gulf of Mexico through our offshore pipeline transportation segment, which focuses on providing a suite of services to integrated and large independent energy companies who make intensive capital investments (often in excess of a billion dollars) to develop large-reservoir, long-lived crude oil and natural gas properties in the Gulf of Mexico, primarily offshore Texas, Louisiana, and Mississippi. This segment provides services to one of the most active drilling and development regions in the U.S. (the Gulf of Mexico) a producing region representing approximately 15% of the crude oil production in the U.S. during 2022. Even though the large-reservoir properties, related pipelines and other infrastructure needed to develop them are capital intensive, we believe they are generally much less sensitive to short-term commodity price volatility, particularly once a project has been sanctioned. Due to the size and scope of these activities, our customers are predominantly large integrated oil and gas companies and large independent crude oil and natural gas producers.

We own interests in various offshore crude oil and natural gas pipeline systems, platforms and related infrastructure. We own interests in approximately 1,396 miles of crude oil pipelines with an aggregate design capacity of approximately 1,944 MBbls/day, a number of which pipeline systems are substantial and/or strategically located. For example, we own a 64% interest in the Poseidon oil pipeline system, or Poseidon pipeline, and a 64% interest in the Cameron Highway oil pipeline system, or CHOPS pipeline, which are two of the largest crude oil pipelines (in terms of both length and design capacity) located in the Gulf of Mexico. We also own 100% of the Southeast Keathley Canyon pipeline system, or SEKCO pipeline, which is a deepwater pipeline servicing the Lucius, Buckskin and Hadrian North fields in the southern Keathley Canyon area of the Gulf of Mexico.

Our interests in operating offshore natural gas pipeline systems and related infrastructure include approximately 764 miles of pipe with an aggregate design capacity of approximately 2,308 MMcf/day. We also own an interest in three offshore hub platforms, two of which are operational, with an aggregate processing capacity of approximately 495 MMcf/day of natural gas and 123 MBbls/day of crude oil. Additionally, we own an interest in a number of junction and service platforms in the Gulf of Mexico, which are used to (i)interconnect the offshore pipeline network; (ii) provide an efficient means to perform pipeline maintenance; and (iii) contain equipment, such as pumps and measurement equipment, which can increase and direct flow on our pipelines.

Our offshore pipelines generate cash flows from fees charged to customers or substantially similar arrangements that otherwise limit our direct exposure to changes in commodity prices.

We believe our offshore pipeline transportation segment is well positioned to participate in the energy transition and lower carbon world as barrels produced from the Gulf of Mexico are some of the least emission intensive barrels, from reservoir to refinery, of any barrel refined by Gulf Coast refineries (including shipping).

Sodium Minerals and Sulfur Services Segment

Our sodium minerals and sulfur services segment includes our Alkali Business and our sulfur removal business.

Our Alkali Business owns the largest leasehold position of accessible trona ore reserves in the Green River, Wyoming trona patch, a geological formation holding the vast majority of the world's accessible trona ore reserves which we mine to ultimately produce, market, and sell soda ash. Soda ash is utilized by our customers as a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent, lithium batteries, solar panels and a variety of chemicals and other industrial products.

Our Alkali Business holds leases covering approximately 86,000 acres of land, containing an estimated 872 million short tons of proved and probable reserves of trona ore, representing an estimated remaining reserve life of over 100 years related to the seam currently being mined, which is disclosed in further detail in Item 2. "Properties." Our Alkali Business also owns and operates soda ash production facilities, underground trona ore mines and brine (solution) mining operations and related equipment, logistics and other assets.

All of our Alkali Business' mining and processing activities are conducted at its "Westvaco" and "Granger" facilities in Wyoming. Utilizing our two facilities near Green River, our Alkali Business involves the mining of trona ore, the processing of the trona ore into soda ash, also known as sodium carbonate (Na_2CO_3), and the marketing, selling and distribution of the soda ash and specialty products.

We sell our soda ash and specialty products to a diverse customer base directly in the U.S., Canada, the European Community, the European Free Trade Area and the South African Customs Union. Our Alkali Business also sells through the American Natural Soda Ash Corporation, or ANSAC, exclusively in all other markets. During 2022, ANSAC operated as a nonprofit foreign sales association to promote export sales of U.S. produced soda ash. On January 1, 2023, ANSAC became a wholly owned subsidiary of Genesis Alkali Wyoming, L.P. and we will continue utilizing its logistical assets and marketing function as an export vehicle for our Alkali Business.

As part of our sulfur services business, we (i) provide sulfur removal services by processing refineries high sulfur (or "sour") gas streams to remove the sulfur at eleven refining and petrochemical processing facilities located mostly in Texas, Louisiana, Arkansas, Oklahoma, Montana and Utah; (ii) operate significant storage and transportation assets in relation to those services; and (iii) sell NaHS and NaOH (also known as caustic soda) to large industrial and commercial companies. Soda ash can be used to make lithium carbonate and lithium hydroxide, which are some of the building blocks for lithium batteries as well as solar panels. Our sulfur removal services footprint also includes NaHS and caustic soda terminals, and we utilize railcars, ships, barges and trucks to transport product. Our sulfur removal services contracts are typically long-term in nature and have an average remaining term of approximately four years. NaHS is a by-product derived from our refinery sulfur removal services process, and it constitutes the sole consideration we receive for these services. A majority of the NaHS we produce is sourced from refineries owned and operated by large companies, including Phillips 66, CITGO, HollyFrontier, Calumet and Ergon. We sell our NaHS to customers in a variety of industries, with the largest customers involved in the mining of base metals, primarily copper and molybdenum, and the production of pulp and paper. We believe we are one of the largest producers and marketers of NaHS in North and South America.

We believe our Alkali Business and sulfur services business are well positioned to participate in the energy transition and lower carbon world. Natural soda ash has a lower Greenhouse Gas footprint than synthetic soda ash as it is less energy intensive. In addition, synthetic soda ash creates by-products such as calcium chloride and ammonia chloride which need further handling, or are disposed of as waste, and ultimately increase synthetic soda ash's carbon footprint. Our sulfur services business helps our host refineries lower their emissions by processing their sour gas streams using our proprietary, closed-loop, non-combustion technology to remove sulfur from the sour gas, whereas the traditional combustion technology releases certain levels of harmful gases and incremental carbon dioxide emissions into the atmosphere. Additionally, certain of our customers also utilize the NaHS we sell them to further reduce air emissions from various chemical and industrial activities.

Onshore Facilities and Transportation Segment

Our onshore facilities and transportation segment owns and/or leases our increasingly integrated suite of onshore crude oil and refined products infrastructure, including pipelines, trucks, terminals and rail unloading facilities. Our onshore facilities and transportation segment uses those assets, together with other modes of transportation owned by third parties and us, to service its customers and for its own account. The increasingly integrated nature of our onshore facilities and transportation assets is particularly evident in certain of our infrastructure assets and complexes in areas such as Louisiana and Texas.

We own four onshore crude oil pipeline systems, with approximately 450 miles of pipe located primarily in Alabama, Florida, Louisiana, Mississippi and Texas that are rate regulated by the Federal Energy Regulatory Commission, or FERC. The rates for certain segments of our Texas onshore pipeline are regulated by the Railroad Commission of Texas. Our onshore pipelines generate cash flows from fees charged to customers. Each of our onshore pipelines has significant available capacity to accommodate potential future growth in volumes.

We own four operational crude oil rail unloading facilities located in Baton Rouge, Louisiana; Raceland, Louisiana; Walnut Hill, Florida; and Natchez, Mississippi, which provide synergies to our existing asset footprint. We generally earn a fee for unloading railcars at these facilities. Three of these facilities, our Baton Rouge, Louisiana, Raceland, Louisiana, and Walnut Hill, Florida facilities are directly connected to our existing integrated crude oil pipeline and terminal infrastructure.

In addition to the above, we have access to a suite of trucks, and trailers, as well as terminals and tankage with approximately 4.2 million barrels of storage capacity (excluding capacity associated with our common carrier crude oil pipelines) in multiple locations along the Gulf Coast, which we use to service customers and for our own account. Usually, our onshore facilities and transportation segment experiences limited direct commodity price risk because it utilizes back-to-back purchases and sales, matching sale and purchase volumes on a monthly basis. Unsold volumes are hedged with exchange-traded commodity derivatives to offset the remaining price risk.

Marine Transportation Segment

Our marine transportation segment is a provider of transportation services by tank barge primarily for intermediate refined petroleum products, including heavy fuel oil and asphalt, as well as crude oil. We own a fleet of 91 barges (82 inland and 9 offshore) with a combined transportation capacity of 3.2 million barrels and 42 push/tow boats (33 inland and 9 offshore). Refiners contracted for approximately 90% of the revenues from our marine inland barges during 2022.

We also own the M/T American Phoenix, an ocean going tanker with 330,000 barrels of cargo capacity. The M/T American Phoenix is currently transporting crude oil.

We are a provider of transportation services for our customers and, in almost all cases, do not assume ownership of the products that we transport. Our marine transportation services are conducted under term contracts, some of which have renewal options for customers with whom we have traditionally had long-standing relationships, and spot contracts. For more information regarding our charter arrangements, please refer to the marine transportation segment discussion below. All of our vessels operate under the U.S. flag and are qualified for domestic trade under the Jones Act.

Our Objectives and Strategies

Our primary objectives are to generate and grow stable free cash flows from operations and continue to deleverage our balance sheet, while never wavering from our commitment to safe and responsible operations, as well as continue to advance and integrate our Environmental, Social and Governance ("ESG") program. We believe the following are critical to meet our objectives:

- New and increased volumes on our existing offshore assets in the Gulf of Mexico through long-term contracted commercial opportunities that require minimal to no additional investment from us, including volumes from the Argos (scheduled for first production in 2023) and King's Quay (which began in the second quarter of 2022) floating production systems.
- New incremental volumes from long-term contracted offshore commercial opportunities in the Gulf of Mexico, including the Shenandoah development, which will tie into our SYNC pipeline (which is currently under construction and discussed further below under "Recent Developments and Status of Certain Growth Initiatives") and further downstream to our CHOPS pipeline, and the Salamanca floating production system, which will tie into our existing SEKCO pipeline for further transportation downstream to our existing pipeline network. These developments and their associated volumes are expected to come online in late 2024 and 2025.

- Increased capacity for soda ash production from the original Granger facility and its approximately 500,000 tons of annual production, which came back online on January 1, 2023, and investing into our Granger Optimization Project (as defined below), which is scheduled to begin first production in the second half of 2023 and ramp to its design capacity of 750,000 tons per year over the subsequent nine to twelve months.
- The continued increase in demand for soda ash (including its anticipated participation in the energy transition).

We continue to have a significant amount of available borrowing capacity under our senior secured credit facility, which will allow us, when combined with our increasing free cash flow from operations as discussed above, to fund our high return capital projects, including our Granger Optimization Project, our SYNC pipeline and the expansion of our existing CHOPS pipeline (all of which are further discussed below in "Recent Developments and Status of Certain Growth Initiatives"), which will provide future cash flows to continue to further deleverage our balance sheet.

Business Strategy

Our primary business strategy is to provide an integrated suite of services to crude oil and natural gas producers, refiners, and industrial and commercial enterprises that use natural soda ash, NaHS and caustic soda. Successfully executing this strategy should enable us to generate and grow stable cash flows from operations.

Our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations focus on providing a suite of services primarily to integrated and large independent energy companies who make intensive capital investments (often in excess of a billion dollars) to develop large-reservoir, long-lived crude oil and natural gas properties. Our offshore oil pipelines transport oil produced from integrated and large independent energy companies that are ideally suited for the vast majority of refineries along the Gulf Coast. Our onshore-based refinery-centric operations, located primarily in the Gulf Coast region of the U.S., focus on providing a suite of services primarily to refiners, which also includes our sulfur removal services, transportation, storage, and other handling services. In 2022, refiners were the shippers of approximately 98% of the volumes transported on our onshore crude pipelines, and refiners contracted for approximately 90% of the revenues from our marine inland barges during 2022, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. Our Alkali Business is one of the world's leading producers of natural soda ash. We believe the significant cost advantage in the production of natural soda ash over synthetically produced soda ash will remain for the foreseeable future, somewhat mitigating the effects of market specific factors in the soda ash market in which we operate.

We intend to develop our business by:

- Identifying and exploiting incremental profit opportunities, including cost synergies, across an increasingly integrated footprint;
- Economically expanding our pipeline and terminal operations by utilizing capacity currently available on our existing assets that requires minimal to no additional investment;
- Optimizing our existing assets and creating synergies through additional commercial and operating advancement;
- Leveraging customer relationships across business segments;
- Attracting new customers and expanding our scope of services offered to existing customers;
- Expanding the geographic reach of our businesses;
- Evaluating internal and third party growth opportunities (including asset and business acquisitions) that leverage our core competencies and strengths and further integrate our businesses; and
- Focusing on health, safety and environmental stewardship, and advancement of our ESG program.

Financial Strategy

We believe that preserving financial flexibility is an important factor in our overall strategy and success. Over the long-term, we intend to:

- Increase the relative contribution of recurring and throughput-based revenues, emphasizing longer-term contractual arrangements;
- Prudently manage our limited direct commodity price risks;
- Maintain a sound, disciplined capital structure, including our current and forward path to deleveraging;
- Fund capital projects through a combination of the available borrowing capacity under our senior secured credit facility, internally generated free cash flows from operations, or externally;
- Pursue divestitures of non-core assets that support our deleveraging objective; and
- Create strategic arrangements and share capital costs and risks through joint ventures and strategic alliances.

Competitive Strengths

We believe we are well positioned to execute our strategies and ultimately achieve our objectives due primarily to the following competitive strengths:

- *Our businesses encompass a balanced, diversified portfolio of customers, operations and assets*. We operate four business segments and own and operate assets that enable us to provide a number of services primarily to refiners, crude oil and natural gas producers, and industrial and commercial enterprises that use natural soda ash, NaHS and caustic soda. Our business lines complement each other by allowing us to offer an integrated suite of services to common customers across our segments. We are not dependent upon any one customer or principal location for our revenues.
- *Certain of our businesses are among the leaders in each of their respective markets and each of which has a long commercial life and significant barriers to entry*. We operate, among others, diversified businesses, each of which is one of the leaders in its market, has a long commercial life, and has significant barriers to entry. We operate one of the largest pipeline networks (based on throughput capacity) in the Deepwater area of the Gulf of Mexico, an area that produced approximately 15% of the oil produced in the U.S. during 2022. We are one of the leading producers (based on tons produced) of natural soda ash in the world. We believe we are one of the largest producers and marketers (based on tons produced) of NaHS in North and South America. We are one of the leading providers of crude oil and petroleum product transportation, storage and other handling services for large, complex refineries in Baton Rouge, Louisiana and Baytown, Texas, both of which have been operational for over 100 years.
- *We are financially flexible and have significant liquidity.* As of December 31, 2022, we had $436.1 million available of our $650 million availability under our senior secured credit facility, subject to compliance with our covenants, including up to $195.3 million available under the $200 million petroleum products inventory loan sublimit and $91.5 million available for letters of credit. Our inventory borrowing base was $4.7 million at December 31, 2022.
- *Our businesses provide relatively consistent consolidated financial performance.* Our historically consistent financial performance, combined with our goal of a conservative capital structure over the long term, has allowed us to generate relatively stable and increasing cash flows from operations.
- *We have limited direct commodity price risk exposure in our oil and gas and NaHS businesses.* The volumes of crude oil, refined products or intermediate feedstocks we purchase are either subject to back-to-back sales contracts or are hedged with exchange-traded derivatives to limit our direct exposure to movements in the price of the commodity, although we cannot completely eliminate commodity price exposure. Our risk management policy requires us to monitor the effectiveness of the hedges to maintain a value at risk of such hedged inventory not in excess of $2.5 million. In addition, our service contracts with refiners allow us to adjust the rates we charge for processing to maintain a balance between NaHS supply and demand.
- *Our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations are located in a significant producing region with large-reservoir, long-lived crude oil and natural gas properties.* We provide a suite of services, primarily to integrated and large independent energy companies who make intensive capital investments to develop numerous large-reservoir, long-lived crude oil and natural gas properties, in one of the largest producing regions in the U.S., the Gulf of Mexico.
- *Our Alkali Business has significant cost advantages over synthetic production methods.* Our Alkali Business has significant cost advantages over synthetic production methods, including lower raw material and energy requirements.

According to IHS, on average, the cash cost to produce material soda ash has historically been about half of the cost to produce synthetic soda ash.

- *Our expertise and reputation for high performance standards and quality enable us to provide refiners with economic and proven services.* Our extensive understanding of the sulfur removal process and crude oil refining can provide us with an advantage when evaluating new opportunities and/or markets.
- *Some of our pipeline transportation and related assets are strategically located.* Our pipelines are critical to the ongoing operations of our refiner and producer customers. In addition, a majority of our terminals are located in areas that can be accessed by pipeline, truck, rail or barge.
- *Some of our onshore facilities and transportation assets are operationally flexible.* Our portfolio of trucks, railcars, barges and terminals affords us flexibility within our existing regional footprint and provides us the capability to enter new markets and expand our customer relationships.
- *Our marine transportation assets provide waterborne transportation throughout North America.* Our fleet of barges and boats provide service to both inland and offshore customers within a large North American geographic footprint. All of our vessels operate under the U.S. flag and are qualified for U.S. coastwise trade under the Jones Act.
- *We have an experienced, knowledgeable and motivated executive management team with a proven track record.* Our executive management team has a significant level of experience in the midstream sector. Its members have worked in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. Through their equity interest in us and compensation package (including long term incentive awards based on available cash before reserves, leverage, sustainability and safety metrics), our executive management team is incentivized to create value.

Recent Developments and Status of Certain Growth Initiatives

The following is a brief listing of developments since December 31, 2021. Additional information regarding most of these items may be found elsewhere in this report.

Credit Facility Amendment

On February 17, 2023, we entered into the Sixth Amended and Restated Credit Agreement (our "new credit agreement") to replace our Fifth Amended and Restated Credit Agreement. Our new credit agreement provides for a $850 million senior secured revolving credit facility. The new credit agreement matures on February 13, 2026, subject to extension at our request for one additional year on up to two occasions and subject to certain conditions, unless more than $150 million of our 6.50% senior notes due 2025 remain outstanding as of June 30, 2025, in which case the new credit agreement matures on such date.

Senior Unsecured Notes Issuance and Related Transactions

On January 25, 2023, we issued $500 million in aggregate principal amount of our 8.875% senior unsecured notes due April 15, 2030 (the "2030 Notes"). Interest payments are due April 15 and October 15 of each year with the initial interest payment due on October 15, 2023. That issuance generated net proceeds of approximately $491 million, net of issuance costs incurred. The net proceeds were used to purchase approximately $316 million of our existing 5.625% senior unsecured notes due June 15, 2024 (the "2024 Notes"), including the related accrued interest and tender premium and fees on those notes that were tendered in the tender offer that ended January 24, 2023, and the remaining proceeds at the time were used to repay a portion of the borrowings outstanding under our senior secured credit facility and for general partnership purposes. On January 26, 2023, we issued a notice of redemption for the remaining principal of approximately $25 million of our 2024 Notes, and discharged the indebtedness with respect to the 2024 Notes on February 14, 2023 by depositing the redemption amount with the trustee of the 2024 Notes for redemption of the 2024 Notes on February 25, 2023, all in accordance with the terms and conditions of the indenture governing the 2024 Notes.

Alkali Senior Secured Notes Issuance and Related Transactions

On May 17, 2022, we, through a newly created wholly-owned unrestricted subsidiary, GA ORRI, LLC ("GA ORRI"), issued $425 million principal amount of our 5.875% Alkali senior secured notes due 2042 ("Alkali senior secured notes") to certain institutional investors, secured by GA ORRI's fifty-year 10% limited term overriding royalty interest in substantially all of our Alkali Business' trona mineral leases (the "ORRI Interests"). The issuance generated net proceeds of $408 million, which is net of the issuance discount of $17 million. We will make quarterly interest payments on our Alkali senior secured notes until March 2024, at which time we will begin making quarterly principal and interest payments through the maturity date. We used a portion of the net proceeds from the issuance to fully redeem the outstanding preferred units held at a subsidiary of our Alkali Business (our "Alkali Holdings preferred units," which are further discussed in Note 11 to our Consolidated Financial Statements in Item 8) and utilized the remainder to repay a portion of the outstanding borrowings on our senior secured credit facility at the time. The redemption of our Alkali Holdings preferred units, which carried an implied interest rate of 12-13%, and the issuance of our Alkali senior secured notes with a coupon rate of 5.875%, has allowed us to simplify our capital structure and lower our cost of capital, provide us additional flexibility under our senior secured credit facility, and remove any risk of refinancing our Alkali Holdings preferred units that were initially due in 2026.

Granger Production Facility Expansion

On September 23, 2019, we announced the expansion of our existing Granger facility (the "Granger Optimization Project" or "GOP"), along with the issuance of the Alkali Holdings preferred units. The anticipated completion date of the GOP is the second half of 2023 and the expansion is expected to increase our production at the Granger facilities by approximately 750,000 tons per year.

The proceeds received from the issuance of our Alkali Holdings preferred units assisted in the funding of the anticipated cost of the GOP. During the fourth quarter of 2021, we made the decision to fund the remaining construction costs required to complete the GOP through a combination of our internally generated free cash flows and availability under our senior secured credit facility, and subsequently, on May 17, 2022, redeemed the outstanding Alkali Holdings preferred units.

Offshore Growth Commitments and Capital Projects

During 2022, we entered into definitive agreements to provide transportation services for 100% of the crude oil production associated with two separate standalone deepwater developments that have a combined production capacity of approximately 160,000 barrels per day. In conjunction with these agreements, we expect to spend total gross capital expenditures of approximately $650 million (or approximately $550 million net to our ownership interests) to: (i) expand the current capacity of the CHOPS pipeline; and (ii) construct a new 100% owned, approximately 105-mile, 20" diameter crude oil pipeline (the "SYNC pipeline") to connect one of the developments to our existing asset footprint in the Gulf of Mexico. We plan to complete the construction in line with the producers' plan for first oil achievement, which is currently expected in late 2024 or 2025. The producer agreements include long term take-or-pay arrangements and, accordingly, we are able to receive a project completion credit for purposes of calculating the leverage ratio under our senior secured credit facility throughout the construction period.

Sale of Independence Hub

On April 29, 2022, we entered into an agreement to sell the Independence Hub platform, the primary asset of Independence Hub, LLC, which we hold an 80% interest in, to a producer group in the Gulf of Mexico for gross proceeds of $40 million. We recognized a gain of $40 million as the asset had no book value at the time of sale and attributed and paid $8 million to our noncontrolling interest holders.

Covid-19, Ukraine War and Market Update

Since March 2020, and throughout the last two years, global markets and commodity prices have been extremely volatile due to the impacts from the Covid-19 pandemic, with further impacts on volatility caused by the war in Ukraine that began in February 2022. While we have seen continued recovery in commodity prices since the beginning of the pandemic, there is still an element of volatility that we expect to continue at least for the near-term and possibly longer, due to the uncertainty of the pandemic, the war in Ukraine and the result of any economic recession or depression that has occurred or may occur in the future.This volatility could negatively impact future prices for oil, natural gas, petroleum products and industrial products.

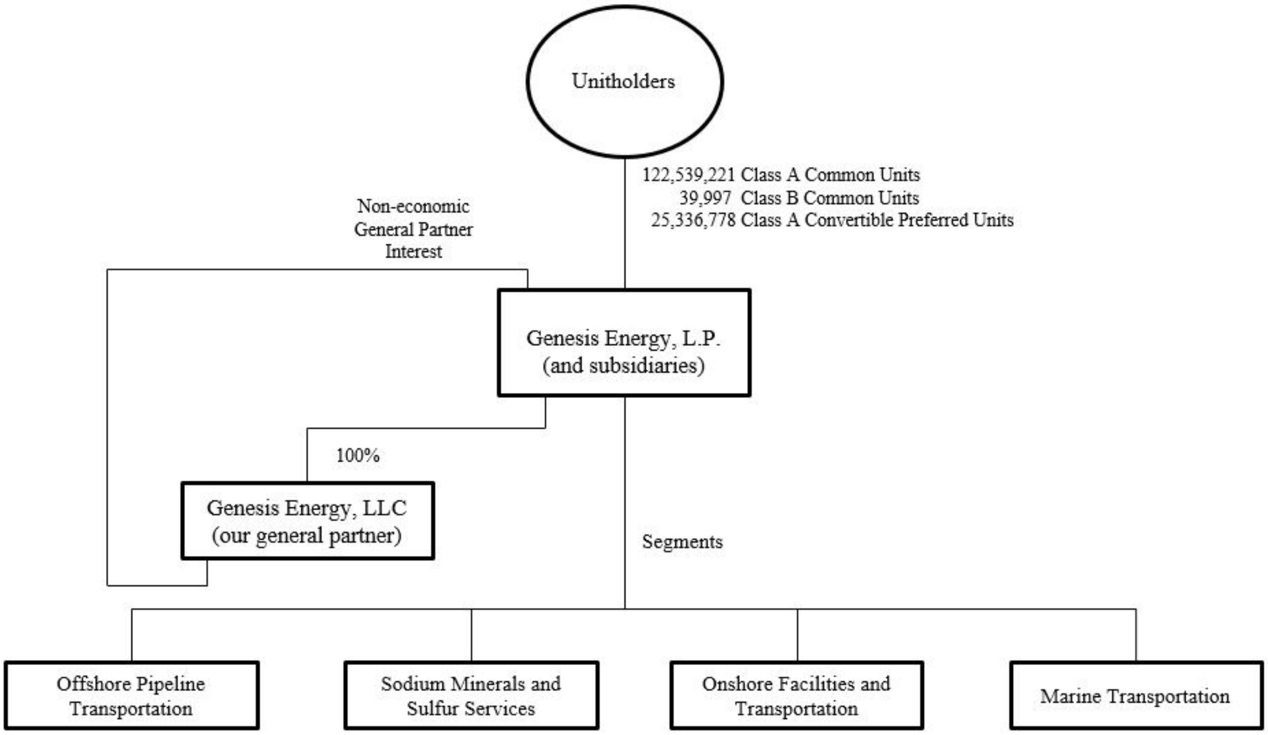
Management's estimates are based on numerous assumptions about future operations and market conditions, which we believe to be reasonable but are inherently uncertain. The uncertainties underlying our assumptions could cause our estimates to differ significantly from actual results, including with respect to the duration and severity of the lasting impacts of the Covid-19 pandemic, the war in Ukraine, the result of any economic recession or depression that has occurred or may occur in the future as a result or as it relates to changes in governmental policies aimed at addressing inflation which could cause fluctuations in global economic conditions, including capital and credit markets. We will continue to monitor the current market environment and to the extent conditions deteriorate, we may identify triggering events that may require future evaluations of the recoverability of the carrying value of our long-lived assets, intangible assets and goodwill, which could result in impairment charges that could be material to our results of operations.

Although the ultimate impacts of the Covid-19 pandemic and the war in Ukraine are still unknown at this time, we believe the fundamentals of our core businesses continue to remain strong and, given the current industry environment and capital market behavior, we have continued our focus on deleveraging our balance sheet as further explained in "Liquidity and Capital Resources".

Ownership Structure

We conduct our operations and own our operating assets through subsidiaries and joint ventures. As is customary with publicly traded limited partnerships, Genesis Energy, LLC, our general partner, is responsible for operating our business, including providing all necessary personnel and other resources.

The following chart depicts our organizational structure at December 31, 2022.



Description of Segments and Related Assets

We conduct our businesses through four operating segments: offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. These segments are strategic business units that provide a variety of midstream energy-related services as well as soda ash production, marketing and sales. Financial information with respect to each of our segments can be found in Note 13 to our Consolidated Financial Statements in Item 8. Below is a more detailed description of our segments and their related assets.

Offshore Pipeline Transportation

Offshore Crude Oil and Natural Gas Pipelines

We own interests in several crude oil and natural gas pipelines and related infrastructure located offshore in the Gulf of Mexico.

The table below reflects our interests in our operating offshore crude oil pipelines:

Offshore crude oil pipelines	Operator	System Miles	Design Capacity (Bbls/day)[1]	Interest Owned	Throughput (Bbls/day) 100% basis[1]	Throughput (Bbls/day) net to ownership interest
Main Lines						
CHOPS Pipeline	Genesis	380	500,000	64 %	207,008	132,485
Poseidon Pipeline	Genesis	332	490,000	64 %	257,444	164,764
Odyssey Pipeline	Shell Pipeline	120	200,000	29 %	84,682	24,558
Eugene Island Pipeline and Other	Genesis/ Shell Pipeline	184	39,000	29 %	6,964	6,964
Total		1,016	1,229,000		556,098	328,771
Lateral Lines[2]						
SEKCO Pipeline	Genesis	149	115,000	100 %		
Shenzi Crude Oil Pipeline	Genesis	83	230,000	100 %		
Allegheny Crude Oil Pipeline	Genesis	40	140,000	100 %		
Marco Polo Crude Oil Pipeline	Genesis	37	120,000	100 %		
Constitution Crude Oil Pipeline	Genesis	67	80,000	100 %		
Tarantula	Genesis	4	30,000	100 %		

(1) Capacity figures presented represent 100% of the design capacity and throughput figures represent 100% of the volumes in the period; except for Eugene Island, which represents our net capacity and volumes in the undivided interest (29%) in that system. Ultimate capacities can vary primarily as a result of pressure requirements, installed pumps, related facilities and the viscosity of the crude oil actually moved.

(2) Represents 100% owned lateral crude oil pipelines which ultimately flow into our other offshore crude oil pipelines (including CHOPS pipeline and Poseidon pipeline) and thus are excluded from main lines above.

- *CHOPS Pipeline.* CHOPS pipeline is comprised of 24- to 30-inch diameter pipelines designed to deliver crude oil from fields in the Gulf of Mexico to refining markets along the Texas Gulf Coast via interconnections with refineries and terminals located in Port Arthur and Texas City, Texas. Cameron Highway Oil Pipeline Company, LLC ("CHOPS") also owns three strategically located multi-purpose offshore platforms. A financial party owns the remaining 36% interest in CHOPS.
- *Poseidon Pipeline.* The Poseidon pipeline is comprised of 16- to 24-inch diameter pipelines to deliver crude oil from developments in the central and western offshore Gulf of Mexico to other pipelines and terminals onshore and offshore Louisiana. An affiliate of Shell owns the remaining 36% interest in Poseidon Oil Pipeline Company, LLC ("Poseidon").
- *Odyssey Pipeline.* The Odyssey pipeline is comprised of 12- to 20-inch diameter pipelines to deliver crude oil from developments in the eastern Gulf of Mexico to other pipelines and terminals onshore Louisiana. An affiliate of Shell owns the remaining 71% interest in Odyssey Pipeline, LLC ("Odyssey").
- *Eugene Island.* The Eugene Island system is comprised of a network of crude oil pipelines, the main pipeline of which is 20 inches in diameter, to deliver crude oil from developments in the central Gulf of Mexico to other pipelines and terminals in onshore Louisiana. Other owners in Eugene Island include affiliates of Exxon Mobil and Shell Oil Company.
- *SEKCO Pipeline.* SEKCO pipeline is a deepwater pipeline serving the Buckskin oil, Hadrian North oil and Lucius oil and natural gas production areas located in the southern Keathley Canyon area of the Gulf of Mexico. Southeast Keathley Canyon Pipeline Company, LLC ("SEKCO") has crude oil transportation agreements with various Gulf of Mexico producers who have dedicated their production from the Lucius, Buckskin and Hadrian North production areas

to the SEKCO pipeline for the life of their reserves. The SEKCO pipeline will be directly connected to the Salamanca Floating Production System ("FPS"), which is anticipated for first production in 2025.

- *Shenzi Crude Oil Pipeline.* The Shenzi Crude Oil Pipeline gathers crude oil production from the Shenzi production field located in the Green Canyon area of the Gulf of Mexico offshore Louisiana as well as from the King's Quay FPS, which supports the Khaleesi, Mormont and Samurai field developments, for delivery to both our CHOPS pipeline and Poseidon pipeline systems.
- *Allegheny Crude Oil Pipeline.* The Allegheny Crude Oil Pipeline connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with the CHOPS pipeline and Poseidon pipeline.
- *Marco Polo Crude Oil Pipeline.* The Marco Polo Crude Oil Pipeline transports crude oil from our Marco Polo crude oil platform to an interconnect with the Allegheny Crude Oil Pipeline in Green Canyon Block 164.
- *Constitution Crude Oil Pipeline.* The Constitution Crude Oil Pipeline gathers crude oil from the Constitution, Constellation, Caesar Tonga and Ticonderoga production fields located in the Green Canyon area of the Gulf of Mexico for delivery to either the CHOPS pipeline or Poseidon pipeline.

None of our offshore crude oil pipelines are rate regulated with the exception of Eugene Island, which is regulated by the FERC.

The table below reflects our interests in our operating offshore natural gas pipelines:

Offshore natural gas pipelines	Operator	System Miles	Design Capacity (MMcf/day)(1)	Interest Owned
High Island Offshore System	Genesis	238	500	100 %
Anaconda Gathering System	Genesis	183	300	100 %
Green Canyon Laterals	Genesis	5	108	100%
Manta Ray Offshore Gathering System	Enbridge	237	800	25.7 %
Nautilus System	Enbridge	101	600	25.7 %
Total		764	2,308	

(1) Capacity figures presented represent 100% of the design capacity.

- *High Island.* The High Island Offshore System ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to interconnects with the Kinetica Energy Express. HIOS includes 152 miles of pipeline and eight pipeline junction and service platforms that are regulated by the FERC. In addition, this system included the 86-mile East Breaks Gathering System, which connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.
- *Anaconda.* The Anaconda Gathering System gathers natural gas from producing fields located in the Green Canyon area in the Gulf of Mexico, including the the King's Quay FPS, which supports the Khaleesi, Mormont and Samurai field developments, for delivery to the Nautilus System.
- *Green Canyon.* The Green Canyon Laterals represent a collection of small diameter pipelines that gather natural gas for delivery to HIOS and various other downstream pipelines.
- *Manta Ray.* The Manta Ray Offshore Gathering System gathers natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico for delivery to numerous downstream pipelines, including the Nautilus System. This system includes three pipeline junction platforms.
- *Nautilus.* The Nautilus System connects the Anaconda Gathering system and Manta Ray Offshore Gathering System to the Neptune natural gas processing plant located in south Louisiana.

Offshore Hub Platforms

Offshore Hub platforms are typically used to: (i) interconnect the offshore pipeline network; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation and production handling equipment and similar assets; and (iv) conduct drilling operations during the initial development phase of a crude oil and natural gas property. The results of operations from offshore platform services are primarily dependent upon the level of commodity charges and/or demand-type fees billable to customers. Revenue from commodity charges is based on a fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Demand-type fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Contracts for platform services often include both demand-type fees and commodity charges, but demand-type fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers.

The table below reflects our interests in our operating offshore hub platforms:

Offshore hub platform	Operator	Water Depth (Feet)	Natural Gas Capacity (MMcf/ day)(1)	Crude Oil Capacity (Bbls/ day)(1)	Interest Owned
Marco Polo	Occidental	4,300	300	120,000	100 %
East Cameron 373	Genesis	441	195	3,000	100 %
Total			495	123,000	

(1) Capacity figures presented represent 100% of the design capacity.

- *Marco Polo.* The Marco Polo platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from production fields located in the South Green Canyon area of the Gulf of Mexico.
- *East Cameron.* The East Cameron 373 platform has the ability to process production from the Garden Banks and East Cameron areas of the Gulf of Mexico.

Customers

Due to the cost of finding, developing and producing crude oil properties in the deepwater regions of the Gulf of Mexico, most of our offshore pipeline customers are integrated crude oil companies and other large producers, and those producers desire to have longer-term arrangements ensuring that their production can access the markets.

Usually, our offshore crude oil pipeline customers enter into buy-sell or other transportation arrangements, pursuant to which the pipeline acquires possession (and, sometimes, title) from its customer of the relevant production at a specified location (often a producer's platform or at another interconnection) and redelivers possession (and title, if applicable) to such customer of an equivalent volume at one or more specified downstream locations (such as a refinery or an interconnection with another pipeline). Most of the production handled by our offshore pipelines is pursuant to life-of-lease commitments that include both firm and interruptible capacity arrangements.

Competition

The principal competition for our offshore pipelines includes other crude oil and natural gas pipeline systems as well as producers who may elect to build or utilize their own production handling facilities. Our offshore pipelines compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. In addition, the ability of our offshore pipelines to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production. In general, most of our offshore pipelines are not subject to regulatory rate-making authority, and the rates our offshore pipelines charge for services are dependent on the quality of the service required by the customer and the amount and term of the reserve commitment by that customer.

Sodium Minerals and Sulfur Services

Our sodium minerals and sulfur services segment consists of our Alkali Business and our sulfur removal business as discussed in further detail below.

Alkali Business

Our Alkali Business is one of the leading producers of natural soda ash worldwide. We provide our soda ash to a variety of industries such as flat glass, container glass, detergent, solar panel and lithium producers and chemical manufacturing. Soda ash, also known by its chemical name sodium carbonate (Na_2CO_3), is a highly valued raw material in the manufacture of glass due to its properties of lowering the melting point of silica in the batch. Soda ash is also valued by detergent manufacturers for its absorptive and water softening properties. We produce our products from trona, which we mine at two sites in the Green River Basin in Wyoming. The vast majority of the world's accessible trona reserves are located in the Green River Basin. According to historical production statistics, approximately 30% of global soda ash is produced from trona or similar sodium carbonate containing materials, with the remainder being produced synthetically, which requires chemical transformation of limestone and salt using a significantly higher amount of energy. Production of soda ash from trona is significantly less expensive than producing it synthetically. In addition, life-cycle analyses reveal that production from trona consumes less energy and produces less carbon dioxide and fewer undesirable by-products than synthetic production.

Our Alkali Business includes the following:

- Dry mining of trona ore underground at our Westvaco facility;
- Secondary recovery of trona from previously dry mined areas underground at our Westvaco and Granger facilities through brine (solution) mining;
- Processing of raw trona ore into soda ash and specialty sodium alkali products; and
- Marketing, sale and distribution of alkali products.

During 2022, our Alkali Business had the ability to produce approximately 3.5 million tons of soda ash and downstream specialty products. We are expecting our production capacity to increase as we restarted our original Granger production facility and its roughly 500,000 tons of annual production on January 1, 2023 in advance of the completion of the Granger Optimization Project, which represents an additional 750,000 tons of annual production, and is expected to have first production in the second half of 2023. All mining and processing activities related to our products take place in our facilities located in the Green River Basin.

Dry Mining of Trona Ore

Trona is dry mined underground at our Westvaco facility primarily through the operation of our single longwall mining machine. Longwall mining provides higher recovery rates leading to extended mine life compared to other dry mining techniques. Development of the "tunnels" necessary to access and ventilate our longwall is through room and pillar mining completed primarily by our fleet of borer miners. The ore is conveyed underground to two hoisting operations where it travels approximately 1,600 feet vertically to the surface and is either taken directly into the processing facilities or stored on outdoor stockpiles for future consumption.

Secondary Recovery Brine (Solution) Mining

We brine (solution) mine trona at both our Westvaco and Granger sites using secondary recovery techniques. Our secondary recovery mining starts with the recovery of water streams from our operations and non-trona solids ("insolubles") remaining from the processing of dry mined trona. The water and some insolubles are injected through a number of wells into the old dry mine workings at both our Westvaco and Granger sites. The insolubles settle out while the water travels through the old workings, dissolving trona that remained during previous dry mining. Multiple pumping systems are used to pump the enriched brine to the surface for processing.

Processing of Trona into Finished Alkali Product*s*

Our Sesqui and Mono plants, located at our Westvaco site, convert dry-mined trona into soda ash. Crushing, dissolution in water, filtration, and crystallization techniques are used to produce the desired final products. In the Mono plant process, the ore is calcined with heat, prior to dissolution, to convert the trona to soda ash by the removal of water and carbon dioxide. A final drying step using steam produces a dense soda ash product from the Mono process. In our Sesqui plant, the calcination is performed at the end of the process, producing a light density soda ash that is preferred in applications desiring increased absorptivity. The Sesqui process also has the ability to produce refined sodium sesquicarbonate (which we sell under the names S-Carb® and Sesqui®) for use as a buffer in animal feed formulations and in cleaning and personal care applications.

Brine (solution) mined trona is converted into dense soda ash in our ELDM operation at the Westvaco site and at our Granger facility. The steps to produce soda ash are similar to the dry mined processes, except the crushing and dissolving steps are eliminated because the trona is already in a water solution as it leaves the mine.

Intermediate, semi-processed products are extracted from our soda ash processes at Westvaco at strategic locations for use as feedstocks for production of sodium bicarbonate and 50% caustic soda (NaOH).

Marketing, Sale and Distribution of Alkali Products

We sell our alkali products to customers directly in the U.S., Canada, the European Community, the European Free Trade Area and the South African Customs Union. We sell through ANSAC exclusively in all other markets. During 2022, ANSAC operated as a nonprofit foreign sales association to promote export sales of U.S. produced soda ash. On January 1, 2023, ANSAC became a wholly owned subsidiary of Genesis Alkali Wyoming, L.P. and we will continue utilizing its logistical assets and marketing function as an export vehicle for our Alkali Business.

All of our alkali products are shipped by rail and truck from our facilities in the Green River Basin. We operate a fleet of approximately 3,300 covered hopper cars which we use to deliver over 90% of the sales of alkali products from the Green River facilities, all of which are shipped via a single rail line owned and operated by Union Pacific Railroad. We lease these railcars from banks and leasing companies and from FMC Corporation under agreements with varying term-lengths. We recover costs of leasing through mileage credits paid under agreements with customers and carriers in accordance with established industry practices and government requirements.

We sell most of our Alkali products as soda ash. Soda ash is the only product we sell to ANSAC. Soda ash is highly valued by manufacturers of flat and container glass because it lowers the temperature of the batch in a glass furnace. It is also valued by detergent manufacturers for its absorptive qualities. Soda ash is also a critical component in the manufacturing of batteries for electric vehicles as well as storage batteries for renewable energy. Demand for soda ash in the U.S. has been relatively flat over the last five years, with the exception of a slight decline in mid-2020 due to economic shutdowns related to the Covid-19 pandemic (which has recovered in 2021 and 2022). Demand for soda ash in developing economies has increased as a growing middle class demands more products that use soda ash, such as glass for housing and autos and detergents for cleaning.

In addition, we also market sodium bicarbonate to private label manufacturers who package it for sale to retail grocery customers as baking soda. We also sell sodium bicarbonate to manufacturers of packaged baked goods and similar products. Animal feed is an important market for sodium bicarbonate, which is mixed with feed to increase the yield of dairy cows and improve the health of poultry and other livestock. Sodium bicarbonate is also sold to customers who use it in hemodialysis applications and as an active ingredient in pharmaceutical products.

Sulfur Removal Business

Our sulfur services business primarily (i) provides sulfur-extraction services to eleven refining and petrochemical processing facilities located mostly in Texas, Louisiana, Arkansas, Oklahoma, Montana and Utah; (ii) operates significant storage and transportation assets in relation to those services; and (iii) sells NaHS and caustic soda to large industrial and commercial companies. Our sulfur removal services primarily involve processing refiners' high sulfur (or "sour") gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses large quantities of caustic soda (the primary raw material used in our process) to act as a scrubbing agent under prescribed temperature and pressure to remove sulfur. Sulfur removal in a refinery is a key factor in optimizing production of refined products such as gasoline, diesel and aviation fuel. Our sulfur removal technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. The resultant NaHS constitutes the sole consideration we receive for our sulfur removal services. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including Phillips 66, CITGO, HollyFrontier, Calumet and Ergon. Our eleven sulfur removal services contracts have an average remaining term of approximately four years. The timing upon which these contracts renew vary based upon location and terms specified within each specific contract.

Our sodium minerals and sulfur services footprint includes NaHS and caustic soda terminals in the Gulf Coast, the Midwest, Montana, Utah, British Columbia and South America. In conjunction with our onshore facilities and transportation segment, we sell and deliver (via railcars, ships, barges and trucks) NaHS and caustic soda to approximately 140 customers. We believe we are one of the largest marketers of NaHS in North and South America. By minimizing our costs through utilization of our own logistical assets and leased storage sites, we believe we have a competitive advantage over other suppliers of NaHS. NaHS is used in the specialty chemicals business (plastic additives, dyes and personal care products), in the pulp and paper business, and in connection with mining operations (separating copper from molybdenum and in the mining of nickel and gold) as well as bauxite refining (aluminum). NaHS has also gained acceptance in environmental applications, including waste treatment programs requiring stabilization and reduction of heavy and toxic metals and flue gas scrubbing. Additionally, NaHS can be used for removing hair from hides at the beginning of the tannery process.

Caustic soda is used in many of the same industries as NaHS. Many applications require both chemicals for use in the same process. For example, caustic soda can increase the yields in bauxite refining, pulp manufacturing and in the recovery of copper, gold and nickel. Caustic soda is also used as a cleaning agent (when combined with water and heated) for process equipment and storage tanks at refineries.

Customers

Our natural soda ash is sold to a diverse customer base in the U.S., Canada, the European Community, the European Free Trade Area and the South African Customs Union. Our Alkali Business sells exclusively through ANSAC in all other markets. During 2022, we and Tata Chemicals were the two members of ANSAC. Tata Chemicals withdrew from ANSAC as of the end of 2022 and we became the sole member of ANSAC beginning on January 1, 2023. ANSAC is our Alkali Business' largest customer. Sales to ANSAC during 2022 represented approximately 34% of total sales in the sodium minerals and sulfur services segment. Soda ash sold to ANSAC is later resold to other customers worldwide. As a result, this creates an indirect exposure for soda ash to global demand for the end products of our customers.

We provide on-site sulfur removal services utilizing NaHS units at eleven refining and petrochemical processing facilities locations. Even though some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. We market all of our NaHS as well as small amounts of NaHS for a handful of third parties.

We sell our NaHS to customers in a variety of industries, with the largest customers involved in mining of base metals, primarily copper and molybdenum, and the production of pulp and paper. We sell to customers in the copper mining industry in the western U.S., Canada and Mexico. We also export NaHS to South America for sale to customers for mining in Peru and Chile. No sulfur removal customer or NaHS sales customer is responsible for more than ten percent of our consolidated revenues. Many of the industries that our NaHS customers are in (such as copper mining and the pulp and paper industry) participate in global markets for their products. As a result, this creates an indirect exposure for NaHS to global demand for the end products of our customers. Provisions in our service contracts with refiners allow us to adjust our sour gas processing rates (sulfur removal) to maintain a balance between NaHS supply and demand.

We sell caustic soda to many of the same customers who purchase NaHS from us, including pulp and paper manufacturers and customers in the copper mining industry. We also supply caustic soda to some of the refineries in which we operate for use in cleaning processing equipment.

Apart from ANSAC, our largest Alkali customer, our sodium minerals and sulfur services segment is not dependent on any single or small group of customers. The loss of any one customer would not have a material adverse effect on us.

Competition - Alkali Business

The global soda ash market which our Alkali Business operates in is competitive. Competition is based on a number of factors such as price, favorable logistics and consistent customer service. In North America, primary competition is from other U.S.-based natural soda ash operations such as Solvay Chemicals, Sisecam Resources LP, and Tata Chemicals Soda Ash Partners in Wyoming, and Searles Valley Minerals in California. Because of the structural cost advantages of natural soda ash production in the U.S., including lower raw material and energy requirements, imports have not been an important source of competition in North America. According to IHS, on average, the cash cost to produce material soda ash has been about half the cost to produce synthetic soda ash. Sales of soda ash and specialty products outside of North America (principally through ANSAC) face competition from a variety of others, in most cases producers of soda ash using the synthetic method, but to a lesser extent producers of natural soda ash based in Turkey, China and Africa, and U.S.-based natural soda ash operations. Our Alkali Business' specialty Alkali products also experience significant competition from producers of sodium bicarbonate, such as Church & Dwight Co., Solvay Chemicals and Natural Soda LLC.

Competition - Sulfur Services

Our competitors for the supply of NaHS consist primarily of parties who produce NaHS as a by-product of or an alternative to other sulfur derivative products, including fertilizers, pesticides, other agricultural products, plastic additives and lubricants. Typically our competitors for the supply of NaHS have only one location and they do not have the logistical infrastructure that we have to supply customers. These competitors often reduce NaHS production when demand for their alternative sulfur derivatives is high and increase NaHS production when demand for these alternatives is low. Also, they tend to supply less when prices and demand for elemental sulfur are higher and supply more NaHS when the price of elemental sulfur falls.

Demand for NaHS faces competition from alternative sulfidity management mediums such as sulfidic caustic, emulsified sulfur, salt cake and flake NaHS. Changes in the value, supply and/or demand of these alternative products can impact the volume and/or value of our NaHS sold.

Typically, our competitors for sulfur removal services include refineries themselves through the use of their sulfur removal processes.

Our competitors for sales of caustic soda include manufacturers of caustic soda. These competitors supply caustic soda to our sodium minerals and sulfur services operations and support us in our third-party caustic soda sales. By utilizing our storage capabilities and having access to transportation assets, we sell caustic soda to third parties who gain efficiencies from acquiring both NaHS and caustic soda from one source.

Onshore Facilities and Transportation

We provide onshore facilities and transportation services to Gulf Coast crude oil refineries and producers through a combination of purchasing, transporting, storing, blending and marketing of crude oil and refined products (primarily fuel oil, asphalt, and other heavy refined products). In connection with these services, we utilize our increasingly integrated portfolio of logistical assets consisting of pipelines, trucks, terminals and barges. The integrated nature of our onshore facilities and transportation assets is particularly evident in areas such as Louisiana and Texas. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by gathering line, truck and barge to pipeline injection points, transporting crude oil for our gathering and marketing operations and for other shippers on our pipelines and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via pipeline, truck, railcar and barge, and sell refined products to customers in wholesale markets. For certain of these services, we generate fee-based income related to the transportation services provided. In some cases, we also profit from the difference between the price at which we re-sell the crude oil and petroleum products less the price at which we purchase the crude oil and petroleum products, minus the associated costs of aggregation and transportation.

Our crude oil onshore facilities and transportation operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations help to ensure (among other things) a base supply source for our crude oil pipeline systems, refinery customers and other shippers while providing our producer customers with a market outlet for their production. By utilizing our network of pipelines, trucks, railcars, barges, and terminals, we are able to provide transportation related services to, and in many cases back-to-back gathering and marketing arrangements with, crude oil refiners and producers. Additionally, our crude oil and petroleum product gathering and marketing expertise and knowledge base provide us with an ability to capitalize on opportunities that arise from time to time in our market areas. We gather and market approximately 24,000 Bbls/day (as of December 31, 2022) of crude oil and petroleum products, most of which is produced from large resource basins throughout Texas and the Gulf Coast. Our crude oil pipelines transport many of these barrels, as well as barrels for third party producers and refiners to which we charge fees for our transportation services. Given our network of terminals, we also have the ability to store crude oil during periods of contango (crude oil prices for future deliveries are higher than for current deliveries) for delivery in future months. When we purchase and store crude oil during periods of contango, we attempt to limit direct commodity price risk by simultaneously entering into a contract to sell the inventory in a future period, either with a counterparty or in the crude oil futures market. The most substantial component of the costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks and incurring other transportation related costs.

Onshore Crude Oil Pipelines

Through the onshore pipeline systems and related assets we own and operate, we transport crude oil for our gathering and marketing operations and for other shippers pursuant to tariff rates regulated by FERC or the Railroad Commission of Texas ("TXRRC"). Accordingly, we offer transportation services to any shipper of crude oil, if the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Pipeline revenues are a function of the level of throughput and the particular point where the crude oil is injected into the pipeline and the delivery point. We also may earn revenue from pipeline loss allowance volumes. In exchange for bearing the risk of pipeline volumetric losses, we deduct volumetric pipeline loss allowances and crude oil quality deductions. Such allowances and deductions are offset by measurement gains and losses. When our actual volume losses are less than the related allowances and deductions, we recognize the difference as income and inventory available for sale valued at the market price for the crude oil.

The margins from our onshore crude oil pipeline operations are generated by the difference between the sum of revenues from regulated published tariffs and pipeline loss allowance revenues and the fixed and variable costs of operating and maintaining our pipelines.

We own and operate four onshore common carrier crude oil pipeline systems: the Texas System, the Jay System, the Mississippi System, and the Louisiana System.

	Texas System	Jay System	Mississippi System	Louisiana System
Product	Crude Oil	Crude Oil	Crude Oil	Crude Oil, Intermediates, and Refined Products
Interest Owned	100%	100%	100%	100%
Design Capacity (Bbls/day)	Existing 8" - 60,000 Looped 18" - 275,000	150,000	45,000	350,000
2022 Throughput (Bbls/day)	90,562	6,601	5,725	94,389
System Miles	47	143	207	51
Approximate owned tankage storage capacity (Bbls)	1,100,000	230,000	247,500	330,000
Location	Hastings Junction, TX to Webster, TX Texas City, TX to Webster, TX	Southern AL/ FL to Mobile, AL	Soso, MS to Liberty, MS	Port Hudson, LA to Baton Rouge, LA Baton Rouge, LA to Port Allen, LA
Rate Regulated	FERC/ TXRRC	FERC	FERC	FERC

- *Texas System*. Our Texas System takes delivery of crude oil volumes at Texas City (which includes the capability of receiving various Gulf of Mexico pipeline volumes) for delivery to our Webster, Texas facility, which ultimately connects to other crude oil pipelines. Our Texas System also transports crude oil from Hastings Junction (south of Houston) to several delivery points near Houston, Texas (including our Webster, Texas facility). We earn a tariff for our transportation services, with the tariff rate per barrel of crude oil varying with the distance from injection point to delivery point.
- *Jay System*. Our Jay System provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. That system also includes gathering connections, additional crude oil storage capacity of approximately 20,000 barrels in the field, an interconnect with our Walnut Hill rail facility, a delivery connection to a refinery in Alabama and an interconnection to another common carrier pipeline that delivers crude oil into Mississippi.
- *Mississippi System.* Our Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminals and other crude oil infrastructure located in the Midwest. That system is adjacent to several crude oil fields that are in various phases of being produced through tertiary recovery strategy, including CO_2 injection and flooding. We provide transportation services on our Mississippi pipeline through an “incentive” tariff which provides that the average rate per barrel that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.
- *Louisiana System*. Our Louisiana System connects the Anchorage Tank Farm to our Port of Baton Rouge Terminal (which was built to service Exxon Mobil Corporation’s Baton Rouge refinery, which is one of the largest refinery complexes in North America, with more than 500,000 Bbls/day of refining capacity), allowing bidirectional flow of crude oil, intermediates and refined products between the Anchorage Tank Farm and this terminal via a dedicated crude oil pipeline and a dedicated intermediates pipeline. Total daily volume for the year ended December 31, 2022 includes 28,850 and 53,459 Bbls/day of intermediate refined products and crude oil, respectively, associated with our Port of Baton Rouge Terminal pipelines. Our Louisiana system also transports crude oil from Port Hudson to our Baton Rouge Scenic Station rail unloading facility and continues downstream to the Anchorage Tank Farm. This pipeline system serves as a key asset in our integrated Baton Rouge area midstream infrastructure.

Other Onshore Facilities and Transportation Operations

We own four operational crude oil rail unloading facilities located in Baton Rouge, Louisiana; Raceland, Louisiana; Walnut Hill, Florida; and Natchez, Mississippi which provide synergies to our existing asset footprint. We generally earn a fee for unloading railcars at these facilities. Three of these facilities, our Baton Rouge, Louisiana, Raceland, Louisiana, and Walnut Hill, Florida facilities are directly connected to our existing integrated crude oil pipeline and terminal infrastructure.

Within our onshore facilities and transportation business segment, we employ many types of logistically flexible assets. These assets include a suite of trucks, trailers, crude oil railcars, as well as terminals and other tankage with approximately 4.2 million barrels of leased and owned storage capacity in multiple locations along the Gulf Coast, accessible by pipeline, truck, rail or barge, in addition to tankage related to our crude oil pipelines, previously mentioned.

Customers and Competition

Our onshore facilities and transportation business encompasses numerous refiners and hundreds of producers, for which we provide transportation related services, as well as gather from and market to crude oil and refined products.

In our crude oil onshore facilities and transportation operations, we compete with other regional and local midstream service providers and companies who may have significant market share in the respective areas in which they operate. Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to refineries, production and connecting pipelines. We believe that high capital costs, tariff regulation and the cost of acquiring rights-of-way make it unlikely that other competing pipeline systems, comparable in size and scope to our onshore pipelines, will be built in the same geographic areas in the near future. In addition, as the majority of our onshore pipelines directly serve refineries, we believe that these pipelines are not subject to the same competitive pressures as those tied directly to crude oil production.

Marine Transportation

Our marine transportation segment consists of (i) our inland marine fleet which transports intermediate refined petroleum products, including asphalt, principally serving refineries and storage terminals along the Gulf Coast, Intracoastal Canal and western river systems of the U.S., principally along the Mississippi River and its tributaries; (ii) our offshore marine fleet which transports crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean; and (iii) our modern double-hulled, Jones Act qualified tanker M/T American Phoenix which is currently under charter serving a customer along the Gulf Coast and Eastern Seaboard. The below table includes operational information relating to our marine transportation fleet:

	Inland	Offshore	American Phoenix
Aggregate Fleet Design Capacity (MBbls)	2,285	884	330
Individual Vessel Capacity Range (MBbls)(1)	23-39	65-135	330
Number of:			
Push/Tug Boats	33	9	—
Barges	82	9	—
Product Tankers	—	—	1

(1) Represents capacity per barge ranges on our inland and offshore barge, as well as the capacity of our M/T American Phoenix.

Customers

Our marine customers are primarily refiners and large energy companies. Our M/T American Phoenix is currently operating under a charter with a refining customer. We are a provider of transportation services for our customers and, in almost all cases, do not assume ownership of the products we transport. Marine transportation services are conducted under term contracts, some of which have renewal options for customers with whom we have traditionally had long-standing relationships, as well as spot contracts. Most of our customers have been our customers for many years and we generally anticipate continued relationships; however, there is no assurance that any individual contract will be renewed.

A term contract is an agreement with a specific customer to transport cargo from a designated origin to a designated destination at a set rate (affreightment) or at a daily rate (time charter). The rate may or may not escalate during the term of the contract; however, the base rate generally remains constant and contracts often include escalation provisions to recover changes in specific costs such as fuel. Time charters, which insulate us from revenue fluctuations caused by weather and navigational delays and temporary market declines, represented over 95% of our marine transportation revenues under term contracts during 2022 and 2021. A spot contract is an agreement with a customer to move cargo from a specific origin to a designated destination for a rate negotiated at the time the cargo movement takes place. Spot contract rates are at the current "market" rate and are subject to market volatility. During 2022, we continued to enter into more short term spot contracts because we believe the day rates for term contracts being offered by the market have yet to fully recover from their cyclical lows. During 2022 and 2021, approximately 46% and 49%, respectively, of our marine transportation revenues were from term contracts and 54% and 51%, respectively, were from spot contracts.

Competition

Our competitors for the marine transportation of crude oil and heavy refined petroleum products are both midstream MLPs with marine transportation divisions, refineries, along with companies that are in the business of solely marine transportation operations. Competition among common marine carriers is based on a number of factors including proximity to production, refineries and connecting infrastructures, customer service, and transportation pricing.

Our marine transportation segment also competes with other modes of transporting crude oil and heavy refined petroleum products, including pipeline, rail and trucking operations. Each mode of transportation has different advantages and disadvantages, which often are fact and circumstance dependent. For example, without requiring longer-term economic commitments from shippers, marine and truck transportation can offer shippers much more flexibility to access numerous markets in multiple directions (i.e., pipelines tend to flow in a single direction and are geographically limited by their receipt and delivery points with other pipelines and facilities), and our marine transportation offers shippers certain economies of scale as compared to truck transportation. In addition, due to construction costs and timing considerations, marine and truck transportation can provide cost effective and immediate services to a nascent producing region, whereas new pipelines can be very expensive and time consuming to construct and may require shippers to make longer-term economic commitments, such as take-or-pay commitments. On the other hand, in mature developed areas serviced by extensive, multi-directional pipelines, with extensive connections to various market, pipeline transportation may be preferred by shippers, especially if shippers are willing to make longer-term economic commitments, such as take-or-pay commitments. Lastly, all but four of our inland marine transportation barges are asphalt capable and heated, which allows us to transport intermediate refined products which other modes of transportation are not necessarily equipped to handle.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of refiners, large oil producers and integrated oil companies. This energy industry concentration has the potential to affect our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our specific customer base in the context of our specific transactions as well as other factors, including the strategic nature of certain of our assets and relationships and our credit procedures. Our portfolio of accounts receivable is generally comprised in large part of obligations of refiners, integrated and large independent oil and natural gas producers, and mining and other industrial companies that purchase NaHS and soda ash, most of which have stable payment histories. The credit risk related to exchange-traded contracts is limited due to the daily cash settlement procedures and other exchange related requirements.

When we market crude oil, petroleum products, NaHS, and soda ash and provide transportation and other services, we must determine the amount, if any, of the line of credit we will extend to any given customer. We have established procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met. We use similar procedures to manage our exposure to our customers in the offshore pipeline transportation and marine transportation segments.

As a result of our activities in the Gulf of Mexico and onshore (including our Alkali Business), our largest customers include Shell, Exxon Mobil Corporation, Phillips 66, Occidental Petroleum Corporation ("Occidental") and ANSAC.

Human Capital

We believe our employees are our most important asset and the cornerstone of our organization. We take steps to attract and retain talented people to safely operate our assets, foster customer relationships, and achieve our long-term goals. We are committed to employee retention and we encourage our employees to maintain long-term careers with us. Human capital measures and objectives which we focus on in managing our business include safety, employee compensation and benefits, diversity and inclusion, and employee development.

Employees and Collective Bargaining Agreements

To carry out our business activities, we employed 2,109 employees at December 31, 2022. Approximately 700 of those employees were covered under collective bargaining agreements. These collective bargaining agreements cover wage increases and other benefits, including the defined benefit pension plan, the post-employment benefit plan and the enhanced 401(k) retirement savings plan. We consider our relationship with the union strong, and our relationship with our employees, including those covered by collective bargaining agreements, to be in good standing.

Safety

Safety is one of our guiding principles and it is our intention to create and sustain a workplace free from recognized safety and health hazards. We have implemented safety programs and management practices to promote a culture of safety, which include policies, training, procedures, audits, inspections, incident evaluations, data analysis, reporting and communications. We also established annual safety and health targets for total recordable injury and illness rates, and tied a portion of our management compensation to safety related goals to emphasize the importance of safety at the Company.

Employee Compensation and Benefits

Our compensation programs are integrated with our overall business strategies and management processes to incentivize performance, maximize returns and build shareholder value. We participate in market surveys as well as work with consultants to benchmark our compensation and benefits programs to help us offer competitive remuneration packages to attract and retain high-performing employees.

Further, to attract and meet the needs of our workforce, we offer a comprehensive and affordable benefits program that includes medical, dental, vision, life insurance, and disability protection, along with a generous retirement savings plan, including up to six percent matching. Our benefits package options may vary depending on the type of employee and date of hire. Additionally, we continuously look for ways to improve employee work-life balance and the well-being of our employees and their families.

Diversity and Inclusion

We are an equal opportunity employer. We believe that eliminating barriers to employment results in a more plentiful recruiting pool, diverse perspectives to problem solving, and stronger teams. We maintain a positive work environment by striving to create a strong culture of diversity and inclusion, supported by both our Code of Business Conduct and our employment practices.

We have policies in place that reinforce our commitment to diversity and inclusion within the workplace. Our employee handbook includes equal employment opportunity commitments and nondiscrimination and anti-harassment disclosures, which communicate our expectations with respect to maintaining a professional workplace free of harassment. We prohibit discrimination or harassment against any employee or applicant on the basis of sex, race, ethnicity, or any other protected categories. We are committed to a harassment free workplace, which is further supported through prevention training we provide for employees.

Employee Development

Our success as a company is measured by the successful performance of our employees in their respective roles. Thus, it is our policy to properly train and equip each employee to perform his or her job functions safely and in compliance with all laws, regulations and internal procedures.

We develop our employees through performance management processes, regular coaching and supervisory and leadership training while also offering a tuition reimbursement program. Our annual performance management cycle enables managers and employees to collaborate to set performance goals and development objectives that align to business objectives. We also provide in-house health and safety training and emergency response training. Employee attendance at external workshops, conferences and other training events is also encouraged.

Regulation

Pipeline Rate and Access Regulation

The rates and the terms and conditions of service of our interstate common carrier pipeline operations are subject to regulation by FERC under the Interstate Commerce Act, or ICA. Under the ICA, rates must be "just and reasonable," and must not be unduly discriminatory or confer any undue preference on any shipper. FERC regulations require that oil pipeline rates and terms and conditions of service for regulated pipelines be filed with FERC and posted publicly.

Effective January 1, 1995, FERC promulgated rules simplifying and streamlining the ratemaking process. Previously established rates were "grandfathered," limiting the challenges that could be made to existing tariff rates. Increases from grandfathered rates of interstate oil pipelines are currently regulated by FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the year-to-year change in an index. Under FERC regulations, we are able to change our rates within prescribed ceiling levels that are tied to the Producer Price Index for Finished Goods. Rate increases made pursuant to the index are presumed to be just and reasonable. They will be subject to protest, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the applicable pipeline's increase in costs. We may be required to lower our rates if the ceiling level decreases below our existing rates in a given year. The FERC indexing is subject to review and revision every five years. On December 17, 2020, the FERC issued a final rule setting the index for the five-year period beginning July 1, 2021, and ending on June 30, 2026, at PPI plus 0.78%. On January 20, 2022, the FERC granted a rehearing of certain aspects of the final rule and revised the index level to PPI minus 0.21% effective March 1, 2022 through June 30, 2026. The FERC ordered pipelines with filed rates that exceed their index ceiling levels based on PPI minus 0.21% to file rate reductions effective March 1, 2022. Subsequent appellate review could result in a further change to the index.

In addition to the index methodology, FERC allows for rate changes under three other methods—cost-of-service, competitive market showings and agreements between shippers and the oil pipeline company that the rate is acceptable, or Settlement Rates. The pipeline tariff rates on our Mississippi, Jay, and Louisiana systems are either rates that are subject to change under the index methodology or Settlement Rates. None of our tariffs have been subjected to a protest or complaint by any shipper or other interested party.

Our offshore pipelines, with the exception of our Eugene Island pipeline, are neither interstate nor common carrier pipelines. However, these pipelines are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires all pipelines operating on or across the outer continental shelf to provide nondiscriminatory transportation service.

Our intrastate common carrier pipeline operations in Texas are subject to regulation by the TXRRC. The applicable Texas statutes require that pipeline rates and practices be reasonable and non-discriminatory and that pipeline rates provide a fair return on the aggregate value of the property of a common carrier, after providing reasonable allowance for depreciation and other factors and for reasonable operating expenses. Although no assurance can be given that the tariffs we charge would ultimately be upheld if challenged, we believe that the tariffs now in effect can be sustained.

Marine Regulations

The operation of towboats, tugboats, barges, vessels and marine equipment create maritime obligations involving property, personnel and cargo and are subject to regulation by the U.S. Coast Guard, or USCG, the Environmental Protection Agency, or EPA, the Department of Homeland Security, or DHS, federal laws, state laws and certain international conventions under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues. Federal regulations also require that all tank barges engaged in the transportation of oil and petroleum in the U.S. be double hulled. All of our barges are double-hulled.

All of our barges are inspected by the USCG and carry certificates of inspection. All of our towboats and tugboats are certificated by the USCG. Most of our vessels are built to American Bureau of Shipping, or ABS, classification standards and in some instances are inspected periodically by ABS to maintain the vessels in class standards. The crews we employ aboard vessels, including captains, pilots, engineers, tankermen and ordinary seamen, are documented by the USCG.

We are required by various governmental agencies to obtain licenses, certificates and permits for our vessels depending upon such factors as the cargo transported, the waters in which the vessels operate and other factors. We are of the opinion that our vessels have obtained and can maintain all required licenses, certificates and permits required by such governmental agencies for the foreseeable future.

Jones Act: The Jones Act is a federal law that restricts maritime transportation between locations in the U.S. to vessels built and registered in the U.S. and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. Jones Act requirements significantly increase operating costs of U.S.-flag vessel operations compared to foreign-flag vessel operations. Further, the USCG and ABS maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags or flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

Merchant Marine Act of 1936: The Merchant Marine Act of 1936 is a federal law providing that, upon proclamation by the President of the U.S. of a national emergency or a threat to the national security, the U.S. Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

Security Requirements: The Maritime Transportation Security Act of 2002 requires, among other things, submission to and approval by the USCG of vessel and waterfront facility security plans, or VSP. Our VSP's have been approved and we are operating in compliance with the plans for all of its vessels and that are subject to the requirements, whether engaged in domestic or foreign trade.

Railcar Regulation

We operate a number of railcar unloading facilities and lease a significant number of railcars. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety and Health Administration, or OSHA, as well as other federal and state regulatory agencies. We believe that our railcar operations are in substantial compliance with all existing federal, state and local regulations.

DOT and OSHA have jurisdiction under several federal statutes over a number of safety and health aspects of rail operations, including the transportation of hazardous materials. State agencies regulate some aspects of rail operations with respect to health and safety in areas not otherwise preempted by federal law.

Regulation of the Mining Industry in the United States

We have the right to mine trona through leases we hold from the U.S. Federal government, the State of Wyoming and Sweetwater Trona OpCo LLC ("Sweetwater"). Our leases with the U.S. government are issued under the provisions of the Mineral Leasing Act of 1920 (30 U.S.C. 18 et. Seq.) and are administered by the U.S. Bureau of Land Management ("BLM") and our leases with the state of Wyoming are issued under Wyoming Statutes 36-6-101 et. seq. Sweetwater acquired the leases and interests from Anadarko Land Corporation, a subsidiary of Occidental following Occidental's August 2019 acquisition of Anadarko Petroleum Corporation, who was the successor to rights originally granted to the Union Pacific Railroad in connection with the construction of the first transcontinental railroad in North America. For more information, please see discussion of "Overview of Mining Property and Operations" in Item 2 below.

We pay royalties to the BLM, the State of Wyoming and Sweetwater Royalties, LLC ("Sweetwater Royalties") who acquired the mineral rights through a conveyance from Sweetwater. These royalties are calculated based upon the gross value of soda ash and related products at a certain stage in the mining process. We are obligated to pay minimum royalties or annual rentals to our lessors regardless of actual sales and in the case of Sweetwater Royalties to pay royalties in advance based on a formula based on the amount of trona produced and sold in the previous year which is then credited against production royalties owed. The royalty rates we pay to our lessors may change upon our renewal of such leases; however, we anticipate being able to renew all material leases at the appropriate time. In the past, the U.S. Congress has passed legislation to cap royalties collected by BLM at a rate lower than the rate stated in our federal leases.

Our mining operations in Wyoming are subject to mine permits issued by the Land Quality Division of the Wyoming Department of Environmental Quality ("WDEQ"). WDEQ imposes detailed reclamation obligations on us as a holder of mine permits. As of December 31, 2022, the amount of our reclamation bonds totaled to approximately $83 million. The amount of the bonds are subject to change based upon periodic re-evaluation by WDEQ.

The health and safety of our employees working underground and on the surface are subject to detailed regulation. The safety of our operations at Westvaco are regulated by the U.S. Mine Safety and Health Administration ("MSHA") and our Granger facility by the Wyoming Occupational Safety and Health Administration ("Wyoming OSHA"). MSHA administers the provisions of the Federal Mine Safety and Health Act of 1977 and enforces compliance with that statute's mandatory safety and health standards. As part of MSHA's oversight, representatives perform at least four unannounced inspections (approximately once quarterly) each year at Westvaco. Wyoming OSHA regulates the health and safety of non-mining operations under a plan approved by the U.S. Occupational Health and Safety Administration. When our Granger facility was restarted in 2009 on brine (solution) mine feed (i.e., without any miners working underground), Wyoming OSHA assumed responsibility for the facility.

Regulation of Finished Product Manufacturing

Our business is subject to extensive regulation by federal, state, local and foreign governments. Governmental authorities regulate the generation and treatment of waste and air emissions at our operations and facilities. We also comply with worldwide, voluntary standards developed by the International Organization for Standardization ("ISO"), a nongovernmental organization that promotes the development of standards and serves as a bridging organization for quality standards, such as ISO 9001:2015 for quality management and ISO 22000 for food safety management.

Several of the production operations in our Alkali Business are subject to regulation by the U.S. Food and Drug Administration ("FDA"). Our sodium bicarbonate plant is a registered facility for the production of food and pharmaceutical grade ingredients and we comply with strict Current Good Manufacturing Practice ("CGMP") requirements in our operations. The U.S. Food Safety Modernization Act requires that parts of our facility that produce animal nutrition products comply with more rigorous manufacturing standards. We believe that we materially comply with requirements currently in effect and have a program in place to maintain such compliance. We also comply with industry standards developed by various private organizations such as U.S. Pharmacopeia, Organic Materials Review Institute and the Orthodox Union. Alkali has also sought and received certification of its Wyoming facilities under ISO.9001:2015.

Environmental Regulations

General - We are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may (i) require the acquisition of and compliance with permits for regulated activities, (ii) limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness area, seismically sensitive areas, or areas inhabited by endangered or threatened species, (iii) result in capital expenditures to limit or prevent emissions or discharges, and (iv) place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this trend will continue in the future. Revised or new additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Hazardous Substances and Waste Handling - The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons. These persons include current owners and operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. We currently own or lease, and have in the past owned or leased, properties that have been in use for many years with the gathering and transportation of hydrocarbons including crude oil and other activities that could cause an environmental impact. Persons deemed "responsible persons" under CERCLA may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

We also may incur liability under the Resource Conservation and Recovery Act, as amended, or RCRA, and analogous state laws which impose requirements and also liability relating to the management and disposal of solid and hazardous wastes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain crude oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges - The Federal Water Pollution Control Act, as amended, also known as the "Clean Water Act," and analogous state laws impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including crude oil, into navigable waters of the U.S., as well as state waters. Permits must be obtained to discharge pollutants into these waters. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit.

The scope of waters regulated under the CWA has fluctuated in recent years. On June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or Corps, jointly promulgated final rules expanding the scope of waters protected under the Clean Water Act. However, on October 22, 2019, the agencies repealed the 2015 rules, and then, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rules, and significantly reducing the waters subject to federal regulation under the Clean Water Act. On August 30, 2021, a federal court struck down the replacement rule and, on January 18, 2023, the EPA and the Corps published a final rule that would restore water protections that were in place prior to 2015. Meanwhile, in October 2022, the Supreme Court heard oral argument in a case addressing the proper test for determining whether wetlands are "waters of the United States." As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The Oil Pollution Act contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The Oil Pollution Act subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or the Oil Pollution Act may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with each of these requirements.

Air Emissions - The Federal Clean Air Act, or CAA, as amended, and analogous state and local laws and regulations restrict the emission of air pollutants, and impose permit requirements and other obligations. Regulated emissions occur as a result of our operations, including the handling or storage of crude oil and other petroleum products. Both federal and state laws impose substantial penalties for violation of these applicable requirements. Accordingly, our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, revocation or suspension of necessary permits and, potentially, criminal enforcement actions.

On August 16, 2012, the EPA published final regulations under the CAA that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, on August 13, 2020, in response to an executive order by former President Trump to review and revise unduly burdensome regulations, the EPA amended the 2012 and 2016 New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. On June 30, 2021, President Biden signed into law a joint resolution of Congress disapproving the 2020 amendments (with the exception of some technical changes) thereby reinstating the 2012 and 2016 New Source Performance standards. The EPA expects owners and operators of regulated sources to take "immediate steps" to comply with these standards. Additionally, on November 15, 2021, the EPA published a proposed rule that would expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries, and prohibiting venting of natural gas in certain situations. On December 6, 2022, the EPA published a supplemental proposal to strengthen and expand the November 2021 proposed rule by increasing the scope of required monitoring of fugitive emissions and require continuous monitoring and inspection of control devices. These new standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

National Environmental Policy Act - Under the National Environmental Policy Act, or NEPA, a federal agency, commonly in conjunction with a current permittee or applicant, may be required to prepare an environmental assessment or a detailed environmental impact statement before taking any major action, including issuing a permit for a pipeline extension or addition that would affect the quality of the environment. Should an environmental impact statement or environmental assessment be required for any proposed pipeline extensions or additions, NEPA may prevent or delay construction or alter the proposed location, design or method of construction.

Endangered Species Act - The federal Endangered Species Act and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans.

Climate Change - In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Accordingly, in recent years, federal, state, and local governments have taken steps to reduce emissions of GHGs. On August 16, 2022, President Biden signed into law the Inflation Reduction Act ("IRA"), which includes billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration. These incentives could accelerate the transition of the economy away from the use of fossil fuels towards lower or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we store, transport and sell and adversely impact our business.

The EPA has also finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and almost half of the states, either individually or through multi-state regional initiatives, have taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and gas operations. The net effect of this regulatory regime is to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. Our compliance with any future legislation or regulation of GHGs, if adopted, may result in materially increased compliance and operating costs.

In addition, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. Although the United States withdrew from the Paris Agreement, effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which took effect on February 19, 2021. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its GHG emissions by 50-52 percent below 2005 levels in 2030. In November 2021, in connection with the 26th Conference of the Parties (COP-26) in Glasgow, Scotland, the United States and other world leaders made further commitments to reduce GHG emissions, including reducing global methane emissions by at least 30% by 2030. The urgency to reduce GHG emissions was further emphasized in the 27th Conference of the Parties (COP-27) in Sharm El-Sheikh, Egypt. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the international climate commitments.

Legislative efforts or related implementation regulations that regulate or restrict emissions of GHGs in areas that we conduct business could adversely affect the demand for the products that we transport, store and distribute and, depending on the particular program adopted, could increase our costs to operate and maintain our facilities by requiring that we, among other things, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any fees or taxes related to our GHG emissions and administer and manage a GHG emissions program. We may be unable to include some or all of such increased costs in the rates charged by our pipelines or other facilities, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the crude oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Furthermore, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. In addition, claims have been made against certain energy companies alleging that GHG emissions from crude oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Moreover, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Safety and Security Regulations

Our crude oil pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration, or PHMSA, and various other federal, state and local agencies under various provisions of Title 49 of the United States Code and comparable state statutes. Congress has enacted several pipeline safety acts over the years. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "Pipeline Safety Act") provides for regulation of the nation's pipelines, penalties for violations of pipeline safety rules, and other DOT matters. The Pipeline Safety Act currently provides for significant financial penalties involving non-compliance with DOT regulations. In addition, the Pipeline Safety Act includes additional safety requirements for newly constructed pipelines. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016," or the 2016 PIPES Act, which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions, and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. In December 2020, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020," or the 2020 PIPES Act, was signed into law. The 2020 PIPES Act extends the PHMSA's statutory mandate through 2023. It continues the legislative mandates that were established in the 2016 PIPES Act and creates new regulatory mandates, including, among other things: (i) requiring regulations prescribing the applicability of pipeline safety requirements to idled natural gas transmission and hazardous liquids pipelines; (ii) the creation of new leak detection and repair programs that impact certain natural gas gathering, transmission, and distribution lines; and (iii) necessitating updates to gas pipeline and hazardous liquid pipeline facility inspection and maintenance plans.

The PHMSA administers pipeline safety requirements for natural gas and hazardous liquid pipelines pursuant to detailed regulations set forth in 49 C.F.R. Parts 190 to 199. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules and specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas, or HCAs, which include populated areas, unusually sensitive areas and commercially navigable waterways. We are subject to the PHMSA Integrity Management, or IM, regulations, which require that we perform baseline assessments of all pipelines that could affect a HCA, and to continually assess all pipelines at specified intervals to periodically evaluate the integrity of each pipeline segment that could affect a HCA. The integrity of these pipelines must be assessed by internal inspection, pressure test, or equivalent alternative new technology. We must also abide by an Integrity Management Plan, or IMP, that details the risk assessment factors, the overall risk rating for each segment of pipe, a schedule for completing the integrity assessment, the methods to assess pipeline integrity, and an explanation of the assessment methods selected. No assurance can be given that the cost of testing and the required rehabilitation identified will not be material costs to us that may not be fully recoverable by tariff increases.

The PHMSA has issued a number of rulemakings in response to the Pipeline Safety Act, the 2016 PIPES Act, and the 2020 PIPES Act, as well as prior statutes, concerning pipeline safety that impact our pipeline facilities. Over the past several years, the PHMSA adopted additional regulations for natural gas and hazardous liquid pipeline safety. In particular, on October 1, 2019, the PHMSA published final rules to expand its IM requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside HCAs that became effective on July 1, 2020. Among other things, the rules require all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule imposes inspection requirements on 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. The rules also extend reporting requirements to certain previously unregulated hazardous liquid gravity and rural gathering lines. Many of the requirements will be phased in over an extended compliance schedule. Also, on November 15, 2021, the PHMSA published a final rule extending reporting requirements to all onshore gas gathering operators and establishing a set of minimum safety requirements for certain gas gathering pipelines with large diameters and high operating pressures. On December 27, 2021, the PHMSA published an Interim Final Rule that designates the Great Lakes, coastal beaches, and marine coastal waters as "Unusually Sensitive Areas," extending more stringent IMP requirements to hazardous liquid pipelines near such areas. Additional final rules were announced in 2022, including a final rule regarding the installation of rupture-mitigation valves, published on April 8, 2022. Further, on August 24, 2022, the PHMSA published a final rule strengthening integrity management requirements for onshore gas transmission lines, bolstering corrosion control standards and repair criteria, and imposing new requirements for inspections after extreme weather events. Also, on June 7, 2021, the PHMSA issued an advisory bulletin reminding pipeline owners and operators that, pursuant to legislation signed into law in December 2020, they must take several steps to eliminate hazardous leaks and minimize releases of natural gas by December 27, 2021. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

We have developed a Risk Management Plan required by the PHMSA as part of our IMP. This plan is intended to minimize the offsite consequences of catastrophic spills. As part of this program, we have developed a mapping program. This mapping program identified HCAs and unusually sensitive areas along the pipeline right-of-ways in addition to mapping of shorelines to characterize the potential impact of a spill of crude oil on waterways.

Our crude oil, refined products and sodium minerals and sulfur services operations are also subject to the requirements of OSHA and comparable state statutes. Various other federal and state regulations require that we train all operations employees in Hazardous Communication ("HAZCOM") and disclose information about the hazardous materials used in our operations. Certain information must be reported to employees, government agencies and local citizens upon request.

In most cases, states are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to intrastate hazardous liquids pipelines, including crude oil and natural gas pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. The Railroad Commission recently updated its pipeline safety regulations consistent with PHMSA requirements, effective September 13, 2021. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

Our trucking operations are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety and many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

The USCG regulates occupational health standards related to our marine operations. Shore-side operations are subject to the regulations of OSHA and comparable state statutes. The Maritime Transportation Security Act requires, among other things, submission to and approval of the USCG of vessel security plans.

Since the terrorist attacks of September 11, 2001, the U.S. Government has issued numerous warnings that energy assets could be the subject of future terrorist attacks. We have instituted security measures and procedures in conformity with federal guidance. We will institute, as appropriate, additional security measures or procedures indicated by the federal government. None of these measures or procedures should be construed as a guarantee that our assets are protected in the event of a terrorist attack.

On May 27, 2021, the Department of Homeland Security's Transportation Security Administration ("TSA") announced Security Directive Pipeline-2021-01 that requires us, as a critical pipeline owner, to report confirmed and potential cybersecurity incidents to the DHS Cybersecurity and Infrastructure Security Agency ("CISA") and to designate a Cybersecurity Coordinator. It also requires us and the third-party operators of our assets to review current practices as well as to identify any gaps and related remediation measures to address cyber-related risks and report the results to TSA and CISA within 30 days. We designated a Cybersecurity Coordinator, developed a plan to comply with mandatory reporting timeframes and completed the vulnerability assessment required under this directive in 2021. On July 20, 2021, the TSA issued a second Security Directive. Then, on July 27, 2022, a third TSA-issued Security Directive took effect. We have evaluated the impacts of this second directive to our pipeline business and have made significant progress in compliance. See "Compliance with and changes in cybersecurity requirements has a cost impact on our business, and failure to comply with such laws and regulations could have an impact on our assets, costs, revenue generation and growth opportunities."

Available Information

We make available free of charge on our internet website (www.genesisenergy.com) our annual report on Form 10-K, 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 Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC. These documents are also available at the SEC's website (www.sec.gov). Additionally, on our internet website we make available our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Audit Committee Charter and Governance, Compensation and Business Development Committee Charter. Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of this Form 10-K or our other securities filings.

Item 1A. Risk Factors

The following risk factors and other information included in this Annual Report on Form 10-K should be carefully considered. The occurrence of any of the following risks or of unknown risks and uncertainties may adversely affect our business, operating results and financial condition.

Risk Factors Summary

Risks Related to the Operations of Our Business

- We may not be able to fully execute our growth strategy due to various factors, such as unreceptive capital markets and/or excessive competition for acquisitions.
- We may not have sufficient cash from operations to pay the current level of quarterly distributions following the establishment of cash reserves and payment of fees and expenses.
- Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity (crude oil, natural gas, refined products, soda ash, NaHS and caustic soda) volumes, which often depend on actions and commitments by parties beyond our control.
- Many of our crude oil and natural gas transportation customers are producers whose drilling activity levels and spending for transportation have historically been, and may continue to be, impacted by volatility in the commodity markets.
- Fluctuations in prices for crude oil, refined petroleum products, NaHS, soda ash and caustic soda could adversely affect our business.

Risks Related to Liquidity and Financing

- Our indebtedness could adversely restrict our ability to operate, affect our financial condition, prevent us from complying with requirements under our debt instruments and prevent us from paying cash distributions to our unitholders.
- We may not be able to access adequate capital (debt and/or equity) on economically viable terms, or any terms.
- The Inflation Reduction Act could accelerate the transition to a low carbon economy and impose new costs on our operations.
- Continuing or worsening inflationary pressures and associated changes in monetary policy have resulted in and may result in additional increases to our operating costs, which in turn have caused and may continue to cause our capital expenditures and operating costs to rise.

Risks Related to Legal and Regulatory Compliance

- Our operations are subject to federal, state and local environmental protection and safety laws and regulations.
- Climate change legislation and regulatory initiatives may decrease demand for the products we store, transport and sell and increase our operating costs.
- Changes in environmental laws could increase costs and harm our business, financial condition and results of operations.

Risks Related to Our Partnership Structure

- Individual members of the Davison family can exert significant influence over us and may have conflicts of interest with us and may be permitted to favor their interests to the detriment of our other unitholders.
- Our Class B Common Units may be transferred to a third party without unitholder consent, which could affect our strategic direction.
- The interruption of distributions to us from our subsidiaries and joint ventures could affect our ability to make payments on indebtedness or cash distributions to our unitholders.

- We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Tax Risks to Our Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation (for U.S. federal income tax purposes) or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.
- Our unitholders will be required to pay taxes on income (as well as deemed distributions, if any) from us even if they do not receive any cash distributions from us.
- Our unitholders will likely be subject to state and local taxes in states where they do not live as a result of an investment in our units.

General Risks

- We are exposed to the credit risk of our customers in the ordinary course of our business activities.
- A natural disaster, pandemic, epidemic, accident, terrorist attack or other interruption event could result in an economic slowdown, severe personal injury, property damage and/or environmental damage, which could curtail our operations or otherwise adversely affect our assets and cash flow.
- We cannot predict the impact of the ongoing military conflict between Russia and Ukraine and the related humanitarian crisis on the global economy, energy markets, geopolitical stability and our business.
- Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.
- Compliance with and changes in cyber security requirements have a cost impact on our business.
- Our significant unitholders may sell units or other limited partner interests in the trading market, which could reduce the market price of our common units.
- We may issue additional common units without unitholders' approval, which would dilute their ownership interests.

Risks Related to the Operations of Our Business

We may not be able to fully execute our growth strategy due to various factors, such as unreceptive capital markets and/or excessive competition for acquisitions.

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other infrastructure and mining assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We regularly consider and enter into discussions regarding additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the infrastructure and mining businesses, and increase our market position and, ultimately, increase distributions to unitholders. A number of factors could adversely affect our ability to execute our growth strategy, including an inability to raise adequate capital on acceptable terms, competition from competitors and/or an inability to successfully integrate one or more acquired businesses into our operations.

We will need new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. Although we intend to continue to expand our business, this strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms, if at all.

In addition, we experience competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in our not being the successful bidder more often or our acquiring assets at a higher relative price than that which we have paid historically. Either occurrence would limit our ability to fully execute our growth strategy. Our ability to execute our growth strategy may impact the market price of our securities.

We may be unable to integrate successfully businesses we acquire. We may incur substantial expenses, delays or other problems in connection with our growth strategy that could negatively impact our results of operations. Moreover, acquisitions and business expansions involve numerous risks, including: difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments; inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

We may not have sufficient cash from operations to pay the current level of quarterly distributions following the establishment of cash reserves and payment of fees and expenses.

The amount of cash we distribute to our common unitholders principally depends upon margins we generate from our businesses, which fluctuate from quarter to quarter based on, among other things: the volumes and prices at which we purchase and sell crude oil, natural gas, refined products and caustic soda; the volumes of sodium hydrosulfide, or NaHS, and soda ash that we receive for our sodium minerals and sulfur services and the prices at which we sell NaHS and soda ash; the demand for our services; the level of competition; the level of our operating costs; the effect of worldwide energy conservation measures; governmental regulations and taxes; the level of our general and administrative costs; and prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution to our common unitholders will depend on other factors that include: the level of capital expenditures and costs associated with asset retirement obligations we make, including the cost of acquisitions (if any); our debt service requirements; fluctuations in our working capital; restrictions on distributions contained in our debt instruments or organizational documents governing our joint ventures and unrestricted subsidiaries; distributions we pay to our Class A Convertible Preferred unitholders; our ability to borrow under our senior secured credit facility to pay distributions; and the amount of cash reserves required in the conduct of our business.

Our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and our cash requirements, so it is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity (crude oil, natural gas, refined products, soda ash, NaHS and caustic soda) volumes, which often depend on actions and commitments by parties beyond our control.

We access commodity volumes through various sources, such as our mines, producers, service providers (including gatherers, shippers, marketers and other aggregators) and refiners. Depending on the needs of each customer and the market in which it operates, we can provide a service for a fee (as in the case of our pipeline, terminal, marine vessel and railcar transportation operations), we can acquire the commodity from our customer and resell it to another party, or, in the case of soda ash, we can produce the commodity ourselves.

Our source of volumes depends on successful exploration and development of additional crude oil and natural gas reserves by others; our successful development of our trona reserves; continued demand for refining and our related sulfur removal and other services, for which we are paid in NaHS; the breadth and depth of our logistics operations; the extent that third parties provide NaHS for resale; and other matters beyond our control.

The crude oil, natural gas and refined products available to us and our refinery customers are derived from reserves produced from existing wells, and these reserves naturally decline over time. In order to offset this natural decline, our energy infrastructure assets must access additional reserves. Additionally, some of the projects we have planned or recently completed are dependent on reserves that we expect to be produced from newly discovered properties that producers are currently developing.

Finding and developing new reserves is very expensive, requiring large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all. The volatility in crude oil and natural gas prices has forced some producers to significantly defer or curtail their planned capital expenditures. Thus, crude oil and natural gas production in our market areas could decline, which could have a material negative impact on our revenues and prospects.

Demand for our services is dependent on the demand for crude oil and natural gas. Any decrease in demand for crude oil or natural gas, including by those refineries or connecting carriers to which we deliver could adversely affect our cash flows. The demand for crude oil also is dependent on the competition from refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements or alternative fuel sources such as electricity, coal, fuel oils or nuclear energy, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services. A reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition and results of operations. Demand for our soda ash is dependent on worldwide economic conditions and the use of everyday end products that utilize soda ash in their production process. Soda ash is a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent, solar panels, lithium batteries and a variety of chemicals and other industrial products. Demand could be adversely affected by economic recessions and many other factors.

Our ability to access NaHS depends primarily on the demand for our proprietary sulfur removal process. Demand for our services could be adversely affected by many factors, including lower refinery utilization rates, U.S. refineries accessing more “sweet” (instead of “sour”) crude and the development of alternative sulfur removal processes that might be more economically beneficial to refiners. We are dependent on third parties for caustic soda for use in our sulfur removal process as well as volume to market to third parties. Should regulatory requirements or operational difficulties disrupt the manufacture of caustic soda by these producers, we could be affected. Caustic soda is a major component of the proprietary sulfur removal process we provide to our refinery customers. Because we are a large consumer of caustic soda, we can leverage our economies of scale and logistics capabilities to effectively market caustic soda to third parties. NaHS, the resulting by-product from our sulfur removal operations, is a vital ingredient in a number of industrial and consumer products and processes. Any decrease in the supply of caustic soda could affect our ability to provide sulfur removal services to refiners and any decrease in the demand for NaHS by the parties to whom we sell the NaHS could adversely affect our business. Refineries’ need for our sulfur removal services is also dependent on refining competition from other refineries by refiners to process more “sweet” (instead of “sour”) crude, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

Our crude oil and natural gas transportation operations are dependent upon demand for crude oil by refiners, primarily in the Midwest and Gulf Coast, and the demand for natural gas.

Any decrease in this demand for crude oil by those refineries or connecting carriers to which, or for the natural gas, we deliver could adversely affect our cash flows. Those refineries’ demand for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services. The demand for natural gas is dependent on the impact of future economic conditions, fuel conservation measures, alternative fuel requirements and alternative fuel sources such as electricity, coal, fuel oils or nuclear energy, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We face intense competition to obtain crude oil, natural gas and refined products volumes and to sell and market soda ash.

Our competitors-gatherers, transporters, marketers, brokers and other aggregators-include integrated, large and small independent energy companies, as well as their marketing affiliates, who vary widely in size, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control substantially greater supplies of crude oil, natural gas and refined products.

Even if reserves exist or refined products are produced in the areas accessed by our facilities, we may not be chosen by the refiners or producers to gather, refine, market, transport, store or otherwise handle any of these crude oil and natural gas reserves, NaHS, caustic soda or other refined products. We compete with others for any such volumes on the basis of many factors, including: geographic proximity to the production and/or refineries; costs of connection; available capacity; rates; logistical efficiency in all of our operations; operational efficiency in our sulfur removal business; customer relationships; and access to markets.

Additionally, on our onshore pipelines, most of our third-party shippers do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. In Mississippi, we are dependent on interconnections with other pipelines to provide shippers with a market for their crude oil, and in Texas we are dependent on interconnections with other pipelines to provide shippers with transportation to our pipeline. Any reduction of throughput available to our shippers on these interconnecting pipelines as a result of testing, pipeline repair, reduced operating pressures or other causes could result in reduced throughput on our pipelines that would adversely affect our cash flows and results of operations.

Fluctuations in demand for crude oil or natural gas or availability of refined products or NaHS, such as those caused by refinery downtime or shutdowns, can negatively affect our operating results. Reduced demand in areas we service with our pipelines, marine vessels, rail facilities and trucks can result in less demand for our transportation services.

Competition in our Alkali Business is based on a number of factors, including price, favorable logistics, customer service, and the cost of production of natural soda ash (including energy costs and raw materials, amongst others). Adverse effects to these factors could negatively affect our operating results.

Many of our crude oil and natural gas transportation customers are producers whose drilling activity levels and spending for transportation have historically been, and may continue to be, impacted by volatility in the commodity markets.

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Extreme volatility in commodity prices has caused many of our customers' equity value to substantially decline. New credit facilities and other debt financing from institutional sources have generally become more difficult and expensive to obtain, and there may be a general reduction in the amount of credit available in the markets in which we conduct business. Over the last two years, prices for crude oil ranged from a high of over $120 per barrel to a low of less than $20 per barrel, and such extreme volatility may continue going forward. Adverse price changes put downward pressure on drilling budgets for crude oil and natural gas producers, which have resulted, and could continue to result, in lower volumes than we otherwise would have seen being transported on our pipeline and transportation systems, which could have a material negative impact on our revenues and prospects.

Fluctuations in prices for crude oil, refined petroleum products, NaHS, soda ash and caustic soda could adversely affect our business.

Because we purchase (or otherwise acquire or, in the case of soda ash, produce) and sell crude oil, refined petroleum products, NaHS, soda ash and caustic soda we are exposed to some direct commodity price risks. Prices for those commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control, which could have an adverse effect on our cash flows, profit and/or Segment Margin. We attempt to limit those commodity price risks through back-to-back purchases and sales, hedges and other contractual arrangements; however, we cannot completely eliminate our commodity price risk exposure.

Our use of derivative financial instruments could result in financial losses.

We use derivative financial instruments and other hedging mechanisms from time to time to limit a portion of the effects resulting from changes in commodity prices. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, we could experience losses resulting from our hedging and other derivative positions. Such losses could occur under various circumstances, including if our counterparty does not perform its obligations under the hedge arrangement, our hedge is imperfect or our hedging policies and procedures are not followed.

Non-utilization of certain assets could significantly reduce our profitability due to the fixed costs incurred with respect to such assets.

From time to time in connection with our business, we may lease or otherwise secure the right to use certain third party assets (such as railcars, trucks, barges, pipeline capacity, storage capacity and other similar assets) with the expectation that the revenues we generate through the use of such assets will be greater than the fixed costs we incur pursuant to the applicable leases or other arrangements. However, when such assets are not utilized or are under-utilized (including pressure on the rates we charge), our profitability is negatively affected because the revenues we earn are either non-existent or reduced (in the event of under-utilization), but we remain obligated to continue paying any applicable fixed charges, in addition to incurring any other costs attributable to the non-utilization of such assets. For example, in connection with our operations, we lease all of our railcars that obligate us to pay the applicable lease rate without regard to utilization. If business conditions are such that we do not utilize a portion of our leased assets for any period of time, we will still be obligated to pay the applicable fixed lease rate. In addition, during the period of time that we are not utilizing such assets, we will incur incremental costs associated with the cost of storing such assets, and we will continue to incur costs for maintenance and upkeep. Our failure to utilize a significant portion of our leased assets and other similar assets could have a significant negative impact on our profitability and cash flows.

In addition, certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes transported by truck, marine vessel or rail or transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

We cannot cause our joint ventures and certain of our unrestricted subsidiaries to take or not to take certain actions unless some or all of the joint venture or third party participants agree.

Due to the nature of joint ventures, each participant (including us) in our material joint ventures has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features often include a governance structure that consists of a management committee or other governing body composed of members or member-designees, only some of which are appointed by us. In addition, many of our joint ventures are operated by our "partners" and have "stand-alone" credit agreements that limit their freedom to take certain actions. Thus, without the concurrence of the other joint venture participants and/or the lenders of our joint venture participants, we cannot cause our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the joint ventures or us.

The insolvency of an operator of our joint ventures, the failure of an operator of our joint ventures to adequately perform operations or an operator's breach of applicable agreements could reduce our revenue and cash flow and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements and to the operator's suppliers and vendors. As a result, the success and timing of development activities of our joint ventures operated by others and the economic results derived therefrom depends upon a number of factors outside our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, and the inclusion of other participants**.**

In addition, joint venture participants may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance and ability of third parties to satisfy their obligations under joint venture arrangements is outside our control. If these third parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

We may not be able to renew our marine transportation time charters and contracts when they expire at favorable rates, for extended periods, or at all, which may increase our exposure to the spot market and lead to lower revenues and increased expenses.

During the year ended December 31, 2022, our marine transportation segment received approximately 46% of its revenue from time charters and other fixed contracts, which help to insulate us from revenue fluctuations caused by weather, navigational delays and short-term market declines. We earned approximately 54% of our marine transportation revenues from spot contracts, where competition is high and rates are typically volatile and subject to short-term market fluctuations, and where we could bear the risk of vessel downtime due to weather and navigational delays. If we deploy a greater percentage of our vessels in the spot market, we may experience a lower overall utilization of our fleet through waiting time or ballast voyages, leading to a decline in our operating revenue and gross profit. There can be no assurance that we will be able to enter into future time charters or other fixed contracts on terms favorable to us. For further discussion of our marine transportation contracts, see "Marine Transportation - Customers".

A decrease in the cost of importing refined petroleum products could cause demand for U.S. flag product carrier and barge capacity and charter rates to decline, which would decrease our revenues and cash flows from operations.

The demand for U.S. flag product carriers and barges is influenced by the cost of importing refined petroleum products. Historically, charter rates for vessels qualified to participate in the U.S. coastwise trade under the Jones Act have been higher than charter rates for foreign flag vessels. This is due to the higher construction and operating costs of U.S. flag vessels under the Jones Act requirements that such vessels be built in the U.S. and manned by U.S. crews. This has made it less expensive for certain areas of the U.S. that are underserved by pipelines or which lack local refining capacity, such as in the Northeast, to import refined petroleum products carried aboard foreign flag vessels than to obtain them from U.S. refineries. If the cost of importing refined petroleum products decreases to the extent that it becomes less expensive to import refined petroleum products to other regions of the East Coast and the West Coast than producing such products in the U.S. and transporting them on U.S. flag vessels, demand for our vessels and the charter rates for them could decrease.

We face periodic dry-docking costs for our vessels, which can be substantial.

Vessels must be dry-docked periodically for regulatory compliance and for maintenance and repair. Our dry-docking requirements are subject to associated risks, including delay, cost overruns, lack of necessary equipment, unforeseen engineering problems, employee strikes or other work stoppages, unanticipated cost increases, inability to obtain necessary certifications and approvals and shortages of materials or skilled labor. A significant delay in dry-dockings could have an adverse effect on our marine transportation contract commitments. The cost of repairs and renewals required at each dry-dock are difficult to predict with certainty and can be substantial.

The U.S. inland waterway infrastructure is aging and may result in increased costs and disruptions to our marine transportation segment.

Maintenance of the U.S. inland waterway system is vital to our marine transportation operations. The system is composed of over 12,000 miles of commercially navigable waterway, supported by over 240 locks and dams designed to provide flood control, maintain pool levels of water in certain areas of the country and facilitate navigation on the inland river system. The U.S. inland waterway infrastructure is aging, with more than half of the locks over 50 years old. As a result, due to the age of the locks, scheduled and unscheduled maintenance outages may be more frequent in nature, resulting in delays and additional operating expenses. Failure of the federal government to adequately fund infrastructure maintenance and improvements in the future would have a negative impact on our ability to deliver products for our marine transportation customers on a timely basis.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation obligations and, therefore, our ability to conduct our mining operations.

We are required to obtain surety bonds or post other financial security to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs. The amount of security required to be obtained can change as the result of new laws, as well as changes to the factors used to calculate the bonding or security amounts. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees or additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required to have these bonds or other acceptable security in place before mining can commence or continue, our failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine trona. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our financing arrangements.

Risks Related to Liquidity and Financing

Our indebtedness could adversely restrict our ability to operate, affect our financial condition, prevent us from complying with requirements under our debt instruments and prevent us from paying cash distributions to our unitholders.

We have outstanding debt and the ability to incur more debt. As of December 31, 2022, we had approximately $205.4 million outstanding under our senior secured credit facility, $2.9 billion of senior unsecured notes and $425.0 million of Alkali senior secured notes. We must comply with various affirmative and negative covenants contained in our credit agreement and the indentures or purchase agreement governing our notes, some of which may restrict the way in which we would like to conduct our business. Among other things, these covenants limit or will limit our ability to incur additional indebtedness or liens, make payments in respect of or redeem or acquire any debt or equity issued by us, sell assets, make loans or investments, make guarantees, enter into any hedging agreement for speculative purposes, acquire or be acquired by other companies, and amend some of our contracts.

The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to unitholders. For example, they could increase our vulnerability to general adverse economic and industry conditions, limit our ability to make distributions; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions, construction or development activities; to access capital markets (debt and equity); or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness; limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and place us at a competitive disadvantage as compared to our competitors that have less debt.

We may incur additional indebtedness (public or private) in the future under our existing credit agreement, by issuing debt instruments, under new credit agreements, under joint venture credit agreements, under new credit agreements of our unrestricted subsidiaries, under finance leases or synthetic leases, on a project-finance or other basis or a combination of any of these. If we incur additional indebtedness in the future, it likely would be under our existing or replacement credit agreement or under arrangements that may have terms and conditions at least as or even more restrictive as those contained in our existing credit agreement and the indentures or purchase agreement governing our existing notes. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders or noteholders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. In addition, if there is a change of control as described in our senior secured credit facility, that would be an event of default, unless our creditors agreed otherwise, and, under our senior secured credit facility, any such event could limit our ability to fulfill our obligations under our debt instruments and to make cash distributions to unitholders which could adversely affect the market price of our securities.

In addition, from time to time, some of our joint ventures or unrestricted subsidiaries may have substantial indebtedness, which will include affirmative and negative covenants and other provisions that limit their freedom to conduct certain operations, events of default, prepayment and other customary terms.

We may not be able to access adequate capital (debt and/or equity) on economically viable terms or any terms.

The capital markets (debt and equity) have previously been disrupted and volatile as a result of adverse conditions, including recessionary pressures, bubble-effects and precipitous commodity price declines. These circumstances and events, which can last for extended periods of time, have led to reduced capital availability, tighter lending standards and higher interest rates on loans for companies in the energy industry, especially non-investment grade companies. Although we cannot predict the future condition of the capital markets, future turmoil in capital markets and the related higher cost of capital could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be limited.

If we are unable to access the amounts and types of capital we seek at a cost and/or on terms that have been available to us historically, we could be materially and adversely affected. Such an inability to access capital, including renewing and extending the terms at the relevant time on our existing debt, including the debt at our unrestricted subsidiaries, could limit or prohibit our ability to execute significant portions of our business plan, such as executing our growth strategy and/or optimizing our capital structure.

Our actual construction, development and acquisition costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate.

Our forecast contemplates significant expenditures for the development, construction or other acquisition of on shore and offshore infrastructure as well as mining assets, including some construction and development projects with technological challenges. We (or our joint ventures) may not be able to complete our projects at the costs or within the timeframes currently estimated. If we (or our joint ventures) experience material cost overruns, we will have to finance these overruns using one or more of the following methods: using cash from operations; delaying other planned projects; incurring additional indebtedness; or issuing additional debt or equity.

Any or all of these methods may not be available when needed, may be prohibited or restricted by our or our joint venture's debt or other contractual arrangements or may adversely affect our future results of operations.

In addition, some construction projects require substantial investments over a long period of time before they begin generating any meaningful cash flow.

The Inflation Reduction Act could accelerate the transition to a low carbon economy and impose new costs on our operations.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act ("IRA") which, among other provisions, imposes a fee on methane emissions from sources required to report their greenhouse gas emissions to the U.S. Environmental Protection Agency, including those sources in the onshore petroleum and natural gas production and gathering and boosting source categories. Beginning in 2024, the IRA's methane emissions charge imposes a fee on excess methane emissions from certain oil and gas facilities, starting at $900 per metric ton of leaked methane in 2024 and rising to $1,200 in 2025, and $1,500 for 2026 and thereafter. The imposition of this fee and other provisions contained within the IRA could accelerate the transition away from oil and gas, which could adversely affect our business and results of operations.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our senior secured credit facility ($205.4 million outstanding at December 31, 2022) and the debt at certain of our unrestricted subsidiaries is variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases in interest rates. As of December 31, 2022, obligations under our senior secured credit facility bear interest at the Secured Overnight Financing Rate ("SOFR"), which recently replaced the historical LIBOR benchmark under our credit agreement, or an alternate base rate at our option, plus the applicable margin in accordance with our credit agreement. We have not historically hedged our interest rates. Adverse effects to interest rates could have a negative effect on our financial condition, operating results and cash flow.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

Continuing or worsening inflationary pressures and associated changes in monetary policy have resulted in and may result in additional increases to our operating costs, which in turn have caused and may continue to cause our capital expenditures and operating costs to rise.

The U.S. inflation rate increased in 2021 and 2022 and may continue to increase in 2023. These inflationary pressures have resulted in and may result in additional increases to our operating costs, which in turn have caused and may continue to cause our capital expenditures and operating costs to rise. Sustained levels of high inflation have likewise caused the Federal Reserve and other central banks to increase interest rates, which have the effects of raising the cost of capital, including the cost of borrowings under our credit facility, and depressing economic growth, either of which - or the combination thereof - could hurt the financial and operating results of our business.

Risks Related to Legal and Regulatory Compliance

Our operations are subject to federal, state and local environmental protection and safety laws and regulations.

Our operations are subject to stringent federal, state and local environmental protection and safety laws and regulations. See "Regulation-Environmental Regulations." Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not materially affect us, there is no assurance that this trend will continue in the future. Revised or new additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. Moreover, our operations, including the transportation and storage of crude oil, natural gas and other commodities, involves a risk that crude oil, natural gas and related hydrocarbons or other substances may be released into the environment, which may result in substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages and significant business interruption. These costs and liabilities could rise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we are unable to recover such resulting costs through increased rates or insurance reimbursements, our cash flows and distributions to our unitholders could be materially affected.

Climate change legislation and regulatory initiatives may decrease demand for the products we store, transport and sell and increase our operating costs.

In recent years, federal, state, and local governments have taken steps to reduce emissions of GHGs. For example, the IRA includes billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration. These incentives could accelerate the transition of the economy away from the use of fossil fuels towards lower or zero-carbon emissions alternatives, which could decrease demand for, and in turn the prices of, the oil and natural gas that we store, transport and sell and adversely impact our business.

The EPA has also finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and gas operations.

In addition, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. Although the United States withdrew from the Paris Agreement, effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which took effect on February 19, 2021. On April 21, 2021, the United States announced that it was setting an economy-wide target of reducing its greenhouse gas emissions by 50-52 percent below 2005 levels in 2030. In November 2021, in connection with the 26th Conference of the Parties (COP-26) in Glasgow, Scotland, the United States and other world leaders made further commitments to reduce greenhouse gas emissions, including reducing global methane emissions by at least 30% by 2030. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the international climate commitments.

Efforts to regulate or restrict emissions of GHGs in areas that we conduct business could adversely affect the demand for the products that we transport, store and distribute and, depending on the particular program adopted, could increase our costs to operate and maintain our facilities by requiring that we, among other things, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any fees or taxes related to our GHG emissions and administer and manage a GHG emissions program. We may be unable to include some or all of such increased costs in the rates charged by our pipelines or other facilities, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the crude oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Moreover, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

We have reclamation and mine closing obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

Our mining operations in Wyoming are subject to mine permits issued by the Land Quality Division of the Wyoming Department of Environmental Quality ("WDEQ"). WDEQ imposes detailed reclamation obligations on us as a holder of mine permits. We accrue for the costs of current mine disturbance and of final mine closure. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates and the assumed credit-adjusted risk-free interest rates. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be materially adversely affected.

Regulation of the rates, terms and conditions of services and a changing regulatory environment could affect our financial position, results of operations or cash flow.

FERC regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state agencies. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety and Health Administration, as well as other federal and state regulatory agencies. This regulation extends to such matters as: rate structures; rates of return on equity; recovery of costs; the services that our regulated assets are permitted to perform; the acquisition, construction and disposition of assets; and to an extent, the level of competition in that regulated industry.

In addition, some of our pipelines and other infrastructure are subject to laws providing for open and/or non-discriminatory access.

Given the extent of this regulation, the evolving nature of federal and state regulation and the possibility for additional changes, the current regulatory regime may change and affect our financial position, results of operations or cash flow.

Our business would be adversely affected if we failed to comply with the Jones Act foreign ownership provisions.

We are subject to the Jones Act and other federal laws that restrict maritime cargo transportation between points in the U.S. only to vessels operating under the U.S. flag, built in the U.S., at least 75% owned and operated by U.S. citizens (or owned and operated by other entities meeting U.S. citizenship requirements to own vessels operating in the U.S. coastwise trade and, in the case of limited partnerships, where the general partner meets U.S. citizenship requirements) and manned by U.S. crews. To maintain our privilege of operating vessels in the Jones Act trade, we must maintain U.S. citizen status for Jones Act purposes. To ensure compliance with the Jones Act, we must be U.S. citizens qualified to document vessels for coastwise trade. We could cease being a U.S. citizen if certain events were to occur, including if non-U.S. citizens were to own 25% or more of our equity interest or were otherwise deemed to control us or our general partner. We are responsible for monitoring ownership to ensure compliance with the Jones Act. The consequences of our failure to comply with the Jones Act provisions on coastwise trade, including failing to qualify as a U.S. citizen, would have an adverse effect on us as we may be prohibited from operating our vessels in the U.S. coastwise trade or, under certain circumstances, permanently lose U.S. coastwise trading rights or be subject to fines or forfeiture of our vessels.

Our business would be adversely affected if the Jones Act provisions on coastwise trade or international trade agreements were modified or repealed or as a result of modifications to existing legislation or regulations governing the crude oil and natural gas industry.

If the restrictions contained in the Jones Act were repealed or altered or certain international trade agreements were changed, the maritime transportation of cargo between U.S. ports could be opened to foreign flag or foreign-built vessels. The Secretary of the Department of Homeland Security, or the Secretary, is vested with the authority and discretion to waive the coastwise laws if the Secretary deems that such action is necessary in the interest of national defense. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign product carrier and barge operators, which could reduce our revenues and cash available for distribution.

Foreign-flag vessels generally have lower construction costs and generally operate at significantly lower costs than we do in U.S. markets, which would likely result in reduced charter rates. We believe that continued efforts will be made to modify or repeal the Jones Act. If these efforts are successful, foreign-flag vessels could be permitted to trade in the U.S. coastwise trade and significantly increase competition with our fleet, which could have an adverse effect on our business.

Events within the crude oil and natural gas industry may adversely affect our customers' operations and, consequently, our operations and may also subject companies operating in the crude oil and natural gas industry, including us, to additional regulatory scrutiny and result in additional regulations and restrictions adversely affecting the U.S. crude oil and natural gas industry.

Risks Related to Our Partnership Structure

Individual members of the Davison family can exert significant influence over us and may have conflicts of interest with us and may be permitted to favor their interests to the detriment of our other unitholders.

James E. Davison and James E. Davison, Jr., each of whom is a director of our general partner, each own a significant portion of our common units, including our Class B Common Units, the holders of which elect our directors. Other members of the Davison family also own a significant portion of our common units. Collectively, members of the Davison family and their affiliates own approximately 11.1% of our Class A Common Units and 77.0% of our Class B Common Units and are able to exert significant influence over us, including the ability to elect at least a majority of the members of our board of directors and the ability to control most matters requiring board approval, such as material business strategies, mergers, business combinations, acquisitions or dispositions of assets, issuances of additional partnership securities, incurrences of debt or other financings and payments of distributions. In addition, the existence of a controlling group (if one were to form) may have the effect of making it difficult for, or may discourage or delay, a third party from seeking to acquire us, which may adversely affect the market price of our common units. Further, conflicts of interest may arise between us and other entities for which members of the Davison family serve as officers or directors. In resolving any conflicts that may arise, such members of the Davison family may favor the interests of another entity over our interests.

Members of the Davison family own, control and have interests in diverse companies, some of which may (or could in the future) compete directly or indirectly with us. As a result, the interests of the members of the Davison family may not always be consistent with our interests or the interests of our other unitholders. Members of the Davison family could also pursue acquisitions or business opportunities that may be complementary to our business. Our organizational documents allow the holders of our units (including affiliates, like the Davisons') to take advantage of such corporate opportunities without first presenting such opportunities to us. As a result, corporate opportunities that may benefit us may not be available to us in a timely manner, or at all. To the extent that conflicts of interest may arise among us and any member of the Davison family, those conflicts may be resolved in a manner adverse to us or you. Other potential conflicts may involve, among others, the following situations: our general partner is allowed to take into account the interest of parties other than us, such as one or more of its affiliates, in resolving conflicts of interest; our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty; our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and its affiliates, retention of counsel, accountants and service providers and cash reserves, each of which can also affect the amount of cash that is distributed to our unitholders; and our general partner determines which costs incurred by it and its affiliates are reimbursable by us and the reimbursement of these costs and of any services provided by our general partner could adversely affect our ability to pay cash distributions to our unitholders.

Our Class B Common Units may be transferred to a third party without unitholder consent, which could affect our strategic direction.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Only holders of our Class B Common Units have the right to elect our board of directors. Holders of our Class B Common Units may transfer such units to a third party without the consent of the unitholders. The new holders of our Class B Common Units may then be in a position to replace our board of directors and officers of our general partner with its own choices and to control the strategic decisions made by our board of directors and officers.

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 we, our general partner and our and its subsidiaries own 80% or more of the Class A or Class B units, our general partner will have the right, but not the obligation, which it may assign to us or our subsidiaries, to acquire all, but not less than all, of the Class A or Class B units, respectively, held by unaffiliated persons at a price not less than the greater of (i) their then-current market price and (ii) the highest price paid by our general partners, us or our respective subsidiaries for such class of units in the 90 days preceding the purchase notice. 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.

The interruption of distributions to us from our subsidiaries and joint ventures could affect our ability to make payments on indebtedness or cash distributions to our unitholders.

We are a holding company. As such, our primary assets are the equity interests in our subsidiaries and joint ventures. Consequently, our ability to fund our commitments (including payments on our indebtedness) and to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. While some of our joint ventures and our unrestricted subsidiaries may generally be required to make cash distributions to us on a quarterly or other periodic basis, distributions from our joint ventures and our unrestricted subsidiaries are subject to the discretion of their respective management committee or similar governing body in one or more respects even if such distributions are generally required, such as with respect to the establishment of cash reserves. Further, the charter documents of certain of our joint ventures and unrestricted subsidiaries may vest in the management committees or similar governing body's certain discretion or contain certain limitations regarding cash distributions even if such distributions are generally required. Accordingly, our joint ventures and our unrestricted subsidiaries may not continue to make distributions to us at current levels or at all.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you 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 an 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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Unitholder liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states in which we do business or may do business in from time to time in the future. Unitholders could be liable for any and all of our obligations as if unitholders were a general partner if a court or government agency were to determine that: we were conducting business in a state but had not complied with that particular state's partnership statute; or unitholders right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Tax Risks to Our Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation (for U.S. federal income tax purposes) or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our 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 federal income tax purposes. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception exists with respect to publicly traded partnerships, 90% or more of the gross income of which for each taxable year consists of "qualifying income."

If less than 90% of our gross income for any taxable year is "qualifying income" from transportation, processing or marketing of natural resources (including minerals, crude oil, natural gas or products thereof), interest or dividends income, we will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years. We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

The decision of the U.S. Court of Appeals for the Fifth Circuit in Tidewater Inc. v. U.S., 565 F.3d 299 (5th Cir. April 13, 2009) held that the marine time charter being analyzed in that case was a "lease" that generated rental income rather than income from transportation services for purposes of a foreign sales corporation provision of the Internal Revenue Code. Even though (i) the Tidewater case did not involve a publicly traded partnership and it was not decided under Section 7704 of the Internal Revenue Code relating to "qualifying income," (ii) some experienced practitioners believe the decision was not well reasoned, (iii) the IRS stated in an Action on Decision (AOD 2010-01) that it disagrees with and will not acquiesce to the Fifth Circuit's marine time charter analysis contained in the Tidewater case and (iv) the IRS has issued several favorable private letter rulings (which can be relied upon and cited as precedent by only the taxpayers that obtained them) relating to time charters since the Tidewater decision was issued, the Tidewater decision creates some uncertainty regarding the status of income from certain of our marine time charters as "qualifying income" under Section 7704 of the Internal Revenue Code. Notwithstanding the foregoing, the Tidewater case is relevant authority because it is the only case of which we and our outside tax counsel are aware directly analyzing whether a particular time charter would constitute a lease or service agreement for certain U.S. federal tax purposes. Due to the uncertainty created by the Tidewater decision, our outside tax counsel, Akin Gump Strauss Hauer & Feld, LLP, was required to change the standard in its opinion relating to our status as a partnership for federal income tax purposes to "should" from "will."

Although we do not believe based upon our current operations that we are treated as a corporation for federal income tax purposes, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and would pay state income tax at varying rates. Distributions to our unitholders would generally be taxable to them again as corporate distributions and no income, gains, losses, or deductions would flow through to them. 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.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax on our gross income apportioned to Texas. Imposition of any such taxes on us by any other state would 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 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 interpretation at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for certain publicly traded partnerships.

Any modifications 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 of these changes, or other proposals, will ultimately be enacted. Any such changes could cause a material reduction in our anticipated cash flows and could cause us to be treated as an association taxable as a corporation for U.S. federal income tax purposes subjecting us to the entity-level tax and adversely affecting the value of our units.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the costs of any IRS contest would reduce our cash available for distribution to our unitholders and our general partner.

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 some or all of 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, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because these costs will reduce our cash available for distribution.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes 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 the new rules, our general partner may elect to either cause us to 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 it, 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. If we make payments of taxes and any penalties and interest directly to the IRS in the year in which the audit is completed, our cash available for distribution to our unitholders might be substantially reduced, in which case our current unitholders may bear some or all of the tax liability resulting from such audit adjustments, even if such unitholders did not own units in us during the tax year under audit.

Our unitholders will be required to pay taxes on income (as well as deemed distributions, if any) from us even if they do not receive any cash distributions from us.

Our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income (as well as deemed distributions, if any) even if unitholders receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income (or deemed distributions, if any) or even the tax liability that results from that income (or deemed distribution).

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 their tax basis in those units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price received is less than its original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Our ability to deduct interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year may be limited in certain circumstances. If this limitation were to apply with respect to a taxable year, it could result in an increase in the taxable income allocable to a unitholder for such taxable year without any corresponding increase in the cash available for distribution to such unitholder. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our units.

Tax-exempt entities and non-U.S. persons 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 individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in 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 (“effectively connected income”). 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. 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 foreign person. While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, recently issued Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our common 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. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2023, and after that date, if effected through a broker, the obligation to withhold is imposed on the transfer's broker. Non-U.S. unitholders should consult a tax advisor before investing in our units.

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

Because we cannot match transferors and transferees of our common units, we adopt depreciation and amortization conventions that may not conform to all aspects of existing Treasury Regulations and may result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions. A successful IRS challenge to those conventions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our unitholders will likely be subject to state and local taxes in states where they do not live as a result of an investment in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state, and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and do business in more than 20 states including Texas, Louisiana, Mississippi, Alabama, Florida, Arkansas and Oklahoma. Many of the states we currently do business in impose a personal income tax. It is our unitholders' responsibility to file all applicable U.S. federal, foreign, state and local tax returns. 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.

We have subsidiaries that are treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

We conduct a portion of our operations through subsidiaries that are, or are treated as, corporations for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. These corporate subsidiaries will be subject to corporate-level tax, which, effective for taxable years beginning after December 31, 2017, is 21%, and will likely pay state (and possibly local) income tax at varying rates, on their taxable income. Any such entity level taxes will reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS were to successfully assert that these corporate subsidiaries have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

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 (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets and (iii) 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 loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, such unitholder 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 a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, 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 a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The IRS could challenge our treatment of the holders of Class A Convertible Preferred Units as partners for tax purposes, and if such challenge were sustained, certain holders of Class A Convertible Preferred Units could be adversely impacted.

The IRS may disagree with our treatment of the Class A Convertible Preferred Units as equity for U.S. federal income tax purposes, and no assurance can be given that our treatment will be sustained. If the IRS were to successfully characterize the Class A Convertible Preferred Units as indebtedness for tax purposes, certain holders of Class A Convertible Preferred Units may be subject to additional withholding and reporting requirements. Further, if the Class A Convertible Preferred Units were treated as indebtedness for U.S. federal tax purposes, rather than equity, distributions likely would be treated as payments of interest by us to the holders of Class A Convertible Preferred Units. Holders of Class A Convertible Preferred Units are encouraged to consult their tax advisors regarding the tax consequences applicable to the re-characterization of the Class A Convertible Preferred Units as indebtedness for tax purposes.

The amount that a Class A Convertible Preferred unitholder would receive upon liquidation may be less than the liquidation value of the Class A Convertible Preferred Units.

In general, we intend to specially allocate to the Class A Convertible Preferred Units items of our gross income in an amount equal to the distributions paid in respect of the Class A Convertible Preferred Units during the taxable year. If the distributions paid in respect of the Class A Convertible Preferred Units during a taxable year exceed the amount of our gross income allocated to the Class A Convertible Preferred Units for such taxable year (as in the case of prior distributions during the PIK period), the per unit capital account balance of the Class A Convertible Preferred unitholders would be reduced by the amount of such excess. If we were to dissolve or liquidate, after satisfying all of our liabilities, our unitholders (including the Class A Convertible Preferred unitholders) would be entitled to receive liquidating distributions in accordance with their capital account balances. In such event, Class A Convertible Preferred unitholders would be specially allocated items of gross income and gain in a manner designed to cause the capital account balance of a preferred unit to equal the liquidation value of a preferred unit. If we were to have insufficient gross income and gain to cause the capital account balance to equal the liquidation value of a preferred unit, then the amount that a Class A Convertible Preferred unitholder would receive upon liquidation would be less than the liquidation value of the Class A Convertible Preferred Units, even though there may be cash available for distribution to the holders of common units or any other junior securities with respect to their capital accounts.

General Risks

We are exposed to the credit risk of our customers in the ordinary course of our business activities.

When we (or our joint ventures) market our products or services, we (or our joint ventures) must determine the amount, if any, of the line of credit. Since certain transactions can involve very large payments, the risk of nonpayment and nonperformance by customers, industry participants and others is an important consideration in our business.

For example, in those cases where we provide division order services for crude oil and natural gas purchased at the wellhead, we may be responsible for distribution of proceeds to all of the interest owners. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint.

Additionally, we sell NaHS, soda ash and caustic soda to customers in a variety of industries. Some of these customers are in industries that have been or could be impacted by a decline in demand for their products and services. Even if our credit review and analytical procedures work properly, we have experienced, and we could continue to experience losses in dealings with other parties.

We utilize ANSAC as our exclusive export vehicle for sales to customers in all countries excluding Canada, South Africa, members of the European Community and European Free Trade Area and the South African Customs Union. Because ANSAC makes sales to its end customers directly and then allocates a portion of such sales to each member, during 2022, we did not have direct access to ANSAC's customers and we had no direct control over the credit or other terms ANSAC extended to its customers. As a result, we are indirectly exposed to ANSAC's customer relationships and the credit and other terms

ANSAC extended to its customers. Upon becoming the sole member of ANSAC in 2023, we plan to integrate its operations with our own. As a result, we could face incremental costs and risks associated with being the sole member.

Further, many of our customers could be impacted by weakened economic conditions, and volatility in commodity prices, such as crude oil, natural gas, copper, molybdenum, and aluminum in a manner that could influence the need for our products and services and their ability to pay us for those products and services. It is uncertain to what extent commodity prices will experience increased volatility in the future.

A natural disaster, pandemic, epidemic, accident, terrorist attack or other interruption event could result in an economic slowdown, severe personal injury, property damage and/or environmental damage, which could curtail our operations or otherwise adversely affect our assets and cash flow.

Some of our operations involve significant risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations or otherwise expose us to liability and adversely affect our cash flow. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods, earthquakes and extended periods of below freezing weather. A significant portion of our operations are located along the U.S. Gulf Coast, and our offshore pipelines are located in the Gulf of Mexico, which can be heavily subjected to these types of disasters or storms throughout a given year.

If one or more facilities that are owned by us or that connect to us or our customers is damaged or otherwise affected by severe weather or any other disaster, pandemic, epidemic, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs or recovery might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. Additionally, the proceeds of any property insurance maintained by us may not be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur, and we may not be able to renew it or obtain other desirable insurance on commercially reasonable terms, if at all.

Any terrorist attack at our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

In addition, a natural disaster, pandemic, epidemic, accident, terrorist attack or other interruption event may cause significant volatility in global financial markets, disruptions to commerce and reduced economic activity. 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. Additional vaccine mandates or health prerequisites may be announced in jurisdictions in which our businesses operate. Our implementation of any such requirements if and when they are deemed to be enforceable may result in attrition, including attrition of critically skilled labor, and difficulty securing future labor needs. These potential impacts, while uncertain, could adversely affect our operating results. The resulting macroeconomic conditions could adversely affect our cash flows, as well as the market price of our securities.

We cannot predict the impact of the ongoing military conflict between Russia and Ukraine and the related humanitarian crisis on the global economy, energy markets, geopolitical stability and our business.

The ultimate consequences of the Russian-Ukrainian military conflict, which may include further sanctions, embargoes, supply chain disruptions, regional instability and geopolitical shifts, may have adverse effects on global macroeconomic conditions, increase volatility in the price of and demand for oil and natural gas, increase exposure to cyberattacks, cause disruptions in global supply chains, increase foreign currency fluctuations, cause constraints or disruption in the capital markets and limit sources of liquidity. We cannot predict the extent of the conflict's effect on our business and results of operations, as well as on the global economy and energy and soda ash markets.

Compliance with and changes in cybersecurity requirements have a cost impact on our business, and failure to comply with such laws and regulations could have an impact on our assets, costs, revenue generation and growth opportunities.

In the third quarter of 2022, the Department of Homeland Security's Transportation Security Administration ("TSA") announced the revision and re-issuance of two new security directives originally issued in the second quarter of 2021. These directives require critical pipeline owners to comply with mandatory reporting measures and provide vulnerability assessments. We may be required to expend significant additional resources to respond to cyberattacks, to continue to modify or enhance our protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Any failure to remain in compliance with these government regulations may results in enforcement actions which may have a material adverse effect on our business and operations.

Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.

We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. While we believe that we maintain appropriate information security policies and protocols, we face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational and safety systems that operate our pipelines, facilities and other assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, “hacktivists” or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, loss of intellectual property, impairment of our ability to conduct our operations, disruption of our customers’ operations, loss or damage to our customer data delivery systems, safety incidents, damage to the environment and could have a material adverse effect on our operations, financial position and results of operations. It is also possible that breaches to our systems could go unnoticed for some period of time.

We and our third-party service providers may therefore be vulnerable to security events that are beyond our control, and we may be the target of cyber-attacks, as well as physical attacks, which could result in information security breaches and significant disruption to our business. Such data breaches and cyberattacks could compromise our operational or other capabilities and cause significant damage to our business and our reputation. Our information systems have experienced threats to the security of our digital infrastructure, but none of these have had a significant impact on our business, operations or reputation relating to such attacks. We maintain a 24/7 dedicated security operations center to anticipate, detect and prevent cyberattacks; however, there is no assurance that we will not suffer such losses or breaches in the future. As cyberattacks continue to evolve, we may be required to expend significant additional resources to respond to cyberattacks, to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities. We may also be subject to regulatory investigations or litigation relating from cybersecurity issues.

Our significant unitholders may sell units or other limited partner interests in the trading market, which could reduce the market price of our common units.

As of December 31, 2022, we have a number of significant unitholders. For example, certain members of the Davison family (including their affiliates) and management owned approximately 18 million, or approximately 15%, of our common units. From time to time, we also may have other unitholders that have large positions in our common units. In the future, any such parties may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, such sales could reduce the market price of common units. In connection with certain transactions, we have put in place resale shelf registration statements, which allow unit holders thereunder to sell their common units at any time (subject to certain restrictions) and to include those securities in any equity offering we consummate for our own account.

We may issue additional common units without common unitholders’ approval, which would dilute their ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our common unitholders. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects: our unitholders’ proportionate ownership interest in us will decrease; the amount of cash available for distribution on each unit may decrease; the relative voting strength of each previously outstanding unit may be diminished; and the market price of our common units may decline.

If we are unable to attract and retain senior management and key technical professionals with elite skills, we may not be able to execute our business strategy effectively and, our operations could be adversely affected.

The success of our business and ability to meet our strategic objectives depends upon our ability to attract, develop, retain and replace key qualified technical and management professionals. The market for these professionals is competitive in the sectors in which we operate, and we rely heavily upon the expertise and leadership of our professionals. If we are unable to attract and retain a sufficient number of elite skilled professionals, our ability to pursue our business objectives may be adversely affected thus reducing our revenue, increasing our cost, or damaging our reputation.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. "Business," in addition to the Summary Overview of Mining Operations disclosure below. We also have various operating leases for rental of office space, facilities and field equipment and transportation equipment. See "Commitments and Off-Balance Sheet Arrangements" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 4 to our Consolidated Financial Statements in Item 8 for details on our right of use assets and related lease liabilities. Such information is incorporated herein by reference.

Summary Overview of Mining Operations

Information concerning our mining properties in this Annual Report on Form 10-K has been prepared in accordance with the requirements of subpart 1300 of Regulation S-K, which first became applicable to us for the fiscal year ended December 31, 2021. These requirements differ significantly from the previously applicable disclosure requirements of SEC Industry Guide 7. Among other differences, subpart 1300 of Regulation S-K requires us to disclose our mineral resources, in addition to our mineral reserves, as of the end of our most recently completed fiscal year for our material mining property.

As used in this Annual Report on Form 10-K, the terms "mineral resource," "measured mineral resource," "indicated mineral resource," "inferred mineral resource," "mineral reserve," "proven mineral reserve" and "probable mineral reserve" are defined and used in accordance with subpart 1300 of Regulation S-K. Under subpart 1300 of Regulation S-K, mineral resources may not be classified as "mineral reserves" unless the determination has been made by a qualified person that the mineral resources can be the basis of an economically viable project. You are specifically cautioned not to assume that any part or all of the mineral deposits (including any mineral resources) in these categories will ever be converted into mineral reserves, as defined by the SEC.

You are further cautioned that, except for that portion of mineral resources classified as mineral reserves, mineral resources do not have demonstrated economic value. Inferred mineral resources are estimates based on limited geological evidence and sampling and have too high of a degree of uncertainty as to their existence to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Estimates of inferred mineral resources may not be converted to mineral reserves. A significant amount of exploration must be completed in order to determine whether an inferred mineral resource may be upgraded to a higher category of mineralization and it cannot be assumed that this will occur. Therefore, you are cautioned not to assume that all or any part of an inferred mineral resource exists, that it can be the basis of an economically viable project, or that it will ever be upgraded to a higher category of mineralization. Likewise, you are cautioned not to assume that all or any part of measured or indicated mineral resources will ever be converted to mineral reserves.

The information that follows is derived, in part, from the technical report summary ("TRS") prepared by Stantec Consulting Services Inc. ("Stantec"), an external qualified person ("QP") in compliance with Item 601(b)(96) and subpart 1300 of Regulation S-K. Portions of the following information are based on assumptions, qualifications and procedures that are not fully described herein. Reference should be made to the full text of the TRS that was filed as Exhibit 96.1 as a part of the Annual Report on Form 10-K for the fiscal year ended December 31, 2021 and is incorporated herein by reference. A new TRS was not filed as a part of this Annual Report on Form 10-K because (i) there was not a material change in the mineral reserves or mineral resources from such previously filed TRS and (ii) all material assumptions and information pertaining to the disclosure of our mineral resources and mineral reserves required by paragraphs (d), (e), and (f) of subpart 1302 of Regulation S-K, including material assumptions relating to all modifying factors, price estimates, and scientific and technical information (e.g., sampling data, estimation assumptions and methods), were current as of December 31, 2022, as confirmed by Stantec.

Overview of Mining Property and Operations

Our Alkali Business is one of the world's leading producers of natural soda ash. Natural soda ash is processed from trona, a sodium carbonate mineral composed of soda ash (Na_2CO_3), sodium bicarbonate ($NaHCO_3$) and water with the chemical formula $Na_2CO_3NaHCO_3H_2O$. Approximately 60% of the world's natural soda ash is produced from trona extracted from underground mines and brine (solution) mining in the Green River Basin of southwestern Wyoming. Our trona mining and processing facilities are located in southwestern Wyoming approximately 18 miles west of the city of Green River, Wyoming. The following maps show the location of our mining property, as of December 31, 2022:

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Figure 2.1. General Location Map

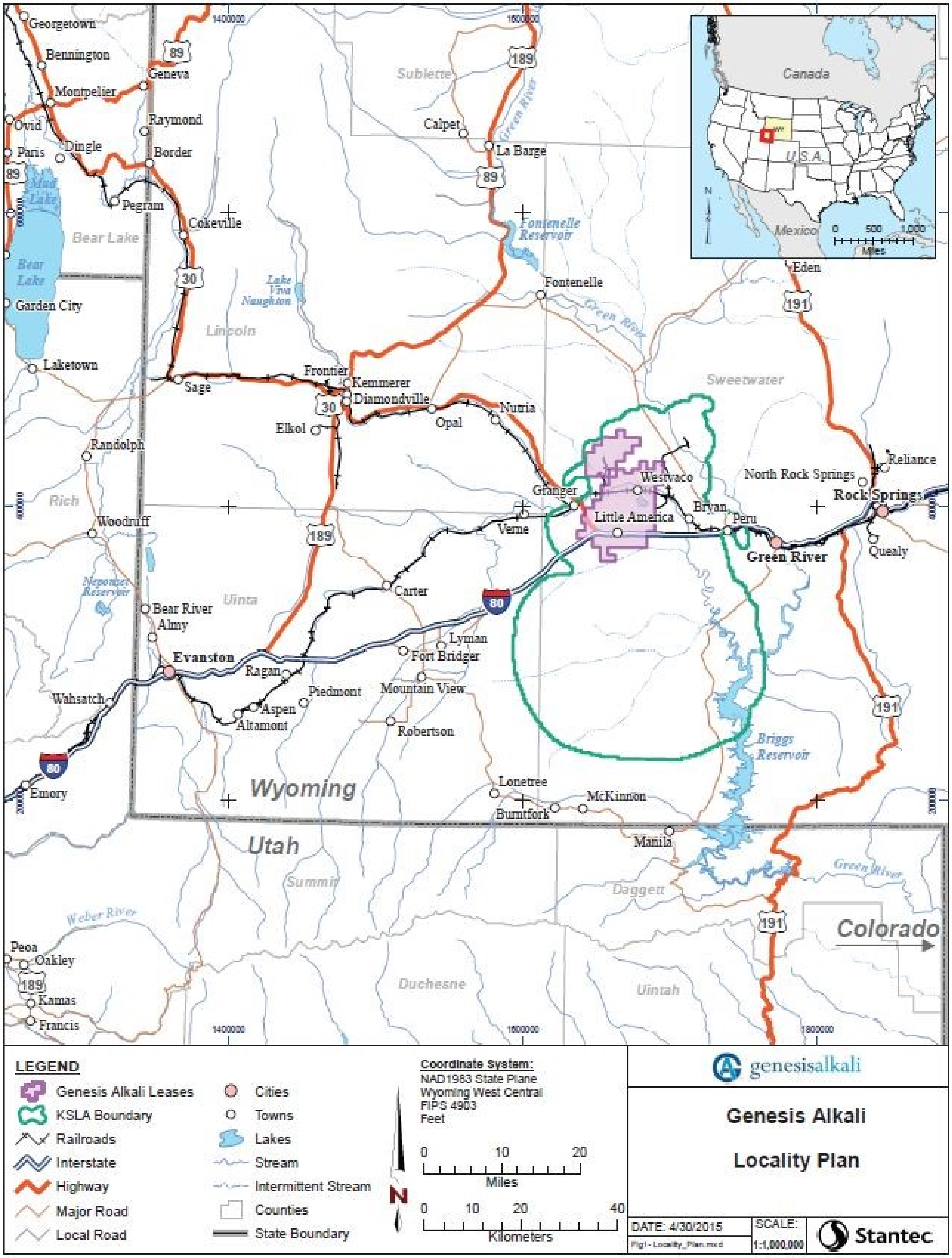

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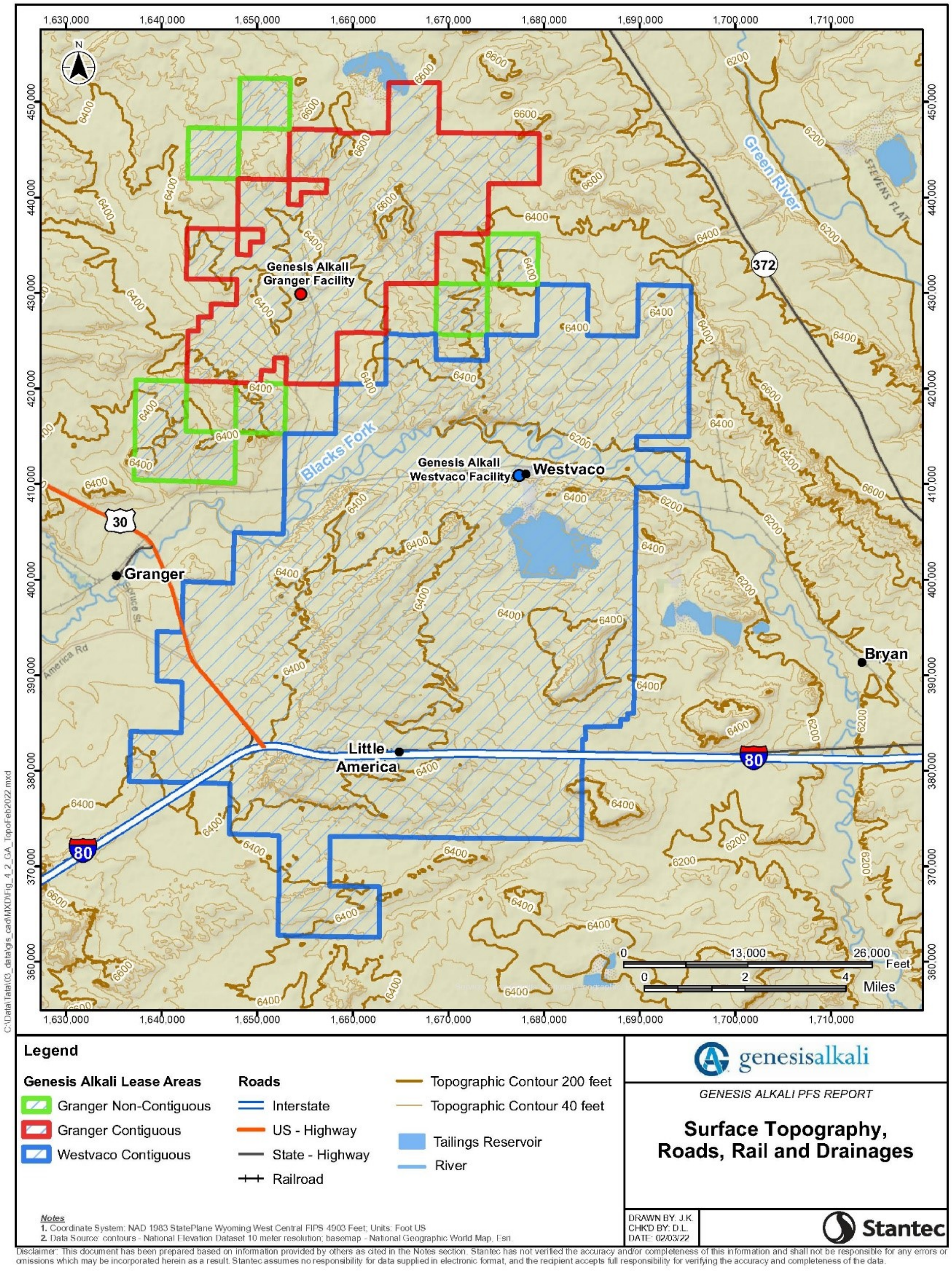
Figure 2.2. Map of Mining Areas



The Green River trona beds are collectively the largest known deposit of trona and the undisputed largest source of raw material feed for the production of natural soda ash in the world. The trona deposits are the result of very unusual, geological circumstances. Sodium-rich springs are believed to have fed ancient Lake Gosiute, a large, shallow inland lake that reached a maximum extent of over 15,000 square miles around 50 million years ago. In response to repetitive cycles of lake expansion, contraction and evaporation, and changes in temperature and salinity, trona was precipitated in beds of remarkable purity and extent. In addition to trona, the evaporite sodium mineral assemblage includes variable levels of other sodium carbonate minerals as well as halite (NaCl). At least 25 beds of natural trona in the Wilkins Peak Member of the Eocene Green River Formation exceed at least three feet in thickness and are estimated by the U.S. Geological Survey ("USGS") to contain a cumulative resource of over 100 billion tons of trona. Individual trona beds are numbered in ascending order and trona beds of significance lie at depths between approximately 400 to 2,000 feet. Our current dry mining and brine (solution) mining operations exploit three trona beds, and our reserves are contained in four trona beds.

Genesis has one trona mineral property, located in the Known Sodium Leasing Area in Southwest Wyoming, primarily encompassed by the Westvaco area and the Granger area. Due to differences in geology between these two mine areas, the mineral leases and, ultimately, the trona resources and reserve estimates have been separated into Westvaco contiguous leases, Granger contiguous leases and Granger non-contiguous leases. The table and figures below are summaries of our acreage under each mineral lease type as of December 31, 2022.

	Area by lessor *(acres)*			
	Contiguous leases		Non-contiguous leases	
Location	Granger	Westvaco	Granger	Remaining
Federal	4,236	19,699	—	320
State	1,280	6,403	640	13,280
Sweetwater	8,320	27,379	4,480	—
Total Area	13,836	53,481	5,120	13,600

Our trona resources and mining operations are held under leases covering 86,037 acres over portions of 23 townships, primarily in two contiguous units informally known as the "Westvaco" and "Granger" blocks. Mineral and mining rights are secured by leases from the Federal government, the State of Wyoming, and Sweetwater. We lease approximately 24,255 acres from the U.S. Government under the Mineral Leasing Act of 1920 (Title 30 §181) which includes trona under its definition of a "solid leasable mineral." Federal minerals are administered by the U.S. Bureau of Land Management ("BLM"). We lease 40,179 acres from Sweetwater who acquired the mineral rights from Anadarko Land Corporation, a subsidiary of Occidental following Occidental's August 2019 acquisition of Anadarko Petroleum Corporation, which acquired the ownership from the Union Pacific Resources Group ("UPRG") in 2000. The lease includes alternate sections of land for 20 miles on either side of the trans-continental railroad, originally granted to UPRG under the Pacific Railroad Act of 1862 and subsequent railroad land grants. We also lease 21,603 acres from the State of Wyoming. Our mineral leases have varying terms. Our private leases are held indefinitely by production, BLM and State Leases expire and are renewed every 10 years. Royalty payments range from 2% to 8% of the sales value of soda ash products. We believe that all of our leases were entered into at market terms.

See Item 1. "Business—Recent Developments and Status of Certain Growth Initiatives—Granger Production Facility Expansion" for more information.

Our senior secured credit facility is guaranteed by substantially all of our restricted subsidiaries and is secured by liens on a substantial portion of our assets, including our trona leases. Refer to further discussion over our senior secured credit facility in Item 7. "Liquidity and Capital Resources." Our Alkali senior secured notes are secured by GA ORRI's fifty-year 10% limited term overriding royalty interest in substantially all of the Alkali Business' trona mineral leases. See Item 1. "Recent Developments and Status of Certain Growth Initiatives—Alkai Senior Secured Notes Issuance and Related Transactions" for more information.

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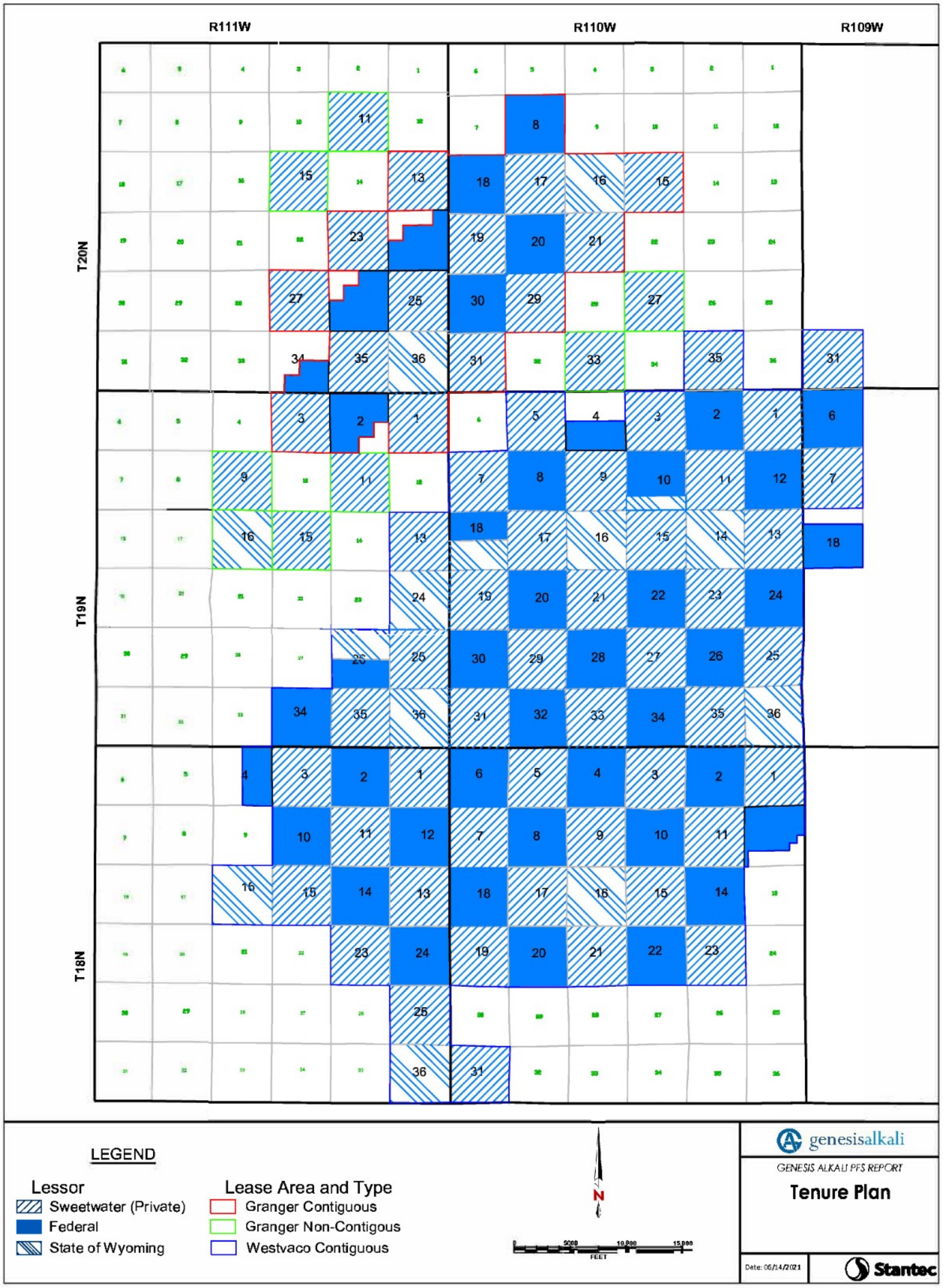
Figure 2.3. Lease Tenure



The table below shows certain key information for leases in the Westvaco contiguous leases, Granger contiguous leases, and Granger non-contiguous leases that are included in the resource and reserve estimates, including lessor, lease term, size, royalty information and expiration date.

Township	Range	Type	Location	Lessor	Lease No.	Royalty Rate (%)	Renewal (m/d/y)	Expiration (m/d/y)	Description	Acres
20	111	C	G	State	0-25386	6	4/2/2019	4/1/2029	Sec: 36	640
		C	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 13,23,25,27,35	3,200
		NC	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 11,15	1,280
		C	G	Federal	WYW0256443	2	8/1/2016	7/31/2026	Sec 26: NE4, SE4NW4, S2	520
		C	G	Federal	WYW0313075	2	8/1/2016	7/31/2026	Sec 24: Lots 1-4, SW4NE4, SE4NW4, SW4, W2SE4	482
		C	G	Federal	WYW0313077	2	8/1/2016	7/31/2026	Sec 34: Lots 2-4, N2SE4	216
20	110	C	G	State	0-25384A	6	4/2/2019	4/1/2029	Sec: 16	640
		C	W	Sweetwater	701-01	8	11/1/1997	2047+	Sec: 35	640
		NC	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 27,33	1,280
		C	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 15,17,19,21,29,31	3,840
		C	G	Federal	WYW0252727	2	8/1/2016	7/31/2026	Sec 30: Lots 1-4, E2, E2W2	617
		C	G	Federal	WYW-085356	2	8/1/2016	7/31/2026	Sec: 8, 20, Sec 18: LOTS 1-4, E2, E2W2	1,894
20	109	C	W	Sweetwater	701-01	8	11/1/1997	2047+	Sec: 31	640
19	111	C	W	State	0-24406	6	7/2/2018	7/1/2028	Sec: 36	640
		C	W	State	0-24407	6	7/2/2018	7/1/2028	Sec: 24,26	960
		NC	G	State	0-25386	6	4/2/2019	4/1/2029	Sec: 16	640
		NC	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 9,11,15	1,920
		C	G	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 1,3	1,280
		C	W	Sweetwater	704-01	8	3/17/1976	2006 +	Sec: 13	640
		C	W	Sweetwater	715-01	8	5/30/1991	2021 +	Sec: 25,35	1,280
		C	W	Federal	WYW0057154	2	8/1/2016	7/31/2026	Sec: 34	640
		C	G	Federal	WYW0256443	2	8/1/2016	7/31/2026	Sec 2: Lots 1-4, S2N2, SW4, NW4SE4	507
		C	W	Federal	WYW-148787	2	8/1/2016	7/31/2026	Sec 26: S2	320
19	110	C	W	State	0-18730	6	9/2/2014	9/1/2024	Sec: 16	640
		C	W	State	0-18731	6	9/2/2014	9/1/2024	Sec: 14	640
		C	W	State	0-18732	6	9/2/2014	9/1/2024	Sec: 36	640
		C	W	State	0-24876	6	9/2/2018	9/1/2028	Sec: 10, S2S2, Sec 18 S2	477
		C	W	Sweetwater	701-01	8	11/1/1997	2047+	Sec: 1,3,5,7,9,11,13,15,17,19,21,23,25,27,29,33,35	10,739
		C	W	Sweetwater	705-01	8	12/10/1976	2006 +	Sec: 31	640
		C	W	Federal	WYE0021612	2	8/1/2016	7/31/2026	Sec: 22,24,26,28	2,560
		C	W	Federal	WYW0053867	2	8/1/2016	7/31/2026	Sec 20, Sec 30: LOTS 1-4, E2, E2W2,Sec: 32, 34	2,556
		C	W	Federal	WYW0053868	2	8/1/2016	7/31/2026	Sec: 2 LOTS 1-4, S2N2, S2, Sec 10: N2,N2S2, Sec: 12	2,000
		C	W	Federal	WYW0252726	2	8/1/2016	7/31/2026	Sec: 8	640
		C	W	Federal	WYW0323406	2	12/1/2017	11/30/2027	Sec 18: Lots 1-2, NE4,E2NW4	317
		C	W	Federal	WYW-148786	2	8/1/2016	7/31/2026	Sec 4: S2	320
19	109	C	W	State	0-25382	6	4/2/2019	4/1/2029	Sec 18, S2NE:SENW:E2SW:SE: Lots 2, 3, 4	486
		C	W	Sweetwater	701-01	8	11/1/1997	2047+	Sec: 7	640
		C	W	Federal	WYW0053868	2	8/1/2016	7/31/2026	Sec 6: LOTS 1-7, S2NE4, SE4NW4, E2SW4, SE4	417
18	111	C	W	State	0-25328A	6	3/2/2019	3/1/2029	Sec: 36	640
		C	W	State	0-40218	6	9/2/2018	9/1/2028	Sec: 16	640
		C	W	Sweetwater	715-01	8	5/30/1991	2021 +	Sec: 1,3,11,13,15,23,25	4,480
		C	W	Federal	WYW0064005	2	8/1/2016	7/31/2026	Sec 4: LOTS 1-2, S2NE4, SE4, Sec: 10	960
		C	W	Federal	WYW0064006	2	8/1/2016	7/31/2026	Sec: 12,14,24	1,920
		C	W	Federal	WYW-148787	2	8/1/2016	7/31/2026	Sec 2: LOTS 1-4, S2N2, S2	642
18	110	C	W	State	0-25328	6	3/2/2019	3/1/2029	Sec: 16	640
		C	W	Sweetwater	705-01	8	12/10/1976	2006 +	Sec: 1,3,5,7,9,11,13*,15,17,21,23	6,400
		C	W	Sweetwater	715-01	8	5/30/1991	2021 +	Sec: 19,31	1,280
		C	W	Federal	WYW0044874	2	8/1/2016	7/31/2026	Sec: 12*,14,24	2,560
		C	W	Federal	WYW0044875	2	8/1/2016	7/31/2026	Sec 2: LOTS1-4, S2N2, S2, Sec 4 : LOTS 1-4, S2N2, S2, SEC 6: LOTS 1-7, S2NE4, SE4NW4, E2SW4, SE4, Sec 8.	2,572
		C	W	Federal	WYW0064006	2	8/1/2016	7/31/2026	Sec 18: LOTS 1-4, E2, E2,W2	635
		C	W	Federal	WYW-180015	2	8/1/2016	7/31/2026	Sec: 20	640

Notes:

'+ - Lease term extends indefinitely with continued operation on any of the leases (production of commercial quantities)

C - Contiguous Lease, NC - Non Contiguous Lease, G - Granger Area, W - Westvaco Area, Sweetwater - Sweetwater Trona OpCo LLC, OR - Overriding Royalty

* Portions of Section 12 and all of Section 13 in T18N R110W have been assigned to neighboring mine. No resources and reserves have been included in any bed for this lease area

Our Westvaco site is a production stage property that mines trona through both dry mining and brine (solution) mining methods. The Westvaco mine has been in uninterrupted, continuous operation since its start in 1947 by Westvaco Chemical Company. We acquired the Westvaco facility in September 2017.

The location of the Westvaco site and contiguous lease boundary can be found in Figure 2.2. It is located in Sweetwater County, Wyoming, 18 miles west of Green River and is accessible from Interstate 80 (I-80), a four-lane divided highway. I-80 exit 72 is approximately seven miles from the processing plant. The Union Pacific Railroad passes just north of the Westvaco facilities with siding to access the mainline. The two main population centers of Green River, Wyoming and Rock Springs, Wyoming are 18 miles and 30 miles to the east, respectively. Evanston, Wyoming is 66 miles to the west. The area population provides a more than adequate base for staffing the Westvaco facilities, with a pool of talent for management.

The Westvaco site has been in continuous operation since 1947. Westvaco Chemical Corporation notified Union Pacific in 1946 of its intention to sink a mine shaft and to construct a trona processing plant. A shaft was sunk in 1947 to the top of Bed 17 bringing the first skipload of trona to the surface in late 1947. In the fall of 1948, Westvaco Chemical Corporation was acquired by the Food Machinery Corporation (later known as "FMC"). In 1952, the Westvaco Division of FMC formed the Intermountain Chemical Company as Wyoming's first trona mining company. In 1953, Intermountain Chemical Company began producing refined soda ash by a sesquicarbonate process through a plant with a 300,000-ton capacity. The Alkali Chemical Division of FMC, including the trona mining and processing operations in the Green River Basin of Wyoming, was acquired by Tronox Alkali in May 2015. In September 2017, we acquired the Westvaco facility from Tronox Alkali and currently operate the facility through Genesis Alkali Wyoming, LP.

Infrastructure on the Westvaco site is very well developed as the facilities have been in operation for nearly seventy years. The infrastructure consists of sufficient truck and rail loadout facilities, electrical generation and transmission facilities, tailings facilities, product storage facilities, process facilities, natural gas pipelines and distribution facilities and water pipelines, treatment and distribution facilities. The Westvaco site also has ample buildings for offices, labs, change rooms, warehouses and maintenance shops.

Our Granger site is a production stage property that mines trona through brine (solution) mining methods.

The location of the Granger site and contiguous lease boundary can be found in Figure 2.2. The Granger site is located in Sweetwater County, Wyoming and can be accessed by traveling eight miles west of Green River, Wyoming on I-80, then turning north on state highway 372 and traveling about 12 miles to county road 11. The Granger site is accessible to the Union Pacific Railroad by a spur line that connects to the mainline near the town of Granger, Wyoming. The two main population centers of Green River, Wyoming and Rock Springs, Wyoming are 18 miles and 30 miles to the east, respectively. Evanston, Wyoming is 66 miles to the west. The area population provides a more than adequate base for staffing the Granger facilities, with a pool of talent for management.

The Granger mine and processing facility operated as an underground mine from 1976 to 2002. FMC acquired the properties in 1999 by acquiring Tg Soda Ash Inc., originally developed as a unit of Texasgulf and then owned by Elf Atochem. FMC converted the mine and mill to brine (solution) mining in 2005. The Alkali Chemical Division of FMC, including the trona mining and processing operations in the Green River Basin of Wyoming, was acquired by Tronox Alkali in May 2015. In September 2017, we acquired the Granger facility from Tronox Alkali and currently operate the facility through Genesis Alkali Wyoming, LP.

Infrastructure on the Granger site is very well developed as the facilities have operated for over 35 years. The infrastructure consists of sufficient rail loadout facilities, electrical transmission facilities, tailings facilities, product storage facilities, process facilities, natural gas pipelines and distribution facilities and water pipelines, treatment and distribution facilities. The Granger site also has ample buildings for offices, labs, change rooms, warehouses and maintenance shops.

As both the Westvaco site and Granger site have been operating for many years, all permits necessary for the operation of these facilities are in place. The Westvaco site includes approximately 36,000 permitted acres, of which the processing, support facilities, and tailings and evaporation ponds cover about 2,600 surface acres. The Granger facility includes about 16,000 permitted acres of which the processing, support facilities, and tailings and evaporation ponds cover about 1,800 surface acres. The WDEQ is the primary issuer of the environmental permits relevant to our operations, including air quality permits, mining and reclamation permits, as well as class III and class V underground injection control permits. With respect to each facility, permits, licenses and approvals are obtained as needed in the normal course of business based on our mine plans and federal, state, provincial and local regulatory provisions regarding mine permitting and licensing. There have been no outstanding violations or orders that would prevent continued operation of the plants and mines. This includes air, land, surface and groundwater, drinking water, wildlife, and waste. Approved reclamation plans are in place along with surety in the amounts of approximately $54 million for the Westvaco site and $28 million for the Granger site. Based on our historical permitting experience, we expect to be able to continue to obtain necessary mining permits and approvals to support historical rates of production.

At our Wyoming property, we use both mechanical and brine mining to mine the trona ore:

- *Dry Mining of Trona Ore.* We extract trona ore from our Westvaco underground mine by mechanized, continuous mining methods. Our current underground dry mine production is from trona bed 17, a near-horizontal bed approximately 10 feet thick at a depth from the surface of 1,500-1,650 feet. Ore is extracted primarily by our single longwall mining machine from an extensive network of parallel drifts and connecting cross-cuts, known as room-and-pillar mining, and from longwall mining. Longwall miners shear off successive panels of ore which drops onto a conveyor belt for delivery to the vertical hoisting shafts. Longwall mining provides higher recovery rates leading to extended mine life compared to other dry mining techniques. Development of the "tunnels" necessary to access and ventilate our longwall is through room-and-pillar mining completed primarily by our fleet of borer miners. The ore is conveyed underground to two hoisting operations where it travels about 1,600 feet vertically to the surface and is either taken directly into our processing facilities or stored on two outdoor stockpiles for future consumption.

- *Secondary Recovery Brine Mining.* We brine (solution) mine trona at both our Westvaco and Granger sites using secondary recovery techniques. Our secondary recovery mining starts with the recovery of water streams from our operations and non-trona solids ("insolubles") remaining from the processing of dry mined trona. The water and some insolubles are injected through a number of wells into the old dry mine workings at both our Westvaco and Granger sites. The insolubles settle out while the water travels through the old workings, dissolving sodium carbonate and sodium bicarbonate from the trona left behind during previous dry mining. Multiple pumping systems are used to pump the enriched brine to the surface for processing.

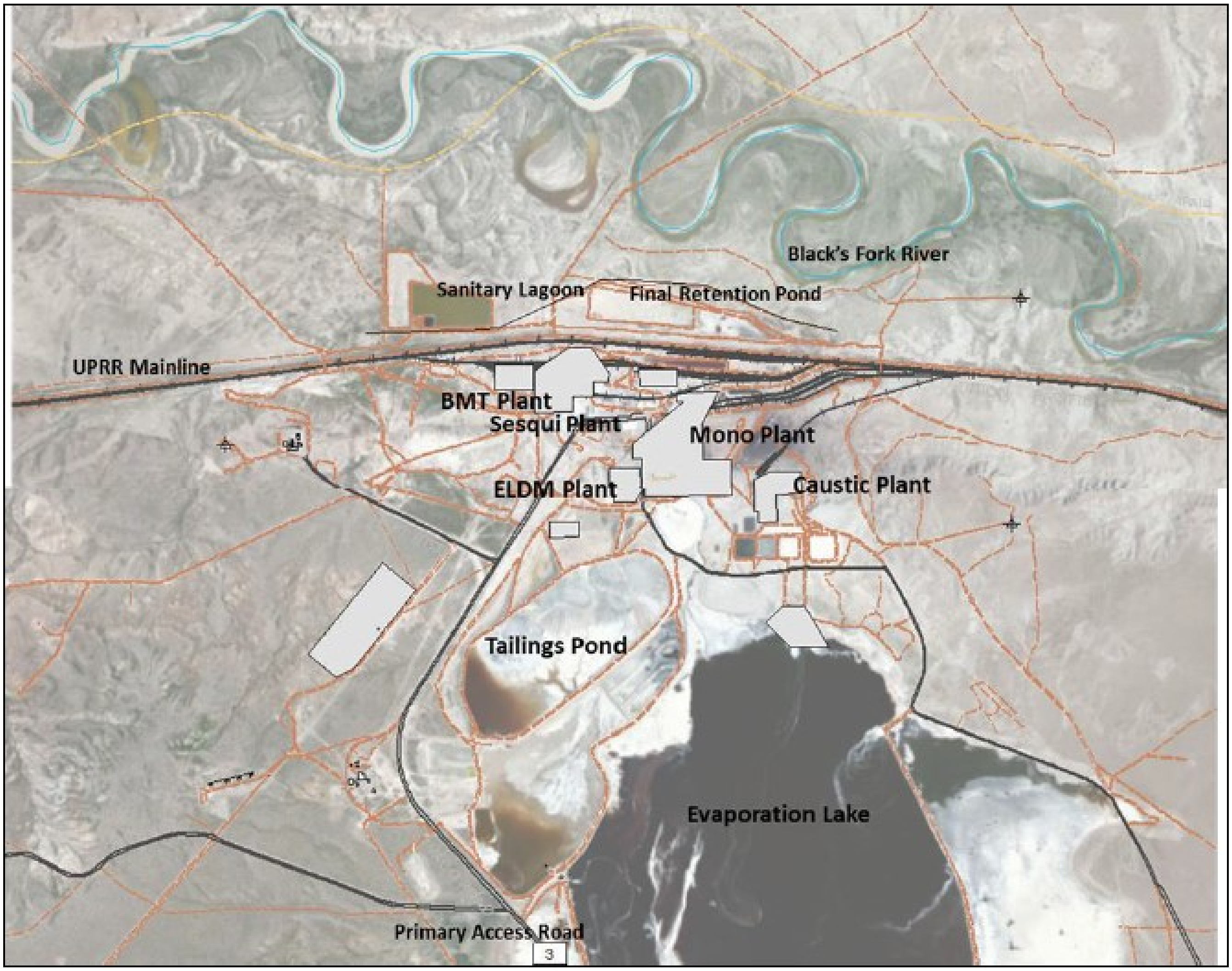
Our mineral recovery consists of four processing plants producing soda ash at two surface sites, Westvaco and Granger.

Dry mined and brine mined trona are processed into soda ash at our Westvaco site, located within the boundaries of our Westvaco contiguous lease blocks, involving multiple processing lines, steam generation facilities, evaporation ponds, spare parts warehouses, maintenance shops, and offices for engineering, production, and support staff. Mineral recovery at Westvaco site consists of three plants: the Sesqui plant, the Mono plant and the evaporation, lime, decahydrate crystallization, and monohydrate crystallization ("ELDM") plant.

Our Sesqui and Mono plants process dry-mined trona into soda ash. Crushing, dissolution in water, filtration, and crystallization techniques are used to produce the desired final products. The Mono plant consists of two separate processing lines to produce soda ash. Mono I began operation in May 1972, while Mono II was started up in January 1976. In the Mono plant, the ore is calcined with heat, prior to dissolution, to process the trona into soda ash by the removal of water and carbon dioxide. A final calcining step using steam produces a dense soda ash product from the Mono process. The Sesqui plant was the first soda ash plant built and operated at the Westvaco site. In our Sesqui plant, the calcination is performed at the end of the process, producing a light density soda ash that is preferred in applications desiring increased absorptivity. The Sesqui process also has the ability to produce refined sodium sesquicarbonate (which we sell under the names S-Carb® and Sesqui®™) for use as a buffer in animal feed formulations and in cleaning and personal care applications.

Our ELDM plant was constructed in 1995 and started operations in 1996. Our brine based ELDM plant uses the tailings return water as a feed source for soda ash production. Solution mined trona brine is processed into dense soda ash in our ELDM operation. The steps to produce soda ash are similar to the dry mined processes, except the crushing and dissolving steps are eliminated because the trona is already in a water solution as it leaves the mine.

Figure 2.4 Westvaco Surface Production Facilities

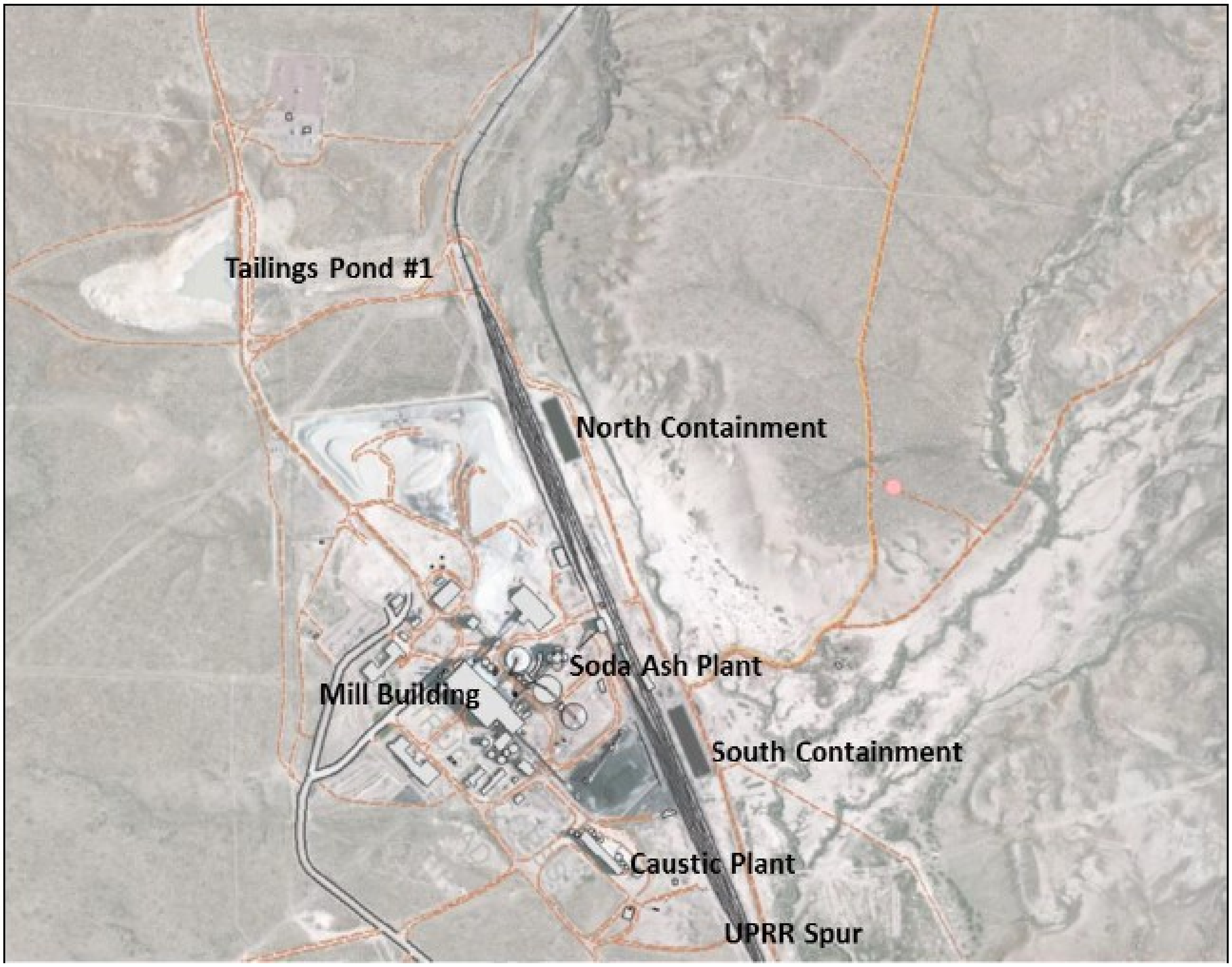


The Westvaco site also has a facility producing food, feed, and pharmaceutical grade sodium bicarbonate from a Sesqui plant intermediate product. Fifty percent caustic is produced on the Westvaco site for commercial sale from a Mono plant intermediate product.

The Westvaco site has successfully mined and processed trona ore at a profit for over 70 years. In this time, capital has been expended as appropriate to sustain the operation at the current production and operating cost level. We plan for capital expenditures necessary to replace equipment and facilities over time in order to sustain production and operating costs. We believe that the Westvaco site and its operating equipment are maintained in good working condition.

Solution mined trona brine is processed into soda ash at our Granger plant, located within the boundaries of the Granger contiguous lease blocks, and involves multiple processing lines, steam generation facilities, evaporation ponds, spare parts warehouses, maintenance shops, and offices for engineering, production, and support staff. The steps to produce soda ash are similar to the dry mined processes, except the crushing and dissolving steps are eliminated because the trona is already in a water solution as it leaves the mine.

Figure 2.5. Granger Surface Production Facilities



The Granger site has successfully mined and processed trona ore at a profit for over 35 years. In this time, capital has been expended as appropriate to sustain the operation at the current production and operating cost level. The Granger Optimization Project is underway with the upgraded operation scheduled to start in the second half of 2023. Capital expenditures are generally for sustaining production and operating costs except for some remaining capital for our Granger Optimization Project. We believe that the Granger site and its operating equipment are maintained in good working condition.

The total book value of the Westvaco and Granger sites as of December 31, 2022 and December 31, 2021 was approximately $1,528 million and $1,439 million, respectively.

In many cases, market demand drives annual production so that actual production may be less than plant capacities. The table below shows annual production from our trona property and its four plants for the fiscal years ended December 31, 2022, 2021 and 2020.

	Year ended December 31,		
	2022	2021	2020
Total (in thousands of tons)	3,635	3,483	3,206

On January 1, 2023, we restarted our original Granger facility (which was put in cold standby in the second half of 2020) and its estimated 500,000 tons of annual production capacity and expect to complete the Granger Optimization Project and its incremental 750,000 tons of annual production capacity in the second half of 2023.

Summaries of our mineral resources and reserves for the fiscal year ended December 31, 2022 are set forth in the tables below:

Area	Resource Category[(1)]	Million short tons (dry weight)	Grade (% Trona)[(2)]
Granger Contiguous Leases	Measured	617	84
	Indicated	145	89
	Measured + Indicated	762	85
Westvaco Contiguous Lease Area	Measured	1,067	88
	Indicated	158	84
	Measured + Indicated	1,225	87
	Inferred	4	80
Granger Non-Contiguous Leases	Measured	87	85
	Indicated	60	84
	Measured + Indicated	147	85
	Inferred	3	84
Total	Measured + Indicated	2,134	86
Total	Measured + Indicated + Inferred	2,141	86

(1) Mineral resources are exclusive of mineral reserves, which are summarized in the table below. Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no certainty that all or any part of the mineral resources will be converted into mineral reserves upon application of modifying factors.

(2) Based on the analysis described in Section 11.3 of the TRS, no economic cutoff grade has been applied to the resource given the long history of uninterrupted trona mining on the property, spatial consistency of the trona content and overall low insoluble and halite content. No elements or compounds from within the beds were identified as having a material impact on the ability to extract trona from the beds via mechanical or brine (solution) mining methods.

Reserve Area/Type	Resource Category	December 31, 2022 Million short tons (dry weight)[1]	December 31, 2022 Grade (% Trona)[5]	December 31, 2021 Million short tons (dry weight)[1]	December 31, 2021 Grade (% Trona)[5]
Westvaco dry extraction	Proven[2]	252	88	257	88
	Probable[2]	179	88	179	88
	Total Reserves[3]	431	88	436	88
Westvaco solution mining	Proven[2]	—		—	
	Probable[2]	369	88	371	88
	Total Reserves[4]	369	88	371	88
Granger solution mining	Proven[2]	—		—	
	Probable[2]	72	85	72	85
	Total Reserves[4]	72	85	72	85
Total solution mining	Total Reserves[4]	441	88	443	88
Total dry extraction and solution mining	Total Reserves	872	87	879	87

(1) Our trona ore reserves are calculated from in-place trona-bearing material that can be economically and legally extracted and processed into commercial products at the time of reserve determination. Our reserves estimates are developed using industry-standard procedures and have been reviewed internally and externally to ensure compliance with subpart 1300 of Regulation S-K.

(2) We use "measured and indicated" resources as the primary basis in determining our proven and probable reserves. We define proven reserves and probable reserves as follows:

a. Proven dry-mining reserves are measured reserves that fall within a 0.5 mile radius from drillhole data points or previously mined areas with a 7.0 feet minimum ore thickness.

b. Probable dry-mining reserves are indicated reserves that fall between 0.5 miles and 1.0 miles from drillhole data points or previously mined areas with a 7.0 feet minimum ore thickness.

c. All brine (solution) mining reserves are designated as probable based on the degree of confidence in the reserve estimate related to uncertainties involving brine flow paths, trona ore surface area available for dissolution, and the inaccuracy of depletion verification methods. They consist of both measured resources falling within a 0.5 mile radius from drillhole data points or previously mined areas and indicated resources that fall between 0.5 miles and 1.0 miles from drillhole data points or previously mined areas. Brine (solution) mining reserves are not limited to a minimum ore thickness, but rather are subjected to a 50 foot halo limit into large blocks of trona adjacent to areas impacted by previous dry mining and adjacent to areas planned for future dry mining.

(3) Estimated dry mining ore reserves include dilution from un-mineralized material within and marginal to the trona ore bed. We exclude support pillars from dry mining reserves, but a portion of the trona contained in the pillars is recovered by brine (solution) mining. We apply a bulk density factor of 133 lb/cu ft for conversion of volumes to mass. Key dry mining parameters include minimum trona ore bed thickness.

(4) Our brine (solution) mining ore reserves are reported on an in-place basis, inclusive of dilution from insoluble material that remains in the ground. The brine (solution) mining reserves are calculated using recovery parameters developed from our 20-plus years of cumulative secondary recovery brine (solution) mining experience. Key factors include the surface area of remaining support pillars and other trona-mineralized surfaces exposed to liquid brines injected into voids created by dry mining, solubility and alkalinity data, and predicted dissolution rates.

(5) Our ore reserves have a minimum trona grade of 66.2% (occurs in Bed 15). The balance of the ore consists of clays, shales, and other impurities.

Total trona reserves for the fiscal year ended December 31, 2022 decreased approximately seven million short tons from fiscal year ended December 31, 2021, representing approximately 0.8% of the total reserves.

Our 2021 reserves were largely based on an assessment completed by Stantec, an external QP, meeting the requirements of subpart 1300 of Regulation S-K.

Dry mining reserves at year end 2022 are approximately five million short tons, or 1.2%, lower than year end 2021 reserves as a result of dry mine extraction in 2022.

Brine (solution) mining reserves at year end 2022 are approximately two million short tons, or 0.5% lower than year end 2021 reserves as a result of brine (solution) mining extraction in 2022.

Our mineral resource and reserve estimates are based on many factors, including the area and volume covered by our mining rights, assumptions regarding our extraction rates (based upon an expectation of operating the mines on a long-term basis) and the quality of in-place reserves. Stantec reviewed our data at the end of 2022 and determined that, other than updating reserves to reflect ore consumption in 2022, there was no material change in mineral resources and reserves disclosed in the TRS and the TRS can be relied upon in stating 2022 reserves. Key assumptions and parameters relating to our mineral resources and reserves at the Westvaco site are discussed in the TRS, and include, among other things, the following:

- The economic analysis of our resources and reserves was prepared based on 2022 dollars with annual inflation at 2.5% which has been applied to revenue, operating costs, and capital spending.
- The production schedule to mine and process the remaining reserves is based on the existing production capacity of the mine and processing plants.
- Bed 15, which lies approximately 35 to 55 feet below bed 17, can be effectively dry mined starting in roughly the year 2071, after the completion of longwall mining in overlying areas of Bed 17.
- Future secondary brine (solution) mining recoveries are similar to those that have been demonstrated thus far in certain areas of our Westvaco mine.
- Prices for bulk soda ash are based on the 2020 USGS price, which was escalated to establish the 2022 price while prices for bag and specialty products were consistent with recent history.
- Cash production costs include dry mining, brine (solution) mining, processing, royalties and production taxes, insurance, and administrative costs. Administrative costs include mine administration and corporate overhead allocations. Other costs include distribution, sales general and administrative, and research and development costs.
- The operating costs are based on our historical averages. Other costs are based on our five-year estimate. Costs are assumed to be similar in the future with annual inflation similar to pricing inflation. Modeled underground dry mining costs include a step change in approximately 50 years when longwall mining is phased out and replaced by borer and continuous mining in Bed 15 and the remaining areas of Bed 17.
- Capital expenditures are generally for sustaining production and operating costs. Sustaining cap-ex in the future is assumed similar to recent history and short term projections, with inflation similar to product pricing escalation.
- All leases remain valid throughout the time required to mine the reserves
- All permits remain valid throughout the life of the operation, and no new laws are enacted that require any extraordinary compliance which would significantly impact production or cost.
- New permits and approved mine plans will be obtained for mining reserves that lie within existing leases, but outside of our current mining permit areas.
- Tailings storage capacity will be developed as necessary over the life of the mine and processing plants.
- Because our Alkali Business is structured as a pass-through entity for income tax purposes, there is no provision for income taxes in the cash flow analysis.

Internal Control Disclosure

The modeling and analysis of our resources and reserves has been developed by our mine personnel and reviewed by several levels of internal management and external consultants, including the QP. The development of such resources and reserves estimates, including related assumptions, was a collaborative effort between the QP and our management. This section summarizes the internal control considerations for our development of estimations, including assumptions, used in resource and reserve analysis and modeling.

When determining resources and reserves, as well as the differences between resources and reserves, management developed specific criteria, each of which must be met to qualify as a resource or reserve, respectively. These criteria, such as demonstration of economic viability, points of reference and grade, are specific and attainable. The QP and our management agree on the reasonableness of the criteria for the purposes of estimating resources and reserves. Calculations using these criteria are reviewed and validated by the QP.

We base our mineral reserve estimates on detailed geological, geotechnical, mine engineering and mineral processing inputs, and financial models developed and reviewed by management and technical staff of our Alkali Business, who possess years of experience directly related to the resources, mining and processing characteristics or financial performance of our operations. Additionally, our management and technical staff includes senior personnel who have remained closely involved with each of our active mining and mineral processing operations.

In preparing our reserve estimates for our Alkali operations at Green River, Wyoming, we follow accepted mining industry practice and are guided by our long-term experience in extraction of trona ore from underground mining and sodium carbonate from brine (solution) mining in the district. Estimates of recoverable reserves for both techniques are routinely reconciled with actual production, and our Alkali ore reserves disclosures comply with subpart 1300 of Regulation S-K.

All estimates require a combination of historical data and key assumptions and parameters. When possible, resources and data from generally accepted industry sources, such as governmental resource agencies, were used to develop these estimations.

Management also assesses risks inherent in mineral resource and reserve estimates, such as the accuracy of geophysical data that is used to support mine planning, identify hazards and inform operations of the presence of mineable deposits. Also, management is aware of risks associated with potential gaps in assessing the completeness of mineral extraction licenses, entitlements or rights, or changes in laws or regulations that could directly impact the ability to assess mineral resources and reserves or impact production levels. Risks inherent in overestimated reserves can impact financial performance when revealed, such as changes in amortizations that are based on life of mine estimates.

Documentation of sample security measures, quality control and assurance (“QAQC”) was not observed by the QP. However, given that there has been successful underground dry mining of Bed 17 and Bed 20 within and nearby the exploration sample sites, it would appear that previous sampling methods, sample security, analysis methods, and internal QAQC measures met the requirements for successful mine planning over the history of the Westvaco site and Granger site mining operations.

Item 3. Legal Proceedings

We are involved from time to time in various claims, lawsuits and administrative proceedings incidental to our business. In our opinion, the ultimate outcome, if any, of such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. See Note 21 to our Consolidated Financial Statements in Item 8.

Item 103 of SEC Regulation S-K requires disclosure of certain environmental matters when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that we reasonably believe will exceed a specified threshold. Pursuant to recent SEC amendments to this item, we will be using a threshold of $1 million for such proceedings. We believe that such threshold is reasonably designed to result in disclosure of environmental proceedings that are material to our business or financial condition. Applying this threshold, there are no environmental matters to disclose for this period.

Item 4. Mine Safety Disclosures

Information regarding mine safety and other regulatory action at our mine in Green River, Wyoming is included in Exhibit 95 to this Form 10-K.

PART II

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

Our Class A common units are listed on the New York Stock Exchange, or NYSE, under the symbol "GEL."

At February 23, 2023, we had 122,539,221 Class A common units outstanding. As of December 31, 2022, the closing price of our common units was $10.21 and we had approximately 28,000 record holders of our Class A common units, which include holders who own units through their brokers "in street name." Additionally, we have issued 25,336,778 Class A Convertible Preferred Units for which there is no established public trading market.

Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions to our 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. Working capital borrowings are generally borrowings that are made under our senior secured credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

The full definition of available cash is set forth in our partnership agreement and amendments thereto, which are incorporated by reference as an exhibit to this Form 10-K.

See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Expenditures and Distributions Paid to our Unitholders" and Note 11 to our Consolidated Financial Statements in Item 8 for further information regarding restrictions on our distributions. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding securities authorized for issuance under equity compensation plans.

Item 6. Selected Financial Data

None.

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

Introduction

We are a growth-oriented MLP formed in Delaware in 1996. Our common units are traded on the New York Stock Exchange, or NYSE, under the ticker symbol "GEL." We are (i) a provider of an integrated suite of midstream services (primarily transportation, storage, sulfur removal, blending, terminaling and processing) for a large area of the Gulf of Mexico and the Gulf Coast region of the crude oil and natural gas industry and (ii) one of the leading producers in the world of natural soda ash. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, refinery-related plants, storage tanks and terminals, railcars, rail unloading facilities, barges and other vessels, and trucks. The other core focus of our business is our trona and trona-based exploring, mining, processing, producing, marketing and selling business based in Wyoming (our "Alkali Business"). Our Alkali Business mines and processes trona from which it produces natural soda ash, also known as sodium carbonate (Na_2CO_3), a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products, and has been operating for over 70 years.

Included in Management's Discussion and Analysis are the following sections:

- Overview of 2022 Results
- Recent Developments and Initiatives
- Results of Operations
- Other Consolidated Results
- Financial Measures
- Liquidity and Capital Resources
- Guarantor Summarized Financial Information
- Critical Accounting Estimates
- Recent Accounting Pronouncements

Overview of 2022 Results

We reported Net Income Attributable to Genesis Energy, L.P. of $75.5 million in 2022 compared to Net Loss Attributable to Genesis Energy, L.P. of $165.1 million in 2021.

Net Income Attributable to Genesis Energy, L.P. in 2022 was impacted by: (i) an increase in segment margin of $152.3 million compared to 2021 (which was inclusive of $70.0 million in cash receipts associated with our previously owned NEJD pipeline not included in operating income, see "Results of Operations" below for additional details on the results of our operating segments); (ii) a decrease in depreciation, depletion and amortization expense of $13.5 million and a decrease in interest expense of $7.6 million (see "Results of Operations" below for additional details); and (iii) cancellation of debt income of $8.6 million from the repurchase of certain of our senior unsecured notes on the open market throughout 2022, which is recorded in "Other expense, net." Additionally, we incurred an unrealized (non-cash) loss from the valuation of the embedded derivative associated with our Class A Convertible Preferred Units of $18.6 million in 2022 compared to an unrealized (non-cash) loss of $30.9 million in 2021 recorded within "Other expense, net." These increases were partially offset by higher net income that we attributed to our noncontrolling interests during 2022 as a result of the sale of our 36% interest in our CHOPS pipeline in the fourth quarter of 2021.

Cash flows from operating activities were $334.4 million for the 2022 period compared to $338.0 million for 2021. This decrease was primarily attributable to the 2021 period including $70.0 million in cash receipts associated with our previously owned NEJD pipeline and is included in cash flows from operating activities and changes in our working capital requirements. These were offset by higher segment margin reported during 2022.

Available Cash before Reserves (as defined below in "Financial Measures") increased $148.7 million in 2022 to $352.6 million as compared to 2021 Available Cash before Reserves of $203.9 million, primarily due to an increase in segment margin, which is further discussed below in "Results from Operations." See "Financial Measures" below for additional information on Available Cash before Reserves.

Segment Margin was $770.1 million in 2022, an increase of $152.3 million as compared to 2021. We currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. A more detailed discussion of our segment results and other costs is included below in "Results of Operations".

Distributions to Unitholders

On February 14, 2023, we paid a distribution of $0.15 per common unit related to the fourth quarter of 2022.

With respect to our Class A Convertible Preferred Units, we declared a quarterly cash distribution of $0.9473 per unit (or $3.789 on an annualized basis). These distributions were paid on February 14, 2023 to unitholders holders of record at the close of business January 31, 2023.

Recent Developments and Initiatives

Our primary objectives are to generate and grow stable free cash flows and continue to deleverage our balance sheet, while never wavering from our commitment to safe and responsible operations, as well as continue to advance and integrate our Environmental, Social and Governance ("ESG") program. We believe the following are important to meet our objectives:

- New and increased volumes on our existing offshore assets in the Gulf of Mexico through long-term contracted commercial opportunities that require minimal to no additional investment from us, including volumes from the Argos (scheduled for first production in 2023) and King's Quay (which achieved first oil in the second quarter of 2022 and has ramped to in excess of 100,000 barrels of oil equivalent per day) floating production systems.
- New volumes from long-term contracted offshore commercial opportunities in the Gulf of Mexico, including the Shenandoah development, which will tie into our SYNC pipeline (which is currently under construction) and further downstream to our CHOPS pipeline (which we are currently in the process of expanding the capacity of), and the Salamanca floating production system, which will tie into our existing SEKCO pipeline for further transportation downstream to our existing pipeline network. These developments and their associated volumes are expected to come online in late 2024 and 2025.
- Increased capacity for soda ash production by bringing the original Granger facility and its approximately 500,000 tons of annual production back online on January 1, 2023 and investing into our Granger Optimization Project, which is scheduled to begin first production in the second half of 2023 and ramp up to its design capacity of 750,000 tons per year over the subsequent nine to twelve months.
- The continued increase in demand for soda ash (including its anticipated participation in the energy transition).

We continue to have a significant amount of available borrowing capacity under our senior secured credit facility, which will allow us, when combined with our increasing free cash flow from operations as discussed above, to fund our high return capital projects, including our Granger Optimization Project, our SYNC pipeline and the expansion of our existing CHOPS pipeline (all of which are further discussed below), which will provide future cash flows to continue to further deleverage our balance sheet.

Offshore Growth Commitments and Capital Projects

During 2022, we entered into definitive agreements to provide transportation services for 100% of the crude oil production associated with two separate, standalone deepwater developments that have a combined production capacity of approximately 160,000 barrels per day. In conjunction with these agreements, we expect to spend total gross capital expenditures of approximately $650 million (or approximately $550 million net to our ownership interests) to: (i) expand the current capacity of the CHOPS pipeline; and (ii) construct a new, 100% owned, approximately 105 mile, 20" diameter crude oil pipeline (the "SYNC pipeline") to connect one of the developments to our existing asset footprint in the Gulf of Mexico. We plan to complete the construction in line with the producers' plan for the achievement of first oil production, which is currently expected in late 2024 or 2025. The producer agreements include long term take-or-pay arrangements and, accordingly, we are able to receive a project completion credit for purposes of calculating the leverage ratio under our senior secured credit facility throughout the construction period.

Granger Production Facility Expansion

On September 23, 2019, we announced the Granger Optimization Project along with the issuance of the Alkali Holdings preferred units. The anticipated completion date of the GOP is the second half of 2023 and the expansion is expected to increase our production at the Granger facilities by approximately 750,000 tons per year while also reducing our fixed cost per ton of production.

The proceeds received from the issuance of our Alkali Holdings preferred units assisted in the funding of the anticipated cost of the GOP. During the fourth quarter of 2021, we made the decision to fund the remaining construction costs required to complete the GOP through a combination of our internally generated free cash flows and availability under our senior secured credit facility, and subsequently, as noted above, redeemed the outstanding Alkali Holdings preferred units.

Results of Operations

In the discussions that follow, we will focus on our revenues, costs and expenses, as well as two measures that we use to manage the business and to review the results of our operations - Segment Margin and Available Cash before Reserves. Segment Margin and Available Cash before Reserves are defined in the "Financial Measures" section below.

Revenues, Costs and Expenses

Our revenues for the year ended December 31, 2022 increased $663.5 million, or 31%, from the year ended December 31, 2021, and our costs and expenses (excluding the gain on sale of assets in 2022) increased $464.2 million, or 23%, between the two periods, with a net increase to operating income (loss) of $199.3 million. The increase in our operating income during 2022 is primarily attributable to increased volumes and pricing within our sodium minerals and sulfur services segment and increased utilization and day rates in our marine transportation segment, as well as lower depreciation, depletion and amortization during 2022.

A substantial portion of our revenues and costs are derived from the purchase and sale of crude oil in our crude oil marketing business, which is included in our onshore facilities and transportation segment, revenues and costs associated with our Alkali Business, which is included in our sodium minerals and sulfur services segment, and revenues and costs associated with our offshore pipeline transportation segment. We describe, in more detail, the impact on revenues and costs for each of our businesses below.

As it relates to our crude oil marketing business, the average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange ("NYMEX") increased approximately 39% to $94.90 per barrel in 2022 as compared to $68.14 per barrel in 2021. We would expect changes in crude oil prices to continue to proportionately affect our revenues and costs attributable to our purchase and sale of crude oil and petroleum products, producing minimal direct impact on Segment Margin, Net income (loss) and Available Cash before Reserves. We have limited our direct commodity price exposure in our crude oil and petroleum products operations through the broad use of fee-based service contracts, back-to-back purchase and sale arrangements, and hedges. As a result, changes in the price of crude oil would proportionately impact both our revenues and our costs, with a disproportionately smaller net impact on our Segment Margin. However, we do have some indirect exposure to certain changes in prices for oil and petroleum products, particularly if they are significant and extended. We tend to experience more demand for certain of our services when prices increase significantly over extended periods of time, and we tend to experience less demand for certain of our services when prices decrease significantly over extended periods of time. For additional information regarding certain of our indirect exposure to commodity prices, see our segment-by-segment analysis below and the previous section above entitled "Risks Related to Our Business".

As it relates to our Alkali Business, our revenues are derived from the extraction of trona, as well as the activities surrounding the processing and sale of natural soda ash and other alkali specialty products, including sodium sesquicarbonate (S-Carb) and sodium bicarbonate (Bicarb), and are a function of our selling prices and volume sold. We sell our products to an industry-diverse and worldwide customer base. Our sales prices are contracted at various times throughout the year and for different durations. Our sales prices for volumes sold internationally and to ANSAC are contracted for the current year either annually in the prior year or periodically throughout the current year (often quarterly), and our volumes priced and sold domestically are contracted at various times and can be of varying durations, often multi-year terms. Our sales volumes can fluctuate from period to period and are dependent upon many factors, of which the main drivers are the global market, customer demand, economic growth, and our ability to produce soda ash. Positive or negative changes to our revenue, through fluctuations in sales volumes or sales prices, can have a direct impact to Segment Margin, Net income (loss) and Available Cash before Reserves as these fluctuations have a lesser impact to operating costs due to the fact that a portion of our costs are fixed in nature. Our costs, some of which are variable in nature and others are fixed in nature, relate primarily to the processing and producing of soda ash (and other alkali specialty products) and marketing and selling activities. In addition, costs include activities associated with mining and extracting trona ore, including energy costs and employee compensation. In our Alkali Business, during 2022, as noted above, we had positive effects to our revenues compared to 2021 (with a lesser impact to costs) due to favorable export pricing of soda ash and higher sales volumes as a result of increased economic and market demand. For additional information, see our segment-by-segment analysis below.

Our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations focus on integrated and large independent energy companies who make intensive capital investments (often in excess of a billion dollars) to develop large reservoir, long-lived crude oil and natural gas properties. Our revenues are primarily derived from the fees, typically on a per barrel basis, we charge to transport and deliver commodities (or reserve capacity on our infrastructure in some cases) downstream to other pipelines or refineries along the Gulf Coast. The shippers on our offshore pipelines are mostly integrated and large independent energy companies whose production is ideally suited for the vast majority of refineries along the Gulf Coast. Their large-reservoir properties and the related pipelines and other infrastructure needed to develop them are capital intensive and yet, we believe, economically viable, in most cases, even in volatile commodity price environments. Costs include activities associated with employee compensation and benefits, the maintenance of our pipelines and pipeline related infrastructure, marketing, and other variable type expenses associated with operating the business. We do not expect changes in commodity prices to impact our Net income (loss), Available Cash before Reserves or Segment Margin derived from our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations in the same manner in which they impact our revenues and costs derived from the purchase and sale of crude oil and petroleum products.

In addition to our crude oil marketing business, Alkali Business and offshore pipeline transportation and handling operations discussed above, we continue to operate in our other core businesses, including our sulfur services business and our onshore-based refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners. Refiners are the shippers of approximately 98% of the volumes transported on our onshore crude pipelines, and refiners contract for approximately 90% of the revenues from our marine inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes.

Additionally, changes in certain of our operating costs between the respective periods, such as those associated with our sodium minerals and sulfur services, offshore pipeline and marine transportation segments, are not directly correlated with crude oil prices. We discuss certain of those costs in further detail below in our segment-by-segment analysis.

Included below is additional detailed discussion of the results of our operations focusing on Segment Margin and other costs including general and administrative expenses, depreciation, depletion and amortization, gain on sale of assets, interest expense and income taxes.

Segment Margin

The contribution of each of our segments to total Segment Margin in each of the last three years was as follows:

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Offshore pipeline transportation	$ 363,373	$ 317,560	$ 270,078
Sodium minerals and sulfur services	306,718	166,773	130,083
Onshore facilities and transportation	33,755	98,824	147,254
Marine transportation	66,209	34,572	60,058
Total Segment Margin	$ 770,055	$ 617,729	$ 607,473

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

Offshore Pipeline Transportation Segment

Operating results and volumetric data for our offshore pipeline transportation segment are presented below:

	Year Ended December 31,	
	2022	2021
	(in thousands)	
Offshore crude oil pipeline revenue, net to our ownership interest and excluding non-cash revenues	$ 287,318	$ 264,690
Offshore natural gas pipeline revenue, excluding non-cash revenues	46,660	41,776
Offshore pipeline operating costs, net to our ownership interest and excluding non-cash expenses	(75,811)	(71,812)
Distributions from equity investments[1]	73,206	82,906
Distributions from unrestricted subsidiaries[2]	32,000	—
Offshore pipeline transportation Segment Margin	$ 363,373	$ 317,560
Volumetric Data 100% basis:		
Crude oil pipelines (average Bbls/day unless otherwise noted):		
CHOPS	207,008	189,904
Poseidon	257,444	263,169
Odyssey	84,682	114,128
GOPL[3]	6,964	7,826
Total crude oil offshore pipelines	556,098	575,027
Natural gas transportation volumes (MMBtus/day)	343,347	345,870
Volumetric Data net to our ownership interest[4]:		
Crude oil pipelines (average Bbls/day unless otherwise noted):		
CHOPS[5]	132,485	180,173
Poseidon	164,764	168,428
Odyssey	24,558	33,097
GOPL[3]	6,964	7,826
Total crude oil offshore pipelines	328,771	389,524
Natural gas transportation volumes (MMBtus/day)	108,908	107,417

(1) Offshore pipeline transportation Segment Margin includes distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2022 and 2021, respectively.

(2) Offshore pipeline transportation Segment Margin in 2022 includes distributions received from one of our unrestricted subsidiaries, Independence Hub LLC, of $32.0 million associated with the sale of our 80% owned platform asset.

(3) One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided interest in the Eugene Island pipeline system.

(4) Volumes are the product of our effective ownership interest throughout the year, including changes in ownership interest, multiplied by the relevant throughput over the given year.

(5) On November 17, 2021, we divested a 36% minority interest in our CHOPS pipeline. The volumes for 2021 represent our 100% ownership during 2021 through November 16, 2021 and our 64% ownership from November 17, 2021 through December 31, 2021.

Offshore Pipeline Transportation Segment Margin for 2022 increased $45.8 million, or 14%, from 2021, primarily due to (i) distributions received from one of our unrestricted subsidiaries, Independence Hub LLC, of $32 million, net to our interest, for the sale of our 80% owned platform asset, and (ii) increased crude oil and natural gas activity, primarily from first oil achieved at the King's Quay FPS on April 12, 2022, which supports volumes from the Khaleesi, Mormont and Samurai field developments, succeeded by a ramp up in production that has reached 100,000 barrels of oil equivalent per day. The King's Quay FPS is life-of-lease dedicated to our 100% owned crude oil and natural gas lateral pipelines and further downstream to our 64% owned Poseidon and CHOPS crude oil systems and our 25.67% owned Nautilus natural gas system for ultimate delivery to shore. Additionally, our 2022 segment margin benefited from our minimum volume commitments associated with the Argos FPS, which will handle production from the Mad Dog 2 field development and is anticipated to come online in the middle part of 2023. These increases were partially offset by an increased level of operational downtime during 2022 that was primarily a result of unplanned operational maintenance associated with one of our lateral pipelines that also impacted volumes on our main pipeline downstream of it in the first quarter of 2022, and a period of unplanned producer downtime at numerous fields connected to our pipeline infrastructure in the fourth quarter of 2022, which returned to normal operations by the end of the year. Lastly, the 2022 period was impacted, relative to the 2021 period, by our decrease in ownership of CHOPS, as we sold a 36% minority interest on November 17, 2021.

Sodium Minerals and Sulfur Services Segment

Operating results for our sodium minerals and sulfur services segment were as follows:

	Year Ended December 31,	
	2022	2021
Volumes sold :		
NaHS volumes (Dry short tons "DST")	128,851	114,292
Soda Ash volumes (short tons sold)	3,096,494	2,994,507
NaOH (caustic soda) volumes (DST sold)	90,876	84,278
Revenues (in thousands):		
NaHS revenues, excluding non-cash revenues	$ 183,966	$ 128,959
NaOH (caustic soda) revenues	74,284	42,182
Revenues associated with our Alkali Business	896,125	696,117
Other revenues	8,226	4,728
Total segment revenues, excluding non-cash revenues[1]	$ 1,162,601	$ 871,986
Sodium minerals and sulfur services operating costs, excluding non-cash items[1]	(855,883)	(705,213)
Segment Margin (in thousands)	$ 306,718	$ 166,773
Average index price for NaOH per DST[2]	$ 1,118	$ 787

(1) Totals are for external revenues and costs prior to intercompany elimination upon consolidation.

(2) Source: IHS Chemical.

Sodium minerals and sulfur services Segment Margin for 2022 increased $139.9 million, or 84%, from 2021. This increase is primarily due to more favorable export and domestic pricing and higher sales volumes in our Alkali Business and higher NaHS sales volumes in our refinery services business during 2022. In our Alkali Business, we have continued to see strong demand improvement and growth as a result of the global economic recovery and the continued application of soda ash in everyday end use products, including solar panels, and in the production of lithium carbonate and lithium hydroxide, which are some of the building blocks of lithium batteries that are expected to play a large role in the anticipated energy transition. This continued demand, combined with flat or even slightly declining supply of soda ash in the near term, has tightened the overall supply and demand balance and created a higher price environment for our tons and increased contribution to Segment Margin during 2022. We expect our weighted average sales price for 2023 to exceed 2022 prices. Additionally, we successfully restarted our original Granger production facility on January 1, 2023 and are still on schedule to complete our Granger Optimization Project in the second half of 2023, which represents an incremental 750,000 tons of annual production that we anticipate to ramp up. In our refinery services business, we had an increase in NaHS sales volumes and the corresponding pricing of these sales volumes in 2022 due to an increase in demand from our mining customers as a result of the continued global economic recovery and the use of NaHS in the mining of copper, which is used in products that are a key part of the anticipated energy transition.

Onshore Facilities and Transportation Segment

Our onshore facilities and transportation segment utilizes an integrated set of pipelines and terminals, trucks and barges to facilitate the movement of crude oil and refined products on behalf of producers, refiners and other customers. This segment includes crude oil and refined products pipelines, terminals and rail unloading facilities operating primarily within the U.S. Gulf Coast crude oil market. In addition, we utilize our trucking fleet that supports the purchase and sale of gathered and bulk-purchased crude oil, as well as purchased and sold refined products. Through these assets we offer our customers a full suite of services, including the following as of December 31, 2022:

- facilitating the transportation of crude oil from producers to refineries and from our terminals, as well as those owned by third parties, to refiners via pipelines;
- shipping crude oil and refined products to and from producers and refiners via trucks and pipelines;
- storing and blending of crude oil and intermediate and finished refined products;
- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining;
- purchasing products from refiners, transporting those products to one of our terminals and blending those products to a quality that meets the requirements of our customers and selling those products (primarily fuel oil, asphalt and other heavy refined products) to wholesale markets; and
- unloading railcars at our crude-by-rail terminals.

We also may use our terminal facilities to take advantage of contango market conditions for crude oil gathering and marketing and to capitalize on regional opportunities which arise from time to time for both crude oil and petroleum products.

Despite crude oil being considered a somewhat homogeneous commodity, many refiners are very particular about the quality of crude oil feedstock they process. Many U.S. refineries have distinct configurations and product slates that require crude oil with specific characteristics, such as gravity, sulfur content and metals content. The refineries evaluate the costs to obtain, transport and process their preferred feedstocks. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources and transport crude oil meeting their requirements. The imbalances and inefficiencies relative to meeting the refiners' requirements may also provide opportunities for us to utilize our purchasing and logistical skills to meet their demands. The pricing in the majority of our crude oil purchase contracts contains a market price component and a deduction to cover the cost of transportation and to provide us with a margin. Contracts sometimes contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically, the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

Operating results for our onshore facilities and transportation segment were as follows:

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(in thousands)	
Gathering, marketing, and logistics revenue	$ 890,719	$ 651,097
Crude oil and CO_2 pipeline tariffs and revenues	31,822	35,303
Distributions from unrestricted subsidiaries not included in income[(1)]	—	70,000
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(828,933)	(584,880)
Operating costs, excluding non-cash charges for long-term incentive compensation and other non-cash expenses	(66,400)	(60,992)
Other	6,547	(11,704)
Segment Margin	$ 33,755	$ 98,824
Volumetric Data (average Bbls/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	90,562	65,918
Jay	6,601	7,941
Mississippi	5,725	5,206
Louisiana[(2)]	94,389	99,927
Onshore crude oil pipelines total	197,277	178,992
Total crude oil and petroleum products sales	24,643	24,239
Rail unload volumes[(3)]	10,834	11,782

(1) 2021 includes total cash payments received from our previously owned NEJD pipeline of $70.0 million not included in income, which is defined as unrestricted subsidiaries under our senior secured credit agreement.

(2) Total daily volumes for the years ended December 31, 2022 and 2021 include 28,850 and 32,526 Bbls/day, respectively, of intermediate refined products and 53,459 and 55,363 Bbls/day, respectively, of crude oil associated with our Port of Baton Rouge Terminal pipelines.

(3) Includes total barrels for unloading at all rail facilities.

Segment Margin for our onshore facilities and transportation segment decreased $65.1 million, or 66% , in 2022 as compared to 2021. The decrease is primarily due to 2021 including cash receipts of $70 million associated with our previously owned NEJD pipeline. This decrease was partially offset by higher volumes on our Texas pipeline during 2022, which is a destination point for various grades of crude oil produced in the Gulf of Mexico including those transported on our 64% owned CHOPS pipeline.

Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 91 barges (82 inland and 9 offshore) with a combined transportation capacity of 3.2 million barrels, 42 push/tow boats (33 inland and 9 offshore), and a 330,000 barrel capacity ocean going tanker, the M/T American Phoenix. Operating results for our marine transportation segment were as follows:

	Year Ended December 31, 2022	Year Ended December 31, 2021
Revenues (in thousands):		
Inland freight revenues	$ 105,583	$ 73,465
Offshore freight revenues	87,587	68,703
Other rebill revenues(1)	100,125	48,659
Total segment revenues	$ 293,295	$ 190,827
Operating costs, excluding non-cash charges for long-term incentive compensation and other non-cash expenses(1)	$ 227,086	$ 156,255
Segment Margin (in thousands)	$ 66,209	$ 34,572
Fleet Utilization:(2)		
Inland Barge Utilization	98.6 %	81.9 %
Offshore Barge Utilization	96.9 %	95.9 %

(1) Under certain of our marine contracts, we “rebill” our customers for a portion of our operating costs.

(2) Utilization rates are based on a 365 day year, as adjusted for planned downtime and drydocking.

Marine Transportation Segment Margin for 2022 increased $31.6 million, or 92%, from 2021. This increase is primarily attributable to higher utilization rates, which exited the year at 100% in both our inland and offshore fleets, and higher day rates, including the M/T American Phoenix, during 2022. Demand for our barge services to move intermediate and refined products has increased throughout 2022 due to the recovery of refinery utilization rates as well as the lack of new supply of similar type vessels (primarily due to higher construction costs) as well as the retirement of older vessels in the market. These factors have also contributed to an overall increase in spot and term rates for our services. These increases were partially offset by the M/T American Phoenix. While the M/T American Phoenix had higher day rates throughout 2022 relative to 2021, its contribution to our segment margin was negatively impacted as it went into a planned mandatory regulatory dry-dock from July 21, 2022 through September 16, 2022. Upon completion of the dry-dock, the M/T American Phoenix went back on hire and is currently under contract through the end of 2023 with an investment grade customer at a more favorable rate than 2022.

Other Costs, Interest and Income Taxes

General and administrative expenses

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$ 47,306	$ 43,329
Segment	3,674	4,162
Long-term incentive based compensation plan expense	8,279	4,748
Third-party costs related to business development activities and growth projects	7,339	8,946
Total general and administrative expenses	$ 66,598	$ 61,185

Total general and administrative expenses increased $5.4 million between 2022 and 2021. The increase is primarily due to higher costs associated with our long-term incentive compensation plan as a result of the assumptions used to value our outstanding awards and higher corporate general and administrative costs during 2022.

Depreciation, depletion and amortization expense

	Year Ended December 31,	
	2022	2021
	(in thousands)	
Depreciation and depletion expense	$ 285,302	$ 298,953
Amortization expense	10,903	10,793
Total depreciation, depletion and amortization expense	$ 296,205	$ 309,746

Total depreciation, depletion and amortization expense decreased $13.5 million between 2022 and 2021. The decrease in depreciation and depletion expense is primarily attributable to the acceleration of depreciation on certain of our asset retirement obligation assets during 2021 as a result of updates to the estimated timing and costs associated with certain of our non-core offshore natural gas assets.

Interest expense, net

	Year Ended December 31,	
	2022	2021
	(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$ 10,980	$ 22,287
Interest expense, Alkali senior secured notes	15,811	—
Interest expense, senior unsecured notes	209,001	206,352
Amortization of debt issuance costs, premium and discount	8,479	9,452
Capitalized interest	(18,115)	(4,367)
Interest expense, net	$ 226,156	$ 233,724

Net interest expense decreased $7.6 million between 2022 and 2021 primarily due to a decrease in interest expense associated with our senior secured credit facility and an increase in capitalized interest. The decrease in interest expense on our senior secured credit facility is due to a lower outstanding balance throughout 2022 as a result of: (i) the proceeds we received from the additional issuance of $250 million in aggregate principal of our 2027 Notes in April 2021; (ii) the proceeds from the sale of a noncontrolling interest in our CHOPS pipeline in November 2021; and (iii) the proceeds we received from the issuance of our Alkali senior secured notes in May 2022 in excess of the funds used to redeem our Alkali Holdings preferred units, all of which were used to pay down the outstanding balance under our senior secured credit facility. Additionally, we had higher capitalized interest during 2022 as a result of our increased capital expenditures associated with the GOP and our offshore growth capital construction projects, both of which are being funded internally.

Income tax expense

A portion of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, a substantial portion of the income tax expense we record relates to the operations of those corporations, and will vary from period to period as a percentage of our income before taxes based on the percentage of our income or loss that is derived from those corporations. The balance of the income tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles and foreign income taxes.

Other Consolidated Results

Net income for the year ended December 31, 2022 included an unrealized loss of $18.6 million from the valuation of our previously recognized embedded derivative associated with our Class A Convertible Preferred Units, and also included cancellation of debt income of $8.6 million associated with the open market repurchase and extinguishment of certain of our senior unsecured notes. Both of these amounts are included within “Other,expense, net” on the Consolidated Statement of Operations. In addition, net income for the year ended December 31, 2022 included a gain of $40.0 million recorded in “Loss (gain) on sale of asset” on the Consolidated Statement of Operations, of which $8.0 million, or 20%, is attributable to our noncontrolling interest holder, related to the sale of our Independence Hub platform to a producer group in the Gulf of Mexico for gross proceeds of $40.0 million.

Net loss for the year ended December 31, 2021 included an unrealized loss of $30.8 million from the valuation of our embedded derivative associated with our Class A Convertible Preferred Units included in “Other expense, net” in the Consolidated Statement of Operations.

A discussion of the operating results for the year ended December 31, 2021 compared with the year ended December 31, 2020 has been omitted from this Form 10-K. This discussion can be found within our previously filed 2021 Form 10-K, which was filed with the SEC on February 24, 2022.

Non-GAAP Financial Measures

General

To help evaluate our business, this Annual Report on Form 10-K includes the non-generally accepted accounting principle ("non-GAAP") financial measure of Available Cash before Reserves. We also present total Segment Margin as if it were a non-GAAP measure. Our non-GAAP measures may not be comparable to similarly titled measures of other companies because such measures may include or exclude other specified items. The accompanying schedules provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated in accordance with generally accepted accounting principles in the United States of America (GAAP). A reconciliation of Net income (loss) attributable to Genesis Energy, L.P. to total Segment Margin is included in our segment disclosure in Note 13 to our Consolidated Financial Statements in Item 8. Our non-GAAP financial measures should not be considered (i) as alternatives to GAAP measures of liquidity or financial performance or (ii) as being singularly important in any particular context; they should be considered in a broad context with other quantitative and qualitative information. Our Available Cash before Reserves and total Segment Margin measures are just two of the relevant data points considered from time to time.

When evaluating our performance and making decisions regarding our future direction and actions (including making discretionary payments, such as quarterly distributions) our board of directors and management team have access to a wide range of historical and forecasted qualitative and quantitative information, such as our financial statements; operational information; various non-GAAP measures; internal forecasts; credit metrics; analyst opinions; performance, liquidity and similar measures; income; cash flow expectations for us; and certain information regarding some of our peers. Additionally, our board of directors and management team analyze, and place different weight on, various factors from time to time. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants. We attempt to provide adequate information to allow each individual investor and other external user to reach her/his own conclusions regarding our actions without providing so much information as to overwhelm or confuse such investor or other external user. Our non-GAAP financial measures should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance.

Segment Margin

We define Segment Margin as revenues less product costs, operating expenses, and segment general and administrative expenses (all of which are net of the effects of our noncontrolling interest holders), plus or minus applicable Select Items (defined below). Although, we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes where relevant and capital investment.

A reconciliation of Net income (loss) attributable to Genesis Energy, L.P. to total Segment Margin is included in our segment disclosure in Note 13 to our Consolidated Financial Statements in Item 8.

Available Cash before Reserves

Purposes, Uses and Definition

Available Cash before Reserves, often referred to by others as distributable cash flow, is a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and is commonly used as a supplemental financial measure by management and by external users of financial statements such as investors, commercial banks, research analysts and rating agencies, to aid in assessing, among other things:

(1) the financial performance of our assets;

(2) our operating performance;

(3) the viability of potential projects, including our cash and overall return on alternative capital investments as compared to those of other companies in the midstream energy industry;

(4) the ability of our assets to generate cash sufficient to satisfy certain non-discretionary cash requirements, including interest payments and certain maintenance capital requirements; and

(5) our ability to make certain discretionary payments, such as distributions on our preferred and common units, growth capital expenditures, certain maintenance capital expenditures and early payments of indebtedness.

We define Available Cash before Reserves ("Available Cash before Reserves") as Net income (loss) attributable to Genesis Energy, L.P. before interest, taxes, depreciation, depletion and amortization (including impairment, write-offs, accretion and similar items) after eliminating other non-cash revenues, expenses, gains, losses and charges (including any loss on asset dispositions), plus or minus certain other select items that we view as not indicative of our core operating results (collectively, "Select Items"), as adjusted for certain items, the most significant of which in the relevant reporting periods have been the sum of maintenance capital utilized, net interest expense, cash tax expense and cash distributions paid to our Class A convertible preferred unitholders. Although we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. The most significant Select Items in the relevant reporting periods are set forth below.

	Year Ended December 31,	
	2022	2021
I. Applicable to all Non-GAAP Measures	*(in thousands)*	
Differences in timing of cash receipts for certain contractual arrangements[(1)]	$ 51,102	$ 15,482
Distributions from unrestricted subsidiaries not included in income[(2)]	32,000	70,000
Certain non-cash items:		
Unrealized losses (gains) on derivative transactions excluding fair value hedges, net of changes in inventory value[(3)]	(5,717)	30,700
Loss on debt extinguishment[(4)]	794	1,627
Adjustment regarding equity investees[(5)]	21,199	26,207
Other	(2,598)	207
Sub-total Select Items, net	96,780	144,223
II. Applicable only to Available Cash before Reserves		
Certain transaction costs[(6)]	7,339	8,946
Other	2,208	1,398
Total Select Items, net	$106,327	$154,567

(1) Represents the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts. For purposes of our non-GAAP measures, we add those amounts in the period of payment and deduct them in the period in which GAAP recognizes them.

(2) 2022 includes $32.0 million in cash receipts associated with the sale of the Independence Hub platform by our 80% owned unrestricted subsidiary (as defined under our credit agreement), Independence Hub, LLC. 2021 includes $70.0 million in cash receipts associated with principal repayments on our previously owned NEJD pipeline not included in income, which is defined as an unrestricted subsidiary under our credit agreement.

(3) 2022 includes an unrealized loss of $18.6 million from the valuation of our previously recorded embedded derivative associated with our Class A Convertible Preferred Units and an unrealized gain of $24.3 million from the valuation of our commodity derivatives transactions (excluding fair value hedges). 2021 includes an unrealized loss of $30.8 million from the valuation of the embedded derivative and an unrealized gain of $0.1 million from the valuation of our commodity derivatives (excluding fair value hedges).

(4) 2022 includes the write-off of the unamortized issuance costs associated with the repurchase and extinguishment of certain of our senior unsecured notes during the year. 2021 includes the transaction costs and write-off of the unamortized issuance costs associated with the redemption of our remaining 2023 Notes.

(5) Represents the net effect of adding distributions from equity investees and deducting earnings of equity investees net to us.

(6) Represents transaction costs relating to certain merger, acquisition, divestiture, transition and financing transactions incurred in advance of the associated transaction.

Disclosure Format Relating to Maintenance Capital

We use a modified format relating to maintenance capital requirements because our maintenance capital expenditures vary materially in nature (discretionary vs. non-discretionary), timing and amount from time to time. We believe that, without such modified disclosure, such changes in our maintenance capital expenditures could be confusing and potentially misleading to users of our financial information, particularly in the context of the nature and purposes of our Available Cash before Reserves measure. Our modified disclosure format provides those users with information in the form of our maintenance capital utilized measure (which we deduct to arrive at Available Cash before Reserves). Our maintenance capital utilized measure constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period.

Maintenance Capital Requirements

Maintenance capital expenditures are capitalized costs that are necessary to maintain the service capability of our existing assets, including the replacement of any system component or equipment which is worn out or obsolete. Maintenance capital expenditures can be discretionary or non-discretionary, depending on the facts and circumstances.

Prior to 2014, substantially all of our maintenance capital expenditures were (a) related to our pipeline assets and similar infrastructure, (b) non-discretionary in nature and (c) immaterial in amount as compared to our Available Cash before Reserves measure. Those historical expenditures were non-discretionary (or mandatory) in nature because we had very little (if any) discretion as to whether or when we incurred them. We had to incur them in order to continue to operate the related pipelines in a safe and reliable manner and consistently with past practices. If we had not made those expenditures, we would not have been able to continue to operate all or portions of those pipelines, which would not have been economically feasible. An example of a non-discretionary (or mandatory) maintenance capital expenditure would be replacing a segment of an old pipeline because one can no longer operate that pipeline safely, legally and/or economically in the absence of such replacement.

Beginning with 2014, we believe a substantial amount of our maintenance capital expenditures from time to time will be (a) related to our assets other than pipelines, such as our marine vessels, trucks and similar assets, (b) discretionary in nature and (c) potentially material in amount as compared to our Available Cash before Reserves measure. Those expenditures will be discretionary (or non-mandatory) in nature because we will have significant discretion as to whether or when we incur them. We will not be forced to incur them in order to continue to operate the related assets in a safe and reliable manner. If we chose not make those expenditures, we would be able to continue to operate those assets economically, although in lieu of maintenance capital expenditures, we would incur increased operating expenses, including maintenance expenses. An example of a discretionary (or non-mandatory) maintenance capital expenditure would be replacing an older marine vessel with a new marine vessel with substantially similar specifications, even though one could continue to economically operate the older vessel in spite of its increasing maintenance and other operating expenses.

In summary, as we continue to expand certain non-pipeline portions of our business, we are experiencing changes in the nature (discretionary vs. non-discretionary), timing and amount of our maintenance capital expenditures that merit a more detailed review and analysis than was required historically. Management’s increasing ability to determine if and when to incur certain maintenance capital expenditures is relevant to the manner in which we analyze aspects of our business relating to discretionary and non-discretionary expenditures. We believe it would be inappropriate to derive our Available Cash before Reserves measure by deducting discretionary maintenance capital expenditures, which we believe are similar in nature in this context to certain other discretionary expenditures, such as growth capital expenditures, distributions/dividends and equity buybacks. Unfortunately, not all maintenance capital expenditures are clearly discretionary or non-discretionary in nature. Therefore, we developed a measure, maintenance capital utilized, that we believe is more useful in the determination of Available Cash before Reserves.

Maintenance Capital Utilized

We believe our maintenance capital utilized measure is the most useful quarterly maintenance capital requirements measure to use to derive our Available Cash before Reserves measure. We define our maintenance capital utilized measure as that portion of the amount of previously incurred maintenance capital expenditures that we utilize during the relevant quarter, which would be equal to the sum of the maintenance capital expenditures we have incurred for each project/component in prior quarters allocated ratably over the useful lives of those projects/components.

Our maintenance capital utilized measure constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period. Because we did not use our maintenance capital utilized measure before 2014, our maintenance capital utilized calculations will reflect the utilization of solely those maintenance capital expenditures incurred since December 31, 2013.

Available Cash before Reserves for the years ended December 31, 2022 and 2021 was as follows:

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(in thousands)	
Net income (loss) attributable to Genesis Energy, L.P.	$ 75,457	$ (165,067)
Income tax expense	3,169	1,670
Depreciation, depletion, amortization, and accretion	307,519	315,896
Gain on sale of assets	(32,000)	—
Plus (minus) Select Items, net	106,327	154,567
Maintenance capital utilized	(57,400)	(53,150)
Cash tax expense	(815)	(690)
Distributions to preferred unitholders	(80,052)	(74,736)
Redeemable noncontrolling interest redemption value adjustments[1]	30,443	25,398
Available Cash before Reserves	$ 352,648	$ 203,888

(1) Includes PIK distributions and accretion on the redemption feature attributable to each period, and valuation adjustments to the redemption feature as the associated preferred units were redeemed during the year ended December 31, 2022.

Liquidity and Capital Resources

General

On April 8, 2021, we entered into our Fifth Amended and Restated Credit Agreement, which initially provided for a $950 million senior secured credit facility, which comprised a revolving loan with a borrowing capacity of $650 million and a term loan with a borrowing capacity of $300 million, with the ability to increase the aggregate size of the revolving loan by an additional $200 million subject to lender consent and certain other customary conditions. Our term loan was paid off in full on November 17, 2021 with a portion of the gross proceeds of $418 million received from the sale of a 36% minority interest in CHOPS. On February 17, 2023, we entered into the Sixth Amended and Restated Credit Agreement (our "new credit agreement") to replace our Fifth Amended and Restated Credit Agreement. The new credit agreement matures on February 13, 2026, subject to extension at our request for one additional year on up to two occasions and subject to certain conditions, unless more than $150 million of our 6.500% senior notes due 2025 remain outstanding as of June 30, 2025, in which case the new credit agreement matures on such date.

On April 22, 2021 we completed our offering of an additional $250 million in aggregate principal amount of our 2027 Notes (as defined in Note 10 to our Consolidated Financial Statements in Item 8). The additional $250 million of notes have identical terms as (other than with respect to issue price) and constitute part of the same series as our 2027 Notes and the net proceeds from this additional offering were used for general partnership purposes, including repaying a portion of the outstanding borrowings under our senior secured credit facility.

On April 29, 2022, we received $40 million, or $32 million net to our ownership interests, for the sale of our 80% owned Independence Hub platform which allowed us to repay a portion of the borrowings outstanding under our senior secured credit facility and further increase our borrowing capacity.

On May 17, 2022, Genesis Energy, L.P., through its newly created indirect unrestricted subsidiary, GA ORRI, issued $425 million principal amount of our 5.875% Alkali senior secured notes due 2042 to certain institutional investors, secured by GA ORRI's fifty-year 10% limited term overriding royalty interest in substantially all of the Company's Alkali Business trona mineral leases. The issuance generated net proceeds of $408 million, net of the issuance discount of $17 million. We make quarterly interest payments on our Alkali senior secured notes until March 2024, at which time we begin making quarterly principal and interest payments through the maturity date. We used a portion of net proceeds from the issuance to fully redeem the outstanding Alkali Holdings preferred units and utilized the remainder to repay a portion of the outstanding borrowings under our senior secured credit facility. The redemption of our Alkali Holdings preferred units, which carried an implied interest rate of 12-13%, and the issuance of our Alkali senior secured notes with a coupon rate of 5.875%, has allowed us to simplify our capital structure and lower our cost of capital, provide us additional flexibility under our senior secured credit facility, and remove any risk of refinancing our Alkali Holdings preferred units that were initially due in 2026.

On January 25, 2023, we issued $500 million in aggregate principal amount of our 8.875% senior unsecured notes due April 15, 2030 (the "2030 Notes"). Interest payments are due April 15 and October 15 of each year with the initial interest payment due on October 15, 2023. That issuance generated net proceeds of approximately $491 million, net of issuance costs incurred. The net proceeds were used to purchase approximately $316 million of our existing 2024 Notes, including the related accrued interest and tender premium and fees on those notes that were tendered in the tender offer that ended January 24, 2023 and the remaining proceeds at the time were used to repay a portion of the borrowings outstanding under our senior secured credit facility and for general partnership purposes. On January 26, 2023, we issued a notice of redemption for the remaining principal of approximately $25 million of our 2024 Notes, and discharged the indebtedness with respect to the 2024 Notes on February 14, 2023 by depositing the redemption amount with the trustee of the 2024 Notes for redemption of the 2024 Notes on February 25, 2023, all in accordance with the terms and conditions of the indenture governing the 2024 Notes.

The successful completion of the above events has resulted in no scheduled maturities of our unsecured notes until 2025 and has provided us a significant amount of available borrowing capacity under our senior secured credit facility, subject to compliance with covenants, to, amongst other things, utilize for funding the remaining growth capital expenditures associated with our Granger Optimization Project and our offshore growth projects discussed earlier. Additionally, these events have allowed us to simplify our capital structure and eliminate our highest interest rate instrument, the Alkali Holdings preferred units.

As of December 31, 2022, we believe our balance sheet and liquidity position remained strong, including $436.1 million of borrowing capacity available (which does not include our repayment of excess proceeds from the issuance of our 2030 Notes), subject to compliance with our covenants, under the $650 million revolving portion of our senior secured credit facility as of such date.

We anticipate that our future internally-generated funds and the funds available under our senior secured credit facility will allow us to meet our ordinary course capital needs. Our primary sources of liquidity have historically been cash flows from operations, borrowing availability under our senior secured credit facility, proceeds from the sale of non-core assets, the creation of strategic arrangements to share capital costs through joint ventures or strategic alliances, and the proceeds from issuances of equity (common and preferred) and senior unsecured or secured notes.

Our primary cash requirements consist of:

- working capital, primarily inventories and trade receivables and payables;
- routine operating expenses;
- capital growth (as discussed in more detail below) and maintenance projects;
- interest payments related to outstanding debt;
- asset retirement obligations;
- quarterly cash distributions to our preferred and common unitholders; and
- acquisitions of assets or businesses.

Capital Resources

Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital from time to time, including through equity and debt offerings (public and private), borrowings under our senior secured credit facility and other financing transactions, and to implement our growth strategy successfully. No assurance can be made that we will be able to raise necessary funds on satisfactory terms.

At December 31, 2022, we had $205.4 million borrowed under our senior secured credit facility, with $4.7 million of the borrowed amount designated as a loan under the inventory sublimit. Our senior secured credit facility does not include a "borrowing base" limitation except with respect to our inventory loans. Due to the revolving nature of loans under our senior secured credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of our senior secured credit facility. The total amount available for borrowings under our senior secured credit facility at December 31, 2022 was $436.1 million, subject to compliance with our covenants. On a pro forma basis, when considering the increased borrowing capacity associated with our new credit agreement, we would have had $636.1 million available for borrowings, subject to compliance with our covenants.

At December 31, 2022, our long-term debt totaled approximately $3.5 billion, consisting of $205.4 million outstanding under our senior secured credit facility (including $4.7 million borrowed under the inventory sublimit tranche), $2.9 billion of senior unsecured notes, net and $402.4 million of Alkali senior secured notes, net, which are secured by the ORRI Interests. Our senior unsecured notes, net balance is comprised of $671.7 million of our 2028 notes, $976.3 million of our 2027 Notes, $336.8 million of our 2026 Notes, $531.6 million of our 2025 Notes, and $339.9 million of our 2024 Notes.

Future payment obligations related to our senior secured credit facility and senior unsecured notes as of December 31, 2022, including both principal and estimated interest payments, are summarized in the table below:

	Interest Rate	Maturity Date	Principal	Estimated Annual Interest Payable
			(in thousands)	
Senior secured credit facility[1]	Varies	March 15, 2024	$ 205,400	$ 12,324
2024 Notes[2][3]	5.625%	June 15, 2024	341,135	19,189
2025 Notes[2]	6.500%	October 1, 2025	534,834	34,764
2026 Notes[2]	6.250%	May 15, 2026	339,310	21,207
2027 Notes[2]	8.000%	January 15, 2027	981,245	78,500
2028 Notes[2]	7.750%	February 1, 2028	679,360	52,650
Total estimated payments			$ 3,081,284	$ 218,634

(1) Amounts shown above for estimated interest payments represent the amounts that would be paid on an annual basis if the debt outstanding at December 31, 2022 remained outstanding through the final maturity date of March 15, 2024, and interest rates remained constant from December 31, 2022 through the maturity date.

(2) Each series of senior unsecured notes is further discussed and defined in Note 10 to our Consolidated Financial Statements in Item 8.

(3) Subsequent to December 31, 2022, net proceeds from the issuance of our 2030 Notes were used to repurchase and retire our 2024 Notes, the obligations in respect of the remaining portion of 2024 Notes have been discharged, all as further discussed above.

Future payment obligations associated with our Alkali senior secured notes, as of December 31, 2022, including both estimated principal and interest payments, are summarized in the table below:

Payment Obligations	Estimated Interest Payments	Estimated Principal Payments
2023	$ 24,969	$ —
2024	24,712	11,618
2025	23,997	13,097
2026 through 2042	227,794	400,285

We have the right to redeem each of our series of senior unsecured notes beginning on specified dates as summarized below, at a premium to the face amount of such notes that varies based on the time remaining to maturity on such notes. Additionally, we may redeem up to 35% of the principal amount of each of our series of senior unsecured notes with the proceeds from an equity offering of our common units during certain periods. A summary of the applicable redemption periods is provided in the table below.

	2024 Notes	2025 Notes	2026 Notes	2027 Notes	2028 Notes
Redemption right beginning on	June 15, 2019	October 1, 2020	February 15, 2021	January 15, 2024	February 1, 2023
Redemption of up to 35% of the principal amount of notes with the proceeds of an equity offering permitted prior to	June 15, 2019	October 1, 2020	February 15, 2021	January 15, 2024	February 1, 2023

For additional information on our long-term debt and covenants see Note 10 to our Consolidated Financial Statements in Item 8.

Class A Convertible Preferred Units

On September 1, 2017, we sold $750 million of Class A Convertible Preferred Units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the "Issue Price") to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our Class A Convertible Preferred Units. Our Class A Convertible Preferred Units are a new class of security that ranks senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our Class A Convertible Preferred Units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those Class A Convertible Preferred Units.

Our Class A Convertible Preferred Units contained a distribution Rate Reset Election (as defined in Note 11), which was elected by the holders of the Class A Convertible Preferred Units on September 29, 2022 (the "election date"). From the date of issuance through the election date, each of our Class A Convertible Preferred Units accumulated quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374). On the election date, the holders of the Class A Convertible Preferred Units elected to reset the rate to 11.24%, yielding a quarterly distribution of $0.9473 per preferred unit beginning with the fourth quarter of 2022.

With respect to any quarter ending on or prior to March 1, 2019, we exercised our option to pay the holders of our Class A Convertible Preferred Units the applicable distribution in additional Class A Convertible Preferred Units equal the product of (i) the number of then outstanding Class A Convertible Preferred Units and (ii) the quarterly rate. For all subsequent periods ending after March 1, 2019, we have paid and will pay all distribution amounts in respect of our Class A Convertible Preferred Units in cash. As of December 31, 2022, there are 25,336,778 Class A Convertible Preferred Units outstanding.

Redeemable Noncontrolling interests

On September 23, 2019, we, through a subsidiary, Alkali Holdings, entered into an amended and restated Limited Liability Company Agreement of Alkali Holdings (the "LLC Agreement") and a Securities Purchase Agreement (the "Securities Purchase Agreement") whereby BXC purchased $55.0 million of preferred units (or 55,000 preferred units) and committed to purchase, during a three-year commitment period, up to a total of $350.0 million of preferred units (or 350,000 preferred units) in Alkali Holdings. Alkali Holdings utilized the net proceeds from the preferred units to fund a portion of the anticipated cost of the Granger Optimization Project. On April 14, 2020, we entered into an amendment to our agreements with BXC to, among other things, extend the construction timeline of the Granger Optimization Project by one year, which we currently anticipate completing in the second half of 2023. In consideration for the amendment, we issued 1,750 Alkali Holdings preferred units to BXC, which was accounted for as issuance costs. As part of the amendment, the commitment period was increased to four years, and the total commitment of BXC was increased to, subject to compliance with the covenants contained in our agreements with BXC, up to $351.8 million of preferred units (or 351,750 preferred units) in Alkali Holdings.

From time to time after we had drawn at least $251.8 million, we had the option to redeem the outstanding preferred units in whole for cash at a price equal to the initial $1,000 per preferred unit purchase price, plus no less than the greater of a predetermined fixed internal rate of return amount or a multiple of invested capital metric, net of cash distributions paid to date ("Base Preferred Return"). Additionally, if all outstanding preferred units were redeemed, we had not drawn at least $251.8 million, and BXC was not a "defaulting member" under the LLC Agreement, BXC had the right to a make-whole amount on the number of undrawn preferred units.

On May 17, 2022 (the "Redemption Date"), we fully redeemed the 251,750 outstanding Alkali Holdings preferred units a Base Preferred Return Amount of $288.6 million utilizing a portion of the proceeds we received from the issuance of our Alkali senior secured notes. As of December 31, 2022, there were no Alkali Holdings preferred units outstanding.

See Note 11 to our Consolidated Financial Statements in Item 8 for additional information regarding our mezzanine capital.

Shelf Registration Statements

We have the ability to issue additional equity and debt securities in the future to assist us in meeting our future liquidity requirements, particularly those related to opportunistically acquiring assets and businesses and constructing new facilities and refinancing outstanding debt.

We have a universal shelf registration statement (our "2021 Shelf") on file with the SEC which we filed on April 19, 2021 to replace our previous universal shelf registration statement that expired on April 20, 2021. Our 2021 Shelf allows us to issue an unlimited amount of equity and debt securities in connection with certain types of public offerings. However, the receptiveness of the capital markets to an offering of equity and/or debt securities cannot be assured and may be negatively impacted by, among other things, our long-term business prospects and other factors beyond our control, including market conditions. Our 2021 Shelf is set to expire in April 2024. We expect to file a replacement universal shelf registration statement before our 2021 Shelf expires.

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our common and preferred distributions and working capital needs. Excess funds that are generated are used to repay borrowings under our senior secured credit facility and/or to fund a portion of our capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the carrying amount of inventory and the timing of payment of accounts payable and accrued liabilities related to capital expenditures and interest charges, and the timing of accounts receivable collections from our customers.

We typically sell our crude oil in the same month in which we purchase it, so we do not need to rely on borrowings under our senior secured credit facility to pay for such crude oil purchases, other than inventory. During such periods, our accounts receivable and accounts payable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil.

In our petroleum products activities, we buy products and typically either move those products to one of our storage facilities for further blending or sell those products within days of our purchase. The cash requirements for these activities can result in short term increases and decreases in the borrowings under our senior secured credit facility.

In our Alkali Business, we typically extract trona from our mining facilities, process into soda ash and other alkali products, and deliver and sell to our customers all within a relatively short time frame. If we did experience any differences in timing of extraction, processing and sales of this trona or Alkali products, this could impact the cash requirements for these activities in the short term.

The storage of our inventory of crude oil, petroleum products and alkali products can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil or petroleum products (or pay for extraction and processing activities in the case of alkali products), we borrow under our senior secured credit facility (or use cash on hand) to pay for the crude oil or petroleum products (or extraction/processing of alkali products), utilizing a portion of our operating cash flows. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil, petroleum products or alkali products. Additionally, for our exchange-traded derivatives, we may be required to deposit margin funds with the respective exchange when commodity prices increase as the value of the derivatives utilized to hedge the price risk in our inventory fluctuates. These deposits also impact our operating cash flows as we borrow under our senior secured credit facility or use cash on hand to fund the deposits.

Net cash flows provided by our operating activities were $334.4 million and $338.0 million for 2022 and 2021, respectively. The decrease in operating cash flow for 2022 compared to 2021 was primarily due to our working capital requirements partially offset by the increase in our segment margin during 2022.

Capital Expenditures and Distributions Paid to Our Unitholders

We use cash primarily for our operating expenses, working capital needs, debt service, acquisition activities, internal growth projects and distributions we pay to our common and preferred unitholders. We finance maintenance capital expenditures and smaller internal growth projects and distributions primarily with cash generated by our operations. We have historically funded material growth capital projects (including acquisitions and internal growth projects) with borrowings under our senior secured credit facility, equity issuances (common and preferred units), the issuance of senior unsecured or secured notes, and/or the creation of strategic arrangements to share capital costs through joint ventures or strategic alliances.

Capital Expenditures for Fixed and Intangible Assets and Equity Investees

The following table summarizes our expenditures for fixed and intangible assets and equity investees in the periods indicated:

	Years Ended December 31,		
	2022	2021	2020
		(in thousands)	
Capital expenditures for fixed and intangible assets:			
Maintenance capital expenditures:			
Offshore pipeline transportation assets	$ 6,292	$ 8,749	$ 8,715
Sodium mineral and sulfur services assets	77,918	51,241	43,744
Marine transportation assets	39,084	34,456	31,357
Onshore facilities and transportation assets	2,928	4,476	3,644
Information technology systems	6,317	946	383
Total maintenance capital expenditures	132,539	99,868	87,843
Growth capital expenditures:			
Offshore pipeline transportation assets(1)	$ 227,803	$ 41,445	$ 4,608
Sodium minerals and sulfur services assets	96,600	175,877	51,767
Marine transportation assets	—	—	—
Onshore facilities and transportation assets	—	133	489
Information technology systems	9,379	8,259	6,331
Total growth capital expenditures	333,782	225,714	63,195
Total capital expenditures for fixed and intangible assets	466,321	325,582	151,038
Capital expenditures related to equity investees	10,301	352	—
Total capital expenditures	$ 476,622	$ 325,934	$ 151,038

(1) Growth capital expenditures in our offshore pipeline transportation segment for 2022 represent 100% of the costs incurred.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital. We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows. We continue to pursue a long term growth strategy that may require significant capital.

Growth Capital Expenditures

On September 23, 2019, we announced the GOP along with the issuance of the Alkali Holdings preferred units, which were anticipated to fund up to the total estimated cost of the GOP. The anticipated completion date of the project is the second half of 2023. The expansion is expected to increase our production at the Granger facilities by approximately 750,000 tons per year. During the fourth quarter of 2021, we made the decision to fund the remaining capital expenditures associated with the GOP internally in lieu of issuing additional Alkali Holdings preferred units.

During 2022, we entered into definitive agreements to provide transportation services for 100% of the crude oil production associated with two separate standalone deepwater developments that have a combined production capacity of approximately 160,000 barrels per day. In conjunction with these agreements, we are in the process of expanding the current capacity of the CHOPS pipeline and constructing a new 100% owned, approximately 105 mile, 20" diameter crude oil pipeline (the "SYNC pipeline") to connect one of the developments to our existing asset footprint in the Gulf of Mexico. We plan to complete the construction in line with the producers' plan for first oil achievement, which is currently expected in late 2024 or 2025. The producer agreements include long term take-or-pay arrangements and, accordingly, we are able to receive a project completion credit for purposes of calculating the leverage ratio under our senior secured credit facility throughout the construction period.

We plan to fund our estimated growth capital expenditures utilizing the available borrowing capacity under our senior secured credit facility and our recurring cash flows generated from operations, which we anticipate to increase during 2023 as a result of increased offshore volumes from King's Quay and Argos, favorable export pricing and continued demand in our Alkali business, and the restart of our original Granger facility on January 1, 2023 and our expanded Granger facility in the second half of 2023.

Maintenance Capital Expenditures

Maintenance capital expenditures incurred primarily relate to our marine transportation segment to replace and upgrade certain equipment associated with our vessels and in our Alkali Business, which is included in our sodium minerals and sulfur services segment, due to the costs to maintain our related equipment and facilities. Additionally, our offshore transportation assets incur maintenance capital expenditures to replace, maintain, and upgrade equipment at certain of our offshore platforms and pipelines that we operate. We expect future expenditures to be within a reasonable range of 2022's expenditures dependent upon the timing of when we incur certain costs. See previous discussion under "Available Cash before Reserves" for how such maintenance capital utilization is reflected in our calculation of Available Cash before Reserves.

Distributions to Unitholders

Our partnership agreement requires us to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
    - provide for the proper conduct of our business;
    - comply with applicable law, any of our debt instruments, or other agreements; or
    - provide funds for distributions to our common and preferred 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. Working capital borrowings are generally borrowings that are made under our senior secured credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

On February 14, 2023, we paid a distribution of $0.15 per common unit related to the fourth quarter of 2022. With respect to our Class A Convertible Preferred Units, we declared a quarterly cash distribution of $0.9473 per unit (or $3.7890 on an annualized basis). These distributions were paid on February 14, 2023 to unitholders holders of record at the close of business January 31, 2023.

Our historical distributions to common unitholders and Class A Convertible Preferred unitholders are shown in the table below (in thousands, except per unit amounts).

Distribution For	Date Paid	Per Common Unit Amount	Total Amount	Per Preferred Unit Amount	Total Amount
2020					
1st Quarter	May 15, 2020	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
2nd Quarter	August 14, 2020	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
3rd Quarter	November 13, 2020	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
4th Quarter	February 12, 2021	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
2021					
1st Quarter	May 14, 2021	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
2nd Quarter	August 13, 2021	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
3rd Quarter	November 12, 2021	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
4th Quarter	February 14, 2022	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
2022					
1st Quarter	May 13, 2022	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
2nd Quarter	August 12, 2022	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
3rd Quarter	November 14, 2022	$ 0.1500	$ 18,387	$ 0.7374	$ 18,684
4th Quarter	February 14, 2023 (1)	$ 0.1500	$ 18,387	$ 0.9473	$ 24,000

(1) This distribution was paid on February 14, 2023 to unitholders of record as of January 31, 2023.

Contractual Obligations and Commitments

In addition to the principal and interest payment commitments associated with our long-term debt discussed above, we have other contractual obligations and commitments as of December 31, 2022, which are summarized below.

- We have estimated operating lease payment obligations totaling $234.6 million, of which $25.8 million is expected to be paid in 2023 (see Note 4 to our Consolidated Financial Statements in Item 8 for details on our lease obligations).
- We have unconditional purchase obligations from agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. The estimated total for our unconditional purchase obligations is $54.1 million, of which $41.9 million is estimated to be paid in 2023. Contracts to purchase natural gas and utilities are generally at market-based prices. The estimated volumes and market prices at December 31, 2022 were used to value those obligations. The actual physical volumes and settlement prices may vary due to uncertainties involved in these estimates which include levels of production at the wellhead, changes in market prices and other conditions beyond our control.
- We have estimated cash requirements associated with our growth capital spending program. We expect to complete our Granger Optimization Project during 2023 and anticipate approximately $100 million of remaining capital expenditures. Additionally, we expect to spend approximately $400 million, which is net to our interests, over the next two years to complete the construction of our SYNC pipeline and expansion of our CHOPS pipeline. We also have current asset retirement obligations of approximately $27 million that we expect to pay in 2023. These requirements are expected to be funded primarily with free cash flow generated from our operations and availability under our senior secured credit facility.

Guarantor Summarized Financial Information

Our $2.9 billion aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.'s current and future 100% owned domestic subsidiaries (the "Guarantor Subsidiaries"), except GA ORRI and GA ORRI Holdings and certain other subsidiaries. The remaining non-guarantor subsidiaries are indirectly owned by Genesis Crude Oil, L.P., a Guarantor Subsidiary. The Guarantor Subsidiaries largely own the assets that we use to operate our business. As a general rule, the assets and credit of our unrestricted subsidiaries are not available to satisfy the debts of Genesis Energy, L.P., Genesis Energy Finance Corporation or the Guarantor Subsidiaries, and the liabilities of our unrestricted subsidiaries do not constitute obligations of Genesis Energy, L.P., Genesis Energy Finance Corporation or the Guarantor Subsidiaries. See Note 10 to our Consolidated Financial Statements in Item 8 for additional information regarding our consolidated debt obligations.

The guarantees are senior unsecured obligations of each Guarantor Subsidiary and rank equally in right of payment with other existing and future senior indebtedness of such Guarantor Subsidiary, and senior in right of payment to all existing and future subordinated indebtedness of such Guarantor Subsidiary. The guarantee of our senior unsecured notes by each Guarantor Subsidiary is subject to certain automatic customary releases, including in connection with the sale, disposition or transfer of all of the capital stock, or of all or substantially all of the assets, of such Guarantor Subsidiary to one or more persons that are not us or a restricted subsidiary, the exercise of legal defeasance or covenant defeasance options, the satisfaction and discharge of the indentures governing our senior unsecured notes, the designation of such Guarantor Subsidiary as a non-Guarantor Subsidiary or as an unrestricted subsidiary in accordance with the indentures governing our senior unsecured notes, the release of such Guarantor Subsidiary from its guarantee under our senior secured credit facility, or liquidation or dissolution of such Guarantor Subsidiary (collectively, the "Releases"). The obligations of each Guarantor Subsidiary under its note guarantee are limited as necessary to prevent such note guarantee from constituting a fraudulent conveyance under applicable law. We are not restricted from making investments in the Guarantor Subsidiaries and there are no significant restrictions on the ability of the Guarantor Subsidiaries to make distributions to Genesis Energy, L.P.

The rights of holders of our senior unsecured notes against the Guarantor Subsidiaries may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law.

On May 17, 2022, we entered into our credit agreement amendment, which designated GA ORRI and GA ORRI Holdings as unrestricted subsidiaries under our credit agreement. In addition, the credit agreement amendment re-designated Genesis Alkali Holdings Company LLC, Genesis Alkali Holdings, LLC, Genesis Alkali, LLC and Genesis Alkali Wyoming, LP (the subsidiary entities that own our Alkali Business, other than the ORRI Interests) as restricted entities and guarantors of our credit agreement. On May 17, 2022, we designated GA ORRI and GA ORRI Holdings as unrestricted subsidiaries and reclassified the entities that originally held our Alkali Business as restricted subsidiaries under the indentures governing our senior unsecured notes. The Alkali Business was historically presented as non-guarantor subsidiaries and because of such designation are now presented as guarantor subsidiaries. The changes made did not impact the Company's previously reported consolidated net operating results, financial position, or cash flows.

The following is the summarized financial information for Genesis Energy, L.P. and the Guarantor Subsidiaries on a combined basis after elimination of intercompany transactions among the Guarantor Subsidiaries (which includes related receivable and payable balances) and the investment in and equity earnings from the non-Guarantor Subsidiaries.

Balance Sheets		**Genesis Energy, L.P. and Guarantor Subsidiaries**
		December 31, 2022
		(in thousands)
ASSETS:		
Current assets	$	795,381
Fixed assets, net		3,680,119
Non-current assets[1]		869,793
LIABILITIES AND CAPITAL:[2]		
Current liabilities		498,358
Non-current liabilities	$	3,635,959
Class A Convertible Preferred Units		891,909

Statements of Operations		**Genesis Energy, L.P. and Guarantor Subsidiaries**
		Year Ended December 31, 2022
		(in thousands)
Revenues[3]	$	2,638,473
Operating costs		2,443,529
Operating income		194,944
Net income before income taxes		29,031
Net income[2]		25,862
Less: Accumulated distributions to Class A Convertible Preferred Units		(80,052)
Net loss available to common unitholders	$	(54,190)

(1) Excluded from non-current assets in the table above are $23.0 million of net intercompany receivables due to Genesis Energy, L.P. and the Guarantor Subsidiaries from the non-Guarantor Subsidiaries as of December 31, 2022.

(2) There are no noncontrolling interests held at the Issuer or Guarantor Subsidiaries for the period presented.

(3) Excluded from revenues in the table above are $5.1 million of sales from Guarantor Subsidiaries to non-Guarantor Subsidiaries for the year ended December 31, 2022.

Critical Accounting Estimates

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We base these estimates and assumptions on historical experience and other information that are believed to be reasonable under the circumstances. Although we believe our estimates to be reasonable, these estimates and assumptions about future events and their effects cannot be determined with certainty, and, accordingly, are evaluated on a regular basis and revised as needed as new events occur or more information is acquired, and as the business environment in which we operate changes. Significant accounting policies that we employ are presented in Note 2 to our Consolidated Financial Statements in Item 8.

We have defined critical accounting estimates as those that: (i) are material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (ii) the impact to the financial condition or operating performance of the Company is material. Our most critical accounting estimates are discussed below.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets such as customer relationships, contracts, trade names and non-compete agreements involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets and liabilities acquired, and to the extent available, third-party assessments. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill, if any, is not amortized but instead is periodically assessed for impairment, as discussed further below. Uncertainties associated with these estimates include fluctuations in economic obsolescence factors in the area and potential future sources of cash flow.

Depreciation, Amortization and Depletion of Long-Lived Assets and Intangibles

In order to calculate depreciation, depletion and amortization we must estimate the useful lives of our fixed and intangible assets (including the reserve life of our mineral leaseholds) at the time the assets are placed in service. We compute depreciation and amortization on a straight-line basis using the best estimated useful life at the time the asset is placed into service. The actual period over which we will use the asset may differ from the assumptions we have made about the estimated useful life. Any subsequent events that result in a change in these estimates can impact future depreciation and amortization calculations, and these changes are adjusted as we become aware of such circumstances. At a minimum, we will assess the useful lives and residual values of all long-lived assets on an annual basis to determine if adjustments are required.

We compute depletion using the units of production method using actual production and our estimated reserve life. The actual reserve life may differ from the assumptions we have made about the estimated reserve life.

Impairment of Long-Lived Assets

When events or changes in circumstances indicate that the carrying amount of a fixed asset, intangible asset, equity method investment, or right of use asset with finite lives may not be recoverable, we review our assets for impairment. We compare the carrying value of the associated asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes and/or contractual commitments, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset's unamortized cost may not be recoverable due to impairment, we may be required to reduce the carrying value and/or the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of a long-lived asset would increase costs and expenses at that time. For the years ended December 31, 2022 and 2021, we did not recognize an impairment expense associated with our long-lived assets. For the year ended December 31, 2020, we recognized impairment expense of $280.8 million associated with long-lived assets (refer to Note 7 in our Consolidated Financial Statements in Item 8 for additional details).

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we evaluate, and test if necessary, our goodwill (at the reporting unit level) for impairment on October 1 of each fiscal year, and more frequently, if indicators of impairment are present.

We may perform a qualitative assessment of relevant events and circumstances about the likelihood of goodwill impairment. If it is deemed more likely than not the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. We may also elect to exercise our unconditional option to bypass this qualitative assessment, in which case we would also calculate the fair value of the reporting unit. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit's fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. Changes in these estimates could have a significant impact on fair value. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value. One of our other monitoring procedures is the comparison of our market capitalization to our book equity to determine if there is an indicator of impairment.

We performed a qualitative assessment as of October 1, 2022 for our refinery services reporting unit, which is the only reporting unit as of our assessment date that has goodwill. We did not identify any relevant events or circumstances indicating that it is more likely than not that the fair value of the reporting unit is less than the respective carrying value. As such, a quantitative goodwill test was not required, and no goodwill impairment was recognized for the year ended December 31, 2022.

For additional information regarding our goodwill, see Note 9 to our Consolidated Financial Statements in Item 8.

Revenue recognition - Estimation of variable consideration

Our offshore pipeline transportation segment has certain long-term contracts with customers that include variable consideration that must be estimated at contract inception and re-assessed at each reporting period. Total consideration for these arrangements is recognized as revenue over the applicable contract period and is based on our measure of satisfaction of our corresponding performance obligation. Any difference in timing of revenue recognition and billings results in contract assets and liabilities. The estimated performance obligation over the life of a contract includes significant judgments by management including volume and forecasted production information, future price indexing, our ability to transport volumes produced by our customers, and the contract period. Changes in these assumptions or a contract modification could have a material effect on the amount of variable consideration recognized as revenue.

Fair Value of Derivatives

We reflect estimates for the fair value of our derivatives based on our internal records and information from third parties. We have commodity and other derivatives that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations. Changes in these estimates could cause a material change to our financial results.

We identified a feature within our Class A Convertible Preferred Units that was required to be bifurcated and recorded as an embedded derivative measured at fair value. Our final valuation of the embedded derivative occurred on September 29, 2022, which is when the feature within the Class A Convertible Preferred Units that required bifurcation and fair value measurement no longer existed. On September 29, 2022, the fair value of the liability associated with the embedded derivative was reclassified to mezzanine equity.

The fair value of the embedded derivative associated with our Class A Convertible Preferred Units was estimated using a Monte Carlo simulation approach that contained inputs, including our common unit price relative to the issuance price, dividend yield, discount yield, equity volatility, 30-year U.S. Treasury rates, and default and redemption probabilities and timing estimates, which involved management judgment.

During the years ended December 31, 2022 and 2021, we recorded unrealized losses of $18.6 million and $30.8 million, respectively, associated with fair value changes of the embedded derivative. Changes in the fair value estimate during 2022 were primarily driven by the election of the rate reset, which increased the distribution rate from 8.75% to 11.24%, and changes in the fair value estimate during 2021 were primarily driven by fluctuations in the discount yield from period to period. A significant increase or decrease in these inputs could have materially affected our fair value estimate, resulting in impacts to our Consolidated Financial Statements. For example, a 10% increase or decrease in the volatility used in the calculation could have caused a decrease or an increase to the fair value of our embedded derivative of approximately $8 million or $11 million, respectively as of September 29, 2022.

For additional information regarding the Class A Convertible Preferred Units and the associated embedded derivative, see Note 11 and Note 18 to our Consolidated Financial Statements in Item 8.

Liability and Contingency Accruals and Asset Retirement Obligations

We accrue reserves for contingent liabilities including environmental remediation and potential legal claims. When our assessment indicates that it is probable that a liability has occurred and the amount of the liability can be reasonably estimated, we make accruals. We base our estimates on all known facts at the time and our assessment of the ultimate outcome, including consultation with external experts and counsel. We revise these estimates as additional information is obtained or resolution is achieved.

We also make estimates related to future payments for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include costs for studies and testing as well as remediation and restoration. We sometimes make these estimates with the assistance of third parties involved in monitoring the remediation effort.

Significant changes in new information or judgments could have a material impact to our financial results.

At December 31, 2022, we were not aware of any contingencies or environmental liabilities that would have a material effect on our financial position, results of operations or cash flows.

Additionally, certain of our assets have contractual and regulatory obligations to perform dismantlement and removal activities, and in some instances remediation, when the assets are abandoned. Our asset retirement obligations are recorded as a liability at fair value and have significant assumptions and inputs, including the estimated costs and timing of the associated abandonment activities as well as the discount and inflation rates utilized to calculate the present value of the future estimated costs, that could materially impact our financial results. During 2022, we recognized changes in estimates (primarily due to updated estimated costs and the timing of when we expect to spend these costs) associated with certain of our non-core offshore assets of approximately $11 million. We could have impacts to our future earnings based on the actual costs we incur relative to our estimated costs.

Employee Benefits

We sponsor a defined benefit pension plan for union-only employees of our Alkali Business. We recognize the net funded status of the pension plan under GAAP as a net liability, included within "Other long-term liabilities" as of December 31, 2022 and 2021 on our Consolidated Balance Sheets. The funded status represents the difference between the fair value of the pension plan's assets and the estimated benefit obligation of the plan. The benefit obligation represents the present value of the estimated future benefits we expect to pay to plan participants based on service at the end of each period. The benefit obligation and plan assets are measured at the end of each year, or more frequently, upon the occurrence of a significant event, such as a settlement or curtailment. We utilize actuarial valuations to measure our funded status in the plan, which include assumptions such as discount rates, expected long-term rate of return on our plan assets, the timing of our contributions and payments, employee headcount and compensation changes, amongst others. Significant changes to certain of these assumptions can have a material impact to our financial statements. We recognized an actuarial gain of $11.2 million during 2022 in accumulated other comprehensive income (loss) primarily as a result of an increase to the discount rate utilized to calculate our benefit obligation from 3.27% at December 31, 2021 to 5.33% at December 31, 2022. The impact of the increase in our discount rate was partially offset as a result of an actuarial loss recognized due to the difference between the actual and expected return on our plan assets during 2022.

Recent Accounting Pronouncements

Recently Issued and Recently Adopted

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform (Topic 848), which provides expedients and exceptions for accounting treatment of contracts which are affected by the anticipated discontinuation of the London InterBank Offered Rate ("LIBOR") and other rates resulting from rate reform that are entered into on or before December 31, 2022. Contract terms that are modified due to the replacement of a reference rate are not required to be remeasured or reassessed under relevant accounting standards. On May 17, 2022, we entered into our Second Amendment and Consent to the credit agreement (defined in Note 10 to our Consolidated Financial Statements in Item 8), which among other things, replaced our existing LIBOR rate based borrowings with the Term SOFR rate, which is based on the Secured Overnight Financing Rate ("SOFR") borrowings. The impact to our senior secured credit facility and related interest expense upon transition to SOFR did not have a material impact on our Consolidated Financial Statements for the year ended December 31, 2022. Refer to Note 10 in our Consolidated Financial Statements in Item 8 for more details.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including (i) commodity price risk and (ii) interest rate risk. We use various derivative instruments primarily to manage commodity price risk. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as our physical volumes, grades, locations, and delivery schedules. We do not acquire and hold futures contracts or other derivatives for the purpose of speculating on price changes. The following discussion addresses each category of risk:

Commodity Price Risk

We use derivative instruments to hedge price risk associated with the following commodities:

- Crude Oil and Petroleum Products — We utilize crude oil and petroleum product derivatives to hedge commodity price risk inherent in our onshore facilities and transportation segment. Our objectives for these derivatives include hedging fixed price purchase and sales, crude inventories, and basis differentials. We manage these exposures with various instruments including futures, swaps, and options. Our risk management policies are designed to monitor our physical volumes, grades and delivery schedules to ensure our hedging activities address the market risks inherent in our gathering and marketing activities. As of December 31, 2022 we had entered into derivative instruments that will settle between January 2023 and March 2023.
- Natural Gas — We utilize natural gas derivatives to hedge commodity price risk inherent in our sodium minerals and sulfur services segment. Our objectives for these derivatives include hedging anticipated purchases of natural gas used by our Alkali business to generate heat and power for operations. We manage these exposures with various instruments including futures, swaps, and options. As of December 31, 2022 we had entered into derivative instruments that will settle between January 2023 and December 2023.

The accounting treatment for our commodity derivatives is discussed further in Note 18 to our Consolidated Financial Statements in Item 8.

The table below presents information about our open commodity derivative contracts at December 31, 2022. Notional amounts in barrels or MMBtu, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars of our open positions are presented below. Fair values were determined by using the notional amount in barrels or MMBtu multiplied by the December 31, 2022 quoted market prices. The table does not include offsetting physical exposures hedged by our derivative contracts.

	Unit of Measure for Volume	Contract Volumes (in 000's)	Unit of Measure for Price	Weighted Average Market Price	Contract Value (in 000's)	Mark-to Market Change (in 000's)	Settlement Value (in 000's)
Futures and Swap Contracts							
Sell (Short) Contracts:							
Crude Oil	Bbl	93	Bbl	$ 78.31	$ 7,282	$ 197	$ 7,479
#6 Fuel Oil	Bbl	25	Bbl	$ 56.15	$ 1,404	$ 95	$ 1,499
Natural Gas	MMBtu	1,480	MMBtu	$ 5.27	$ 7,794	$ (829)	$ 6,965
Buy (Long) Contracts:							
Crude Oil	Bbl	90	Bbl	$ 76.43	$ 6,878	$ 348	$ 7,226
Natural Gas Swaps	MMBtu	9,765	MMBtu	$ 0.64	$ 6,231	$ 32,151	$ 38,382
Natural Gas	MMBtu	8,060	MMBtu	$ 5.36	$ 43,185	$ (8,809)	$ 34,376
Option Contracts							
Written Contracts:							
Natural Gas	MMBtu	1,910	MMBtu	$ 0.70	$ 1,340	$ 559	$ 1,899
Purchased Contracts:							
Natural Gas	MMBtu	340	MMBtu	$ 0.03	$ 9	$ (9)	$ —

We manage our risks of volatility in NaOH prices by indexing prices for the sale of NaHS to the market price for NaOH in most of our contracts. Given the competitive advantages associated with our naturally produced soda ash as previously discussed (relative to that which is synthetically produced), we believe this somewhat mitigates market risk within our Alkali Business.

Interest Rate Risk

We are also exposed to market risks due to the floating interest rates on our senior secured credit facility.

As noted above, on May 17, 2022, we entered into our Second Amendment and Consent to the credit agreement, which among other things, replaced our existing LIBOR rate based borrowings with the Term SOFR rate. The impact to our senior secured credit facility and related interest expense upon transition to SOFR did not have a material impact on our Consolidated Financial Statements for the year ended December 31, 2022. Obligations under our senior secured credit facility bear interest at the SOFR rate or alternate base rate (which approximates the prime rate), at our option, plus the applicable margin. We have not historically hedged our interest rates. On December 31, 2022, we had $205.4 million of debt outstanding under our senior secured credit facility. A 10% change in the SOFR rate would have resulted in an immaterial impact to Net income for the year ended December 31, 2022.

The Preferred Distribution Rate Reset Election associated with our Class A Convertible Preferred Units represented a feature that was required to be bifurcated from the related host contract, the preferred unit purchase agreement, and accounted for as an embedded derivative recorded at fair value in our Consolidated Balance Sheets. Our final valuation of the embedded derivative occurred on September 29, 2022, which is the date at which the feature within the Class A Convertible Preferred Units that required bifurcation and fair value measurement no longer existed. On September 29, 2022, the fair value of the liability associated with the embedded derivative was reclassified to mezzanine equity. The valuation model utilized for this embedded derivative contained inputs including our common unit price relative to the issuance price, the current dividend yield, the discount yield (which was adjusted periodically for changed associated with the industry's credit markets), equity volatility, default probabilities, U.S. treasury rates, and timing estimates to ultimately calculate the fair value of our Class A Convertible Preferred Units with and without the Preferred Distribution Rate Reset Option. See Note 11 and Note 18 to our Consolidated Financial Statements in Item 8 for further discussion of our Class A Convertible Preferred Units and embedded derivatives.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the "Index to Consolidated Financial Statements."

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. As described in our Quarterly Report on Form 10-Q for the period ended June 30, 2022, management identified a material weakness in our internal control over financial reporting during the quarter ended June 30, 2022. The Company implemented measures in an effort to remediate the material weakness and enhance the Company's accounting and review processes during the three months ended September 30, 2022, which included the following actions: (i) implementing additional review procedures; and (ii) participating in various continuing education courses associated with the review of revenue contracts. As of December 31, 2022, management believes that the measures described above have remediated the material weakness identified during the quarter ended June 30, 2022.

Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K and have determined that such disclosure controls and procedures are effective in providing assurance of the timely recording, processing, summarizing and reporting of information, and in accumulation and communication to management on a timely basis material information relating to us (including our consolidated subsidiaries) required to be disclosed in this Annual Report on Form 10-K.

Changes in Internal Controls over Financial Reporting

Except as noted above, there have been no changes in internal control over financial reporting during the quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Partnership's internal control over financial reporting is designed to provide reasonable assurance to the Partnership's management and board of directors regarding the preparation and fair presentation of published 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.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our assessment, we believe that, as of December 31, 2022, the Partnership's internal control over financial reporting is effective based on those criteria.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2022. Ernst & Young LLP, the Partnership's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Partnership's internal control over financial reporting. Ernst & Young's attestation report on the Partnership's internal control over financial reporting appears in Item 8. "Financial Statements and Supplementary Data."

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

We are a Delaware limited partnership. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. Our general partner, Genesis Energy, LLC, a wholly-owned subsidiary that owns a non-economic general partner interest in us, has sole responsibility for conducting our business and managing our operations. It also employs most of our personnel, including executive officers. Employees of our Alkali operations are employed by our subsidiary, Genesis Alkali, LLC.

The board of directors of our general partner (which we refer to as "our board of directors") must approve significant matters (such as material business strategies, mergers, business combinations, acquisitions or dispositions of assets, issuances of common units, incurrences of debt or other financings and the payments of distributions on common and preferred units). The holders of our Class B Common Units are entitled to (i) vote in the election of our board of directors, subject to the Davison family's rights under its unitholder rights agreement (described below), as well as (ii) vote on substantially all other matters on which our Class A holders are entitled to vote. The holders of our Class A Common Units are not entitled to vote in the election of directors, but they are entitled to vote in a very limited number of other circumstances, including our merger with another company. As is common with MLPs, our partnership structure does not grant our unitholders (in such capacity) the right to directly or indirectly participate in our management or operations other than through the exercise of their limited voting rights.

Collectively, members of the Davison family own 11.1% of our Class A Common Units and 77.0% of our Class B Common Units, for a combined ownership percentage of 11.1% of total Common Units. Pursuant to its unitholder rights agreement, the Davison family is entitled to elect up to three of our directors based on its members' collective ownership percentage of our outstanding common units: (i) with 15% or more ownership, they have the right to appoint three directors, (ii) with less than 15% ownership but more than 10%, they have the right to appoint two directors, and (iii) with less than 10% ownership, they have the right to appoint one director. That unitholder rights agreement also provides that, so long as the Davison family has the right to elect three directors thereunder, our board of directors cannot have more than 11 directors without the Davison family's consent. In addition to their rights under that unitholder rights agreement, if the members of the Davison family act as a group, they have the ability to elect at least a majority of our directors because they own a majority of our Class B units.

Under our limited partnership agreement, the organizational documents of our general partner and indemnification agreements with our directors, subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

Our board of directors currently consists of Sharilyn S. Gasaway, James E. Davison, James E. Davison, Jr., Kenneth M. Jastrow II, Conrad P. Albert, Jack T. Taylor and Grant E. Sims. Our board of directors has determined that each of Ms. Gasaway and Messrs. Jastrow, Albert and Taylor is an independent director under the NYSE rules.

Board Leadership Structure and Risk Oversight

Board Leadership Structure

Our board of directors has no policy that requires the positions of the Chairman of the Board and the Chief Executive Officer to be held by the same or different persons or that we designate a lead or presiding independent director. Our board of directors believes it is important to retain the flexibility to make those determinations based on an assessment of the circumstances existing from time to time, including the composition, skills and experience of our board of directors and its members, specific challenges faced by the Company or the industry in which it operates, and governance efficiency.

Presently, our board of directors believes that, because Mr. Sims is the director most familiar with our business and industry and the most capable of leading the discussion of, and executing on, our business strategy, he is best situated to serve as Chairman, regardless of the fact that he is the Chief Executive Officer of our general partner. Our board of directors also believes that the appointment of a lead independent director, who will preside over executive sessions of non-management directors of our board of directors, will facilitate teamwork and communication between the non-management directors and management. Our board of directors appointed Mr. Jastrow as our lead independent director because of his executive experience and service as a director of other companies. Our board of directors believes that the combined role of Chairman and Chief Executive Officer working with the lead independent director is currently in the best interest of unitholders, providing the appropriate balance between developing our strategy and overseeing management.

On September 1, 2017, we sold $750 million of Class A Convertible Preferred Units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the "Issue Price") to two initial purchasers. In connection with the private placement, we have granted each initial purchaser (including its applicable affiliate transferees) certain rights, including (i) the right to appoint an observer, who shall have the right to attend our board meetings for so long as an initial purchaser (including its affiliates) owns at least $200 million of our Class A Convertible Preferred Units and (ii) the right to appoint two directors to our general partner's board of directors if (and so long as) we fail to pay in full any three quarterly distribution amounts, whether or not consecutive.

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, personnel, suppliers, business partners and stakeholders. We believe independent directors are a key element for strong governance, although we have reserved or exercised our right as a limited partnership under the listing standards of the NYSE not to comply with certain requirements of the NYSE. For example, although at least a majority of the members of our board of directors is independent under the NYSE rules, we reserve the right not to comply with Section 303A.01 of the NYSE Listed Company Manual in the future, which would require that our board of directors be comprised of at least a majority of independent directors. In addition, among other things, we have elected not to comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require our board of directors to maintain a nominating/corporate governance committee and a compensation committee, each consisting entirely of independent directors. Our corporate governance guidelines are available on our website (www.genesisenergy.com) free of charge. For further discussion of director independence, please see Item 13. "Certain Relationships and Related Transactions, and Director Independence—Director Independence."

Risk Oversight

We face a number of risks, including exposure to matters relating to the environment, regulation, competition, fluctuations in commodity prices and interest rates, pandemics and severe weather. Management is responsible for the day-to-day management of the risks our company faces, although our board of directors, as a whole and through its committees, has responsibility for the oversight of risk management. In fulfilling its risk oversight role, our board of directors must determine whether risk management processes designed and implemented by our management are adequate and functioning as designed. Senior management regularly delivers presentations to our board of directors on strategic matters, operations, risk management and other matters, and are available to address any questions or concerns raised by our board of directors. Board of directors meetings also regularly include discussions with senior management regarding strategies, key challenges and risks and opportunities for our company.

Our board committees assist our board of directors in fulfilling its oversight responsibilities in certain areas of risk. For example, the audit committee assists with risk management oversight in the areas of financial reporting, internal controls, cybersecurity, compliance with legal and regulatory requirements and our risk management policy relating to our hedging program. The governance, compensation and business development committee assists our board of directors with risk management relating to our compensation policies and programs.

Our board of directors believes that it is important to align (when practical) the interests of the members of our board of directors and certain of our officers with the interests of our long-term stakeholders. Our board of directors has adopted certain policies to further promote that alignment of interests. For example, among other things, our policies prohibit our directors and officers from (i) buying, selling or engaging in transactions with respect to our common units while they are aware of material non-public information and (ii) engaging in short sales of our securities. Certain of our directors and/or officers own substantial amounts of our units, some of which are pledged, including being held in broker margin accounts. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

Audit Committee

The audit committee of our board of directors generally oversees our accounting policies and financial reporting and the audit of our financial statements. The audit committee assists our board of directors in its oversight of the quality and integrity of our financial statements and our compliance with legal and regulatory requirements. Our independent registered public accounting firm is given unrestricted access to the audit committee. Our board of directors has determined that the members of the audit committee meet the independence and experience standards established by NYSE and the Securities Exchange Act of 1934, as amended. In accordance with the NYSE rules and the Securities Exchange Act of 1934, as amended, our board of directors has named three of its members to serve on the audit committee—Sharilyn S. Gasaway, Conrad P. Albert and Jack T. Taylor. Ms. Gasaway is the chairperson. Our board of directors believes that Ms. Gasaway and Mr. Taylor qualify as audit committee financial experts as such term is used in the rules and regulations of the SEC. The charter of the audit committee is available on our website (www.genesisenergy.com) free of charge. Each member of the audit committee is an independent director under NYSE rules.

Governance, Compensation and Business Development Committee

The governance, compensation and business development committee, or G&C Committee, of our board of directors generally (i) monitors compliance with corporate governance guidelines, (ii) reviews and makes recommendations regarding board and committee composition, structure, size, compensation and related matters, and (iii) oversees compensation plans and compensation decisions for our employees. All the members of our board of directors, other than our CEO, serve as members of the G&C Committee. Mr. Jastrow is the chairperson. The charter of the G&C Committee is available on our website (www.genesisenergy.com) free of charge.

Conflicts Committee

To the extent requested by our board of directors, a conflicts committee of our board of directors would be appointed to review specific matters in connection with the resolution of conflicts of interest and potential conflicts of interest between any of our affiliates and us. If a specific review is requested by our board of directors, our conflicts committee would be formed by our Board and would be comprised solely of independent directors. See Item 13. “Certain Relationships and Related Transactions, and Director Independence—Review or Special Approval of Material Transactions with Related Persons.”

Executive Sessions of Non-Management Directors

Our board of directors holds executive sessions in which non-management directors meet without any members of management present in connection with regular board meetings. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. Mr. Jastrow, as the lead independent director, serves as the presiding director at those executive sessions. In accordance with NYSE rules, interested parties can communicate directly with non-management directors by mail in care of the General Counsel and Secretary or in care of the chairperson of the audit committee at 811 Louisiana, Suite 1200, Houston, TX 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded. We have established a toll-free, confidential telephone hotline so that interested parties may communicate with the chairperson of the audit committee or with all the non-management directors as a group. All calls to this hotline are reported to the chairperson of the audit committee who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential hotline is (844) 988-1965.

Directors and Executive Officers

Set forth below is certain information concerning our directors and executive officers, effective as of February 24, 2023.

Name	Age	Position
Grant E. Sims	67	Director, Chairman of the Board, and Chief Executive Officer
Conrad P. Albert	76	Director
James E. Davison	85	Director
James E. Davison, Jr.	56	Director
Sharilyn S. Gasaway	54	Director
Kenneth M. Jastrow II	75	Director
Jack T. Taylor	71	Director
Robert V. Deere	68	Chief Financial Officer
Edward T. Flynn	64	Executive Vice President
Kristen O. Jesulaitis	53	Chief Legal Officer and Senior Vice President
Ryan S. Sims	39	Senior Vice President
Garland G. Gaspard	68	Senior Vice President
Karen N. Pape	64	Senior Vice President and Controller
Richard R. Alexander	47	Vice President
William S. Goloway	62	Vice President
Chad A. Landry	59	Vice President

Grant E. Sims has served as a director and Chief Executive Officer of our general partner since August 2006 and Chairman of the Board of our general partner since October 2012. Mr. Sims was affiliated with Leviathan Gas Pipeline Partners, LP from 1992 to 1999, serving as the Chief Executive Officer and a director beginning in 1993 until he left to pursue personal interests, including investments. Leviathan (subsequently known as El Paso Energy Partners, L.P. and then GulfTerra Energy Partners, L.P.) was a NYSE listed MLP. Mr. Sims has an established track record of developing strong companies and has led his companies through a period of substantial growth while increasing geographic and operational diversity. Mr. Sims provides leadership skills, executive management experience and significant knowledge of our business environment, which he has gained through his vast experience with other MLPs.

Conrad P. Albert has served as a director of our general partner since July 2013. Mr. Albert is a private investor and was formerly a director of Anadarko Petroleum Corporation from 1986 to 2006. Mr. Albert also served as a director of DeepTech International, Inc. from 1992 to 1998. From 1969 to 1991, Mr. Albert served in various positions with Manufacturers Hanover Trust Company, ultimately serving as Executive Vice President in charge of worldwide energy lending and corporate finance. Mr. Albert’s extensive financial, executive and directorial experience and his service in various roles in the management of other energy-related companies will allow him to provide valuable expertise to our board of directors.

James E. Davison has served as a director of our general partner since July 2007. Mr. Davison served as chairman of the board of Davison Transport, Inc. for over 30 years. He also serves as President of Terminal Services, Inc. Mr. Davison has over forty years of experience in the energy-related transportation and sulfur removal businesses. Mr. Davison brings to our board of directors significant energy-related transportation and sulfur removal experience and industry knowledge.

James E. Davison, Jr. has served as a director of our general partner since July 2007. Mr. Davison is also a director of another public company, Origin Bancorp, Inc., and serves on its finance, risk and insurance committees. Mr. Davison is the son of James E. Davison. Mr. Davison’s executive and leadership experience enable him to make valuable contributions to our board of directors.

Sharilyn S. Gasaway has served as a director of our general partner since March 2010 and serves as chairperson of the audit committee. Ms. Gasaway is a private investor and was Executive Vice President and Chief Financial Officer of Alltel Corporation, a wireless communications company, from 2006 to 2009, and served as Controller of Alltel Corporation from 2002 through 2006. In her role as CFO, Ms. Gasaway was responsible for the company’s finance, financial reporting, and risk management roles, and gained extensive experience in corporate performance and strategic planning. She brings this vast knowledge to the Partnership. Ms. Gasaway is a director of JB Hunt Transport Services, Inc., a public company where she also serves as the chair of the audit committee. Additionally, Ms. Gasaway serves on the compensation and nominating committees of JB Hunt Transport Services, Inc. Ms. Gasaway provides our board of directors valuable business experience, risk management and financial expertise, including an understanding of the accounting, compliance and financial matters that we address on a regular basis.

Kenneth M. Jastrow II has served as a director of our general partner since March 2010 and serves as our lead independent director and the chairperson of the G&C Committee. Mr. Jastrow served as Chairman and Chief Executive Officer of Temple-Inland, Inc., a manufacturing company and the former parent of Forestar Group, from 2000 to 2007. Prior to that, Mr. Jastrow served in various roles at Temple-Inland, including President and Chief Operating Officer, Group Vice President and Chief Financial Officer. Mr. Jastrow served as a director of MGIC Investment Corporation and a director and Director Emeritus of KB Home. Mr. Jastrow formerly served as Non-Executive Chairman of Forestar Group, Inc. Mr. Jastrow’s executive experience and service as director of other companies enable him to make valuable contributions to our board of directors and particularly well suited to be the lead independent director.

Jack T. Taylor has served as a director of our general partner since July 2013. Mr. Taylor is currently a director of Sempra Energy and Murphy USA Inc. Additionally, Mr. Taylor currently serves on the audit committee of Sempra Energy and Murphy USA Inc. Mr. Taylor was a partner of KPMG LLP for 29 years, where from 2005 to 2010 he served as KPMG's Chief Operating Officer-Americas and Executive Vice Chair of U.S. Operations and from 2001 to 2005 he served as the Vice Chairman of U.S. Audit and Risk Advisory Services. Mr. Taylor’s extensive experience with financial and public accounting issues, his various leadership roles at KPMG LLP and his extensive knowledge of the energy industry make him a valuable resource to our board of directors.

Robert V. Deere has served as Chief Financial Officer of our general partner since October 2008. Mr. Deere served as Vice President, Accounting and Reporting at Royal Dutch Shell (Shell) from 2003 through 2008.

Edward T. Flynn has served as Executive Vice President of our general partner and President, Genesis Alkali since we acquired that business from Tronox Ltd. in September 2017 (where he also previously served as Executive Vice President). Prior to joining Tronox, Mr. Flynn served as President of FMC Minerals. He was previously President of FMC’s Industrial Chemicals Group. Mr. Flynn is a member of the Board of Directors and Chairman of the Board for ANSAC.

Kristen O. Jesulaitis serves as Chief Legal Officer and Senior Vice President. Since joining Genesis in July 2011, Ms. Jesulaitis has been responsible for overseeing all legal matters of the Company, including acquisitions and commercial transactions, compliance and regulatory affairs, corporate governance, finance, and securities. Prior to joining Genesis, Ms. Jesulaitis was a partner at the law firm Akin Gump Strauss Hauer & Feld LLP principally engaged in the areas of corporate and securities law, with primary focus in the midstream energy sector.

Ryan S. Sims has served as Senior Vice President of our general partner since March 2019. Mr. Sims served as Vice President from January 2017 to March 2019. Mr. Sims joined Genesis in 2011 and is responsible for our finance, planning, corporate development, and investor relations functions. He has also previously been responsible for the operational and commercial aspects of our rail and terminals businesses. Prior to joining Genesis, Mr. Sims spent six years in the investment banking industry. Mr. Sims is the son of Grant E. Sims, our Chairman and Chief Executive Officer.

Garland G. Gaspard has served as Senior Vice President of our general partner since January 2017 and is responsible for the operational aspects of our onshore and offshore pipelines, rail facilities, terminals, offshore facilities and assets, engineering, trucking and health, safety, security and environmental compliance. Mr. Gaspard joined Genesis in 2015 as a result of our acquisition of the offshore Gulf of Mexico assets from Enterprise Products and has had responsibility for the operational aspects of our offshore assets since that time. Prior to this acquisition, Mr. Gaspard served in various capacities within Enterprise Products' operations including underground gas storage, natural gas liquids, natural gas pipelines and offshore operations.

Karen N. Pape has served as Senior Vice President and Controller of our general partner since July 2007 and served as Vice President and Controller from May 2002 until July 2007.

Richard R. Alexander has served as Vice President of our general partner since November 2014. Mr. Alexander is responsible for the commercial aspects of our marine transportation segment. Since 2008, Mr. Alexander has served in various capacities within our marine operations.

William S. Goloway has served as Vice President of our general partner since January 2017. Mr. Goloway has been responsible for the commercial aspects of our offshore Gulf of Mexico assets from the time we acquired these offshore assets from Enterprise Products in 2015. Prior to this acquisition, Mr. Goloway served in various roles within the offshore group at Enterprise Products since 2005.

Chad A. Landry has served as Vice President of our general partner since January 2017. Mr. Landry joined Genesis in 2013 and since that time has been responsible for all operational and commercial aspects of our sodium minerals and sulfur services segment. Prior to joining Genesis, he spent 14 years at Axiall Corporation (Georgia Gulf), most recently as Vice President - Chlor-Alkali & Vinyls.

Common Unit Ownership by Directors and Executive Officers

We encourage our directors and officers to own our common units, although we do not feel it is necessary to require them to own a minimum number. Certain of our directors and officers own substantial amounts of our securities, although any (or all) of them may sell, pledge or otherwise dispose of all or a portion of those securities at any time, subject to any applicable legal and company policy requirements. See Item 10. “Directors, Executive Officers and Corporate Governance-Board Leadership Structure and Risk Oversight-Risk Oversight.”

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that is applicable to, among others, the principal financial officer and the principal accounting officer. Our Code of Business Conduct and Ethics is posted at our website (www.genesisenergy.com), where we intend to report any changes or waivers.

Item 11. Executive Compensation

The Compensation Discussion and Analysis below discusses our compensation process and our objectives and philosophy with respect to our Named Executive Officers (“NEOs”) for the fiscal year ended December 31, 2022.

Compensation Discussion and Analysis

Named Executive Officers

Our NEOs for 2022 were:

- Grant E. Sims, Chief Executive Officer;
- Robert V. Deere, Chief Financial Officer;
- Edward T. Flynn, Executive Vice President;
- Kristen O. Jesulaitis, Chief Legal Officer and Senior Vice President; and
- Garland G. Gaspard, Senior Vice President.

Board and Governance, Compensation and Business Development Committee

Our board of directors is responsible for, and effectively determines, compensation programs applicable to our NEOs and to the board itself. Our board of directors has delegated to the G&C Committee, of which a majority of the members are “independent,” according to NYSE listing standards, the authority and responsibility to regularly analyze and evaluate our compensation policies, to determine the annual compensation of our NEOs, and to make recommendations to our board of directors with respect to such matters. As described in more detail below, the G&C Committee engaged Meridian Compensation Partners, LLC, or Meridian, as its independent compensation adviser for 2022. As the need arises, we also utilize committees comprised solely of certain of our independent directors (i.e., the audit committee or special committees) to review and make recommendations with respect to certain matters. Because the G&C Committee is comprised of all the members of our board of directors, excluding our CEO, determinations and recommendations by the G&C Committee are effectively determinations by our board of directors, which has approval authority for all such compensation matters. For a more detailed discussion regarding the purposes and composition of board committees, please see Item 10. “Directors, Executive Officers and Corporate Governance.”

Committee/Board Process

Following the end of each calendar year, our CEO reviews the compensation of all the other NEOs and makes a proposal to the G&C Committee regarding their compensation. The CEO's proposal is based on (among other things) our financial results for the prior year, the relevant executive’s areas of responsibility, market data provided by our independent compensation adviser, and recommendations from the relevant executive’s supervisor (if other than our CEO). The G&C Committee reviews the compensation of our CEO and the proposal of our CEO regarding the compensation of the other NEOs and makes a final determination (and a recommendation to our board of directors) regarding the compensation of our NEOs. Depending on the nature and quantity of changes made to that proposal, there may be additional G&C Committee meetings and discussions with our CEO in advance of that determination. Our board of directors has final approval authority for all such compensation matters.

Committee/Board Approval

The G&C Committee determines salaries, annual cash incentives and long-term awards for executive officers, taking into consideration the CEO’s recommendation regarding the NEOs. In April, any applicable salary increases, retention and annual bonuses, and long-term incentive awards are made or granted.

Role of Compensation Consultant and Peer Group Analysis

The G&C Committee’s charter authorizes it to retain independent compensation consultants from time to time to serve as a resource in support of its efforts to carry out certain duties. In 2022, the G&C Committee engaged Meridian, an independent compensation consultant, to assist the G&C Committee in assessing and structuring competitive compensation packages for the executive officers that are consistent with our compensation philosophy. The G&C Committee assessed the independence of Meridian pursuant to current exchange listing requirements and SEC guidance and concluded that no conflict of interest exists that would prevent Meridian from serving as an independent consultant to the G&C Committee.

At the request of the G&C Committee, Meridian reviewed and provided input on the compensation of our NEOs, trends in executive compensation, meeting materials circulated to the G&C Committee, and management’s recommendations regarding executive compensation plans. Meridian also developed assessments of market levels of compensation through an analysis of peer data and information disclosed in our peer companies' public filings, but did not determine or recommend the amount of compensation.

The peer group used for this market analysis in 2022 consisted of the following 14 companies in the energy industry: Plains All American Pipeline, L.P., Targa Resources Corp., DCP Midstream, LP, Equitrans Midstream Corporation, EnLink Midstream, LLC, Magellan Midstream Partners, L.P., Delek US Holdings, Inc., NGL Energy Partners LP, NuStar Energy L.P., Sunoco LP, Crestwood Equity Partners LP, USA Compression Partners, LP, U.S. Silica Holdings, Inc. and Calumet Specialty Products Partners, L.P. These companies were selected as the compensation peer group for any or all of the following reasons:

1) they reflect our industry competitors for products and services;

2) they operate in similar markets or have comparable geographical reach;

3) they are of similar size and maturity to us; or

4) they are companies that have similar credit profiles to us and/or their growth or capital programs are similar to ours.

The G&C Committee reviews the peer group annually and may, from time to time, add or remove companies in order to assure the composition of the group meets the criteria outlined above.

The information that Meridian compiled included compensation trends for MLPs and levels of compensation for similarly-situated executive officers of companies within this peer group. We believe that compensation levels of executive officers in our peer group are relevant to our compensation decisions because we compete with those companies for executive management talent.

Compensation Objectives and Philosophy

The primary objectives of our compensation program are to:

- encourage our executives to build and operate the partnership in a way that is aligned with our common and preferred unitholders' interests, focusing on growing total unitholder returns and growing the asset base with an emphasis on maintaining a focus on the long-term stability of the enterprise so as to not promote inappropriate risk taking;
- offer near-term and long-term compensation opportunities that are consistent with industry norms; and
- provide appropriate levels of retention to the executive team to ensure long-term continuity and stability for the successful execution of key growth initiatives and projects.

We strive to accomplish these objectives by providing all employees, including our NEOs, with a total compensation package that is market competitive and both service and performance-based. In our assessment of the market competitiveness of compensation, we take into consideration the compensation offered by companies in our peer group described above, but we have not identified a specific percentile of peer company pay as a target. Rather, we use market information as one consideration in setting compensation along with individual performance, our financial and operational performance and our safety and sustainability performance.

We pay base salaries at levels that we feel are appropriate for the skills and qualities of the individual NEOs based on their past performance, current scope of responsibilities and future potential. The incentive-based components of each NEO's compensation include annual cash bonus opportunities and participation in the long-term incentive program. The annual cash bonus rewards incremental operational and financial achievements required to meet investor expectations in the short-term while the long-term component focuses rewards to the long-term stability of the enterprise. Both incentive components are generally linked to base salary and are consistent in general with our understanding of market practice and with our judgment regarding each individual's role in the organization.

As described in more detail below, we believe that the combination of base salaries, cash bonuses and long-term cash-based incentive awards provide an appropriate balance of short and long-term incentives, and alignment of the incentives for our executives, including our NEOs, with the interests of our unitholders.

The amount of compensation contingent on performance is a significant percentage of total compensation, therefore ensuring that business decisions and actions lead to the long-term growth and sustainability of the organization. Our bonus plan (including annual and retention bonuses) is driven by the generation of Available Cash before Reserves (as defined in Item. 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Financial Measures") which is an important metric of value for our unitholders, and our safety record, with the goal of retention of key employees and NEOs. Our long-term incentive plan is also linked to our generation of Available Cash before Reserves, our sustainability and safety record, as well as the partnership's Consolidated Leverage ratio (as defined in its senior secured credit facility agreement).

Elements of Our Compensation Program and Compensation Decisions for 2022

The primary elements of our compensation program are a combination of annual cash and long-term incentive-based compensation. For the year ended December 31, 2022, the elements of our compensation program for the NEOs consisted of an annual base salary, discretionary annual bonus awards, and awards under our long-term incentive compensation program.

Additionally, in order to attract qualified executive personnel, we may make one-time new-hire awards of equity.

Base Salaries

We believe that base salaries should provide a fixed level of competitive pay that reflects the executive officer's primary duties and responsibilities, and which provides a foundation for incentive opportunities and benefit levels. As discussed above, the base salaries of our NEOs are reviewed annually by the G&C Committee, taking into account recommendations from our CEO regarding NEOs other than himself. We pay base salaries at a level that we feel is appropriate for the skills and qualities of the individual NEOs based on their past performance, current scope of responsibilities and future potential. Base salaries may be adjusted to achieve what is determined to be a reasonably competitive level or to reflect promotions, the assignment of additional responsibilities, individual performance or company performance. Salaries are also periodically adjusted based on analysis of peer group practices as described above.

In April 2022, the G&C Committee reviewed the assessments of market levels of compensation developed by Meridian in conjunction with a discussion of individual performance and responsibilities. As a result of this review and taking into account current market conditions, the G&C Committee approved an increase in Mr. Sims' 2022 base salary to $800,000, representing an increase of 23.1%. This is Mr. Sims' first increase in base salary since 2018. The base salaries of Mr. Deere and Mr. Flynn remained the same from 2021 at $450,000 and $500,000, respectively. The G&C Committee also approved an increase in Ms. Jesulaitis' base salary to $450,000, an increase of 12.5%, and an increase in Mr. Gaspard's base salary to $375,000, an increase of 10.3%, as a result of this review, current market conditions, and their respective levels of responsibility.

Bonuses

Our NEOs typically participate in a bonus program, or the Bonus Plan, in which a majority of company employees participate. As designed by the G&C Committee, each NEO has an annual bonus target based on a stated percentage of his or her base salary. The targeted amount for the NEOs is established based on the analysis of market practices of the peer group and consideration of the level of salary and targeted long-term incentives for each NEO. Based on the G&C Committee's subjective review of 2022 operational and financial performance, in the context of total NEO compensation, a discretionary bonus was granted to Mr. Flynn in the amount of $885,000 associated with the performance of the Alkali Business. This bonus will be paid in March 2023, contingent on Mr. Flynn's employment on the payment date. Further, it was determined by the G&C Committee that each NEO will be considered for a retention bonus for 2022, as further discussed below.

Our NEOs may participate in a retention bonus program for which certain key employees, managers and officers are eligible. These retention bonuses are discretionary and are awarded based on individual and company performance with the goal of retaining key employees. In 2022, Mr. Sims was granted a retention bonus of $1,000,000, Ms. Jesulaitis was granted a retention bonus of $550,000, Mr. Flynn was granted a retention bonus of $500,000, Mr. Gaspard was granted a retention bonus of $375,000 and Mr. Deere was granted a retention bonus of $300,000, to be paid in four equal installments at the following dates: September 2023, December 2023, March 2024, and June 2024, contingent upon continued employment at those dates.

We believe that these retention bonuses are an appropriate mechanism to incentivize key executives to remain with us so that we may benefit from their experience in the industry and other competitive opportunities available to them. Over the long term, the G&C committee intends to continue performance-based cash incentives as a cornerstone of our executive pay program.

Long-Term Incentive Compensation

We generally provide certain long-term compensation (cash and equity-based) to directors, officers, and certain employees through our long-term incentive compensation plans, or LTIPs. Our G&C Committee designs those awards to align the interests of plan participants with the interests of our long-term unitholders by promoting a sense of proprietorship and personal involvement in our development, growth, and financial success. Our LTIPs have given us flexibility to grant deferred compensation awards in the form of equity or cash-based compensation that vests outright or upon the satisfaction of one or more conditions that reward measurable service and performance, including the passage of time, continued employment, financial, and operating (including safety and sustainability) metrics and the appreciation in our unit price over time.

In 2018, our G&C Committee adopted our 2018 LTIP. Like our 2010 LTIP, our 2018 LTIP permits awards of equity-based compensation in the form of phantom units and distribution equivalent rights, or DERs. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. DERs are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on outstanding phantom units had they been limited partner units issued by us. In addition, our 2018 LTIP permits cash-based awards.

Our G&C Committee administers our LTIPs and has broad authority to grant awards under and alter, amend, or terminate our LTIPs. For example, our G&C Committee has the authority to determine (i) who (if anyone) will receive awards from time to time as well as (ii) the size, nature, terms and conditions of such award. Our G&C Committee also has the authority to adopt, alter, and repeal rules, guidelines and practices relating to our LTIPs and interpret our LTIPs. Our board of directors can terminate the LTIPs at any time.

During 2022 and 2021, we also granted cash-based awards to certain officers and other employees under our 2018 LTIP, including our NEOs. We established target grant values for NEOs based on an analysis of market practices of our compensation peer group and consideration of the level of salary and targeted bonus for each NEO.

For 2022, 2021 and 2020, the G&C Committee established the following long-term incentive cash grant target values for each of our NEOs:

	Long-Term Incentive Cash Grant Value		
Name	2022 (1)	2021 (1)	2020 (2)
Grant E. Sims	$ 4,000,000	$ 3,600,000	$ —
Robert V. Deere	800,000	800,000	—
Edward T. Flynn	1,500,000	1,500,000	—
Kristen O. Jesulaitis	1,000,000	650,000	—
Garland G. Gaspard	750,000	600,000	—

(1) See additional discussion of awards granted to NEOs under the 2018 LTIP during 2022 and 2021 included in the "Grants of Plan-Based Awards" disclosure below.

(2) As a part of the process to reduce and control our cost structure, management recommended no awards to be granted to NEOs under the 2018 LTIP during 2020, which was approved by our board of directors.

In addition to the established target values noted above for 2021, on April 7, 2021, we granted one-time supplemental cash-based awards to certain officers and other employees under our 2018 LTIP, including our NEOs. The supplemental awards are 100% service-based and will be paid out on their two year anniversary, or April 7, 2023, contingent on each employee's continued employment at that date. These awards were granted, and include a shorter vesting period with the goal of retaining key employees. The amounts of one-time supplemental awards granted to our NEOs were as follows: $720,000 for Mr. Sims, $160,000 for Mr. Deere, $300,000 for Mr. Flynn, $130,000 for Ms. Jesulaitis and $120,000 for Mr. Gaspard.

Other Compensation and Benefits

We offer certain other benefits to our NEOs, including medical, dental, disability and life insurance, and contributions on their behalf to our 401(k) plan. NEOs participate in these plans on the same basis as all other employees. Other than the 401(k) plan, we do not sponsor a pension plan in which our NEOs are eligible to participate, and we do not provide post-retirement medical benefits that would be available to our NEOs.

No perquisites of any material nature are provided to our NEOs.

Tax and Accounting Implications

Since we are a partnership and not a corporation for federal income tax purposes, we are not subject to the executive compensation tax deduction limitations of Section 162(m) of the Internal Revenue Code. Accordingly, none of the compensation paid to our NEOs is subject to limitation as to tax deductibility. However, if the relevant tax laws change in the future, the Committee will consider the implications of such changes to us. For our equity-based and cash-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 16 of our Consolidated Financial Statements in Item 8.

Compensation Committee Report

The G&C Committee has reviewed and discussed with management the Compensation Discussion and Analysis included above. Based on that review and discussion, the G&C Committee recommended to our board of directors that this Compensation Discussion and Analysis be included in this Form 10-K.

The foregoing report is provided by the following directors, who constitute the G&C Committee:

- Kenneth M. Jastrow II, Chairman
- Conrad P. Albert
- James E. Davison
- James E. Davison, Jr.
- Sharilyn S. Gasaway
- Jack T. Taylor

The information contained in this report shall not be deemed to be soliciting material or filed with the SEC or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act or the Exchange Act.

Compensation Risk Assessment

Our board of directors does not believe that our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us. We compensate most employees with a combination of competitive base salary and incentive compensation. Meridian advised the G&C Committee that our programs include multiple features and practices that appropriately control motivations for excessive risk taking. Our board of directors believes that the mix and design of the elements of employee compensation does not encourage employees to assume excessive or inappropriate risk taking.

Our board of directors concluded that the following risk oversight and compensation design features guard against excessive risk-taking:

- the Company has strong internal financial controls;
- base salaries are consistent with employees' responsibilities so that they are not motivated to take excessive risks to achieve a reasonable level of financial security;
- the determination of incentive awards is based on a review of a variety of indicators of performance as well as a meaningful subjective assessment of personal performance, thus diversifying the risk associated with any single indicator of performance;
- incentive awards are capped by the G&C Committee;
- compensation decisions include discretionary authority to adjust annual awards and payments, which further reduces any business risk associated with our plans; and
- long-term incentive awards are designed to provide appropriate awards for dedication to a corporate strategy that delivers long-term returns to unitholders.

Summary Compensation Table

The following Summary Compensation Table summarizes the total compensation paid or accrued to our NEOs in 2022, 2021 and 2020.

Name & Principal Position	Year	Salary ($)	Bonus ($)[2]	Non-equity Incentive Plan Compensation ($)[3]	All Other Compensation ($)[4]	Total ($)
Grant E. Sims	2022	$ 758,461	$ 665,000	$ 792,000	$ 716,488	$ 2,931,949
Chief Executive Officer	2021	650,000	480,000	495,360	8,154	1,633,514
(Principal Executive Officer)	2020	650,000	480,000	—	37,034	1,167,034
Robert V. Deere	2022	450,000	270,000	288,000	41,704	1,049,704
Chief Financial Officer	2021	450,000	240,000	165,120	25,554	880,674
(Principal Financial Officer)	2020	450,000	240,000	—	46,814	736,814
Edward T. Flynn[1]	2022	500,000	850,000	240,000	37,890	1,627,890
Executive Vice President	2021	500,000	60,000	180,000	22,637	762,637
	2020	500,000	850,000	—	27,868	1,377,868
Kristen O. Jesulaitis	2022	436,154	410,000	198,000	35,896	1,080,050
Chief Legal Officer and Senior Vice President	2021	400,000	300,000	109,740	15,384	825,124
	2020	400,000	318,750	—	28,773	747,523
Garland G. Gaspard	2022	365,307	295,000	180,000	44,754	885,061
Senior Vice President	2021	340,000	240,000	123,840	25,554	729,394
	2020	340,000	390,000	—	36,721	766,721

(1) Mr. Flynn’s bonus for 2022 includes a discretionary bonus of $600,000 relating to 2021 but paid in March 2022, contingent upon his continued employment on the payment date. Mr. Flynn's bonus for 2020 includes a discretionary bonus of $360,000 relating to 2019 but paid in March 2020, contingent upon Mr. Flynn's continued employment on the payment date.

(2) The amounts shown represent any retention bonuses vested and paid during each of 2020, 2021, and 2022, as well as any cash or special bonus awards earned relative to each year.

(3) The amounts shown represent the non-equity incentive plan awards vested and paid in 2022 and 2021 from the awards granted in 2019 and 2018, respectively, under our 2018 LTIP.

(4) The following table presents the components of “All Other Compensation” for each NEO for the year ended December 31, 2022.

Name	401(k) Matching and Profit Sharing Contributions[1]	Insurance Premiums[2]	Totals
Grant E. Sims	$ 15,250	$ 701,238	$ 716,488
Robert V. Deere	33,550	8,154	41,704
Edward T. Flynn	30,500	7,390	37,890
Kristen O. Jesulaitis	33,550	2,346	35,896
Garland G. Gaspard	36,600	8,154	44,754

The amounts in this table represent:

(1) Contributions by us to our 401(k) and profit sharing plan on each NEO’s behalf.

(2) Term life insurance premiums paid by us on each NEO’s behalf. Mr. Sims insurance premiums for 2022 include the premium associated with his life insurance policy that is paid by us.

Grants of Plan-Based Awards

The following table shows the cash-based awards granted to our NEOs in 2022 under our 2018 LTIP.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards		
Name	Grant Date(1)	Vest Date	Threshold	Target	Maximum
Grant E. Sims	4/7/2022	4/7/2025	2,400,000	4,000,000	7,200,000
Robert V. Deere	4/7/2022	4/7/2025	480,000	800,000	1,440,000
Edward T. Flynn	4/7/2022	4/7/2025	900,000	1,500,000	2,700,000
Kristen O. Jesulaitis	4/7/2022	4/7/2025	600,000	1,000,000	1,800,000
Garland G. Gaspard	4/7/2022	4/7/2025	450,000	750,000	1,350,000

(1) For awards granted to NEOs on April 7, 2022, 80% of the amount represents the cash to be paid if the Company meets certain performance conditions (threshold, target and maximum) associated with our Available Cash before Reserves, our Consolidated Leverage Ratio (as defined in the credit agreement), and safety and sustainability metrics during 2024. The remaining 20% of the awards are service-based. See additional discussion in "Long-Term Incentive Compensation" above relating to the 2018 LTIP.

There were no equity based awards granted to our NEOs as of December 31, 2022.

Termination or Change of Control Benefits

We consider maintaining a stable and effective management team to be essential to protecting and enhancing the best interests of us and our unitholders. To that end, we recognize that the possibility of a change of control or other acquisition event may raise uncertainty and questions among management, and such uncertainty could adversely affect our ability to retain our key employees, which would be to our unitholders' detriment. Because our management team was built over time, as described above, and our NEOs became NEOs under different circumstances, the compensation and benefits awarded to our individual NEOs in the event of termination or a change of control varies. In extending these benefits, we considered a number of factors, including the prevalence of similar benefits adopted by other publicly traded MLPs. See "Potential Payments Upon Termination or Change of Control" below for further discussion of these benefits, including the definitions of certain terms such as change of control and cause.

We believe that the interests of unitholders will best be served if the interests of our management and unitholders are aligned. We believe the termination and change of control benefits described above strike an appropriate balance between the potential compensation payable and the objectives described above.

Potential Payments upon Termination or Change of Control

Based upon a hypothetical termination date of December 31, 2022, the termination benefits for Messrs. Sims, Deere, Flynn, Gaspard and Ms. Jesulaitis for voluntary termination or termination for cause would be zero.

If termination occurs due to death or disability, Messrs. Sims, Deere, Flynn, Gaspard and Ms. Jesulaitis would vest in outstanding awards under our 2018 LTIP at 100%, including the awards granted in both 2022 and 2021, would result in payments under the 2018 LTIP of the following amounts upon death or disability:

Grant E. Sims	$ 8,320,000
Robert V. Deere	1,760,000
Edward T. Flynn	3,300,000
Kristen O. Jesulaitis	1,780,000
Garland G. Gaspard	1,470,000

Upon a change of control for the outstanding LTIP awards granted in April 2022 and April 2021, the unvested service tranche of the cash awards granted will become fully vested and the unvested performance tranche of the cash award granted will vest at 200% of the performance metric. Based on a hypothetical simultaneous change of control and termination date of December 31, 2022, the change of control termination benefits for Messrs. Sims, Deere, Flynn, Gaspard and Ms. Jesulaitis would have been as follows:

	Grant E. Sims	Robert V. Deere	Edward T. Flynn	Kristen O. Jesulaitis	Garland G. Gaspard
Cash payment for vested awards under 2018 LTIP granted in 2022	$7,200,000	$1,440,000	$2,700,000	$1,800,000	$1,350,000
Cash payment for vested awards under 2018 LTIP granted in 2021	7,200,000	1,600,000	3,000,000	1,300,000	1,200,000
Total	$14,400,000	$3,040,000	$5,700,000	$3,100,000	$2,550,000

Director Compensation in Fiscal Year 2022

The table below reflects compensation for our non-employee directors. Mr. Sims does not receive any compensation attributable to his status as a director.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2) (3)	All Other Compensation ($)(4)	Total
Conrad P. Albert	109,000	115,000	21,475	245,475
James E. Davison	$ 100,000	$ 110,000	$ 20,890	$ 230,890
James E. Davison, Jr.	100,000	110,000	20,890	230,890
Sharilyn S. Gasaway	116,500	122,500	23,469	262,469
Kenneth M. Jastrow II	112,500	122,500	23,469	258,469
Jack T. Taylor	107,000	115,000	21,475	243,475

(1) Amounts include annual retainer fees and fees for attending meetings. See further discussion below regarding the change to the pay structure for our non-employee directors that occurred in July 2022.

(2) Amounts in this column represent the fair value of the awards of phantom units under our 2010 LTIP on the date of grant, as calculated in accordance with accounting guidance for equity-based compensation. See further discussion below regarding the change to the pay structure for our non-employee directors that occurred in July 2022.

(3) Outstanding awards to directors at December 31, 2022 consist of phantom units granted under our 2010 LTIP. Messrs. James Davison and James Davison, Jr. each hold 34,901 outstanding phantom units, Ms. Gasaway and Mr. Jastrow each hold 39,124 outstanding phantom units, and Messrs. Albert and Taylor each hold 36,041 outstanding phantom units, respectively.

(4) Amounts in this column represent the amounts paid for tandem DERs related to outstanding phantom units granted under our 2010 LTIP.

In July 2022, the pay structure for our directors who are not officers of our general partner was updated to increase the non-employee directors' base compensation and to eliminate cash compensation for attending Additional Meetings, as discussed more fully below. Beginning in July 2022, our non-employee directors are entitled to a base compensation of $240,000 per year, with $120,000 paid in cash and $120,000 paid in phantom units. The lead director, the chairpersons of the audit committee and G&C Committee, and any non-chair members of the audit committee each receive an additional amount of base compensation split equally between cash and phantom units. The cash compensation is paid in equal quarterly installments. Such additional amount is $10,000 for the lead director, $25,000 for the chair of the audit committee, $15,000 for the chair of the G&C Committee and $15,000 for any audit committee non-chair members.

Cash is paid, and phantom units are awarded, on the first day of each calendar quarter. During 2020, 2021 and 2022, we awarded phantom units under our 2010 LTIP only to directors, all of which were service-based awards with no performance conditions. The number of phantom units awarded is determined by dividing the closing market price of our units on the date of the award into the amount to be paid in phantom units. So long as he or she is a director on the relevant date of determination, each director will receive: (i) a quarterly distribution equal to the number of phantom units held by such director multiplied by the quarterly distribution amount we will pay in respect of each of our outstanding common units on such distribution date, and (ii) for all phantom units granted prior to July 2021, on the third anniversary of each award date for such director, an amount equal to the number of phantom units granted to such director on such award date multiplied by the average closing price of our common units for the 20 trading days ending on the day immediately preceding such anniversary date. Beginning in July 2021, all phantom units granted to our directors will vest and pay out after their one year anniversary at an amount equal to the number of phantom units granted multiplied by the average closing price of our common units for the 20 trading days ending on the day immediately preceding such anniversary date.

Prior to July 2022, participation by a director in Additional Meetings in-person entitled her/him to additional compensation of $2,500 per meeting, and participation by a director by means of telecommunication entitled her/him to additional compensation of $2,000 per meeting. Such payments were made in conjunction with the quarterly payments of base compensation. Additional Meetings consisted of (i) with respect to our board of directors any meetings (in-person or by telecommunication) other than (x) the five pre-set meetings of our board of directors for each calendar year and (y) brief follow-up telecommunication conferences relating to the Annual Report on Form 10-K or any Quarterly Report on Form 10-Q the Company files with the SEC, and (ii) any committee meeting.

CEO Pay Ratio

Our CEO to median employee pay ratio is calculated in accordance with the SEC's pay ratio rules, Item 402(u) of Regulation S-K, which requires the disclosure of (i) the median of the annual total compensation of all employees of the Company (except the CEO), (ii) the annual total compensation for the CEO, and (iii) the ratio of these two amounts.

We identified the median employee during the year ended December 31, 2020 by examining the 2020 total cash compensation for all individuals excluding our CEO, who were employed by us on December 31, 2020. Consistent with Item 402(u), we initially excluded from our employees those individuals who provide services as independent contractors, based on application of the tests used for tax purposes as set forth in the Internal Revenue Service's Publication 15A: "Employer's Supplemental Tax Guide". We selected December 31, 2020, which is within the last three months of 2020, as the date upon which we would identify the median employee because it enabled us to make such identification in a reasonably efficient and economical manner. We did not make any assumptions, adjustments, or estimates with respect to total cash compensation, and we did not annualize the compensation for any full-time employees that were not employed by us for all of 2020. We believe the use of total cash compensation for all employees is a consistently applied compensation measure because we do not widely distribute annual equity awards to employees. Since all of our employees are located in the U.S., including the Commonwealth of Puerto Rico, and paid in U.S. dollars, we did not make any cost-of-living adjustments in identifying the median employee.

We utilized the same median employee for the CEO to median employee pay ratio calculation as of December 31, 2021 and 2022, as we did not experience any significant changes in the employee population or employee compensation arrangements during 2021 or 2022 that we reasonably believe would impact the CEO to median employee pay ratio disclosure. As of December 31, 2022, the Company had 2,109 employees, including 2,088 full-time employees, and 21 temporary employees.

We calculated the annual total compensation for the median employee using the same methodology we use for our named executive officers as set forth in the 2022 Summary Compensation Table above in this 10-K filing. Mr. Sims, our CEO, had 2022 annual total compensation of $2,931,949, as reflected in the Summary Compensation Table. Our median employee's annual total compensation for 2022 was $120,393. Based on this information, Mr. Sims' total annual compensation was approximately twenty-four times that of our median employee in 2022, or 24:1.

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

Beneficial Ownership of Partnership Units

Beneficial Ownership of Common Units

The following table sets forth certain information as of February 24, 2023, regarding the beneficial ownership of our common units by beneficial owners of 5% or more by class of unit and by directors and the executive officers of our general partner and by all directors and executive officers as a group. This information is based on data furnished by the person named.

	Class A Common Units			Class B Common Units	
Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	(1)	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Conrad P. Albert	15,000		*	—	—
James E. Davison	3,738,178	(2)	3.1 %	9,453	23.6 %
James E. Davison, Jr.	5,423,932	(3)	4.4 %	13,648	34.1 %
Sharilyn S. Gasaway	289,445		*	1,081	2.7 %
Kenneth M. Jastrow II	150,000		*	—	—
Jack T. Taylor	32,865		*	—	—
Grant E. Sims	3,010,000	(4)	2.5 %	7,087	17.7 %
Robert V. Deere	829,987		*	1,052	2.6 %
Edward T. Flynn	120,000		*	—	—
Kristen O. Jesulaitis	55,000		*	—	—
Ryan S. Sims	16,300		*	—	—
Garland G. Gaspard	12,000		*	—	—
Karen N. Pape	152,131		*	—	—
Richard R. Alexander	20,245	(5)	*	—	—
William S. Goloway	10,000		*	—	—
Chad A. Landry	30,000	(6)	*	—	—
All directors and executive officers as a group (16 in total)	13,905,083		11.3 %	32,321	80.8 %
Steven K. Davison	2,205,617	(7)	1.8 %	7,676	19.2 %
Global X Management Company LLC	6,307,420		5.1 %	—	
Invesco LTD	16,209,740		13.2 %	—	
FMR LLC	7,400,097		6.0 %		
ALPS Advisors, Inc.	16,265,444		13.3 %	—	

* Less than 1%

(1) The Class B Common Units, which also are included in the Class A Common Unit total, are identical in most respects to the Class A Common Units and have voting and distribution rights equivalent to those of the Class A Common Units. In addition, the Class B Common Units have the right to elect all of our board of directors and are convertible into Class A Common Units under certain circumstances, subject to certain exceptions.

(2) In addition to his direct ownership interests, Mr. Davison is the sole stockholder of Terminal Services, Inc., which owns 1,010,835 Class A Common Units.

(3) 1,339,383 of these Class A Common Units are held by trusts for Mr. Davison's children. 187,856 of these Class A Common Units are held by the James E. and Margaret A. B. Davison Special Trust.

(4) Mr. Sims pledged 2,943,650 of these Class A Common Units as collateral for loans from a bank.

(5) Includes 4,745 Class A Common Units held by Mr. Alexander’s parents over which Mr. Alexander has trading authority. Mr. Alexander pledged 10,000 Class A Common Units as collateral for margin brokerage accounts.

(6) All 30,000 Class A Common Units are held in a trust of which Mr. Landry is the beneficiary and co-trustee.

(7) Includes 147,941 Class A Common Units held by the Steven Davison Family Trust.

Except as noted, each unitholder in the above table is believed to have sole voting and investment power with respect to the units beneficially held, subject to applicable community property laws.

Beneficial Ownership of Preferred Units

The following table sets forth certain information as of December 31, 2022, regarding the beneficial ownership of our Class A Convertible Preferred Units. This information is based on data furnished by the persons named.

Name and Address of Beneficial Owner	Class A Convertible Preferred Units	
	Amount and Nature of Beneficial Ownership	Percent of Class [1]
GSO Rodeo Holdings LP [2]	12,668,389	50.0 %
KKR Rodeo Aggregator L.P.[3]	12,668,389	50.0 %

(1) The percentage of beneficial ownership is calculated based on 25,336,778 Class A Convertible Preferred Units deemed outstanding as of December 31, 2022.

(2) Reflects Class A Convertible Preferred Units directly owned by GSO Rodeo Holdings LP. GSO Rodeo Holdings Associates LLC is the general partner of GSO Rodeo Holdings LP. GSO Holdings I L.L.C. is the managing member of GSO Rodeo Holdings Associates LLC. Blackstone Holdings II L.P. is the managing member of GSO Holdings I L.L.C. Blackstone Holdings I/II GP Inc. is the general partner of Blackstone Holdings II L.P. The Blackstone Group Inc. is the sole member of Blackstone Holdings I/II GP, L.L.C. Blackstone Group Management L.L.C. is the sole holder of Class C common stock of The Blackstone Group Inc. Blackstone Group Management L.L.C. is wholly-owned by Blackstone's senior managing directors and controlled by its founder, Stephen A. Schwarzman. In addition, Bennett J. Goodman may be deemed to have shared voting power and/or investment power with respect to the securities held by GSO Rodeo Holdings LP. Each of the foregoing (other than GSO Rodeo Holdings LP) disclaims beneficial ownership of the Class A Convertible Preferred Units beneficially owned by GSO Rodeo Holdings LP. The business address for GSO Rodeo Holdings LP is c/o GSO Capital Partners LP, 345 Park Avenue, New York, New York 10154.

(3) Reflects Class A Convertible Preferred Units directly owned by KKR Aggregator L.P.. KKR Rodeo Aggregator GP LLC, as the general partner of KKR Rodeo Aggregator L.P., KKR Global Infrastructure Investors II (Rodeo) L.P., as the sole member of KKR Rodeo Aggregator GP LLC, KKR Associates Infrastructure II AIV L.P., as the general partner of KKR Global Infrastructure Investors II (Rodeo) L.P., KKR Infrastructure II AIV GP LLC, as the general partner of KKR Associates Infrastructure II AIV L.P., KKR Financial Holdings LLC, as the Class B member of KKR Infrastructure II AIV GP LLC, KKR Fund Holdings L.P., as the Class A member of KKR Infrastructure II AIV GP LLC and the sole member of KKR Financial Holdings LLC, KKR Fund Holdings GP Limited, as a general partner of KKR Fund Holdings L.P., KKR Group Holdings Corp., as the sole shareholder of KKR Fund Holdings GP Limited and a general partner of KKR Fund Holdings L.P., KKR & Co. Inc., as the sole shareholder of KKR Group Holdings Corp., KKR Management LLC, as the Class B common stockholder of KKR & Co. Inc., and Messrs. Kravis and Roberts, as the designated members of KKR Management LLC, may be deemed to be the beneficial owners having shared voting and investment power with respect to the Class A Convertible Preferred Units described in this footnote. The principal business address of each of the entities and persons identified in this paragraph, except Mr. Roberts, is c/o Kohlberg Kravis Roberts & Co. L.P., 9 West 57th Street, Suite 4200, New York, NY 10019. The principal business address for Mr. Roberts is c/o Kohlberg Kravis Roberts & Co. L.P., 2800 Sand Hill Road, Suite 200, Menlo Park, CA 94025.

Beneficial Ownership of General Partner Interest

Genesis Energy, LLC owns a non-economic general partner interest in us. Genesis Energy, LLC is our wholly-owned subsidiary.

The mailing address for Genesis Energy, LLC and all officers and directors is 811 Louisiana, Suite 1200, Houston, Texas, 77002.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Transactions with Related Persons

Our CEO, Mr. Sims owns an aircraft, which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. In connection with this arrangement, we made payments to Mr. Sims totaling $0.7 million, during 2022. Based on current market rates for chartering of private aircraft under long-term, priority arrangements with industry recognized chartering companies, we believe that the terms of this arrangement are no worse than what we could have expected to obtain in an arms-length transaction.

Family members of certain of our executive officers and directors may work for us from time to time. In 2022, Mr. Sims (our CEO and a director) had two sons that worked for us, one as senior vice president of finance and corporate development and the other as director of commercial development in our offshore pipeline transportation segment. Mr. James Davison, Sr. (a director) had one son (who is also a brother of James E. Davison, Jr., a director) that worked as a director in our onshore facilities and transportation department in 2022. In the aggregate, these family members received total W-2 compensation of less than $1,400,000.

On September 23, 2019 we announced the Granger Optimization Project to expand our existing Granger facility. We entered into agreements with BXC, the beneficial owner of more than 5% of our Class A Convertible Preferred Units, for the purchase of up to a total of $350,000,000 of preferred units (or 350,000 preferred units) of Alkali Holdings. The proceeds we receive from BXC will fund a portion of the anticipated cost of the Granger Optimization Project. On April 14, 2020, we entered into an amendment to our agreements with BXC to, among other things, extend the construction timeline of the Granger Optimization Project by one year, which we currently anticipate completing in the second half of 2023. We issued 1,750 Alkali Holdings preferred units to BXC in consideration for the amendment. As part of the amendment, the total commitment of BXC was increased to, subject to compliance with the covenants contained in our agreements with BXC, up to $351,750,000 of preferred units (or 351,750 preferred units) in Alkali Holdings. The Alkali Holdings preferred unitholders receive PIK distributions in lieu of cash distributions during the new anticipated construction period. From time to time after we had drawn at least $251.8 million, we had the option to redeem the outstanding preferred units in whole for cash at a price equal to the initial $1,000 per preferred unit purchase price, plus no less than the greater of a predetermined fixed internal rate of return amount or a multiple of invested capital metric, net of cash distributions paid to date ("Base Preferred Return Amount"). Additionally, if all outstanding preferred units were redeemed, we had not drawn at least $251.8 million, and BXC was not a "defaulting member" under the LLC Agreement, BXC had the right to a make-whole amount on the number of undrawn preferred units.

On May 17, 2022 (the "Redemption Date"), we fully redeemed the 251,750 outstanding Alkali Holdings preferred units at a Base Preferred Return Amount of $288.6 million. During 2022, we issued 5,356 Alkali Holdings preferred units to BXC to fund the Granger Optimization Project and satisfy the Company's obligation to pay tax distributions. As of December 31, 2022, there were no Alkali Holdings preferred units outstanding.

On May 17, 2022, we, through a newly created wholly-owned unrestricted entity, GA ORRI LLC, issued $425 million principal amount of our 5.875% Alkali senior secured notes due 2042 to certain institutional investors advised by BXC, secured by GA ORRI's fifty-year 10% limited term overriding royalty interest in substantially all of our Alkali Business' trona mineral leases. See Item 1. "Recent Developments and Status of Certain Growth Initiatives - Alkali Senior Secured Notes Issuance and Related Transactions" for more information.

Director Independence

Because we are a limited partnership, the listing standards of the NYSE do not require that we have a majority of independent directors (although at least a majority of the members of our board of directors is independent, as defined by the NYSE rules) or that we have either a nominating committee or a compensation committee of our board of directors. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be "independent" as defined by the NYSE.

Under NYSE rules, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The rules specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants. Our board of directors has determined that each of Ms. Gasaway and Messrs. Jastrow, Albert and Taylor is an independent director under the NYSE rules. See Item 10. "Directors, Executive Officers and Corporate Governance" for additional discussion relating to our directors and director independence.

Item 14. Principal Accounting Fees and Services

The following table summarizes the fees for professional services rendered by Ernst & Young LLP for the years ended December 31, 2022 and 2021.

	2022	2021
	(in thousands)	
Audit Fees[(1)]	$ 3,374	$ 3,087
All Other Fees[(2)]	423	3
Total	$ 3,797	$ 3,090

(1) Includes fees for the annual audit and quarterly reviews (including internal control evaluation and reporting), SEC registration statements and accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles.

(2) Includes fees associated with non-audit related services and licenses for accounting research software.

Pre-Approval Policy

The services by Ernst & Young in 2022 and 2021 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. This policy describes the permitted audit, audit-related, tax and other services, which we refer to collectively as the Disclosure Categories that the independent auditor may perform. The policy requires that each fiscal year, a description of the services, or the Service List expected to be performed by the independent auditor in each of the Disclosure Categories in the following fiscal year be presented to the audit committee for approval.

Any requests for audit, audit-related, tax and other services not contemplated on the Service List must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

In considering the nature of the non-audit services provided by Ernst & Young in 2022 and 2021, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed these services with Ernst & Young and management of our general partner to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements and Financial Statement Schedules".

(a)(2) Financial Statement Schedules.

See "Index to Consolidated Financial Statements and Financial Statement Schedules".

(a)(3) Exhibits

3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 of the Registration Statement on Form S-1 filed on November 15, 1996, File No. 333-11545).
3.2	Amendment to the Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 001-12295).
3.3	Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 5.1 to the Company's Current Report on Form 8-K filed on January 3, 2011, File No. 001-12295).
3.4	First Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated September 1, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295).
3.5	Second Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated December 31, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on January 4, 2018, File No. 001-12295).
3.6	Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on January 7, 2009, File No. 001-12295).
3.7	Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 5.2 to the Company's Current Report on Form 8-K filed on January 7, 2009, File No. 001-12295).
3.8	Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on January 3, 2011, File No. 001-12295).
3.9	Certificate of Incorporation of Genesis Energy Finance Corporation, dated as of November 27, 2006 (incorporated by reference to Exhibit 3.7 to the Company's Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012).
3.10	Bylaws of Genesis Energy Finance Corporation (incorporated by reference to Exhibit 3.8 to the Company's Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012).
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, File No. 001-12295).
4.2	Form of Common Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-12295).
4.3	Davison Unitholder Rights Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on July 31, 2007, File No. 001-12295).
4.4	Amendment No. 1 to the Davison Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on October 19, 2007, File No. 001-12295).
4.5	Amendment No. 2 to the Davison Unitholder Rights Agreement dated December 28, 2010 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on January 3, 2011, File No. 001-12295).
4.6	Davison Registration Rights Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 31, 2007, File No. 001-12295).
4.7	Amendment No. 1 to the Davison Registration Rights Agreement, dated November 16, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 16, 2007, File No. 001-12295).

4.8	Amendment No. 2 to the Davison Registration Rights Agreement, dated December 6, 2007 (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on December 11, 2007, File No. 001-12295).
4.9	Amendment No. 3 to the Davison Registration Rights Agreement, dated as of December 28, 2010 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 3, 2011, File No. 001-12295).
4.10	Registration Rights Agreement, dated as of December 28, 2010, by and among Genesis Energy, L.P. and the former unitholders of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 3, 2011, File No. 001-12295).
4.11	Registration Rights Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295).
4.12	Indenture, dated May 15, 2014, among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 15, 2014, File No. 001-12295).
4.13	Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of May 15, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 15, 2014, File No. 001-12295).
4.14	Second Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of October 15, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.35 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-12295).
4.15	Third Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of December 17, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-12295).
4.16	Fourth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of January 22, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.37 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-12295).
4.17	Fifth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-12295).
4.18	Sixth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.39 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-12295).
4.19	Seventh Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295).
4.20	Eighth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295).
4.21	Ninth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of September 22, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-12295).
4.22	Tenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of December 11, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.52 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-12295).
4.23	Eleventh Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of March 10, 2016, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, File No. 001-12295).

4.24	Twelfth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of June 29, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.57 to the Company's Annual Report on Form 10-K for the year ended December 31, 2017, File No. 001-12295).
4.25	Thirteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of November 13, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.58 to the Company's Annual Report on Form 10-K for the year ended December 31, 2017, File No. 001-12295).
4.26	Fourteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, File No. 001-12295).
4.27	Fifteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of March 22, 2019, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, File No. 001-12295).
4.31	Ninth Supplemental Indenture for 6.50% Senior Notes due 2025, dated as of August 14, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference from Exhibit 4.2 to the Company's Current Report on Form 8-K filed on August 14, 2017, File No. 001-12295).
4.32	Tenth Supplemental Indenture for 6.50% Senior Notes due 2025, dated as of November 13, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.69 to the Company's Annual Report on Form 10-K for the year ended December 31, 2017, File No. 001-12295).
4.33	Eleventh Supplemental Indenture for 6.250% Senior Notes Due 2026, dated as of December 11, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on December 11, 2017, File No. 001-12295).
4.34	Twelfth Supplemental Indenture for 6.50% Senior Notes due 2025, and 6.250% Senior Notes due 2026, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, File No. 001-12295).
4.35	Thirteenth Supplemental Indenture for 6.50% Senior Notes due 2025, and 6.250% Senior Notes due 2026, dated as of March 22, 2019, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, File No. 001-12295).
4.36	Fourteenth Supplemental Indenture for 7.750% Senior Notes due 2028, dated as of January 16, 2020, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on January 16, 2020, File No. 001-12295).
4.37	Fifteenth Supplemental Indenture for 8.0% Senior Notes due 2027, dated as of December 17, 2020, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and the Trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on December 17, 2020, File No. 001-12295).
4.38	Sixteenth Supplemental Indenture for 6.50% Senior Notes due 2025, 6.250% Senior Notes due 2026, 7.750% Senior Notes due 2028, and 8.0% Senior Notes due 2027, dated as of June 28, 2021, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and Regions Bank, as trustee (incorporated by reference to Exhibit 4.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, File No. 001-12295).
4.39	Seventeenth Supplemental Indenture for 6.50% Senior Notes due 2025, 6.250% Senior Notes due 2026, 7.750% Senior Notes due 2028, and 8.0% Senior Notes due 2027, dated as of June 28, 2021, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and Regions Bank, as trustee (incorporated by reference to Exhibit 4.3 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022, File No. 001-12295).
4.40	Eighteenth Supplemental Indenture for 8.875% Senior Notes due 2030, dated as of January 25, 2023, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and Regions Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on January 25, 2023, File No. 001-12295).

	10.1		Fifth Amended and Restated Credit Agreement, dated as of April 8, 2021, among Genesis Energy, L.P., as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, File No. 001-12295).
	10.2		First Amendment and Consent to Fifth Amended and Restated Credit Agreement, dated as of November 17, 2021, among Genesis Energy, L.P., as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and the lenders party thereto (incorporated by reference to Exhibit 10.14 to the Company’s Annual Report on Form 10-K for the year ended December 31, 2021, File No. 001-12295).
	10.3		Second Amendment and Consent to Fifth Amended and Restated Credit Agreement, dated as of May 17, 2022, among Genesis Energy, L.P., as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2022, File No. 001-12295).
	10.4		Sixth Amended and Restated Credit Agreement, dated as of February 17, 2023, among Genesis Energy, L.P., as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A., as syndication agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on February 23, 2023, File No. 001-12295).
	10.5		Form of Indemnity Agreement, among Genesis Energy, L.P., Genesis Energy, LLC and each of the Directors of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on March 5, 2010, File No. 001-12295).
	10.6	+	Genesis Energy, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295).
	10.7	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Directors Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-12295).
	10.8	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Executive Phantom Unit with DERs Award – Officers (incorporated by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-12295).
	10.9	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Employee Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295).
	10.10	+	Genesis Energy 2018 Long-Term Incentive Plan (incorporated by reference from Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295).
	10.11	+	Form of Award for 2018 LTIP (General) (incorporated by reference from Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295)
	10.12	+	Form of Award for 2018 LTIP (Alkali) (incorporated by reference from Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295)
	10.13	+	Form of Award for 2018 LTIP (Marine) (incorporated by reference from Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295)
	10.14		Board Observer Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295).
*	21.1		Subsidiaries of the Registrant.
*	22.1		List of Issuers and Guarantor Subsidiaries.
*	23.1		Consent of Ernst & Young LLP.
*	23.2		Consent of Ernst & Young LLP.
*	23.3		Consent of Stantec Consulting Services Inc.
*	31.1		Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
*	31.2		Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
*	32.1		Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	32.2		Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	99.1		Financial Statements of Poseidon Oil Pipeline Company, LLC for the three years ended December 31, 2022 (audited) pursuant to Rule 3-09 of Regulation S-X (17 CFR 210.3-09).

*	95	Mine Safety Disclosure Exhibit.
	96.1	S-K 1300 Technical Report Summary - Trona Properties, Green River, Wyoming, USA (incorporated by reference to Exhibit 96.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2021, File No. 001-12295).
*	101.INS	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	XBRL Schema Document.
*	101.CAL	XBRL Calculation Linkbase Document.
*	101.LAB	XBRL Label Linkbase Document.
*	101.PRE	XBRL Presentation Linkbase Document.
*	101.DEF	XBRL Definition Linkbase Document.
*	104	Cover Page Interactive Data File (formatted as Inline XBRL)

* Filed herewith

\+ A management contract or compensation plan or arrangement.

Item 16. Form 10-K Summary

Not Applicable

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.

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)

By: GENESIS ENERGY, LLC,

as General Partner

Date: February 24, 2023

By: /s/ GRANT E. SIMS
Grant E. Sims
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

NAME	TITLE (OF GENESIS ENERGY, LLC)*	DATE
/s/ GRANT E. SIMS Grant E. Sims	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)	February 24, 2023
/s/ ROBERT V. DEERE Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	February 24, 2023
/s/ KAREN N. PAPE Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	February 24, 2023
/s/ CONRAD P. ALBERT Conrad P. Albert	Director	February 24, 2023
/s/ JAMES E. DAVISON James E. Davison	Director	February 24, 2023
/s/ JAMES E. DAVISON, JR. James E. Davison, Jr.	Director	February 24, 2023
/s/ SHARILYN S. GASAWAY Sharilyn S. Gasaway	Director	February 24, 2023
/s/ KENNETH M. JASTROW, II Kenneth M. Jastrow, II	Director	February 24, 2023
/s/ JACK T. TAYLOR Jack T. Taylor	Director	February 24, 2023

* Genesis Energy, LLC is our general partner.

Item 8. Financial Statements and Supplementary Data

GENESIS ENERGY, L.P.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, LLC and Unitholders of Genesis Energy, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. (the Partnership) as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2022, and the related notes (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 Matter

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

	Revenue recognition - Estimation of variable consideration
Description of the Matter	As described in Note 3 to the consolidated financial statements, the Partnership's Offshore pipeline transportation segment has certain long-term contracts with customers that include variable consideration that must be estimated at contract inception and re-assessed at each reporting period. Total consideration for these arrangements is recognized as revenue over the performance obligation period, and the difference in timing of revenue recognition and billings results in contract assets and liabilities. As of December 31, 2022, the Partnership has recognized \$2.1 million and \$64.5 million in current and non-current contract liabilities, respectively, in the consolidated financial statements. Auditing the Partnership's revenue recognition for these contracts is particularly challenging because the estimate of variable consideration for these contracts involves management's judgments of volumes that customers are expected to produce and transport over the contract term. Changes in this assumption or a contract modification could have a material effect on the amount of variable consideration recognized as revenue.

How We Addressed the Matter in Our Audit	We tested controls that address the risk of material misstatement relating to the estimation of variable consideration and associated contract assets and liabilities. For example, we tested controls over the completeness and accuracy of volumes transported and billings during the year and management's review of estimated production over the performance obligation period. To test the Partnership's estimates of variable consideration, we performed audit procedures that included, among others, evaluating management's determination of the performance obligations in each arrangement and information used to establish or reassess the estimates including contractual pipeline capacity reserved, historical actual throughput volumes, and third party production forecasts. We tested these assumptions by inspecting contracts, testing completeness and accuracy of production volumes and contract billings, and evaluating information obtained by management from customers and whether the information is consistent with publicly available information. We also performed a retrospective analysis of forecasted production volumes by comparing them to the actual volumes transported, and we performed sensitivity analyses to evaluate the changes in variable consideration that would result from changes in the Partnership's significant assumptions discussed herein. We also recalculated the Partnership's revenue recognized for these arrangements and the recorded contract assets and liabilities as of and for the year ended December 31, 2022.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2017.

Houston, Texas

February 24, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, LLC and Unitholders of Genesis Energy, L.P.

Opinion on Internal Control Over Financial Reporting

We have audited Genesis Energy, L.P.'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, Genesis Energy, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2022 and the related notes, 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 annual 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

GENESIS ENERGY, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands, except units)

	December 31, 2022	December 31, 2021
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,930	$ 19,987
Restricted cash	18,637	5,005
Accounts receivable—trade, net	721,567	400,334
Inventories	78,143	77,958
Other	26,770	39,200
Total current assets	853,047	542,484
FIXED ASSETS, at cost	5,865,038	5,464,040
Less: Accumulated depreciation	(1,768,465)	(1,551,855)
Net fixed assets	4,096,573	3,912,185
MINERALS LEASEHOLDS, net of accumulated depletion	545,122	549,005
EQUITY INVESTEES	284,486	294,050
INTANGIBLE ASSETS, net of amortization	127,320	127,063
GOODWILL	301,959	301,959
RIGHT OF USE ASSETS, net	125,277	140,796
OTHER ASSETS, net of amortization	32,208	38,259
TOTAL ASSETS	$ 6,365,992	$ 5,905,801
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable—trade	$ 427,961	$ 264,316
Accrued liabilities	281,146	232,623
Total current liabilities	709,107	496,939
SENIOR SECURED CREDIT FACILITY	205,400	49,000
SENIOR UNSECURED NOTES, net of debt issuance costs and premium	2,856,312	2,930,505
ALKALI SENIOR SECURED NOTES, net of debt issuance costs and discount	402,442	—
DEFERRED TAX LIABILITIES	16,652	14,297
OTHER LONG-TERM LIABILITIES	400,617	434,925
Total liabilities	4,590,530	3,925,666
MEZZANINE CAPITAL		
Class A Convertible Preferred Units, 25,336,778 issued and outstanding at December 31, 2022 and 2021	891,909	790,115
Redeemable noncontrolling interests, no preferred units issued and outstanding at December 31, 2022 and 246,394 preferred units issued and outstanding at December 31, 2021	—	259,568
COMMITMENTS AND CONTINGENCIES (Note 21)		
PARTNERS' CAPITAL:		
Common unitholders, 122,579,218 units issued and outstanding at December 31, 2022 and 2021	567,277	641,313
Accumulated other comprehensive income (loss)	6,114	(5,607)
Noncontrolling interests	310,162	294,746
Total partners' capital	883,553	930,452
TOTAL LIABILITIES, MEZZANINE CAPITAL AND PARTNERS' CAPITAL	$ 6,365,992	$ 5,905,801

The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31,		
	2022	2021	2020
REVENUES:			
Offshore pipeline transportation	$ 319,045	$ 278,459	$ 237,146
Sodium minerals and sulfur services	1,248,085	964,632	877,769
Marine transportation	293,295	190,827	210,258
Onshore facilities and transportation	928,532	691,558	499,482
Total revenues	2,788,957	2,125,476	1,824,655
COSTS AND EXPENSES:			
Onshore facilities and transportation product costs	828,152	583,824	373,127
Onshore facilities and transportation operating costs	68,066	63,113	70,241
Marine transportation operating costs	228,300	156,307	149,557
Sodium minerals and sulfur services operating costs	926,743	795,964	745,858
Offshore pipeline transportation operating costs	99,881	79,641	76,717
General and administrative	66,598	61,185	56,920
Depreciation, depletion and amortization	296,205	309,746	295,322
Impairment expense	—	—	280,826
Loss (gain) on sale of assets	(40,000)	—	22,045
Total costs and expenses	2,473,945	2,049,780	2,070,613
OPERATING INCOME (LOSS)	315,012	75,696	(245,958)
Equity in earnings of equity investees	54,206	57,898	64,019
Interest expense	(226,156)	(233,724)	(209,779)
Other expense, net	(10,758)	(36,232)	(7,269)
Income (loss) from operations before income taxes	132,304	(136,362)	(398,987)
Income tax expense	(3,169)	(1,670)	(1,327)
NET INCOME (LOSS)	129,135	(138,032)	(400,314)
Net income attributable to noncontrolling interests	(23,235)	(1,637)	(251)
Net income attributable to redeemable noncontrolling interests	(30,443)	(25,398)	(16,113)
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 75,457	$ (165,067)	$ (416,678)
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(80,052)	(74,736)	(74,736)
NET LOSS AVAILABLE TO COMMON UNITHOLDERS	$ (4,595)	$ (239,803)	$ (491,414)
BASIC AND DILUTED NET INCOME (LOSS) PER COMMON UNIT:			
Basic and Diluted	$ (0.04)	$ (1.96)	$ (4.01)
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
Basic and Diluted	122,579	122,579	122,579

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The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 129,135	$ (138,032)	$ (400,314)
Other comprehensive income (loss):			
Decrease (increase) in benefit plan liability	11,721	3,758	(934)
Total Comprehensive income (loss)	140,856	(134,274)	(401,248)
Comprehensive income attributable to noncontrolling interests	(23,235)	(1,637)	(251)
Comprehensive income attributable to redeemable noncontrolling interests	(30,443)	(25,398)	(16,113)
Comprehensive income (loss) attributable to Genesis Energy, L.P.	$ 87,178	$ (161,309)	$ (417,612)

The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Number of Common Units	Partners' Capital	Noncontrolling Interest	Accumulated Other Comprehensive Income (Loss)	Total
December 31, 2019	122,579	$ 1,443,320	$ (3,718)	$ (8,431)	$ 1,431,171
Net income	—	(416,678)	251	—	(416,427)
Cash distributions to partners	—	(122,580)	—	—	(122,580)
Cash contributions from noncontrolling interests	—	—	2,354	—	2,354
Other comprehensive loss	—	—	—	(934)	(934)
Distributions to preferred unitholders	—	(74,736)	—	—	(74,736)
December 31, 2020	122,579	829,326	(1,113)	(9,365)	818,848
Net income (loss)	—	(165,067)	1,637	—	(163,430)
Cash distributions to partners	—	(73,548)	—	—	(73,548)
Sale of noncontrolling interest in subsidiary	—	125,338	294,422	—	419,760
Cash distributions to noncontrolling interests	—	—	(903)	—	(903)
Cash contributions from noncontrolling interests	—	—	703	—	703
Other comprehensive income	—	—	—	3,758	3,758
Distributions to preferred unitholders	—	(74,736)	—	—	(74,736)
December 31, 2021	122,579	641,313	294,746	(5,607)	930,452
Net income	—	75,457	23,235	—	98,692
Cash distributions to partners	—	(73,548)	—	—	(73,548)
Adjustment to valuation of noncontrolling interest in subsidiary	—	(1,209)	1,209	—	—
Cash distributions to noncontrolling interests	—	—	(31,867)	—	(31,867)
Cash contributions from noncontrolling interests	—	—	22,839	—	22,839
Other comprehensive income	—	—	—	11,721	11,721
Distributions to preferred unitholders	—	(74,736)	—	—	(74,736)
December 31, 2022	122,579	$ 567,277	$ 310,162	$ 6,114	$ 883,553

The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2022	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 129,135	$ (138,032)	$ (400,314)
Adjustments to reconcile net income (loss) to net cash provided by operating activities -			
Depreciation, depletion and amortization	296,205	309,746	295,322
Loss (gain) on sale of assets	(40,000)	—	22,045
Impairment expense	—	—	280,826
Amortization and write-off of debt issuance costs and premium or discount	9,271	13,716	22,610
Amortization of unearned income and initial direct costs on direct financing leases	—	—	(8,847)
Payments received under previously owned direct financing leases	—	70,000	56,837
Equity in earnings of investments in equity investees	(54,206)	(57,898)	(64,019)
Cash distributions of earnings of equity investees	55,571	57,080	63,721
Non-cash effect of long-term incentive compensation plans	17,810	8,783	(3,693)
Deferred and other tax liabilities	2,355	980	512
Cancellation of debt income	(8,618)	—	(27,302)
Unrealized losses (gains) on derivative transactions	(5,823)	30,700	1,191
Other, net	20,513	12,832	19,229
Net changes in components of operating assets and liabilities (See Note 15)	(87,818)	30,044	38,627
Net cash provided by operating activities	334,395	337,951	296,745
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(424,195)	(301,395)	(144,133)
Cash distributions received from equity investees—return of investment	19,646	27,026	17,340
Investments in equity investees	(10,301)	(352)	—
Proceeds from asset sales	40,331	604	23,037
Net cash used in investing activities	(374,519)	(274,117)	(103,756)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on senior secured credit facility	971,500	776,300	1,023,000
Repayments on senior secured credit facility	(815,100)	(1,371,000)	(1,338,600)
Net proceeds from issuance of Alkali senior secured notes (Note 10)	408,000	—	—
Redemption of preferred units (Note 11)	(288,629)	—	—
Proceeds from issuance of senior unsecured notes (Note 10)	—	259,375	1,500,000
Net proceeds from issuance of preferred units (Note 11)	—	93,100	—
Repayment of senior unsecured notes (Note 10)	(72,241)	(80,859)	(1,185,096)
Debt issuance costs	(6,019)	(12,348)	(26,680)
Contributions from noncontrolling interests	22,839	703	2,354
Distributions to noncontrolling interests	(31,867)	(903)	—
Distributions to Class A Convertible Preferred unitholders (Note 11)	(74,736)	(74,736)	(74,736)
Distributions to common unitholders (Note 11)	(73,548)	(73,548)	(122,580)
Cash proceeds from the sale of a noncontrolling interest in a subsidiary	—	418,140	—
Other, net	1,500	(84)	(38)
Net cash provided by (used in) financing activities	41,699	(65,860)	(222,376)
Net increase (decrease) in cash and cash equivalents and restricted cash	1,575	(2,026)	(29,387)
Cash and cash equivalents and restricted cash at beginning of period	24,992	27,018	56,405
Cash and cash equivalents and restricted cash at end of period	$ 26,567	$ 24,992	$ 27,018

The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

We are a growth-oriented master limited partnership founded in Delaware in 1996 and focused on the midstream segment of the crude oil and natural gas industry as well as the production of natural soda ash. Our operations are primarily located in the Gulf Coast region of the United States, Wyoming, and in the Gulf of Mexico. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprise and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, our trona and trona-based exploring, mining, processing, producing, marketing, and selling business based on Wyoming (our "Alkali Business"), refinery-related plants, storage tanks and terminals, railcars, rail unloading facilities, barges and other vessels, and trucks. We are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures.

We currently manage our businesses through four divisions that constitute our reportable segments:

- Offshore pipeline transportation, which includes processing of crude oil and natural gas in the Gulf of Mexico;
- Sodium minerals and sulfur services involving trona and trona-based exploring, mining, processing, soda ash production, marketing and selling activities, as well as processing of high sulfur (or "sour") gas streams for refineries to remove the sulfur, and selling the related by-product, sodium hydrosulfide (or "NaHS," commonly pronounced "nash");
- Onshore facilities and transportation, which include terminaling, blending, storing, marketing, and transporting crude oil and petroleum products; and
- Marine transportation to provide waterborne transportation of petroleum products (primarily fuel oil, asphalt and other heavy refined products) and crude oil throughout North America.

2. Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2022 and 2021 and our results of operations, statements of comprehensive income (loss), changes in partners' capital and cash flows for the years ended December 31, 2022, 2021 and 2020. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its subsidiaries.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Joint Ventures

We participate in several joint ventures, including, in our offshore pipeline transportation segment, a 64% interest in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon"), a 25.7% interest in Neptune Pipeline Company, LLC, a 29% interest in Odyssey Pipeline L.L.C. ("Odyssey"), and a 26.8% interest in Paloma Pipeline Company ("Paloma"). We account for our investments in these joint ventures by the equity method of accounting. See Note 8.

Noncontrolling interests

Noncontrolling interests represent any third party or affiliate interest in non-wholly owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our Consolidated Balance Sheets amounts shown as noncontrolling interests in equity. See Note 11 for additional discussion regarding our noncontrolling interests.

Use of Estimates

The preparation of our Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. We based these estimates and assumptions on historical experience and other information that we believed to be reasonable under the circumstances. Significant estimates that we make include: (1) liability and contingency accruals, including the estimates of future asset retirement obligations, (2) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (3) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, (4) estimates of variable consideration for revenue recognition, (5) estimated fair value of derivative instruments, and (6) estimated useful lives of our fixed and intangible assets (including the reserve life of our mineral leaseholds) for the use in calculating depreciation, depletion, and amortization of long-lived assets and intangible assets. While we believe these estimates are reasonable, actual results could differ from these estimates. Changes in facts and circumstances may result in revised estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal.

Restricted Cash

Our restricted cash balance represents a liquidity reserve account owned by GA ORRI to be held as collateral for future interest and principal payments associated with the Alkali senior secured notes. See Note 10 for definitions of and additional discussion regarding GA ORRI and our Alkali senior secured notes.

Accounts Receivable

We review our outstanding accounts receivable balances on a regular basis and estimate an allowance for amounts that we expect will not be fully recovered. An allowance for credit losses is determined based upon historical collectability trends, recoveries, historical write-offs, and current market data for the Partnership's customers in order to estimate projected losses. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Inventories

Our inventories are valued at the lower of cost and net realizable value. With the exception of our Alkali Business, cost is determined principally under the average cost method within specific inventory pools.

Within our Alkali Business, the cost of inventories are determined using the FIFO method, except for materials and supplies which are recorded at average cost, and raw materials which are recorded at standard cost, which approximates actual cost.

Fixed Assets and Mineral Leaseholds

Property and equipment are carried at cost. Depreciation of property and equipment is provided using the straight-line method over the respective estimated useful lives of the assets. Asset lives are 5 to 40 years for pipelines and related assets, 20 to 30 years for marine vessels, 3 to 30 years for machinery and equipment, 3 to 7 years for transportation equipment, and 3 to 20 years for buildings and improvements, office equipment, furniture and fixtures and other equipment.

Interest is capitalized in connection with the construction of major facilities. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life.

Maintenance and repair costs are charged to expense as incurred. Costs incurred for major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset. Certain volumes of crude oil and refined products are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil and refined products volumes are carried at their weighted average cost.

Long-lived assets are reviewed for impairment. An asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to be generated from the use and ultimate disposal of the asset. If the carrying value is determined to not be recoverable under this method, an impairment charge equal to the amount the carrying value exceeds the fair value is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Mineral leaseholds are depleted over their useful lives as determined under the units of production method. When it has been determined that a mineral property can be economically developed as a result of establishing proven and probable reserves, the costs incurred to develop such property through the commencement of production are capitalized.

Deferred Charges on Marine Transportation Assets

Our marine vessels are required by US Coast Guard regulations to be re-certified after a certain period of time, usually every five years. The US Coast Guard states that vessels must meet specified “seaworthiness” standards to maintain required operating certificates. To meet such standards, vessels must undergo regular inspection, monitoring, and maintenance, referred to as “dry-docking.” Typical dry-docking costs include costs incurred to comply with regulatory and vessel classification inspection requirements, blasting and steel coating, and steel replacement. We defer and amortize these costs to maintenance and repair expense over the length of time that the certification is supposed to last.

Asset Retirement Obligations

Some of our assets have contractual or regulatory obligations to perform dismantlement and removal activities, and in some instances remediation, when the assets are abandoned. In general, our asset retirement obligations (“AROs”) relate to future costs associated with the disconnecting or removing of our crude oil and natural gas pipelines and platforms, barge decommissioning, removal of equipment and facilities from leased acreage and land restoration. The estimated fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. An ongoing expense is recognized for changes in fair value of the liability as a result of the passage of time, which is recorded as accretion expense and included within operating costs in the Consolidated Statements of Operations. See Note 7 for additional information.

Lease Accounting

We enter into operating lease contracts for the right to utilize certain transportation equipment, facilities and equipment, and office space from third parties. For contracts that contain a lease and 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. The present value of each lease is based on the future minimum lease payments in accordance with ASC 842 and is determined by discounting these payments using an incremental borrowing rate. From time to time, we enter into agreements in which we are lessors of our property or equipment. For operating leases, revenue is recognized upon the satisfaction of the respective performance obligation. For direct finance leases, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction. The pipeline cost is not included in fixed assets. Refer to Note 4 for additional information.

Intangible and Other Assets

Intangible assets with finite useful lives are amortized over their respective estimated useful lives on a straight-line basis. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required.

We test intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. No impairment has occurred of intangible assets in any of the periods presented.

Costs incurred in connection with our credit facilities and their related amendments have historically been capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the “effective interest” method of amortization. Certain of our capitalized debt issuance costs related to our respective issuances of notes are classified as reductions in long-term debt.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We evaluate, and test if necessary, goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. During the evaluation, we may perform a qualitative assessment of relevant events and circumstances to determine the likelihood of goodwill impairment. If it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not necessary. We may also elect to exercise our unconditional option to bypass this qualitative assessment, in which case we would also calculate the fair value of the reporting unit. If the calculated fair value of the reporting unit exceeds its carrying value including associated goodwill amounts, no impairment charge is required. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, the goodwill of that reporting unit is considered to be impaired and a charge to earnings must be recorded. The impact to earnings is the excess amount of carrying value over fair value, however the charge is not to exceed the total amount of goodwill allocated to the reporting unit under evaluation. See Note 9 for further information.

Environmental Liabilities

We provide for the estimated costs of environmental contingencies when liabilities are probable to occur and a reasonable estimate of the associated costs can be made. Ongoing environmental compliance costs, including maintenance and monitoring costs, are charged to expense as incurred.

Equity-Based Compensation

The phantom units issued under our 2010 Long-Term Incentive Plan result in the payment of cash to our employees or directors of our general partner upon exercise or vesting of the related award. The fair value of our phantom units is equal to the market price of our common units. Our phantom units outstanding at December 31, 2022 include only service-based awards issued to our directors. See Note 16 for more information.

Revenue Recognition

We recognize revenue across our operating segments upon the satisfaction of their respective performance obligations. Refer to Note 3 for additional details on what constitutes a performance obligation in each of our businesses.

Cost of Sales and Operating Expenses

Onshore facilities and transportation operating and product costs include the cost to acquire the product and the associated costs to transport it to our terminal facilities, including storing, or to a customer for sale. Other than the cost of the products, the most significant costs we incur relate to transportation utilizing our fleet of trucks, railcars, terminals, barges and other vessels, including personnel costs, fuel and maintenance of our equipment or third-party owned equipment. Additionally, costs to operate and maintain the integrity of our onshore pipelines are included herein.

When we enter into buy/sell arrangements concurrently or in contemplation of one another with a single counterparty, we reflect the amounts of revenues and purchases for these transactions on a net basis in our Consolidated Statements of Operations as onshore facilities and transportation revenues.

Marine operating costs consist primarily of employee and related costs to man the boats, barges, and vessels, maintenance and supply costs related to general upkeep of the boats, barges, and vessels, and fuel costs which are often rebillable and passed through to the customer.

The most significant operating costs in our sodium minerals and sulfur services segment consist of the costs to operate our trona extraction and soda ash processing facilities, NaHS processing plants located at various refineries, caustic soda used in the process of processing the refiner’s sour gas, and costs to transport the soda ash, other alkali products, NaHS and caustic soda.

Pipeline operating costs consist primarily of power costs to operate pumping and platform equipment, personnel costs to operate the pipelines and platforms, insurance costs and costs associated with maintaining the integrity of our pipelines.

Income Taxes

We are a limited partnership, organized as a pass-through entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our Consolidated Statements of Operations, is included in the federal income tax returns of each partner.

Some of our corporate subsidiaries pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized. Penalties and interest related to income taxes will be included in income tax expense in the Consolidated Statements of Operations.

Derivative Instruments and Hedging Activities

When we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. Derivative transactions, which can include exchange-traded forward contracts and futures positions, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative’s fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income (Loss) ("AOCI") and reclassified into earnings when the underlying position affects earnings. As of December 31, 2022, we did not have any cash flow hedges.

In addition, we determined that a certain feature within our Class A Convertible Preferred Units represented an embedded derivative, which was required to be bifurcated and recorded at fair value, with changes in fair value in respective periods recorded in our Consolidated Statements of Operations. As of September 29, 2022, the feature was no longer required to be bifurcated and valued. See Note 18 for further information on these items.

Fair Value of Current Assets and Current Liabilities

The carrying amount of other current assets and other current liabilities approximates their fair value due to their short-term nature.

Pension benefits

We sponsor a defined benefit plan for employees of our Alkali Business. The defined benefit plan is accounted for using actuarial valuations as required by GAAP. We recognize the funded status of the defined pension plan on the balance sheet and recognize changes in the funded status that arise during the period but are not recognized as components of net periodic benefit cost within other comprehensive income (loss).

Business Acquisitions

For acquired businesses, we apply the acquisition method and generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition.

Recent and Proposed Accounting Pronouncements

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform (Topic 848), which provides expedients and exceptions for accounting treatment of contracts which are affected by the anticipated discontinuation of the London InterBank Offered Rate ("LIBOR") and other rates resulting from rate reform that are entered into on or before December 31, 2022. Contract terms that are modified due to the replacement of a reference rate are not required to be remeasured or reassessed under relevant accounting standards. On May 17, 2022, we entered into our Second Amendment and Consent to the credit agreement (defined in Note 10), which among other things, replaced our existing LIBOR rate based borrowings with the Term SOFR rate, which is based on the Secured Overnight Financing Rate ("SOFR") borrowings. The impact to our senior secured credit facility and related interest expense upon transition to SOFR did not have a material impact on our Consolidated Financial Statements for the year ended December 31, 2022. Refer to Note 10 for more details.

3. Revenue Recognition

Revenue from Contracts with Customers

The following table reflects the disaggregation of our revenues by major category for the years ended December 31, 2022, December 31, 2021, and December 31, 2020, respectively:

	Year Ended December 31, 2022				
	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Marine Transportation	Onshore Facilities & Transportation	Consolidated
Fee-based revenues	$ 319,045	$ —	$ 293,295	$ 68,625	$ 680,965
Product Sales	—	1,152,450	—	859,907	2,012,357
Refinery Services	—	95,635	—	—	95,635
	$ 319,045	$ 1,248,085	$ 293,295	$ 928,532	$ 2,788,957

	Year Ended December 31, 2021				
	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Marine Transportation	Onshore Facilities & Transportation	Consolidated
Fee-based revenues	$ 278,459	$ —	$ 190,827	$ 86,711	$ 555,997
Product Sales	—	863,264	—	604,847	1,468,111
Refinery Services	—	101,368	—	—	101,368
	$ 278,459	$ 964,632	$ 190,827	$ 691,558	$ 2,125,476

	Year Ended December 31, 2020				
	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Marine Transportation	Onshore Facilities & Transportation	Consolidated
Fee-based revenues	$ 237,146	$ —	$ 210,258	$ 106,092	$ 553,496
Product Sales	—	789,307	—	393,390	1,182,697
Refinery Services	—	88,462	—	—	88,462
	$ 237,146	$ 877,769	$ 210,258	$ 499,482	$ 1,824,655

The Company recognizes revenue upon the satisfaction of its performance obligations under its contracts. The timing of revenue recognition varies for the revenue streams described in more detail below. In general, the timing includes recognition of revenue over time as services are being performed as well as recognition of revenue at a point in time for delivery of products.

Fee-based Revenues

We provide a variety of fee-based transportation and logistics services to our customers across several of our reportable segments as outlined below.

Service contracts generally contain a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over the contract period, and therefore qualify as a single performance obligation that is satisfied over time. The customer receives and consumes the benefit of our services simultaneously with the provision of those services.

Offshore Pipeline Transportation

Revenue from our offshore pipelines is generally based upon a fixed fee per unit of volume (typically per Mcf of natural gas or per barrel of crude oil) gathered, transported, or processed for each volume delivered. Fees are based either on contractual arrangements or tariffs regulated by the FERC. Certain of our contracts include a single performance obligation to stand ready, on a monthly basis, to provide capacity on our assets. Revenue associated with these fee-based services is recognized as volumes are delivered over the performance obligation period.

In addition to the offshore pipeline transportation revenue discussed above, we also have certain contracts with customers in which we earn either demand-type fees or firm capacity reservation fees. These fees are charged to a customer regardless of the volume the customer actually delivers to the platform or through the pipeline.

In addition to these offshore pipeline transportation revenue streams, we also have certain customer contracts in which the transportation fee has a tiered pricing structure based on cumulative milestones of throughput on the related pipeline asset and contract, or on a specified date. The performance obligation for these contracts is to transport, gather or process commodity volumes for the customer based on firm (stand ready) service or from monthly nominations made by our customers, which can also be on an interruptible basis. While our transportation rate changes when milestones are achieved for certain cumulative throughput, our performance obligation does not change throughout the life of the contract. Therefore revenue is recognized on an average rate basis throughout the life of the contract. We have estimated the total consideration to be received under the contract beginning at the contract inception date based on the estimated volumes (including certain minimum volumes we are required to stand ready for), price indexing, estimated production or contracted volumes, and the contract period. We have constrained the estimates of variable consideration such that it is probable that a significant reversal of previously-recognized revenue will not occur throughout the life of the contract. These estimates are reassessed at each reporting period as required. Billings to our customers are reflected at the contract rate. The difference between the consideration received from our customers from invoicing compared to the revenue recognized creates a contract asset or liability. In circumstances where the estimated average contract rate is less than the billed current price tier in the contract, we will recognize a contract liability. In circumstances where the estimated average contract rate is higher than the billed current price tier in the contract, we will recognize a contract asset.

Onshore Facilities and Transportation

Within our onshore facilities and transportation segment, we provide our customers with pipeline transportation, terminaling services, and rail unloading services, among others, primarily on a per barrel fee basis.

Revenues from contracts for the transportation of crude oil by our pipelines are based on actual volumes at a published tariff. We recognize revenues for transportation and other services over the performance obligation period, which is the contract term. Revenues for both firm and interruptible transportation and other services are recognized over time as the product is delivered to the agreed upon delivery point or at the point of receipt because they specifically relate to our efforts to transfer the distinct services.

Pricing for our services is determined through a variety of mechanisms, including specified contract pricing or regulated tariff pricing. The consideration we receive under these contracts is variable, as the total volume of the commodity to be transported is unknown at contract inception. At the end of a day or month (as specified in the contract), both the price and volume are known (or "fixed") in order to allow us to accurately calculate the amount of consideration we are entitled to invoice. The measurement of these services and invoicing occurs on a monthly basis.

Pipeline Loss Allowances

To compensate us for bearing the risk of volumetric losses of crude oil in transit in our pipelines (for our onshore and offshore pipelines) due to temperature, crude quality, and the inherent difficulties of measurement of liquids in a pipeline, our tariffs and agreements allow for us to make volumetric deductions for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances ("PLA"). We compare these allowances to the actual volumetric gains and losses of the pipeline and the net gain or loss is recorded as revenue or a reduction of revenue. As the allowance is related to our pipeline transportation services, the performance obligation is the obligation to transport and deliver the barrels and is considered a single obligation.

When net gains occur, we have crude oil inventory. When net losses occur, we reduce any recorded inventory on hand and record a liability for the purchase of crude oil required to replace the lost volumes. Under ASC 606, we record excess oil as non-cash consideration in the transaction price on a net basis. The net oil recorded is valued at the lower of cost or net realizable value using the market price of crude oil during the month the product was transported. The crude oil in inventory can then be sold at current prevailing market prices, resulting in additional revenue if the sales price exceeds the inventory value when control transfers to the customer.

Marine Transportation

Our marine transportation business consists of revenues from the inland and offshore marine transportation of heavy refined petroleum products, asphalt and crude oil, using our barges or vessels. This revenue is recognized over the passage of time of individual trips as determined on an individual contract basis. Revenue from these contracts is typically based on a set day-rate or a set fee per cargo movement. The costs of fuel and certain other operational costs may be directly reimbursed by the customer, if stipulated in the contract.

Our performance obligation consists of providing transportation services using our vessels for a single day either under a term or spot based contract. The transaction price is usually fixed per the contract either as a day rate or as a lump sum to be allocated over the days required to complete the service. Revenue is recognizable as the transportation service utilizing our vessels occurs, as the customer simultaneously receives and consumes these services as they are provided. If provided in the contract, certain items such as fuel or operational costs can be rebilled to the customer in the same period in which the costs are incurred. In the event the timing of a trip to provide our services crosses a reporting period under a lump sum fee contract, the revenue earned is accrued based on the progress completed in the current period on the related performance obligation as we are entitled to payment for each day. Customer invoicing occurs at the completion of a trip, or earlier at the customer's request.

Product Sales

Sodium Minerals and Sulfur Services

Product sales in our sodium minerals and sulfur services segment primarily involve the sales of caustic soda, NaHS, soda ash and other alkali products. As it relates to revenue recognition, these sales transactions contain a single performance obligation, which is the delivery of the product to the customer at the agreed upon point of sale. For some transactions, control of product transfers to the customer at the shipping point, but we are obligated to arrange for shipment of the product as directed by the customer. Rather than treating these shipping activities as separate performance obligations, our policy is to account for them as fulfillment costs in accordance with ASC 606.

The transaction price for these product sales are determined by specific contracts, typically at a fixed rate or based on a market or indexed rate. This pricing is known, or is "fixed," at the time of revenue recognition. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing. The entirety of the transaction price is allocated to the performance obligation, which is delivery of the product at the agreed upon point of sale. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Onshore Facilities and Transportation

Product sales in our onshore facilities and transportation segment primarily involve the sales of crude oil and petroleum products. These contracts contain a single performance obligation, which is the delivery of the product to the customer at a specified location. These contracts are settled on a monthly basis for term contracts, or on a spot basis. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing.

Pricing is designated within the contracts and is either fixed, index-based or formulaic, utilizing an average price for the month or for a specified range of days, regardless of when delivery occurs. In either case, pricing is known at the time of invoicing. The entirety of the consideration is allocated to a single performance obligation, which is delivery of the product to a specified location. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Refinery Services

Our refinery services business primarily provides sulfur extraction services to refiners' high sulfur (or "sour") gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses caustic soda to act as a scrubbing agent at a prescribed temperature and pressure to remove sulfur. The technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. Units of NaHS are produced ratably as a gas stream is processed. We obtain control and ownership of the NaHS immediately upon production, which constitutes the sole consideration that we receive for our sulfur removal services. We later market this product to third parties as part of our product sales, as described above. As part of some of our arrangements, we pay a refinery access fee ("RSA fee") for any benefits received by virtue of our plant's proximity to the customer's refinery. Our RSA fee is recorded as a reduction of revenue.

Providing sulfur removal services is the singular performance obligation in our refinery service agreements. As our customers simultaneously receive and consume the refinery service benefits, control is transferred and revenue is recognized over time based on the extent of progress towards completion of the performance obligations. We use units of NaHS produced during a period to measure progress as the amount we receive corresponds directly with the efforts to provide our services completed to date. The transaction price for each performance obligation is determined using the fair value of a unit of NaHS on the contract inception date for each refinery services agreement. Accordingly, we record the value of NaHS received as non-cash consideration in inventory until it is subsequently sold to our customers (see Product Sales, above).

Contract Assets and Liabilities

The table below depicts our contract asset and liability balances at December 31, 2022 and December 31, 2021:

	Contract Assets	Contract Liabilities	
	Current Assets- Other	Accrued Liabilities	Other Long-Term Liabilities
Balance at December 31, 2021	$ 13,563	$ 2,619	$ 19,028
Balance at December 31, 2022	—	2,087	64,478

$2.6 million and $3.0 million that were classified as a contract liability at the beginning of the period was recognized as revenue for the years ended December 31, 2022 and 2021, respectively. Additionally, we recognized $4.1 million of revenue during 2021 as a result of a contract modification related to one of our offshore pipeline transportation contracts.

Transaction Price Allocations to Remaining Performance Obligations

We are required to disclose the amount of our transaction prices that are allocated to unsatisfied performance obligations as of December 31, 2022. However, ASC 606 provides the following practical expedients and exemptions that we utilized:

1) Performance obligations that are part of a contract with an expected duration of one year or less;

2) Revenue recognized from the satisfaction of performance obligations where we have a right to consideration in an amount that corresponds directly with the value provided to customers; and

3) Contracts that contain variable consideration, such as index-based pricing or variable volumes, that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that is part of a series.

We apply these practical expedients and exemptions to our revenue streams recognized over time. The majority of our contracts qualify for one of these expedients or exemptions. After considering these practical expedients and identifying the remaining contract types that involve revenue recognition over a long-term period and include long term fixed consideration (adjusted for indexing as required), we determined our allocations of transaction price that relate to unsatisfied performance obligations. As it relates to our tiered pricing offshore transportation contracts, we provide firm capacity for both fixed and variable consideration over a long-term period. Therefore, we have allocated the remaining contract value (as estimated and discussed above) to future periods. In our onshore facilities and transportation segment, we have certain contractual arrangements in which we receive fixed minimum payments for our obligation to provide minimum capacity on our pipelines and related assets.

The following chart depicts how we expect to recognize revenues for future periods related to these contracts:

	Offshore Pipeline Transportation	Onshore Facilities and Transportation
2023	$ 79,294	$ 7,200
2024	74,163	1,800
2025	78,604	—
2026	52,006	—
2027	14,743	—
Thereafter	43,006	—
Total	$ 341,816	$ 9,000

4. Lease Accounting

Lessee Arrangements

We lease a variety of transportation equipment (primarily railcars), terminals, land and facilities, and office space and equipment. Lease terms vary and can range from short term (not greater than 12 months) to long term (greater than 12 months). A majority of our leases contain options to extend the life of the lease at our sole discretion. We considered these options when determining the lease terms used to derive our right of use asset and associated lease liability. Leases with a term of 12 months or less are not recorded on our Consolidated Balance Sheets and we recognize lease expense for these leases on a straight-line basis over the lease term.

Certain lease agreements include lease and non-lease components. We have elected to combine lease and non-lease components for all of our underlying assets for the purpose of deriving our right of use asset and lease liability. Additionally, certain lease payments are driven by variable factors, such as plant production or indexing rates. Variable costs are expensed as incurred and are not included in our determination for our lease liability and right of use asset.

As a lessee, we do not have any finance leases and none of our leases contain material residual value guarantees or material restrictive covenants. In addition, most of our leases do not provide an implicit rate, and as such, we determined our incremental borrowing rate based on the information available at the inception of the lease in determining the present value of lease payments.

Our lease portfolio consists of operating leases within three major categories: Transportation Equipment, Office Space and Equipment, and Facilities and Equipment. These values are recorded within "Right of Use Assets, net" on the Consolidated Balance Sheets. Current and non-current lease liabilities are recorded within "Accrued liabilities" and "Other long-term liabilities", respectively, on the Consolidated Balance Sheets. Refer to the table below for our lease balances as of December 31, 2022 and December 31, 2021.

Leases	Classification	Financial Statement Caption	December 31, 2022	December 31, 2021
Assets				
	Transportation Equipment	Right of Use Assets, net	$ 65,375	$ 79,784
	Office Space & Equipment	Right of Use Assets, net	7,238	5,981
	Facilities and Equipment	Right of Use Assets, net	52,664	55,031
Total Right of Use Assets, net			$ 125,277	$ 140,796
Liabilities				
Current		Accrued liabilities	17,978	19,966
Non-Current		Other long-term liabilities	113,844	121,854
Total Lease Liability			$ 131,822	$ 141,820

Our "Right of Use Assets, net" balance includes our unamortized initial direct costs associated with certain of our transportation equipment, office space and equipment, and facilities and equipment leases. Additionally, it includes our unamortized prepaid rents, our deferred rents, and our previously classified intangible asset associated with a favorable lease.

We recorded total operating lease expense of $13.6 million, $18.4 million, and $30.2 million for the years ended December 31, 2022, 2021, and 2020, respectively. The total operating lease expense is net of the variable railcar mileage credits we receive in our Alkali Business of $22.4 million, $20.8 million and $18.4 million for the years ended December 31, 2022, 2021, and 2020, respectively. The total operating cost includes the amounts associated with our existing lease liabilities, along with both short term and variable lease costs incurred during the period which are not significant to the operating lease cost individually, or in the aggregate.

The following table presents the maturities of our operating lease liabilities as of December 31, 2022 on an undiscounted cash flow basis reconciled to the present value recorded on our Consolidated Balance Sheets:

Maturity of Lease Liabilities	Transportation Equipment	Office Space and Equipment	Facilities and Equipment	Operating Leases
2023	$ 18,928	$ 1,386	$ 5,529	$ 25,843
2024	17,889	1,359	5,005	24,253
2025	14,372	2,168	5,041	21,581
2026	9,965	1,997	5,092	17,054
2027	7,110	1,721	5,136	13,967
Thereafter	7,092	9,445	115,349	131,886
Total Lease Payments	75,356	18,076	141,152	234,584
Less: Interest	(10,644)	(5,601)	(86,517)	(102,762)
Present value of operating lease liabilities	$ 64,712	$ 12,475	$ 54,635	$ 131,822

The following table presents the weighted average remaining terms and discount rates related to our right of use assets:

Lease Term and Discount Rate	December 31, 2022	December 31, 2021
Weighted-average remaining lease term	13.70 years	13.48 years
Weighted-average discount rate	7.75%	7.69%

The following table provides information regarding the cash paid and right of use assets obtained related to our operating leases:

Cash Flows Information	Year Ended December 31, 2022	Year Ended December 31, 2021
Cash paid for amounts included in the measurement of lease liabilities	$ 28,576	$ 33,145
Leased assets obtained in exchange for new operating lease liabilities	9,443	8,296

Lessor Arrangements

We have certain contracts discussed below in which we act as a lessor. We also, from time to time, sublease certain of our transportation and facilities equipment to third parties.

Operating Leases

During the years ended December 31, 2022, 2021, and 2020, we acted as a lessor in our revenue contracts associated with the M/T American Phoenix, included in our marine transportation segment. During the year ended December 31, 2020, we acted as a lessor in our Free State pipeline system, included in our onshore facilities and transportation segment. Revenues associated with these contracts were recorded within their respective segment's revenue in the Consolidated Statements of Operations. Our lease revenues for these arrangements (inclusive of fixed and variable consideration) are reflected in the table below for the years ended December 31, 2022, 2021, and 2020, respectively:

	Year Ended December 31, 2022	2021	2020
M/T American Phoenix	$ 16,432	$ 15,031	$ 24,116
Free State Pipeline(1)	—	—	5,234

(1) We sold the Free State pipeline to a subsidiary of Denbury Inc. on October 30, 2020. The 2020 revenues presented above reflect operations through October 29, 2020 as that was the last date the asset operated under our ownership.

Direct Finance Lease

We formerly held a direct finance lease of the Northeast Jackson Dome ("NEJD") Pipeline. Under the terms of the agreement, we were paid a quarterly payment, which commenced on August 3, 2008. These payments were fixed at approximately $5.2 million per quarter during the lease term at an interest rate of 10.25%. At the end of the lease term in 2028, we would convey all of our interest in the NEJD Pipeline to the lessee for a nominal payment. During the third quarter of 2020, our customer, a subsidiary of Denbury, Inc., defaulted under the agreement and we exercised a letter of credit we had issued to us as beneficiary and we collected approximately $41 million in accelerated principal payments during 2020. On October 30, 2020 we executed an agreement with our customer to accelerate the remaining principal payments on the NEJD direct financing lease. As of December 31, 2020, we had an outstanding receivable (included within "Accounts receivable- trade, net" on the Consolidated Balance Sheets) of $70.0 million from Denbury for the remaining payments per the agreement, which was fully collected during 2021. Additionally as part of this agreement, we transferred the ownership of all of our CO_2 assets, including the Free State pipeline system, to Denbury.

5. Receivables

Accounts receivable – trade, net consisted of the following:

	December 31, 2022	December 31, 2021
Accounts receivable - trade	$ 724,419	$ 405,159
Allowance for credit losses	(2,852)	(4,825)
Accounts receivable - trade, net	$ 721,567	$ 400,334

The following table presents the activity of our allowance for credit losses for the periods indicated:

	December 31, 2022	December 31, 2021	December 31, 2020
Balance at beginning of period	$ 4,825	$ 6,258	$ 1,062
Charges to (recoveries of) costs and expenses, net	172	(902)	5,504
Amounts written off	(2,145)	(531)	(308)
Balance at end of period	$ 2,852	$ 4,825	$ 6,258

6. Inventories

The major components of inventories were as follows:

	December 31, 2022	December 31, 2021
Petroleum products	$ 56	$ 998
Crude oil	6,673	11,834
Caustic soda	15,258	5,690
NaHS	7,085	17,040
Raw materials - Alkali Operations	5,819	7,599
Work-in-process - Alkali Operations	9,599	7,496
Finished goods, net - Alkali Operations	18,772	13,681
Materials and supplies, net - Alkali Operations	14,881	13,620
Total	$ 78,143	$ 77,958

Inventories are valued at the lower of cost or net realizable value. The net realizable value of inventories were below cost by $2.9 million as of December 31, 2022, which triggered a reduction of the value of inventory in our Consolidated Financial Statements by this amount. We recorded $2.0 million in inventory reduction adjustments as of December 31, 2021.

Materials and supplies include chemicals, maintenance supplies, and spare parts which will be consumed in the mining of trona ore and production of soda ash processes.

7. Fixed Assets, Mineral Leaseholds and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following:

	December 31, 2022	December 31, 2021
Crude oil and natural gas pipelines and related assets	$ 2,844,288	$ 2,839,443
Alkali facilities, machinery, and equipment	701,313	670,880
Onshore facilities, machinery, and equipment	269,949	269,245
Transportation equipment	22,340	21,106
Marine vessels	1,017,087	1,018,284
Land, buildings and improvements	231,651	227,540
Office equipment, furniture and fixtures	24,271	23,965
Construction in progress (1)	712,971	350,137
Other	41,168	43,440
Fixed assets, at cost	5,865,038	5,464,040
Less: Accumulated depreciation	(1,768,465)	(1,551,855)
Net fixed assets	$ 4,096,573	$ 3,912,185

(1) Construction in progress primarily relates to our Granger Optimization Project, which is expected to be completed in 2023, and our offshore growth capital projects, which are expected to be completed in 2024 and 2025.

Mineral Leaseholds

Our Mineral Leaseholds, relating to our Alkali Business, consist of the following:

	December 31, 2022	December 31, 2021
Mineral leaseholds	$ 566,019	$ 566,019
Less: Accumulated depletion	(20,897)	(17,014)
Mineral leaseholds, net	$ 545,122	$ 549,005

Depreciation expense was $281.4 million, $295.4 million and $276.4 million for the years ended December 31, 2022, 2021, and 2020, respectively. Depletion expense was $3.9 million, $3.6 million, and $3.2 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Asset Sales and Divestitures

On April 29, 2022, we entered into an agreement to sell the Independence Hub platform to a producer group in the Gulf of Mexico for gross proceeds of $40.0 million, of which $8.0 million, or 20% , was attributable and paid to our noncontrolling interest holder. For the year ended December 31, 2022, we recorded a gain of $40.0 million recorded in “Loss (gain) on sale of asset” on the Consolidated Statement of Operations, of which $8.0 million, or 20%, is attributable to our noncontrolling interest holder, as the platform asset sold had no book value at the time of the sale.

On October 30, 2020, we reached an agreement with a subsidiary of Denbury Inc. to transfer to it the ownership of our remaining CO_2 assets, including the NEJD and Free State pipelines, included within our onshore facilities and transportation segment. As a part of the agreement, we received total consideration of $92.5 million, of which $22.5 million was paid in the fourth quarter of 2020 upon execution of the agreements, and the remaining $70.0 million was paid in equal installments in each quarter during 2021. We recorded a loss of $22.0 million, which represents the difference between the proceeds and the net book value of the assets transferred, and is recorded within “Loss (gain) on sale of assets” on the Consolidated Statement of Operations for the year ended December 31, 2020.

Impairment Expense

During the second quarter of 2020, due to the challenging economic environment from the decline in commodity prices (including the collapse in the differential of Western Canadian Select to the Gulf Coast) and Covid-19, crude-by-rail transportation became uneconomic for producers and the demand and outlook for our rail logistics assets declined. Due to these factors, we identified a triggering event that required us to perform an impairment test. For our recoverability test, we utilized management's estimates, including current contractual commitments, for our future cash inflows, and our costs and expenses were determined based on the estimated fixed and variable requirements to operate and maintain the related assets. As our rail logistics asset groups did not pass the initial recoverability assessment, we subsequently performed a fair value calculation using a discounted cash flow model under the income approach. As a result of this test, we recognized impairment expense of $277.5 million as of December 31, 2020 associated with the rail logistics assets in our onshore facilities and transportation segment, as the carrying value of our assets exceeded the estimated realizable value. The impairment expense included $272.7 million of net fixed assets and $4.8 million of right of use assets, net on the Consolidated Balance Sheets. The fair value estimates used in the long-lived asset test were primarily based on level 3 inputs of the fair value hierarchy.

In addition to this, we recognized impairment expense of $3.3 million during the third quarter of 2020 primarily associated with the full write-down of a non-core gas platform in our offshore transportation segment due to it not having a future use for our operations.

Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. For any AROs acquired, we record AROs based on the fair value measurement assigned during the preliminary purchase price allocation.

A reconciliation of our liability for asset retirement obligations is as follows:

December 31, 2020	$	176,852
Accretion expense		10,038
Revisions in timing and estimated costs of AROs		35,735
Settlements		(4,727)
Acquisitions		3,008
December 31, 2021	$	220,906
Accretion expense		13,092
Revisions in timing and estimated costs of AROs		11,216
Settlements		(16,641)
December 31, 2022	$	228,573

At December 31, 2022 and December 31, 2021, $26.6 million and $36.3 million are included as current in "Accrued liabilities" on our Consolidated Balance Sheets, respectively. The remainder of the ARO liability at each period is included in "Other long-term liabilities" on our Consolidated Balance Sheets. Revisions in timing and estimated costs during 2022 and 2021 are primarily attributable to the accelerated timing and revised costs associated with the abandonment of certain of our non-core offshore assets in the Gulf of Mexico. Such revisions take into account several factors, including changes to legal or regulatory requirements, changes in our estimated useful lives of the associated asset, and the timing and method of abandonment. As there are significant judgements involved in deriving our estimates, actual costs, including the scope of work once it is approved by the relative regulatory agency or contracted party, may differ from our estimates.

With respect to our AROs, the following table presents our forecast of accretion expense for the periods indicated:

2023	$	11,437
2024	$	10,721
2025	$	10,955
2026	$	8,191
2027	$	8,701

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2022 and 2021 relating to contractual agreements and regulatory requirements. In addition, certain entities that we consolidate have non-controlling interest owners that are responsible for their representative share of future costs of the related ARO liability. These amounts are immaterial to our Consolidated Financial Statements.

8. Equity Investees

We account for our ownership in our joint ventures under the equity method of accounting (see Note 2 for a description of these investments). The price we pay to acquire an ownership interest in a company may exceed or be less than the underlying book value of the capital accounts we acquire. At December 31, 2022 and 2021, the unamortized differences in carrying value totaled $305.6 million and $319.9 million, respectively. We amortize the differences in carrying value as a change in equity earnings.

The following table presents information included in our Consolidated Financial Statements related to our equity investees:

	Year Ended December 31,		
	2022	2021	2020
Genesis' share of operating earnings	$ 68,469	$ 73,389	$ 79,510
Amortization of differences attributable to Genesis' carrying value of equity investments	(14,263)	(15,491)	(15,491)
Net equity in earnings	$ 54,206	$ 57,898	$ 64,019
Distributions received[1]	$ 75,406	$ 84,106	$ 81,061

(1) Distributions received during the respective period or within 15 days following the period.

The following tables present the combined balance sheet information for the last two years and statements of operations data for the last three years for our equity investees (on a 100% basis):

	December 31,	
	2022	2021
BALANCE SHEET DATA:		
Assets		
Current assets	$ 44,471	$ 33,994
Fixed assets, net	292,398	284,265
Other assets	27,287	21,327
Total assets	$ 364,156	$ 339,586
Liabilities and equity		
Current liabilities	$ 21,563	$ 15,457
Other liabilities	243,094	237,948
Equity	99,499	86,181
Total liabilities and equity	$ 364,156	$ 339,586

	Year Ended December 31,		
	2022	2021	2020
STATEMENTS OF OPERATIONS DATA:			
Revenues	$ 201,124	$ 203,835	$ 214,687
Operating Income	$ 129,212	$ 143,506	$ 153,640
Net Income	$ 120,613	$ 138,783	$ 147,560

Poseidon's revolving credit facility

Borrowings under Poseidon's revolving credit facility, which was amended and restated in March 2019, are primarily used to fund spending on capital projects. The March 2019 credit facility is non-recourse to Poseidon's owners and secured by its assets. The March 2019 credit facility contains customary covenants such as restrictions on debt levels, liens, guarantees, mergers, sale of assets and distributions to owners. A breach of any of these covenants could result in acceleration of the maturity date of Poseidon's debt. Poseidon was in compliance with the terms of its credit agreement for all periods presented in these Consolidated Financial Statements.

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

The following table reflects the components of intangible assets being amortized at December 31, 2022 and 2021:

		December 31, 2022			December 31, 2021		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Marine contract intangibles	20	$ 800	$ 642	$ 158	$ 800	$ 607	$ 193
Offshore pipeline contract intangibles	19	158,101	61,715	96,386	158,101	53,394	104,707
Other	10	44,391	13,615	30,776	37,933	15,770	22,163
Total		$203,292	$ 75,972	$127,320	$196,834	$ 69,771	$127,063

The offshore pipeline contract intangibles relate to customer contracts surrounding certain transportation agreements with producers in the Lucius production area in Southeast Keathley Canyon, which support our SEKCO pipeline.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. All of our current intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $10.3 million, $10.3 million and $15.5 million for the years ended December 31, 2022, 2021 and 2020, respectively.

The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

	2023	2024	2025	2026	2027
Marine contract intangibles	$ 34	$ 33	$ 32	$ 30	$ 29
Offshore pipeline contract intangibles	8,321	8,321	8,321	8,321	8,321
Other	4,216	3,852	3,628	3,330	2,884
Total	$ 12,571	$ 12,206	$ 11,981	$ 11,681	$ 11,234

Goodwill

The carrying amount of goodwill in our sodium minerals and sulfur services segment was $301.9 million at December 31, 2022 and 2021. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Other Assets

Other assets consisted of the following:

	December 31,	
	2022	2021
Deferred marine charges, net [(1)]	$ 20,503	$ 19,930
Unamortized debt issuance costs on senior secured credit facility	2,591	4,736
Other deferred costs	9,114	13,593
Other assets, net of amortization	$ 32,208	$ 38,259

(1) See discussion of deferred charges on marine transportation assets in the Summary of Accounting Policies (Note 2).

10. Debt

At December 31, 2022 and 2021, our obligations under debt arrangements consisted of the following:

	December 31, 2022			December 31, 2021		
	Principal	Unamortized Premium, Discount and Debt Issuance Costs	Net Value	Principal	Unamortized Premium and Debt Issuance Costs	Net Value
Senior secured credit facility-Revolving Loan(1)	$ 205,400	$ —	$ 205,400	$ 49,000	$ —	$ 49,000
5.625% senior unsecured notes due 2024	341,135	1,249	339,886	341,135	2,106	339,029
6.500% senior unsecured notes due 2025	534,834	3,265	531,569	534,834	4,452	530,382
6.250% senior unsecured notes due 2026	339,310	2,481	336,829	359,799	3,410	356,389
8.000% senior unsecured notes due 2027	981,245	4,956	976,289	1,000,000	6,592	993,408
7.750% senior unsecured notes due 2028	679,360	7,621	671,739	720,975	9,678	711,297
5.875% Alkali senior secured notes due 2042	425,000	22,558	402,442	—	—	—
Total long-term debt	$3,506,284	$ 42,130	$3,464,154	$3,005,743	$ 26,238	$2,979,505

(1) Unamortized debt issuance costs associated with our senior secured credit facility Revolving Loan, as defined below (included in "Other Assets, net of amortization" on the Consolidated Balance Sheets) were $2.6 million and $4.7 million as of December 31, 2022 and December 31, 2021, respectively.

Senior Secured Credit Facility

On April 8, 2021, we entered into the Fifth Amended and Restated Credit Agreement (the "credit agreement") to replace our Fourth Amended and Restated Credit Agreement, which provides for a $950 million senior secured credit facility, comprised of a revolving loan facility with a borrowing capacity of $650 million (the "Revolving Loan") and a term loan facility of $300 million (the "Term Loan"). The senior secured credit facility matures on March 15, 2024, subject to extension at our request for one additional year on up to two occasions and subject to certain conditions.

On November 17, 2021, we closed on the sale of a 36% minority equity interest in CHOPS for gross proceeds of approximately $418 million. A portion of the proceeds from the sale were used to repay the full $300 million outstanding under the Term Loan. We incurred a loss of approximately $2.3 million associated with the early extinguishment of the Term Loan relating to the write-off of the related unamortized debt issuance costs, which is recorded as "Other expense, net" in our Consolidated Statements of Operations for the year ended December 31, 2021.

On May 17, 2022, we entered into our Second Amendment and Consent to the credit agreement (the "credit agreement amendment"). This credit agreement amendment, among other things, permitted the entry into and performance of the transactions and agreements secured by the ORRI Interests (as defined below) and replaced our existing LIBOR rate based borrowings with Term SOFR rate, which is a forward looking term rate based on SOFR, discussed in further detail below.

As of December 31, 2022, the key terms for rates under our senior secured credit facility, which are dependent on our leverage ratio (as defined in the credit agreement), are as follows:

- Revolving Loan: The interest rate on borrowings may be based on an alternate base rate or Term SOFR, at our option. Interest on alternate base rate loans is equal to the sum of (a) the highest of (i) the prime rate in effect on such day, (ii) the federal funds effective rate in effect on such day plus 0.5% and (iii) the Adjusted Term SOFR (as defined in our credit agreement amendment) for a one-month tenor in effect on such day plus 1% and (b) the applicable margin. The Adjusted Term SOFR is equal to the sum of (a) the Term SOFR rate (as defined in our credit agreement amendment) for such period plus (b) the Term SOFR Adjustment of 0.1% plus (c) the applicable margin. The applicable margin varies from 2.25% to 3.75% on Term SOFR borrowings and from 1.25% to 2.75% on alternate base rate borrowings, depending on our leverage ratio. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2022, the applicable margins on our borrowings were 2.00% for alternate base rate borrowings and 3.00% for Term SOFR borrowings based on our leverage ratio.
- Letter of credit fees range from 2.25% to 3.75% based on our leverage ratio as computed under the credit agreement amendment. The rate can fluctuate quarterly. At December 31, 2022, our letter of credit rate was 3.00%.
- We pay a commitment fee on the unused portion of the Revolving Loan. The commitment fee on the unused committed amount will range from 0.30% to 0.50% per annum depending on our leverage ratio. At December 31, 2022, our commitment fee rate on the unused committed amount was 0.50%.

- We have the ability to increase the aggregate size of the Revolving Loan by an additional $200 million subject to lender consent and certain other customary conditions.

At December 31, 2022, we had $205.4 million borrowed under our Revolving Loan, with $4.7 million of the borrowed amount designated as a loan under the inventory sublimit. Our credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $8.5 million was outstanding at December 31, 2022. Due to the revolving nature of loans under our Revolving Loan, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of our credit agreement. The total amount available for borrowings under our senior secured credit facility at December 31, 2022 was $436.1 million, subject to compliance with our covenants. Our credit agreement does not include a “borrowing base” limitation except with respect to our inventory loans.

Alkali Senior Secured Notes Issuance and Related Transactions

On May 17, 2022, Genesis Energy, L.P., through its newly created wholly-owned unrestricted subsidiary, GA ORRI, LLC (“GA ORRI”), issued $425 million principal amount of our 5.875% senior secured notes due 2042 (the “Alkali senior secured notes”) to certain institutional investors (the “Notes Offering”), secured by GA ORRI’s fifty-year 10% limited term overriding royalty interest in substantially all of the Alkali Business’ trona mineral leases (the “ORRI Interests”). Interest payments are due on the last day of each quarter with the initial interest payment made on June 30, 2022. The agreement governing the Alkali senior secured notes also requires principal repayments on the last day of each quarter commencing with the first quarter of 2024. Principal repayments totaling $11.6 million, $13.1 million, $14.2 million, and $14.6 million are due in 2024, 2025, 2026 and 2027, respectively, with the remaining quarterly principal repayments due thereafter through March 31, 2042. We are required to maintain a certain level of cash in a liquidity reserve account (owned by GA ORRI) to be held as collateral for future interest and principal payments as calculated and described in the agreement governing the Alkali senior secured notes. As of December 31, 2022 our liquidity reserve account had a balance of $18.6 million, which is classified as “Restricted cash” on the Consolidated Balance Sheet. The issuance generated net proceeds of $408 million, net of the issuance discount of $17 million. We used a portion of the net proceeds from the issuance to fully redeem the outstanding Alkali Holdings preferred units (as defined and further discussed in Note 11) and utilized the remainder to repay a portion of the outstanding borrowings under our Revolving Loan as well as fund our liquidity reserve account.

Additionally, on May 17, 2022, as noted above, we entered into our credit agreement amendment. This amendment also designated GA ORRI and its direct parent, GA ORRI Holdings, LLC (“GA ORRI Holdings”), as unrestricted subsidiaries under our credit agreement. We also designated GA ORRI and GA ORRI Holdings as unrestricted subsidiaries under the indentures governing our senior unsecured notes. On May 17, we also reclassified the subsidiaries originally held by our Alkali Business as restricted subsidiaries under our credit agreement and under the indentures governing our senior unsecured notes.

Senior Unsecured Notes

On May 15, 2014, we issued $350 million in aggregate principal amount of 5.625% senior unsecured notes due June 15, 2024 (the “2024 Notes”). The 2024 Notes were sold at face value. Interest payments are due on June 15 and December 15 of each year with the initial interest payment due December 15, 2014. The 2024 Notes mature on June 15, 2024. The net proceeds were used to repay borrowings under our senior secured credit facility and for general partnership purposes.

On May 21, 2015, we issued $400 million in aggregate principal amount of 6.00% senior unsecured notes due May 15, 2023 (the “2023 Notes”). Interest payments were due on May 15 and November 15 of each year. We used a portion of the proceeds from those notes to effectively redeem all of our outstanding $350 million, 7.875% senior unsecured notes due 2018, using a combination of public tender offer and our redemption rights relating to those notes. On December 17, 2020, $308.8 million of these notes were validly tendered and repaid upon the issuance of our $750 million unsecured notes due in 2027 (the “2027 Notes” as further discussed and defined below). We incurred a loss of approximately $8.2 million relating to the tender of our 2023 Notes, inclusive of our transaction costs and the write-off of the related unamortized debt issuance costs, which is recorded as “Other expense, net” in our Consolidated Statement of Operations for the year ended December 31, 2020. On January 19, 2021 we redeemed the remaining $80.9 million of our 2023 Notes in accordance with the terms and conditions of the indenture governing the 2023 Notes. We incurred a loss of approximately $1.6 million relating to the extinguishment of our remaining 2023 senior unsecured notes, inclusive of the redemption fee and the write-off of the related unamortized debt issuance costs, which is recorded in “Other expense, net” in our Consolidated Statement of Operations for the year ended December 31, 2021.

On July 23, 2015, we issued $750 million in aggregate principal amount of 6.75% senior unsecured notes due August 1, 2022 (the “2022 Notes”). Interest payments were due on February 1 and August of each year. That issuance generated net proceeds of $728.6 million net of issuance discount and underwriting fees. The net proceeds were used to fund a portion of the purchase price for our Enterprise acquisition. On January 16, 2020, $554.8 million of these notes were validly tendered and repaid upon the issuance of our $750 million unsecured notes due in 2028 (the “2028 Notes”), as discussed below. On February 16, 2020, the remaining $222.1 million of the remaining 2022 Notes were redeemed. We incurred a total loss of approximately $23.5 million relating to the extinguishment of our 2022 Notes, inclusive of our transaction costs and the write-off of the related unamortized debt issuance costs and discount, which is recorded in “Other expense, net” in our Consolidated Statements of Operations for the year ended December 31, 2020.

On August 14, 2017, we issued $550 million in aggregate principal amount of 6.50% senior unsecured notes due October 1, 2025 (the “2025 Notes”). Interest payments are due April 1 and October 1 of each year with the initial interest payment due April 1, 2018. That issuance generated net proceeds of $540.1 million, net of issuance costs incurred. The 2025 Notes mature on October 1, 2025. The net proceeds were used to fund a portion of the purchase price for our acquisition of our Alkali Business.

On December 11, 2017, we issued $450 million in aggregate principal amount of 6.25% senior unsecured notes due May 15, 2026 (the “2026 Notes”). Interest payments are due May 15 and November 15 of each year with the initial interest payment due May 15, 2018. That issuance generated net proceeds of $441.8 million, net of issuance costs incurred. We used $204.8 million of the net proceeds to redeem the portion of the 5.75% senior unsecured notes due February 15, 2021 (the “2021 Notes”) that were validly tendered and the remaining net proceeds to repay a portion of the borrowings outstanding under our senior secured credit facility.

On January 16, 2020, we issued $750 million in aggregate principal amount of our 7.75% 2028 Notes (the “2028 Notes”). Interest payments are due February 1 and August 1 of each year with the initial interest payment due on August 1, 2020. That issuance generated net proceeds of $736.7 million net of issuance costs incurred. The 2028 Notes mature on February 1, 2028. We used $554.8 million of the net proceeds to redeem the portion of the 6.75% 2022 Notes (including principal, accrued interest and tender premium) that were validly tendered, and the remaining net proceeds were used to repay a portion of the borrowings outstanding under our senior secured credit facility.

On December 17, 2020, we issued $750 million in aggregate principal amount of our 8.00% 2027 Notes due on January 15, 2027 (the “2027 Notes”). Interest payments are due January 15 and July 15 of each year with the initial interest payment due on July 15, 2021. That issuance generated net proceeds of approximately $737 million net of issuance costs incurred. We used $316.5 million of the net proceeds to repay the portion of the 6.00% 2023 Notes (including principal, accrued interest and tender premium) that were validly tendered, and the remaining proceeds at the time were used to repay a portion of the borrowings outstanding under our senior secured credit facility.

On April 22, 2021, we completed our offering of an additional $250 million in aggregate principal amount of the 2027 Notes. The additional $250 million of notes have identical terms as (other than with respect to the issue price) and constitute part of the same series of the 2027 Notes. The $250 million of the 2027 Notes were issued at a premium of 103.75% plus accrued interest from December 17, 2020. We used the net proceeds from the offering for general partnership purposes, including repaying a portion of the revolving borrowings outstanding under our senior secured credit facility.

We have the right to redeem each of our series of notes beginning on specified dates as summarized below, at a premium to the face amount of such notes that varies based on the time remaining to maturity on such notes. Additionally, we may redeem up to 35% of the principal amount of each of our series of notes with the proceeds from an equity offering of our common units during certain periods. A summary of the applicable redemption periods is provided in the table below:

	2024 Notes	2025 Notes	2026 Notes	2027 Notes	2028 Notes
Redemption right beginning on	June 15, 2019	October 1, 2020	February 15, 2021	January 15, 2024	February 1, 2023
Redemption of up to 35% of the principal amount of notes with the proceeds of an equity offering permitted prior to	June 15, 2019	October 1, 2020	February 15, 2021	January 15, 2024	February 1, 2023

During the year ended December 31, 2022 and 2020, we repurchased $80.9 million and $153.6 million, respectively, of our senior unsecured notes on the open market and recorded cancellation of debt income of $8.6 million and $27.3 million, respectively. These are recorded within “Other expense, net” in our Consolidated Statements of Operations.

Guarantees of our 2024, 2025, 2026, 2027 and 2028 Notes will be released under certain circumstances, including (i) in connection with any sale or other disposition of (a) all or substantially all of the properties or assets of a guarantor (including by way of merger or consolidation) or (b) all of the capital stock of such guarantor, in each case, to a person that is not a restricted subsidiary of the Partnership (ii) if the Partnership designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary, (iii) upon legal defeasance, covenant defeasance or satisfaction and discharge of the applicable indenture, (iv) upon the liquidation or dissolution of such guarantor, or (v) at such time as such guarantor ceases to guarantee any other indebtedness of either of the issuers and any other guarantor.

Our $2.9 billion aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.'s current and future 100% owned domestic subsidiaries (the “Guarantor Subsidiaries”), except GA ORRI and GA ORRI Holdings, and certain other subsidiaries. The non-guarantor subsidiaries are indirectly owned by Genesis Crude Oil, L.P., a Guarantor Subsidiary. The Guarantor Subsidiaries largely own the assets, other than the ORRI Interests, that we use to operate our business. As a general rule, the assets and credit of our unrestricted subsidiaries are not available to satisfy the debts of Genesis Energy, L.P., Genesis Energy Finance Corporation or the Guarantor Subsidiaries, and the liabilities of our unrestricted subsidiaries do not constitute obligations of Genesis Energy, L.P., Genesis Energy Finance Corporation or the Guarantor Subsidiaries.

Covenants and Compliance

Our credit agreement contains customary covenants (affirmative, negative and financial) that could limit the manner in which we may conduct our business. As defined in our credit agreement, we are required to meet three primary financial metrics—a maximum consolidated leverage ratio, a maximum consolidated senior secured leverage ratio and a minimum consolidated interest coverage ratio. Our credit agreement provides for the temporary inclusion of certain pro forma adjustments to the calculations of the required ratios following material transactions. In general, our consolidated leverage ratio calculation compares our consolidated funded debt (including outstanding notes we have issued) to our Adjusted Consolidated EBITDA (as defined and adjusted in accordance with the senior secured credit facility). Our consolidated senior secured leverage ratio calculation compares our consolidated senior secured funded debt (including outstanding borrowings on the senior secured credit facility) to our Adjusted Consolidated EBITDA (as defined and adjusted in accordance with the senior secured credit facility), and our minimum consolidated interest coverage ratio compares our Adjusted Consolidated EBITDA (as defined and adjusted in accordance with the senior secured credit facility) to our Consolidated interest expense (as defined and adjusted in accordance with the senior secured credit facility). As of December 31, 2022, under our credit agreement, the permitted maximum consolidated leverage ratio is 5.50x for the remainder of the term. The permitted maximum consolidated senior secured leverage ratio is 2.50x and the minimum consolidated interest coverage ratio is 2.50x for the remaining term of the agreement.

In addition, our credit agreement and the indentures governing the senior notes contain cross-default provisions. Our credit documents prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, those agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

A default under our credit documents would permit the lenders thereunder to accelerate the maturity of the outstanding debt. As long as we are in compliance with our senior secured credit facility, our ability to make distributions of “available cash” is not restricted. As of December 31, 2022, we were in compliance with the financial covenants contained in our senior secured credit facility and indentures.

11. Partners' Capital, Mezzanine Equity and Distributions

At December 31, 2022, our outstanding equity consisted of 122,539,221 Class A common units and 39,997 Class B common units. The Class A units are traditional common units in us. The Class B units are identical to the Class A units and, accordingly, have voting and distribution rights equivalent to those of the Class A units, and, in addition, the Class B units have the right to elect all of our board of directors and are convertible into Class A units under certain circumstances, subject to certain exceptions. At December 31, 2022, we had 25,336,778 Class A Convertible Preferred Units outstanding, which are discussed below in further detail.

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to common unitholders of record. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions to our common and preferred 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. Working capital borrowings are generally borrowings that are made under our senior secured credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

We paid the following cash distributions to common unitholders:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2020			
1st Quarter	May 15, 2020	$ 0.1500	$ 18,387
2nd Quarter	August 14, 2020	$ 0.1500	$ 18,387
3rd Quarter	November 13, 2020	$ 0.1500	$ 18,387
4th Quarter	February 12, 2021	$ 0.1500	$ 18,387
2021			
1st Quarter	May 14, 2021	$ 0.1500	$ 18,387
2nd Quarter	August 13, 2021	$ 0.1500	$ 18,387
3rd Quarter	November 12, 2021	$ 0.1500	$ 18,387
4th Quarter	February 14, 2022	$ 0.1500	$ 18,387
2022			
1st Quarter	May 13, 2022	$ 0.1500	$ 18,387
2nd Quarter	August 12, 2022	$ 0.1500	$ 18,387
3rd Quarter	November 14, 2022	$ 0.1500	$ 18,387
4th Quarter	February 14, 2023	$ 0.1500	$ 18,387

Equity Issuances and Contributions

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs. We did not issue any common units during the periods presented.

Class A Convertible Preferred Units

On September 1, 2017, we sold $750 million of Class A Convertible Preferred Units (our "Class A Convertible Preferred Units") in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the "Issue Price") to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our Class A Convertible Preferred Units. Our Class A Convertible Preferred Units rank senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our Class A Convertible Preferred Units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those Class A Convertible Preferred Units.

From time to time after September 1, 2020, we have the right to cause the conversion of all or a portion of outstanding Class A Convertible Preferred Units into our common units, subject to certain conditions; provided, however, that we will not be permitted to convert more than 7,416,498 of our Class A Convertible Preferred Units in any consecutive twelve-month period. At any time after September 1, 2020, if we have fewer than 592,768 of our Class A Convertible Preferred Units outstanding, we will have the right to convert each outstanding Class A Convertible Preferred Unit into our common units at a conversion rate equal to the greater of (i) the then-applicable conversion rate and (ii) the quotient of (a) the Issue Price and (b) 95% of the volume-weighted average price of our common units for the 30-trading day period ending prior to the date that we notify the holders of our outstanding Class A Convertible Preferred Units of such conversion.

Upon certain events involving certain changes of control in which more than 90% of the consideration payable to the holders of our common units is payable in cash, our Class A Convertible Preferred Units will automatically convert into common units at a conversion ratio equal to the greater of (a) the then applicable conversion rate and (b) the quotient of (i) the product of (A) the sum of (1) the Issue Price and (2) any accrued and accumulated but unpaid distributions on our Class A Convertible Preferred Units, and (B) a premium factor (ranging from 115% to 101% depending on when such transaction occurs) plus a prorated portion of unpaid partial distributions, and (ii) the volume weighted average price of the common units for the 30 trading days prior to the execution of definitive documentation relating to such change of control.

In connection with other change of control events that do not meet the 90% cash consideration threshold described above, each holder of our Class A Convertible Preferred Units may elect to (a) convert all of its Class A Convertible Preferred Units into our common units at the then applicable conversion rate, (b) if we are not the surviving entity (or if we are the surviving entity, but our common units will cease to be listed), require us to use commercially reasonable efforts to cause the surviving entity in any such transaction to issue a substantially equivalent security (or if we are unable to cause such substantially equivalent securities to be issued, to convert its Class A Convertible Preferred Units into common units in accordance with clause (a) above or exchanged in accordance with clause (d) below or convert at a specified conversion rate), (c) if we are the surviving entity, continue to hold our Class A Convertible Preferred Units or (d) require us to exchange our Class A Convertible Preferred Units for cash or, if we so elect, our common units valued at 95% of the volume-weighted average price of our common units for the 30 consecutive trading days ending on the fifth trading day immediately preceding the closing date of such change of control, at a price per unit equal to the sum of (i) the product of (x) 101% and (y) the Issue Price plus (ii) accrued and accumulated but unpaid distributions and (iii) a prorated portion of unpaid partial distributions.

For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our Class A Convertible Preferred Units may make a one-time election to reset the quarterly distribution amount (a "Rate Reset Election") to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 110% of the Issue Price.

On September 29, 2022 (the "election date"), the Rate Reset Election was elected by the holders of our Class A Convertible Preferred Units.

Upon issuance and up until the election date, each of our Class A Convertible Preferred Units accumulated quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374). On the election date, the holders of the Class A Convertible Preferred Units elected to reset the rate to 11.24%, the sum of the three-month LIBOR of 3.74% plus 750 basis points, yielding a quarterly distribution $0.9473 per preferred unit beginning with the fourth quarter of 2022.

We elected to pay all distributions from inception through March 1, 2019 with additional Class A Convertible Preferred Units. For the quarter ended March 31, 2019, we paid a portion of our distribution in cash, and a portion in Class A Convertible Preferred Units. For each quarter ending after March 1, 2019, we paid all distribution amounts in respect of our Class A Convertible Preferred Units in cash.

Each holder of our Class A Convertible Preferred Units may elect to convert all or any portion of its Class A Convertible Preferred Units into common units initially on a one-for-one basis (subject to customary adjustments and an adjustment for accrued and accumulated but unpaid distributions and limitations) at any time after September 1, 2019 (or earlier upon a change of control, liquidation, dissolution or winding up), provided that any conversion is for at least $50 million or such lesser amount if such conversion relates to all of a holder's remaining Class A Convertible Preferred Units or has otherwise been approved by us.

If we fail to pay in full any preferred unit distribution amount after March 1, 2019 in respect of any two quarters, whether or not consecutive, then until we pay such distributions in full, we will not be permitted to (a) declare or make any distributions (subject to a limited exceptions for pro rata distributions on our Class A Convertible Preferred Units and parity securities), redemptions or repurchases of any of our limited partner interests that rank junior to or pari passu with our Class A Convertible Preferred Units with respect to rights upon distribution and/or liquidation (including our common units), or (b) issue any such junior or parity securities. If we fail to pay in full any preferred unit distribution after March 1, 2019 in respect of any two quarters, whether or not consecutive, then the preferred unit distribution amount will be reset to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to the then-current annualized distribution rate plus 200 basis points until such default is cured.

We have granted each initial purchaser (including its applicable affiliate transferees) certain rights, including (i) the right to appoint an observer, who shall have the right to attend our board meetings for so long as an initial purchaser (including its affiliates) owns at least $200 million of our Class A Convertible Preferred Units; (ii) the right to purchase up to 50% of any parity securities on substantially the same terms offered to other purchasers for so long as an initial purchaser (including its affiliates) owns at least 11,124,747 of our Class A Convertible Preferred Units, and (iii) the right to appoint two directors to our general partner's board of directors if (and so long as) we fail to pay in full any three quarterly distribution amounts, whether or not consecutive, attributable to any quarter ending after March 1, 2019.

Accounting for the Class A Convertible Preferred Units

Our Class A Convertible Preferred Units are considered redeemable securities under GAAP due to the existence of redemption provisions upon a deemed liquidation event that is outside of our control. Therefore, we present them as temporary equity in the mezzanine section of the Consolidated Balance Sheets. We initially recognized our Class A Convertible Preferred Units at their issuance date fair value, net of issuance costs, as they were not redeemable and we did not have plans or expect any events that constitute a change of control in our partnership agreement. From the date of issuance through the election date, the Rate Reset Election was bifurcated and accounted for separately as an embedded derivative and recorded at fair value at each reporting period in "Other long-term liabilities" in our Consolidated Balance Sheets. As of the election date, the feature within the Class A Convertible Preferred Units that required bifurcation no longer existed and we have adjusted the carrying value of the Class A Convertible Preferred Units to include the fair value of the previously bifurcated amount at the election date. Refer to Note 18 and Note 19 for additional discussion.

As of December 31, 2022, we will not be required to further adjust the carrying amount of our Class A Convertible Preferred Units until it becomes probable that they would become redeemable. Once redemption becomes probable, we would adjust the carrying amount of our Class A Convertible Preferred Units to the redemption value over a period of time comprising the date the feature first becomes probable and the date the units can first be redeemed.

We paid the following cash distributions to our Class A Convertible Preferred unitholders:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2020			
1st Quarter	May 15, 2020	$ 0.7374	$ 18,684
2nd Quarter	August 14, 2020	$ 0.7374	$ 18,684
3rd Quarter	November 13, 2020	$ 0.7374	$ 18,684
4th Quarter	February 12, 2021	$ 0.7374	$ 18,684
2021			
1st Quarter	May 14, 2021	$ 0.7374	$ 18,684
2nd Quarter	August 13, 2021	$ 0.7374	$ 18,684
3rd Quarter	November 12, 2021	$ 0.7374	$ 18,684
4th Quarter	February 14, 2022	$ 0.7374	$ 18,684
2022			
1st Quarter	May 13, 2022	$ 0.7374	$ 18,684
2nd Quarter	August 12, 2022	$ 0.7374	$ 18,684
3rd Quarter	November 14, 2022	$ 0.7374	$ 18,684
4th Quarter	February 14, 2023	$ 0.9473	$ 24,000

There were 25,336,778 Class A Convertible Preferred Units outstanding as of December 31, 2022. All quarterly distributions subsequent to the first quarter of 2019 have been paid in cash and as such there have been no changes to the number of Class A Convertible Preferred Units outstanding since May 15, 2019.

Net income (loss) attributable to Genesis Energy, L.P. is reduced by Class A Convertible Preferred Unit distributions that accumulated during the period. Net income (loss) attributable to Genesis Energy, L.P. was reduced by $80.1 million, $74.7 million, and $74.7 million for the years ended December 31, 2022, 2021 and 2020, respectively, as a result of distributions that accumulated during each period.

Redeemable Noncontrolling Interests

On September 23, 2019, we, through a subsidiary, Genesis Alkali Holdings Company, LLC ("Alkali Holdings"), the entity that holds our trona and trona-based exploring, mining, processing, producing, marketing, and selling business, including its Granger facility near Green River, Wyoming, entered into an amended and restated Limited Liability Company Agreement of Alkali Holdings (the "LLC Agreement") and a Securities Purchase Agreement (the "Securities Purchase Agreement") whereby certain investment fund entities affiliated with Blackstone Alternative Credit Advisors LP, formerly known as "GSO Capital Partners LP" (collectively, "BXC") purchased $55.0 million of preferred units (or 55,000 preferred units) and committed to purchase, during a three-year commitment period, up to a total of $350.0 million of preferred units (or 350,000 preferred units) in Alkali Holdings (the "Alkali Holdings preferred units"). Alkali Holdings utilized the net proceeds from the preferred units to fund a portion of the anticipated cost of the Granger Optimization Project.

On April 14, 2020, we entered into an amendment to our agreements with BXC to, among other things, extend the construction timeline of the Granger Optimization Project by one year, which we currently anticipate completing in the second half of 2023. In consideration for the amendment, we issued 1,750 Alkali Holdings preferred units to BXC, which was accounted for as issuance costs. As part of the amendment, the commitment period was increased to four years, and the total commitment of BXC was increased to $351.8 million preferred units (or 351,750 preferred units) in Alkali Holdings.

From time to time after we had drawn at least $251.8 million, we had the option to redeem the outstanding preferred units in whole for cash at a price equal to the initial $1,000 per preferred unit purchase price, plus no less than the greater of a predetermined fixed internal rate of return amount ("IRR") or a multiple of invested capital metric ("MOIC"), net of cash distributions paid to date ("Base Preferred Return Amount"). Additionally, if all outstanding preferred units were redeemed, we had not drawn at least $251.8 million, and BXC was not a "defaulting member" under the LLC Agreement, BXC had the right to a make-whole amount on the number of undrawn preferred units.

On May 17, 2022 (the "Redemption Date"), we fully redeemed the 251,750 outstanding Alkali Holdings preferred units at a Base Preferred Return Amount of $288.6 million utilizing a portion of the proceeds we received from the issuance of our Alkali senior secured notes (Note 10). As of December 31, 2022, there were no Alkali Holdings preferred units outstanding.

Accounting for Redeemable Noncontrolling Interests

Classification

Prior to the Redemption Date, the Alkali Holdings preferred units issued and outstanding were accounted for as a redeemable noncontrolling interest in the mezzanine section on our Consolidated Balance Sheets due to the redemption features for a change of control.

Initial and Subsequent Measurement

We recorded the Alkali Holdings preferred units at their issuance date fair value, net of issuance costs. The fair value of the Alkali Holdings preferred units was approximately $270.1 million as of May 16, 2022, which represented the carrying amount based on the issued and outstanding Alkali Holdings preferred units most probable redemption event on the six and a half year anniversary of the closing, which was the IRR measure accreted using the effective interest method to the redemption value as of each reporting date. On May 16, 2022, certain events occurred that made it probable that an early redemption event on the Alkali Holdings preferred units would occur and the outstanding preferred units would be redeemed at the MOIC, as it was greater than the IRR at the time of the redemption. This required the Company to revalue the Alkali Holdings preferred units to the redemption amount of $288.6 million, which represented the MOIC, net of cash distributions (including tax distributions) paid to date.

Net Income Attributable to Genesis Energy, L.P. for the year ended December 31, 2022 includes $30.4 million of adjustments, of which $10.0 million was allocated to the distribution paid in-kind ("PIK") on the outstanding preferred units, $1.9 million was attributable to redemption accretion value adjustments, and $18.5 million was attributable to a change in the Base Preferred Return Amount of the Alkali Holdings preferred units. Net Loss Attributable to Genesis Energy, L.P. for the year ended December 31, 2021 includes $25.4 million of adjustments, of which $21.3 million was allocated to the PIK distributions on the outstanding preferred units and $4.1 million was attributable to redemption accretion value adjustments. Net Loss Attributable to Genesis Energy, L.P. for the year ended December 31, 2020 includes $16.1 million of adjustments, of which $13.8 million was allocated to the PIK distributions on the outstanding preferred units and $2.3 million was attributable to redemption accretion value adjustments. We elected to pay distributions for the periods ended December 31, 2022, December 31, 2021 and December 31, 2020 in-kind to our Alkali Holdings preferred unitholders.

The following table shows the change in our redeemable noncontrolling interests from December 31, 2020 to December 31, 2022:

Balance as of December 31, 2020	$	141,194
Issuance of preferred units, net of issuance costs(1)		103,042
PIK distribution		21,291
Redemption accretion		4,107
Tax distributions(1)		(10,066)
Balance as of December 31, 2021		259,568
Issuance of preferred units, net of issuance costs(1)		5,249
PIK distribution		9,993
Redemption accretion		1,908
Tax distributions(1)		(6,631)
Adjustment to Base Preferred Return Amount		18,542
Redemption of preferred units on May 17, 2022		(288,629)
Balance as of December 31, 2022	$	—

(1) We issued 5,356 and 10,145 Alkali Holdings preferred units to BXC to satisfy the Company's obligation to pay tax distributions during 2022 and 2021, respectively.

Noncontrolling Interests

On November 17, 2021, we, through a subsidiary, sold 36% of the membership interests in CHOPS for proceeds of approximately $418 million. We retained 64% of the membership interests in CHOPS and remain the operator of the CHOPS pipeline and associated assets. We also own an 80% membership interest in Independence Hub, LLC. On April 29, 2022, we entered into an agreement to sell the Independence Hub platform to a producer group in the Gulf of Mexico for gross proceeds of $40.0 million, of which $8.0 million, or 20%, was attributable and paid to our noncontrolling interest holder. For the year ended December 31, 2022, we recorded a gain of $40.0 million recorded in "Gain on sale of asset" on the Consolidated Statement of Operations, of which $8.0 million, or 20%, is attributable to our noncontrolling interest holder, as the platform asset sold had no book value at the time of the sale. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our Consolidated Balance Sheets amounts shown as noncontrolling interests in equity.

12. Net Income (Loss) Per Common Unit

Basic net income (loss) per common unit is computed by dividing Net Income (Loss) Attributable to Genesis Energy, L.P., after considering income attributable to our Class A preferred unitholders, by the weighted average number of common units outstanding.

The dilutive effect of the Class A Convertible Preferred Units is calculated using the if-converted method. Under the if-converted method, the Class A Convertible Preferred Units are assumed to be 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. For the years ended December 31, 2022, 2021, and 2020, the effect of the assumed conversion of our Class A Convertible Preferred Units was anti-dilutive and was not included in the computation of diluted earnings per unit.

The following table reconciles Net income (loss) and weighted average units used in computing basic and diluted Net income (loss) per common unit (in thousands, except per unit amounts):

	Year Ended December 31,		
	2022	2021	2020
Net income (loss) attributable to Genesis Energy L.P.	$ 75,457	$ (165,067)	$ (416,678)
Less: Accumulated distributions attributable to Class A Convertible Preferred Units	(80,052)	(74,736)	(74,736)
Net loss available to common unitholders	$ (4,595)	$ (239,803)	$ (491,414)
Weighted average outstanding units	122,579	122,579	122,579
Basic and diluted net loss per common unit	$ (0.04)	$ (1.96)	$ (4.01)

13. Business Segment Information

We currently manage our businesses through four divisions that constitute our reportable segments:

- Offshore pipeline transportation – offshore transportation of crude oil and natural gas in the Gulf of Mexico;
- Sodium minerals and sulfur services – trona and trona-based exploring, mining, processing, producing, marketing and selling activities, as well as processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur and selling the related by-product, NaHS;
- Onshore facilities and transportation – terminaling, blending, storing, marketing and transporting crude oil and petroleum products; and
- Marine transportation – marine transportation to provide waterborne transportation of petroleum products (primarily fuel oil, asphalt and other heavy refined products) and crude oil throughout North America.

Substantially all of our revenues are derived from, and substantially all of our assets are located in, the United States.

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash gains and charges, such as depreciation, depletion, amortization and accretion), segment general and administrative expenses, all of which are net of the effects of our noncontrolling interests, plus our equity in distributable cash generated by our equity investees and unrestricted subsidiaries. In addition, our Segment Margin definition excludes the non-cash effects of our long-term incentive compensation plan and includes the non-income portion of payments received under our previously owned direct financing lease.

Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes, where relevant, and capital investment.

Segment information for each year presented below is as follows:

	Offshore Pipeline Transportation	Sodium Minerals & Sulfur Services	Onshore Facilities & Transportation	Marine Transportation	Total
Year Ended December 31, 2022					
Segment Margin(1)	$ 363,373	$ 306,718	$ 33,755	$ 66,209	$ 770,055
Capital expenditures(2)	$ 241,446	$ 174,518	$ 5,878	$ 39,084	$ 460,926
Revenues:					
External customers	$ 319,045	$ 1,258,236	$ 918,751	$ 292,925	$ 2,788,957
Intersegment(3)	—	(10,151)	9,781	370	$ —
Total revenues of reportable segments	$ 319,045	$ 1,248,085	$ 928,532	$ 293,295	$ 2,788,957
Year Ended December 31, 2021					
Segment Margin(1)	$ 317,560	$ 166,773	$ 98,824	$ 34,572	$ 617,729
Capital expenditures(2)	$ 50,546	$ 227,118	$ 4,609	$ 34,456	$ 316,729
Revenues:					
External customers	$ 278,459	$ 973,354	$ 685,652	$ 188,011	$ 2,125,476
Intersegment(3)	—	(8,722)	5,906	2,816	$ —
Total revenues of reportable segments	$ 278,459	$ 964,632	$ 691,558	$ 190,827	$ 2,125,476
Year Ended December 31, 2020					
Segment Margin(1)	$ 270,078	$ 130,083	$ 147,254	$ 60,058	$ 607,473
Capital expenditures(2)	$ 13,323	$ 95,511	$ 4,133	$ 31,357	$ 144,324
Revenues:					
External customers	$ 237,123	$ 886,078	$ 500,420	$ 201,034	$ 1,824,655
Intersegment(3)	23	(8,309)	(938)	9,224	$ —
Total revenues of reportable segments	$ 237,146	$ 877,769	$ 499,482	$ 210,258	$ 1,824,655

(1) A reconciliation of Net income (loss) attributable to Genesis Energy, L.P. to total Segment Margin to for each year is presented below.

(2) Capital expenditures include maintenance and growth capital expenditures, such as fixed asset additions (including enhancements to existing facilities and construction of growth projects) as well as contributions to equity investees, if any.

(3) Intersegment sales were conducted under terms that we believe were no more or less favorable than then-existing market conditions.

Total assets by reportable segment were as follows:

	December 31, 2022	December 31, 2021
Offshore pipeline transportation	$ 2,290,488	$ 2,103,140
Sodium minerals and sulfur services	2,358,086	2,132,588
Onshore facilities and transportation	981,354	923,064
Marine transportation	681,231	703,030
Other assets	54,833	43,979
Total consolidated assets	$ 6,365,992	$ 5,905,801

Reconciliation of Net income (loss) attributable to Genesis Energy, L.P. to total Segment Margin:

	Year Ended December 31,		
	2022	2021	2020
Net income (loss) attributable to Genesis Energy, L.P.	$ 75,457	$ (165,067)	$ (416,678)
Corporate general and administrative expenses	71,820	61,287	51,457
Depreciation, depletion, amortization and accretion	307,519	315,896	302,602
Interest expense	226,156	233,724	209,779
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income(1)	21,199	26,207	17,042
Other non-cash items(2)	(8,315)	30,907	5,847
Distributions from unrestricted subsidiaries not included in income(3)	32,000	70,000	70,490
Cancellation of debt income (Note 10)	(8,618)	—	(27,302)
Loss on extinguishment of debt (Note 10)	794	1,627	31,730
Differences in timing of cash receipts for certain contractual arrangements(4)	51,102	15,482	40,848
Loss (gain) on sale of asset, net to our ownership interest (Note 7)	(32,000)	—	22,045
Change in provision for leased items no longer in use	(671)	598	1,347
Income tax expense	3,169	1,670	1,327
Redeemable noncontrolling interest redemption value adjustments(5)	30,443	25,398	16,113
Impairment expense (Note 7)	—	—	280,826
Total Segment Margin	$ 770,055	$ 617,729	$ 607,473

(1) Includes distributions attributable to the period and received during or promptly following such period.

(2) Includes unrealized losses of $18.6 million, $30.8 million and $0.9 million from the valuation of the embedded derivative associated with our Class A Convertible Preferred Units in 2022, 2021 and 2020, respectively. Also includes unrealized gains of $24.4 million and $0.1 million, and an unrealized loss of $0.3 million, from the valuation of our commodity derivative transactions (excluding fair value hedges) in 2022, 2021, and 2020, respectively.

(3) 2022 includes $32.0 million in cash receipts associated with the sale of the Independence Hub platform by our 80% owned unrestricted subsidiary (as defined under our credit agreement), Independence Hub, LLC. 2021 includes $70.0 million in cash receipts associated with principal repayments on our previously owned NEJD pipeline not included in income. 2020 includes cash payments received from our NEJD pipeline of $48.0 million not included in income and distributions from our Free State pipeline of $22.5 million not included in income, both of which are defined as unrestricted subsidiaries under our credit agreement.

(4) Includes the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts.

(5) Includes PIK distributions and accretion on the redemption feature attributable to each period, and valuation adjustments to the redemption feature as the associated preferred units were redeemed during the year ended December 31, 2022. Refer to Note 11 for details.

14. Transactions with Related Parties

Transactions with related parties were as follows:

	Year Ended December 31,		
	2022	2021	2020
Revenues:			
Revenues from services and fees to Poseidon Oil Pipeline Company, LLC(1)	14,606	13,846	12,902
Revenues from product sales to ANSAC	418,232	280,935	236,408
Expenses:			
Amounts paid to our CEO in connection with the use of his aircraft	$ 660	$ 660	$ 660
Charges for products purchased from Poseidon Oil Pipeline Company, LLC(1)	1,057	965	960
Charges for services from ANSAC	9,891	1,213	2,460

(1) We own a 64% interest in Poseidon Oil Pipeline Company, LLC.

Our CEO, Mr. Sims, owns an aircraft which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. Based on current market rates for chartering of private aircraft under long-term, priority arrangements with industry recognized chartering companies, we believe that the terms of this arrangement are no worse than what we could have expected to obtain in an arms-length transaction.

Transactions with Unconsolidated Affiliates

Poseidon

We provide management, administrative and pipeline operator services to Poseidon under an Operation and Management Agreement. Currently, that agreement automatically renews annually unless terminated by either party (as defined in the agreement). Our revenues for the years ended December 31, 2022, 2021 and 2020 reflect $9.7 million, $9.4 million and $9.2 million, respectively, of fees we earned through the provision of services under that agreement. At December 31, 2022, and 2021, Poseidon Oil Pipeline Company, LLC owed us $2.4 million for services rendered.

ANSAC

We (through a subsidiary of our Alkali Business) are a member of the American Natural Soda Ash Corp. (“ANSAC”), an organization whose purpose is promoting and increasing the use and sale of natural soda ash and other refined or processed sodium products produced in the U.S. and consumed in specified countries outside of the U.S. ANSAC passes its costs through to its members using a pro rata calculation based on sales. Those costs include sales and marketing, employees, office supplies, professional fees, travel, rent, and certain other costs. Those transactions do not necessarily represent arm's length transactions and may not represent all costs we would have otherwise incurred if we operated the Alkali Business on a stand-alone basis. We also benefit from favorable shipping rates for our direct exports when using ANSAC to arrange for ocean transport. Beginning on January 1, 2023, we became the sole member of ANSAC (see further discussion in Note 23).

Net sales to ANSAC were $418.2 million, $280.9 million and $236.4 million for the years ended December 31, 2022, 2021 and 2020, respectively. The costs charged to us by ANSAC, included in “Sodium minerals and sulfur services operating costs” on the Consolidated Statements of Operations, were $9.9 million, $1.2 million and $2.5 million for the years ended December 31, 2022, 2021 and 2020, respectively.

As of December 31, 2022 and 2021, our receivables from and payables to ANSAC were:

	December 31,	
	2022	2021
Receivables:		
ANSAC	$ 137,522	$ 64,799
Payables:		
ANSAC	$ 4,109	$ 116

15. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities:

	Year Ended December 31, 2022	2021	2020
(Increase) decrease in:			
Accounts receivable	$ (261,849)	$ (75,165)	$ 88,116
Inventories	2,087	20,370	(34,740)
Deferred charges	41,634	27,390	24,590
Other current assets	(6,971)	(1,190)	1,188
Increase (decrease) in:			
Accounts payable	152,138	44,119	(9,742)
Accrued liabilities	(14,857)	14,520	(30,785)
Net changes in components of operating assets and liabilities	$ (87,818)	$ 30,044	$ 38,627

Payments of interest and commitment fees were $236.9 million, $202.0 million and $200.6 million during the years ended December 31, 2022, 2021 and 2020, respectively. We capitalized interest of $18.1 million, $4.4 million and $1.9 million during the years ended December 31, 2022, 2021 and 2020, respectively.

During the years ended December 31, 2022, 2021 and 2020, we paid taxes of $1.0 million, $0.7 million and $0.8 million, respectively.

At December 31, 2022, 2021 and 2020, we had incurred liabilities for fixed and intangible asset additions totaling $93.5 million, $51.7 million and $29.1 million, respectively, which had not been paid at the end of the year. Therefore, these amounts were not included in the caption "Payments to acquire fixed and intangible assets" under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows. The increase in this amount is principally due to the increase in capital expenditures associated with our Granger Optimization Project (Note 11) and our offshore growth capital projects.

16. Equity-Based Compensation Plans

2010 Long Term Incentive Plan

In 2010, we adopted the 2010 Long-Term Incentive Plan (the "2010 Plan"). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to members of our board of directors and employees who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights ("DERs") are tandem rights to receive on a quarterly basis a cash amount per phantom unit equal to the amount of cash distributions paid per common unit. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the "G&C Committee") of our board of directors. The G&C Committee (at its discretion) designates participants in the 2010 Plan, determines the types of awards to grant to participants, determines the number of units to be covered by any award, and determines the conditions and terms of any award including vesting, settlement and forfeiture conditions.

The compensation cost associated with the phantom units is re-measured each reporting period based on the market value of our common units, and is recognized over the vesting period. The liability recorded for the estimated amount to be paid to the participants under the 2010 Plan is adjusted to recognize changes in the estimated compensation cost and vesting.

During 2022, we granted 70,068 phantom units with tandem DERs at a weighted average grant fair value of $9.92 per unit. During 2021, we granted 71,340 phantom units with tandem DERs at a weighted average grant date fair value of $8.83 per unit. During 2020, we granted 107,572 phantom units with tandem DERs at a weighted average grant date fair value of $5.86 per unit. The phantom units granted for 2022, 2021, and 2020 were made only to directors. Awards to management and other key employees during 2022 and 2021 were made under the 2018 LTIP plan, and were not equity-based awards.

A summary of our phantom unit activity for our service-based awards to our directors is set forth below:

	Service-Based Awards		
	Number of Phantom Units	Average Grant Date Fair Value	Total Value (in thousands)
Unvested at December 31, 2021	208,518	$ 10.67	$ 2,225
Granted	70,068	9.92	695
Settled	(58,454)	16.17	(945)
Unvested at December 31, 2022	220,132	$ 8.97	$ 1,975

We recorded compensation expense of $0.7 million, $1.4 million, and a credit to compensation expense of $1.0 million for the years ended December 31, 2022, 2021 and 2020, respectively. Our liability for these awards totaled $2.1 million and $2.2 million at December 31, 2022 and 2021, respectively, and is included within “Accrued liabilities” on the Consolidated Balance Sheets.

Equity-Based Compensation Plan Expense

Equity-based compensation expense (credit) during the three years ended December 31, 2022 was as follows:

	Expense (Credit) Related to Equity-Based Compensation Plans		
Consolidated Statements of Operations	2022	2021	2020
Onshore facilities and transportation operating costs	$ —	$ —	$ (209)
Marine transportation operating costs	—	—	(51)
Sodium minerals and sulfur services operating costs	—	—	(115)
Offshore pipeline operating costs	—	—	(277)
General and administrative expenses	730	1,416	(333)
Total	$ 730	$ 1,416	$ (985)

17. Major Customers and Credit Risk

Due to the nature of our onshore facilities and transportation operations, a disproportionate percentage of our trade receivables constitute obligations of refiners, large crude oil producers and integrated oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of accounts owed by integrated and large independent energy companies with stable payment histories. The credit risk related to contracts which are exchange-traded is limited due to daily margin requirements of the exchange.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

In 2022, 2021 and 2020 our largest customer was ANSAC, which accounted for 15%, 13% and 13% of total consolidated revenues, respectively. As discussed in Note 14, ANSAC’s purpose is promoting and increasing the use and sale of natural soda ash and other refined or processed sodium products produced in the U.S. and consumed in specified countries outside of the U.S. Given this relationship, a large portion of our soda ash production is sold to ANSAC. As such, a disproportionate amount of our trade receivables and sales in our sodium minerals and sulfur services segment are related to ANSAC.

18. Derivatives

Commodity Derivatives

We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (exchange-traded futures, options and swap contracts) to hedge our exposure to commodity prices, primarily of crude oil, fuel oil, natural gas and petroleum products. Our decision as to whether to designate derivative instruments as fair value hedges for accounting purposes relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under accounting guidance in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil that we supply, cannot be hedged with a high degree of effectiveness with exchange-traded derivative contracts; therefore, we do not designate derivative contracts utilized to limit our price risk related to petroleum products as hedges for accounting purposes. Typically we utilize crude oil and other petroleum products futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges for accounting purposes can occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged. Therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.

We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the accounting guidance. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss within “Onshore facilities and transportation costs - product costs” in the Consolidated Statements of Operations.

In accordance with exchange requirements, we fund the margin associated with our exchange-traded commodity derivative contracts. The amount of the margin is adjusted daily based on the fair value of the commodity derivative contracts. Margin requirements are intended to mitigate a party’s exposure to market volatility and counterparty credit risk. We offset fair value amounts recorded for our exchange-traded derivative contracts against margin funding in “Current Assets - Other” in our Consolidated Balance Sheets.

Additionally, we utilize swap arrangements. Our Alkali Business relies on natural gas to generate heat and electricity for operations. We use a combination of commodity price swap contracts, future purchase contracts and option contracts to manage our exposure to fluctuations in natural gas prices. The swap contracts fix the basis differential between NYMEX Henry Hub and NW Rocky Mountain posted prices. We do not designate these contracts as hedges for accounting purposes. We recognize any changes in fair value of natural gas derivative contracts as increases or decreases within “Sodium minerals and sulfur services operating costs” in the Consolidated Statements of Operations.

At December 31, 2022, we had the following outstanding commodity derivative commodity contracts that were entered into to economically hedge inventory, fixed price purchase commitments or forecasted purchases.

	Sell (Short) Contracts	Buy (Long) Contracts
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 Bbls)	93	90
Weighted average contract price per Bbl	$ 78.31	$ 76.43
Natural gas swaps:		
Contract volumes (10,000 MMBtu)	—	976.5
Weighted average price differential per MMBtu	$ —	$ 0.64
Natural gas futures:		
Contract volumes (10,000 MMBtu)	148	806
Weighted average contract price per MMBtu	$ 5.27	$ 5.36
Petroleum products (#6 fuel oil) futures:		
Contract volumes (1,000 Bbls)	25	—
Weighted average contract price per Bbl	$ 56.15	$ —
Natural gas options:		
Contract volumes (10,000 MMBtu)	191	34
Weighted average premium received/paid	$ 0.70	$ 0.03

Financial Statement Impacts

The following table summarizes the accounting treatment and classification of our derivative instruments on our Consolidated Financial Statements.

		Impact of Unrealized Gains and Losses	
Derivative Instrument	Hedged Risk	Consolidated Balance Sheets	Consolidated Statements of Operations
Designated as hedges under accounting guidance:			
Crude oil futures contracts (fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in "Current Assets - Other" (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventories	Excess, if any, over effective portion of hedge is recorded in "Onshore facilities and transportation costs - product costs" Effective portion is offset in cost of sales against change in value of inventory being hedged
Not qualifying or not designated as hedges under accounting guidance:			
Commodity hedges consisting of crude oil, heating oil, fuel oil, petroleum products and natural gas futures, forward contracts, swaps and put and call options	Volatility in crude oil, natural gas and petroleum products prices - effect on market value of inventory, fixed price purchase commitments or forecasted purchases	Derivative is recorded in "Current Assets - Other" (offset against margin deposits) or Accrued liabilities	Entire amount of change in fair value of derivative is recorded in "Onshore facilities and transportation costs - product costs" and "Sodium minerals and sulfur services operating costs"
Preferred Distribution Rate Reset Election	This instrument is not related to a risk, but is rather part of a host contract with the issuance of our Class A Convertible Preferred Units	Derivative is recorded in "Other long-term liabilities"	Entire amount of change in fair value of derivative is recorded in "Other expense, net"

Unrealized gains are subtracted from net income and unrealized losses are added to net income in determining cash flows from operating activities. To the extent that we have fair value hedges outstanding, the offsetting change recorded in the fair value of inventory is also eliminated from net income in determining cash flows from operating activities. Changes in margin deposits necessary to fund unrealized losses also affect cash flows from operating activities.

The following tables reflect the estimated fair value position of our derivatives at December 31, 2022 and 2021:

Fair Value of Derivative Assets and Liabilities

	Consolidated Balance Sheets Location	Fair Value December 31, 2022	Fair Value December 31, 2021
Asset Derivatives:			
Natural Gas Swap (undesignated hedge)	Current Assets - Other	36,844	1,867
Commodity derivatives—futures and put and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$ 1,238	$ 310
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other	(1,238)	(310)
Net amount of assets presented in the Consolidated Balance Sheets		$ —	$ —
Commodity derivatives—futures (designated hedges):			
Gross amount of recognized assets	Current Assets - Other	$ —	$ 49
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other	—	(49)
Net amount of assets presented in the Consolidated Balance Sheets		$ —	$ —
Liability Derivatives:			
Preferred Distribution Rate Reset Election[2]	Other Long-Term Liabilities[2]	$ —	$ (83,210)
Natural Gas Swap (undesignated hedge)	Current Liabilities - Accrued Liabilities	(4,692)	(608)
Commodity derivatives—futures and put and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other[1]	$ (11,061)	$ (2,380)
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other[1]	5,217	2,380
Net amount of liabilities presented in the Consolidated Balance Sheets		$ (5,844)	$ —
Commodity derivatives—futures (designated hedges):			
Gross amount of recognized liabilities	Current Assets - Other[1]	$ —	$ (209)
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other[1]	—	209
Net amount of liabilities presented in the Consolidated Balance Sheets		$ —	$ —

(1) These derivative liabilities have been funded with margin deposits recorded in our Consolidated Balance Sheets under "Current Assets - Other."

(2) Refer to Note 11 and Note 19 for additional discussion surrounding the Preferred Distribution Rate Reset Election derivative.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with our cash margin balance. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash margin balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2022, we had a net broker receivable of approximately $4.0 million (consisting of initial margin of $3.8 million increased by $0.2 million of variation margin). As of December 31, 2021, we had a net broker receivable of approximately $2.9 million (consisting of initial margin of $2.1 million increased by $0.8 million of variation margin). At December 31, 2022 and December 31, 2021, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

Preferred Distribution Rate Reset Election

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our Class A Convertible Preferred Units may make a Rate Reset Election to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 110% of the Issue Price. The Rate Reset Election of our Class A Convertible Preferred Units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Unaudited Condensed Consolidated Balance Sheets. Corresponding changes in fair value are recognized in “Other income (expense)” in our Unaudited Condensed Consolidated Statement of Operations.

On the election date, the holders of the Class A Convertible Preferred Units elected to reset the rate to 11.24%, the sum of the three-month LIBOR of 3.74% plus 750 basis points. The fair value of the embedded derivative at the time of election was a liability of $101.8 million. As of the election date, the feature within the Class A Convertible Preferred Units that required bifurcation no longer existed and we have adjusted the carrying value of the Class A Convertible Preferred Units to include the fair value of the previously bifurcated amount at the election date See Note 11 for additional information regarding our Class A Convertible Preferred Units and the Rate Reset Election.

Effect on Operating Results

		Amount of Gain (Loss) Recognized in Income		
		Year Ended December 31,		
	Consolidated Statements of Operations Location	2022	2021	2020
Commodity derivatives—futures and options:				
Contracts designated as hedges under accounting guidance	Onshore facilities and transportation product costs	$ 1,403	$ (7,634)	$ (14,454)
Contracts not considered hedges under accounting guidance	Onshore facilities and transportation product costs, sodium minerals and sulfur services operating costs	6,013	(8,891)	(5,475)
Total commodity derivatives		$ 7,416	$ (16,525)	$ (19,929)
Natural gas swaps	Sodium minerals and sulfur services operating costs	31,904	$ 1,174	$ 1,186
Preferred Distribution Rate Reset Election	Other expense, net	$ (18,584)	$ (30,838)	$ (857)

We have no derivative contracts with credit contingent features.

19. Fair-Value Measurements

We classify financial assets and liabilities into the following three levels based on the inputs used to measure fair value:

(1) Level 1 fair values are based on observable inputs such as quoted prices in active markets for identical assets and liabilities;

(2) Level 2 fair values are based on pricing inputs other than quoted prices in active markets for identical assets and liabilities and are either directly or indirectly observable as of the measurement date; and

(3) Level 3 fair values are based on unobservable inputs in which little or no market data exists.

As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2022 and 2021.

	December 31, 2022			December 31, 2021		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$ 1,238	$ 36,844	$ —	$ 359	$ 1,867	$ —
Liabilities	$ (11,061)	$ (4,692)	$ —	$ (2,589)	$ (608)	$ —
Preferred Distribution Rate Reset Election	$ —	$ —	$ —	$ —	$ —	$ (83,210)

Rollforward of Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in fair value at the beginning and ending balances for our derivatives classified as level 3:

Balance as of December 31, 2019	$ (51,515)
Net loss for the period including earnings	(857)
Balance as of December 31, 2020	(52,372)
Net loss for the period including earnings	(30,838)
Balance as of December 31, 2021	(83,210)
Net loss for the period included in earnings	(18,584)
Reclassification to Mezzanine Equity	101,794
Balance as of December 31, 2022	$ —

Our commodity derivatives include exchange-traded futures and exchange-traded options contracts. The fair value of these exchange-traded derivative contracts is based on unadjusted quoted prices in active markets and is, therefore, included in Level 1 of the fair value hierarchy. The fair value of the swaps contracts was determined using market price quotations and a pricing model. The swap contracts were considered a level 2 input in the fair value hierarchy at December 31, 2022.

The fair value of the embedded derivative feature was based on a valuation model that estimates the fair value of the convertible preferred units with and without a Rate Reset Election. This model contained inputs, including our common unit price relative to the issuance price, the current dividend yield, the discount yield (which is adjusted periodically for changes associated with the industry's credit markets), default probabilities, equity volatility, U.S. Treasury yields and timing estimates which involved management judgment. Our equity volatility rate used to value our embedded derivative feature was 50% at September 29, 2022, which represented the final valuation date of the embedded derivative due to the Rate Reset Election. Due primarily to the election of the rate reset increasing the distribution rate from 8.75% to 11.24%, we recorded an unrealized loss of $18.6 million for the year ended December 31, 2022. Due primarily to a decrease in our discount yield compared to December 31, 2020 as a result of significant fluctuations in the energy industry credit markets and volatility in our common unit price during the period, we recorded an unrealized loss of $30.8 million for the year ended December 31, 2021. Due primarily to a an increase in our volatility rate compared to December 31, 2019, we recorded an unrealized loss of $0.9 million for the year ended December 31, 2020. We report unrealized gains and losses associated with this embedded derivative in our Consolidated Statements of Operations as "Other expense, net."

See Note 18 for additional information on our derivative instruments.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified in Level 3, in the event that we were required to measure and record such assets within our Consolidated Financial Statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

Other Fair Value Measurements

We believe the debt outstanding under our senior secured credit facility approximates fair value as the stated rate of interest approximates current market rates of interest for similar instruments with comparable maturities. At December 31, 2022 our senior unsecured notes had a carrying value of $2.9 billion and fair value of $2.7 billion, compared to a carrying value of $3.0 billion and fair value of $3.0 billion at December 31, 2021. The fair value of the senior unsecured notes is determined based on trade information in the financial markets of our public debt and is considered a Level 2 fair value measurement. At December 31, 2022, our Alkali senior secured notes had a carrying value of $0.4 billion and fair value of $0.4 billion. The fair value of the Alkali senior secured notes is determined based on trade information in the financial market of securities with similar features and is considered a Level 2 fair value measurement.

20. Employee Benefit Plans

We sponsor a defined benefit pension plan for union-only employees of our Alkali Business. We account for the Alkali Business pension plan as a single employer pension plan that benefits only employees of our Alkali Business, and thus, the related assets and liability costs of the plan are recorded in the Consolidated Balance Sheets. Under the Alkali Business pension plan, each eligible employee will automatically become a participant upon completion of one year of credited service. Retirement benefits under this plan are calculated based on the total years of service of an eligible participant, multiplied by a specified benefit rate in effect at the termination of the plan participant’s years of service.

The change in benefit obligations, plan assets and funded status along with amounts recognized in the Consolidated Balance Sheets are as follows:

	December 31, 2022	December 31, 2021
Change in benefit obligation:		
Benefit Obligation, beginning of year	$ 55,934	$ 52,510
Service Cost	5,181	6,020
Interest Cost	1,804	1,576
Actuarial Gain	(19,557)	(3,051)
Benefits Paid	(1,297)	(1,121)
Benefit Obligation, end of year	42,065	55,934
Change in plan assets:		
Fair Value of Plan Assets, beginning of year	35,288	32,043
Actual Return on Plan Assets	(6,363)	2,051
Employer Contributions	2,445	2,315
Benefits Paid	(1,297)	(1,121)
Fair Value of Plan assets, end of year	30,073	35,288
Funded Status at end of period	$ (11,992)	$ (20,646)
Amounts recognized in the Consolidated Balance Sheets:		
Non-current assets	$ —	$ —
Current liabilities	—	—
Non-current Liabilities	(11,992)	(20,646)
Net Liability at end of year	$ (11,992)	$ (20,646)
Amounts recognized in accumulated other comprehensive income (loss):		
Prior Service Cost	4,702	5,189
Net actuarial loss (gain)	(10,816)	418
Amounts recognized in accumulated other comprehensive loss:	$ (6,114)	$ 5,607

Estimated Future Cash Flows- The following employer contributions and benefit payments, which reflect expected future service, are expected to be paid as follows:

Employer Contributions		
Expected 2023 Contributions by Employer	$	2,980
Future Expected Benefit Payments		
2023	$	1,465
2024		1,606
2025		1,772
2026		1,917
2027		2,091
2028-2032		12,533

Net Periodic Pension Costs- The components of net periodic pension costs for the Alkali benefit plan are as follows:

	December 31,		
	2022	2021	2020
Service Cost	$ 5,181	$ 6,020	$ 5,493
Interest Cost	1,804	1,576	1,469
Expected Return on Assets	(1,959)	(1,831)	(1,539)
Amortization of Prior Service Cost	487	487	487
Total Net Periodic Benefit Costs	$ 5,513	$ 6,252	$ 5,910

Significant Assumptions - Discount rates are determined annually and are based on rates of return of high-quality long-term fixed income securities currently available and expected to be available during the maturity of the pension benefits.

The long-term rate of return estimation for the Alkali Business pension plan is based on a capital asset pricing model using historical data and a forecasted earnings model. An expected return on plan assets analysis is performed which incorporates the current portfolio allocation, historical asset-class returns and an assessment of expected future performance using asset-class risk factors.

The Alkali Business pension plan is administered by a Board-appointed committee that has fiduciary responsibility for the plan's management. The committee is responsible for the oversight and management of the plan's investments. The committee maintains an investment policy that provides guidelines for selection and retention of investment managers or funds, allocation of plan assets and performance review procedures and updating of the policy. The objective of the committee's investment policy is to manage the plan assets in such a way that will allow for the on-going payment of the Company's obligation to the beneficiaries.

Weighted average assumptions used to determine benefit obligation:	December 31, 2022	December 31, 2021
Discount Rate	5.33 %	3.27 %
Expected Long-term Rate of Return	6.71 %	5.35 %
Rate of Compensation Increase	N/A	N/A

The discount rate used to determine the net periodic cost at the beginning of the period was 3.27%.

Pension Plan Assets - We maintain target allocation percentages among various asset classes based on an investment policy established for the pension plan, which was last amended in November 2020. The target allocation is designed based on the strategic objectives, spending policy and risk tolerance of the plan. Pension plan asset allocations at December 31, 2022 by asset category are as follows:

	December 31, 2022		
	Target %	Minimum	Maximum
Equity securities	67 %	58 %	76 %
Fixed Income	20 %	11 %	29 %
Alternative Investments	11 %	2 %	20 %
Cash and Equivalents	2 %	— %	7 %

A summary of total investments for our pension plan assets measured at fair value is presented as of December 31 for the periods below:

	2022				2021			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 4,592	$ —	$ —	$ 4,592	$ 2,989	$ —	$ —	$ 2,989
Equity securities	20,838	—	—	20,838	25,309	—	—	25,309
Fixed income and other securities	4,643	—	—	4,643	6,990	—	—	6,990
	$ 30,073	$ —	$ —	$30,073	$ 35,288	$ —	$ —	$ 35,288

21. Commitments and Contingencies

Commitments and Guarantees

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities; however no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material effect on our financial position, results of operations or cash flows.

22. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. Other than with respect to our corporate subsidiaries and the Texas Margin Tax, our taxable income or loss is includible in the federal income tax returns of each of our partners.

A few of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. During 2022, we paid federal and state income taxes on these operations.

Our income tax (benefit) expense is as follows:

	Year Ended December 31, 2022	2021	2020
Current:			
Federal	$ —	$ —	$ —
State	815	690	650
Total current income tax expense	$ 815	$ 690	$ 650
Deferred:			
Federal	$ 1,814	$ 1,097	$ 78
State	540	(117)	599
Total deferred income tax expense	$ 2,354	$ 980	$ 677
Total income tax expense	$ 3,169	$ 1,670	$ 1,327

Deferred income taxes relate to temporary differences based on tax laws and statutory rates that were enacted at the balance sheet date. Deferred tax assets and liabilities consist of the following:

	December 31, 2022	2021
Deferred tax assets:		
Net operating loss carryforwards	$ 15,313	$ 16,174
Other	2,333	1,277
Total long-term deferred tax asset	17,646	17,451
Valuation allowances	(3,471)	(2,760)
Total deferred tax assets	$ 14,175	$ 14,691
Deferred tax liabilities:		
Long-term:		
Fixed assets	$ (1,730)	$ (1,803)
Intangible assets	(27,033)	(25,772)
Other	(2,064)	(1,413)
Total long-term liability	(30,827)	(28,988)
Total deferred tax liabilities	$ (30,827)	$ (28,988)
Total net deferred tax liability	$ (16,652)	$ (14,297)

We record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character in the future and in the appropriate taxing jurisdictions.

The reconciliation between the Partnership's effective tax rate on income (loss) from operations and the statutory tax rate is as follows:

	Year Ended December 31,		
	2022	2021	2020
Income (loss) from operations before income taxes	$ 132,304	$ (136,362)	$ (398,987)
Partnership income not subject to federal income tax	(126,403)	140,092	398,729
Income (loss) subject to federal income taxes	$ 5,901	$ 3,730	$ (258)
Tax expense (benefit) at federal statutory rate	$ 1,239	$ 783	$ (54)
State income taxes, net of federal tax	1,248	574	1,213
Return to provision, federal and state	44	(227)	(383)
Other	(18)	112	117
Valuation allowance	656	428	434
Income tax expense	$ 3,169	$ 1,670	$ 1,327
Effective tax rate on income (loss) from operations before income taxes	2.4 %	(1.2)%	(0.3)%

At December 31, 2022, 2021 and 2020, we had no uncertain tax positions.

23. Subsequent Events

On January 1, 2023, we became the sole member of ANSAC and ANSAC became a wholly owned subsidiary of Genesis Alkali Wyoming, L.P. As the sole member of the organization, beginning in 2023, we will include the assets, liabilities, and operating results of ANSAC within our consolidated financial statements.

On January 25, 2023, we issued $500.0 million in aggregate principal amount of our 2030 Notes. Interest payments are due April 15 and October 15 of each year with the initial interest payment due on October 15, 2023. The issuance generated net proceeds of approximately$491 million, net of issuance costs incurred. The net proceeds were used to purchase approximately $316 million of our existing 2024 Notes, including the related accrued interest and tender premium and fees on those notes that were tendered in the tender offer that ended January 24, 2023 and the remaining proceeds at the time were used to repay a portion of the borrowings outstanding under our senior secured credit facility and for general partnership purposes. On January 26, 2023 we issued a notice of redemption for the remaining principal of approximately $25 million of our 2024 Notes, and discharged the indebtedness with respect to the 2024 Notes on February 14, 2023 by depositing the redemption amount with the trustee of the 2024 Notes for redemption of the 2024 Notes on February 25, 2023, all in accordance with the terms and conditions of the indenture governing the 2024 Notes.

On February 17, 2023, we entered into the Sixth Amended and Restated Credit Agreement (our “new credit agreement”) to replace our Fifth Amended and Restated Credit Agreement. Our new credit agreement provides for a $850 million senior secured revolving credit facility. The new credit agreement matures on February 13, 2026, subject to extension at our request for one additional year on up to two occasions and subject to certain conditions, unless more than $150 million of our 2025 Notes remain outstanding as of June 30, 2025, in which case the new credit agreement matures on such date.