GENESIS ENERGY LP
Form 10-K
February 27, 2017

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016
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.)

919 Milam, Suite 2100, Houston, TX 77002
(Address of principal executive offices) (Zip code)
(713) 860-2500
Registrant's telephone number, including area code:
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units	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 x No o
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 o No x
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 x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer ¨

Non-accelerated filer o Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2) of the Act). Yes o No x

The aggregate market value of the Class A common units held by non-affiliates of the Registrant on June 30, 2016 (the last business day of Registrant's most recently completed second fiscal quarter) was approximately $3.5 billion based on $38.37 per unit, the closing price of the common units as reported on the NYSE. For purposes of this computation, all executive officers, directors and 10% owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates. On February 24, 2017, the Registrant had 117,939,221 Class A Common Units and 39,997 Class B Common Units outstanding.

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Definitions

Unless the context otherwise requires, references in this annual report to "Genesis Energy, L.P.," "Genesis," "we," "our," "us" 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/d: Thousand Bbls per day.

Mcf: Thousand cubic feet of gas.

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

MMcf: Thousand Mcf.

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 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 n 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, caustic soda and CO_2, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;

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- 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 energy 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, and processing operations;
- shutdowns or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, petroleum, natural gas or other products or to whom we sell such 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 the suspension of drilling in the Gulf of Mexico and the effects of future laws and government regulation resulting from the Macondo accident and oil spill in the Gulf;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- 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 at the current level or continue 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;
- natural disasters, accidents or terrorism;
- 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; and
- 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.

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.

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PART I

Item 1. Business

General

We are a growth-oriented master limited partnership formed in Delaware in 1996 and focused on the midstream segment of the crude oil and natural gas industry in the Gulf Coast region of the United States, Wyoming and in the Gulf of Mexico. Our common units are traded on the New York Stock Exchange under the ticker symbol "GEL." Our principal executive offices are located at 919 Milam, Suite 2100, Houston, Texas 77002 and our telephone number is (713) 860-2500. Except to the extent otherwise provided, the information contained in this annual report is as of December 31, 2016.

We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises. We currently have two distinct, complimentary types of operations-(i) 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, and (ii) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, which focus on providing a suite of services primarily to integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties. Our onshore-based operations occur upstream of, at, and downstream of refinery complexes. Upstream of refineries, we aggregate, purchase, gather and transport crude oil, which we sell to refiners. Within refineries, we provide services to assist in sulfur removal/balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for finished refined petroleum products and certain refining by-products. In our offshore crude oil and natural gas pipeline transportation and handling operations, we provide service to one of the most active drilling and development regions in the U.S.—the Gulf of Mexico, a producing region representing approximately 18% of the crude oil production in the U.S. in 2016. We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. Substantially all of our revenues are derived from providing services to refiners, integrated and large independent crude oil and natural gas companies, and industrial and commercial enterprises.

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) representing limited partner interests constitute all of the economic equity interests in us.

In the fourth quarter of 2016, we reorganized our operating segments as a result of the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. The results of our onshore pipeline transportation segment, formerly reported under its own segment, are now reported in our supply and logistics segment. This change is consistent with the increasingly integrated nature of our onshore operations.

As a result of the above changes, we currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, refinery services, marine transportation, and supply and logistics. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

Offshore Pipeline Transportation Segment

We conduct our offshore crude oil and natural gas pipeline transportation and handling operations 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 billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties in the Gulf of Mexico, primarily offshore Texas, Louisiana, Mississippi and Alabama. 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 18% of the crude oil production in the U.S. in 2016. Even though those large-reservoir properties and the 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 companies and large independent crude oil producers.

We own interests in various offshore crude oil and natural gas pipeline systems, platforms and related infrastructure. We own interests in approximately 1,437 miles of crude oil pipelines with an aggregate design capacity of approximately 1,810 MBbls per day, a number of which pipeline systems are substantial and/or strategically located. For example, we own a 64% interest in the Poseidon pipeline system and 100% of the Cameron Highway pipeline system, or CHOPS, which is one 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 Company, LLC ("SEKCO"), which is a deepwater pipeline servicing the Lucius field in the southern Keathley Canyon area of the Gulf of Mexico.

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Our interests in offshore natural gas pipeline systems and related infrastructure includes approximately 1,157 miles of pipe with an aggregate design capacity of approximately 4,863 MMcf per day. We also own an interest in six offshore hub platforms with aggregate processing capacity of approximately 2,256 MMcf per day of natural gas and 167 MBbls per day of crude oil.

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. Each of our offshore pipelines currently has significant available capacity to accommodate future growth in the fields from which the production is dedicated to that pipeline, including fields that have yet to commence production activities, as well as volumes from non-dedicated fields.

Refinery Services Segment

We primarily (i) provide services to ten refining operations 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 (pronounced nash, and also known as sodium hydrosulfide) and NaOH (also known as caustic soda) to large industrial and commercial companies. Our refinery services primarily involve processing refiners' high sulfur (or "sour") gas streams to remove the sulfur. Our refinery services footprint also includes NaHS and caustic soda terminals, and we utilize railcars, ships, barges and trucks to transport product. Our refinery services contracts are typically long-term in nature and have an average remaining term of three 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 receive 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 mining of base metals, primarily copper and molybdenum, and the production of pulp and paper. We believe we are one of the largest marketers of NaHS in North and South America.

Marine Transportation Segment

We own a fleet of 83 barges (74 inland and 9 offshore) with a combined transportation capacity of 2.9 million barrels and 43 push/tow boats (34 inland and 9 offshore). Our marine transportation segment is a provider of transportation services by tank barge primarily for refined petroleum products, including heavy fuel oil and asphalt, as well as crude oil. Refiners accounted for approximately 80% of our marine transportation volumes for 2016.

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 refined products.

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. Most of 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. 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.

Supply and Logistics Segment

Our supply and logistics segment owns and/or leases our increasingly integrated suite of onshore crude oil and refined products infrastructure, including pipelines, trucks, terminals, railcars, and rail loading and unloading facilities. It 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 supply and logistics assets is particularly evident in certain of our recently completed or ongoing growth initiatives in areas such as Louisiana, Texas and Wyoming.

We own five onshore crude oil pipeline systems, with approximately 580 miles of pipe located primarily in Alabama, Florida, Louisiana, Mississippi, Texas and Wyoming. The Federal Energy Regulatory Commission, or FERC, regulates the rates charged by four of our onshore systems to their customers. The rates for the other 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 two CO_2 pipelines with approximately 270 miles of pipe. We have leased our NEJD System, comprised of 183 miles of pipe in North East Jackson Dome, Mississippi, to an affiliate of an independent crude oil company through 2028. We receive a fixed quarterly payment under the NEJD arrangement. That company also has the exclusive right to use our Free State pipeline, comprised of 86 miles of pipe, pursuant to a transportation agreement that expires in 2028. Payments on the Free State pipeline are subject to an "incentive" tariff which provides that the average rate per mcf that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.

We have access to a suite of more than 200 trucks, 400 trailers, 523 railcars, and terminals and tankage with 4.6 million barrels of storage capacity (excluding capacity associated with our common carrier crude oil pipelines) in multiple locations along the Gulf Coast. Our crude-by-rail operations consist of a total of six facilities, either in operation or under

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construction, designed to load and/or unload crude oil. The two facilities located in Texas and Wyoming were designed primarily to load crude oil produced locally onto railcars for further transportation to refining markets. The four other facilities (two in Louisiana, one in Mississippi and one in Florida) were designed primarily to unload crude oil from railcars into pipelines, or onto barges, for delivery to refinery customers. In addition, four of these facilities are directly connected to our integrated pipeline and terminal infrastructure. Usually, our supply and logistics 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 NYMEX derivatives to offset the remaining price risk.

Our Objectives and Strategies

Our primary objective continues to be to deliver the best value to our unitholders while never wavering from our commitment to safe and responsible operations. A lot has changed, we recognize, in how the market apparently values unit prices for MLPs or other midstream entities over the last year and a half to two years. The move to eliminate our IDRs over six years ago and our track record of delivering annualized double-digit growth in distributions were historically rewarded. However, we have recently concluded the valuation metrics demanded by the markets have changed in recent times, especially in light of numerous freezes, cuts or total elimination of distributions over the recent energy business cycle by other entities in our space with which we compete commercially and/or for external capital.

We now believe the best way to promote unit price appreciation under current conditions is to exercise strong financial discipline designed primarily to maintain and enhance our financial flexibility across the business cycle. We believe prospectively we can naturally restore our financial flexibility with cash flows from operations. During 2016, we accelerated that process by issuing additional equity and lowering the future growth rate of quarterly distributions.

Business Strategy

Our primary business strategy is to provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises. Successfully executing this strategy should enable us to generate and grow sustainable cash flows. We currently have two distinct, complimentary types of operations: (i) our onshore-based crude oil and refined petroleum products transportation, supply and logistics, and handling operations, focusing predominantly on refinery-centric customers (as opposed to producers), and (ii) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, focusing on integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties. Refiners are the shippers of approximately 80% of the volumes transported on our onshore crude pipelines, and refiners contract for approximately 80% of the use of our inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. The shippers on our offshore pipelines are mostly integrated and large independent energy companies who have developed, and continue to explore for, numerous large-reservoir, long-lived crude oil properties whose production is ideally suited for the vast majority of refineries along the Gulf Coast, unlike the lighter crude oil and condensates produced from numerous onshore shale plays. Those 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 this lower commodity price environment.

We intend to develop our business by:

- Identifying and exploiting incremental profit opportunities, including cost synergies, across an increasingly integrated footprint;
- 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;
- Economically expanding our pipeline and terminal operations;
- 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.

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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; 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:

- We have limited direct commodity price risk exposure. 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 NYMEX 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 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 NaHS and caustic soda. Our business lines complement each other by allowing us to offer an integrated suite of services to common customers across segments. Our businesses are primarily focused on providing (i) onshore-based refinery-centric crude oil and refined products transportation and handling services and (ii) offshore crude oil and natural gas pipeline transportation and related handling services in the Gulf of Mexico to mostly integrated and large independent energy companies. We are not dependent upon any one customer or principal location for our revenues.
- 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 truck, rail or barge.
- We believe we are one of the largest marketers of NaHS in North and South America. We believe the scale of our well-established refinery services operations as well as our integrated suite of assets provides us with a unique cost advantage over some of our existing and potential competitors.
- Some of our supply and logistics 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.
- Our businesses provide relatively consistent consolidated financial performance. Our historically consistent and improving 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, allowing us to increase our distribution for forty-six consecutive quarters as of our most recent distribution declaration.
- We are financially flexible and have significant liquidity. As of December 31, 2016, we had $412.3 million available under our $1.7 billion revolving credit agreement, including up to $125.5 million available under the $200 million petroleum products inventory loan sublimit and $90.5 million available for letters of credit. Our inventory borrowing base was $74.5 million at December 31, 2016.
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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.

- We have an experienced, knowledgeable and motivated executive management team with a proven track record. Our executive management team has an average of more than 25 years of experience in the midstream sector. Its members

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have worked in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. Through their equity interest in us, our executive management team is incentivized to create value by increasing cash flows.

Recent Developments and Status of Certain Growth Initiatives

The following is a brief listing of developments since December 31, 2015. Additional information regarding most of these items may be found elsewhere in this report.

Houston Area Crude Oil Pipeline and Terminal Infrastructure

We are constructing new, and expanding existing, crude oil pipeline and terminal facilities in Webster, Texas and Texas City, Texas as a result of expanding our crude oil pipeline and terminal infrastructure in the Houston area. We are constructing a new crude oil pipeline that will deliver crude oil received from upstream crude oil pipelines (including CHOPS, which delivers crude oil originating in the deepwater Gulf of Mexico to the Texas City area) to our new Texas City Terminal, which will ultimately connect to our existing 18-inch Webster to Texas City crude oil pipeline. Our new Texas City Terminal will initially include approximately 750,000 barrels of crude oil tankage. As a part of this project, we are also making the necessary upgrades on our existing 18-inch Webster to Texas City crude oil pipeline to reverse the direction of flow. The result of this expanded crude oil infrastructure will allow additional optionality to Houston and Baytown area refineries, including the Exxon-Mobil Baytown refinery, its largest refinery in the U.S.A., and provide additional delivery outlets for other crude oil pipelines. We expect these assets to become operational in the first half of 2017.

Raceland Terminal and Crude Oil Pipeline

We are constructing a new crude oil terminal and pipeline in Raceland, Louisiana that will be connected to existing midstream infrastructure that will provide further distribution to the Louisiana refining markets. Our new Raceland Terminal will consist of 515,000 barrels of crude oil tankage and unit train unloading facilities capable of unloading up to two unit trains per day. We are constructing a new crude oil pipeline that will deliver crude oil received from the Poseidon system, which currently delivers crude oil originating in the deepwater Gulf of Mexico to the Houma, Louisiana area, to our Raceland Terminal for further distribution. We expect these assets to become fully operational in the first half of 2017.

Inland Marine Barge Transportation Expansion

We ordered 28 new-build barges and 18 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 20 of those barges and 14 of those push boats through December 31, 2016. We expect to take delivery of those remaining vessels periodically into 2017.

Baton Rouge Terminal

We constructed a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that is located near the Port of Greater Baton Rouge and is connected to the port's existing deepwater docks on the Mississippi River. We constructed approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we constructed a new pipeline from the terminal that will allow for deliveries to existing ExxonMobil facilities in the area, as well as connect our previously constructed 17 mile line to the terminal allowing for receipts from the Scenic Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our Baton Rouge Terminal. Our Baton Rouge Terminal and related facilities became operational early in the fourth quarter of 2016.

Wyoming Crude Oil Pipeline

In the third quarter of 2015, we completed construction of a new 60 mile crude oil pipeline to transport crude oil from new receipt point stations in Campbell County and Converse County, Wyoming to our existing Pronghorn Rail Facility. This new crude oil pipeline has an initial capacity of approximately 30,000 barrels per day and is supplied by truck volumes and third party gathering infrastructure in the Powder River Basin.

We also constructed a new 75 mile pipeline from our Pronghorn Rail Facility to a delivery point at our new Guernsey Station in Platte County, Wyoming. This Pronghorn to Guernsey pipeline has an initial capacity of approximately 45,000 barrels per day and will allow for connectivity to additional downstream pipeline markets at Guernsey, including regional refineries and Cushing, Oklahoma via the Pony Express Pipeline. This pipeline became operational in the first quarter of 2016.

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Forty-six Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for forty-six consecutive quarters. On February 14, 2017, we paid a quarterly cash distribution of $0.710 (or $2.84 on an annualized basis) per unit to unitholders of record as of January 31, 2017, an increase of 1.4% from the distribution in the prior quarter, and an increase of 8.4% from the distribution in February 2016. As in the past, future increases (if any) in our quarterly distribution rate will depend on our ability to execute critical components of our business strategy.

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, 2016.

Description of Segments and Related Assets

We conduct our businesses through four operating segments: offshore pipeline transportation, refinery services, marine transportation and supply and logistics. These segments are strategic business units that provide a variety of energy-related services. Financial information with respect to each of our segments can be found in Note 12 to our Consolidated Financial Statements in Item 8.

We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. Substantially all of our revenues are derived from providing services to refiners, integrated and large independent crude oil and natural gas companies, and large industrial and commercial enterprises. Our onshore-based operations occur upstream of, at, and downstream of refinery complexes. Upstream of refineries, we aggregate, purchase, gather and transport crude oil, which we sell to refiners. Within refineries, we provide services to assist in sulfur removal/balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for finished refined petroleum products and certain refining byproducts.

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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, a producing region representing approximately 18% of the crude oil production in the U.S. in 2016.

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	Throughput (Bbls/day) net to ownership interest
Main Lines						
CHOPS	Genesis	380	500,000	100 %	204,533	204,533
Poseidon	Genesis	367	350,000	64 %	262,829	168,211
Odyssey	Shell Pipeline	120	200,000	29 %	106,933	31,011
Eugene Island Pipeline and Other	Genesis/Shell Pipeline	184	39,000	23 %	7,468	7,468
Total		1,051	1,089,000		581,763	411,223
Lateral Lines (2)						
SEKCO	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 %		
Viosca Knoll Crude Oil Pipeline	Genesis	6	5,000	100 %		
Tarantula	Genesis	4	30,000	100 %		

(1) Capacity figures presented represent 100% of the design capacity; except for Eugene Island, which represents our net capacity in the undivided interest (23%) 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, other than our Viosca Knoll Crude Oil Pipeline, ultimately flow into our other offshore crude oil pipelines (including CHOPS and Poseidon) and thus are excluded from main lines above.

- CHOPS. CHOPS 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 located in Port Arthur and Texas City, Texas. CHOPS also includes two strategically located multi-purpose offshore platforms.
- Poseidon. The Poseidon system 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.
- Odyssey. The Odyssey system 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.
- 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 onshore Louisiana. Other owners in Eugene Island include affiliates of Exxon Mobil, Chevron, ConocoPhillips and Shell Oil Company.

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- SEKCO Pipeline. SEKCO is a deepwater pipeline serving the Lucius crude oil and natural gas field located in the southern Keathley Canyon area of the Gulf of Mexico. SEKCO has crude oil transportation agreements with seven Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Inpex Corporation. Those producers have dedicated their production from Lucius to that pipeline for the life of the reserves. We expect the SEKCO pipeline to also provide capacity for additional projects in the deepwater Gulf of Mexico in the future.
- Shenzi Crude Oil. 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 for delivery to both our CHOPS and Poseidon pipeline systems.
- Allegheny Crude Oil. 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 and Poseidon pipelines.
- Marco Polo Crude Oil. 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. The Constitution Crude Oil Pipeline gathers crude oil from the Constitution, Caesar Tonga and Ticonderoga production fields located in the Green Canyon area of the Gulf of Mexico for delivery to either the CHOPS or Poseidon pipelines.

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	
Independence Trail	Genesis	135	1,000	100	%
Viosca Knoll Gathering System	Genesis	107	600	100	%
High Island Offshore System	Genesis	287	500	100	%
Anaconda Gathering System	Genesis	183	300	100	%
Green Canyon Laterals	Genesis	34	213	Various (2)	
Manta Ray Offshore Gathering System	Enbridge	237	800	25.7	%
Nautilus System	Enbridge	101	600	25.7	%
Total		1,084	4,013		

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

(2) We proportionately consolidate our undivided interests, which range from 2.7% to 33.3%, in 28 miles of the Green Canyon Lateral pipelines. The remainder of the laterals are wholly owned.

- Independence Trail. The Independence Trail pipeline transports natural gas from certain pipeline interconnects to the Tennessee Gas Pipeline at a pipeline interconnect on the West Delta 68 pipeline junction platform. Natural gas transported on the Independence Trail Pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.
- Viosca Knoll Gathering System. Viosca Knoll gathers natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico for delivery to several major interstate pipelines, including the High Point Gas Transmission, Transco, Dauphin Island Gathering System, Tennessee Gas Pipeline and Destin Pipelines.
- 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 TC Offshore system and Kinetica Energy Express. HIOS includes 201 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 of the Gulf of Mexico 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.

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- 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 interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and 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	Anadarko	4,300	300	120,000	100 %
Viosca Knoll 817	Genesis	671	145	5,000	100 %
Garden Banks 72 (2)	Genesis	518	216	36,000	50 %
East Cameron 373	Genesis	441	195	3,000	100 %
Total			856	164,000	

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

(2) We proportionately consolidate our undivided interest in the Garden Banks 72 platform.

- 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.
- Viosca Knoll. The Viosca Knoll 817 platform primarily serves as a base for gathering deepwater production in the Viosca Knoll area, including the Ram Powell development.
- Garden Banks. The Garden Banks 72 platform serves as a base for gathering deepwater production from the Garden Banks area of the Gulf of Mexico. This platform also serves as a junction platform for the CHOPS and Poseidon pipeline systems.
- East Cameron. The East Cameron 373 platform processes 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-reserve commitments that include both firm and interruptible capacity arrangements.
Revenues from customers of our offshore pipeline transportation segment did not account for more than ten percent of our consolidated revenues.

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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.

Refinery Services

Our refinery services segment primarily (i) provides sulfur-extraction services to ten refining operations located mostly in Texas, Louisiana, Arkansas, Oklahoma 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 refinery 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 refinery services activities. 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 ten refinery services contracts have an average remaining life of three years. This includes the extended term of our recently renegotiated refinery services contract with Phillips 66 at our Westlake, Louisiana facility, which now extends through 2026. The timing upon which these contracts renew vary based upon location and terms specified within each specific contract.

Our refinery 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 supply and logistics segment, we sell and deliver (via railcars, ships, barges and trucks) NaHS and caustic soda to approximately 150 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 pulp and paper business, and in connection with mining operations (nickel, gold and separating copper from molybdenum) 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

We provide on-site sulfur removal services utilizing NaHS units at ten refining 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 the 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.

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Competition

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 refinery 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.

We do not have any NaHS sales customer or sulfur removal customer that accounted for more than ten percent of our consolidated revenues.

Marine Transportation

Our marine transportation segment consists of (i) our inland marine fleet which transports heavy 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 until 2020. The below table includes operational information relating to our marine transportation fleet:

	Inland	Offshore	American Phoenix
Aggregate Fleet Design Capacity (Bbls) (in thousands)	2,058	884	330
Individual Vessel Capacity Range (Bbls) (in thousands) (1)	23-39	65-136	330
Number of:			
Push/Tug Boats	34	9	—
Barges	74	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 some large energy companies. Our M/T American Phoenix is currently operating under a long term charter into 2020 with Phillips 66. 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 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

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2016, 2015 and 2014. 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. We typically maintain a higher mix of term contracts to spot contracts to provide a predictable revenue stream while maintaining spot market exposure to take advantage of new business opportunities and existing customers' peak demands. During 2016, 2015 and 2014, approximately 62%, 75% and 80%, respectively, of our marine transportation revenues were from term contracts and 38%, 25% and 20%, respectively, were from spot contracts.

Revenues from customers of our marine transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

Our competitors for the marine transportation of crude oil and heavy refined petroleum products are both midstream MLPs with marine transportation divisions, 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 such 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 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.

Supply and Logistics

We provide supply and logistics 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, railcars and barges. The increasingly integrated nature of our supply and logistics assets is particularly evident in certain of our recently completed or ongoing growth initiatives in areas such as Louisiana, Texas and Wyoming. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by gathering line, truck, railcar 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 products, minus the associated costs of aggregation and transportation.

Our crude oil supply and logistics operations are concentrated in Texas, Louisiana, Alabama, Florida, Mississippi and Wyoming. 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. We attempt to limit our direct commodity price risk in our supply and logistics segment by utilizing back-to-back purchases and sales, matching sale and purchase volumes on a monthly basis and hedging unsold volumes (primarily with NYMEX derivatives to offset the remaining price risk); however, we cannot completely eliminate commodity price risks. 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 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 50,000 barrels per day of crude oil, much 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 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

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costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks and railcars and incurring 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, or 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 five onshore common carrier crude oil pipeline systems: the Texas System, the Jay System, the Mississippi System, the Louisiana System and the Wyoming System.

	Texas System	Jay System	Mississippi System	Louisiana System	Wyoming System
Product	Crude Oil	Crude Oil	Crude Oil	Crude Oil Intermediates Refined Products	Crude Oil
Interest Owned	100%	100%	100%	100%	100%
Design Capacity (Bbls/day) [(1)]	Existing 8" - 60,000 Looped 18" - 275,000	150,000	45,000	350,000	30,000/ 45,000
2016 Throughput (Bbls/day)	33,814	14,815	10,247	44,295	10,959
System Miles	47	135	235	25	135
Approximate owned tankage storage capacity (Bbls)	360,000	230,000	247,500	350,000	450,000
Location	Hastings Junction, TX to Webster, TX Webster, TX to Texas City, 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	Wright, WY (Campbell County) to Douglas, WY (Pronghorn) Douglas, WY to Guernsey, WY
Rate Regulated	TXRRC	FERC	FERC	FERC	FERC

(1) Our Wyoming pipeline system has an initial capacity of approximately 30,000 barrels per day from Campbell County to the Pronghorn Rail Facility and an initial capacity of 45,000 barrels per day from the Pronghorn Rail Facility to Platte County, Wyoming.

- Texas System. Our Texas System transports crude oil from Hastings Junction (south of Houston) to several delivery points near Houston, Texas (including our Webster, Texas facility and ultimately into the Texas City refining market). This system also takes delivery of crude oil volumes at Texas City for delivery to our Webster, Texas facility, which ultimately connects to other crude oil pipelines. 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. See "Recent Developments and

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Status of Certain Growth Initiatives" for further information surrounding developments and current growth initiatives surrounding our Houston area crude oil infrastructure project.

- Jay System. Our Jay System provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. That system also includes gathering connections to approximately 46 wells, additional crude oil storage capacity of 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 transports crude oil from Port Hudson to our Baton Rouge Scenic Station rail unloading facility and continues downstream to the Anchorage Tank Farm servicing Exxon Mobil Corporation's Baton Rouge refinery. This refinery is one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our Louisiana system also connects the Anchorage Tank Farm to our new Port of Baton Rouge Terminal (which was also built to service Exxon's Baton Rouge refinery), allowing bidirectional flow of crude oil, intermediates and refined products between the Anchorage Tank Farm and this terminal.

This pipeline system serves as a key asset in our increasingly integrated Baton Rouge area midstream infrastructure, which also includes terminal and rail facilities as discussed previously.

Additionally, as discussed in "Recent Developments and Growth Initiatives" above, in the fourth quarter of 2013, we began construction on a new terminal, crude oil pipeline and unit train unloading facility in Raceland, Louisiana which will be connected to existing midstream infrastructure that will provide further distribution to the Louisiana refining markets. We expect this facility to be operational in the first half of 2017.

- Wyoming System. Our Wyoming System transports crude oil from receipt point stations in Campbell County and Converse County, Wyoming to our Pronghorn Rail Facility near Douglas, Wyoming. This crude oil pipeline has an initial capacity of approximately 30,000 barrels per day and is supplied by truck volumes and third party gathering infrastructure in the Powder River Basin. This pipeline system became operational in the third quarter of 2015. We have also completed construction of a new 75 mile pipeline from our Pronghorn Rail Facility to a delivery point at our new Guernsey Station in Platte County, Wyoming. This Pronghorn to Guernsey pipeline has an initial capacity of approximately 45,000 barrels per day and will allow for connectivity to additional downstream pipeline markets at Guernsey, including regional refineries and Cushing, Oklahoma via the Pony Express Pipeline. This pipeline became operational in the first quarter of 2016.

This pipeline system serves as a key asset in our increasingly integrated Wyoming midstream infrastructure, which also includes terminal and rail facilities as discussed previously.

Other Supply and Logistics Operations

We own five operational crude oil rail loading/unloading facilities located in Baton Rouge, Louisiana; Walnut Hill, Florida; Wink, Texas; Natchez, Mississippi and Douglas, Wyoming which provide synergies to our existing asset footprint. We generally earn a fee for loading or unloading railcars at these facilities. Three of these facilities, our Baton Rouge, Louisiana, Walnut Hill, Florida, and Douglas, Wyoming facilities are directly connected to our existing integrated crude oil pipeline and terminal infrastructure. See further discussion of these facilities above.

Within our supply and logistics business segment, we employ many types of logistically flexible assets. These assets include 200 trucks, 400 trailers, 523 railcars, and terminals and other tankage with 4.6 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. Our leased railcars consist of approximately 51 refined product railcars and 472 crude oil railcars.

Our refined products supply and logistics operations are concentrated in the Gulf Coast region, principally Texas and Louisiana, and in Wyoming. Through our footprint of owned and leased pipelines, trucks, leased railcars, terminals and barges, we are able to provide Gulf Coast area refineries with transportation services as well as market outlets for certain heavy refined products. We primarily engage in the transportation and supply of fuel oil, asphalt, and other heavy refined products to our customers in wholesale markets. We have the ability from time to time to obtain various grades of refined products from our refinery customers and blend them to meet the requirements of our other market customers. However, because our refinery customers may choose to manufacture such refined products based on a number of economic and operating factors, we cannot predict the timing of contribution margins related to our blending services.

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CO2 Pipelines

We transport CO_2 on our Free State pipeline for a fee and we lease our Northeast Jackson Dome Pipeline System, or NEJD System, for a fee.

	Free State Pipeline
Product	CO_2
Interest owned	100%
System miles	86
Pipeline diameter	20"
Location	Jackson Dome near Jackson, MS to East Mississippi
Rate Regulated	No

Our Free State pipeline extends from CO_2 source fields near Jackson, Mississippi to crude oil fields in eastern Mississippi. We have a transportation services agreement through 2028 related to our Free State pipeline with a single shipper who has the right to use 100% of that pipeline's capacity.

Our NEJD System transports CO_2 to tertiary crude oil recovery operations in southwest Mississippi. We have leased that pipeline to an affiliate of the shipper on our Free State pipeline through 2028. Our NEJD lessee is responsible for all operations and maintenance on that system and will bear and assume substantially all obligations and liabilities with respect to that system.

Customers

Our supply and logistics 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. During 2016, more than 10% of our consolidated revenues were generated from Shell.

Competition

In our crude oil supply and logistics operations, we compete with other midstream service providers and regional and local 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. Additionally, the shipper on our Free State pipeline is required to use our Free State pipeline for any transportation of CO_2 within a dedicated area.

In our refined products supply and logistics operations, we compete primarily with regional companies. See "Marine Transportation - Competition" for additional discussion of our competitors. Competitive factors in our supply and logistics business include price, relationships with customers, range and quality of services, knowledge of products and markets, availability of trade credit and capabilities of risk management systems.

Geographic Segments

All of our operations are in the U.S.. Additionally, we transport and sell NaHS to customers in South America and Canada. Revenues from customers in foreign countries totaled approximately $8 million, $12 million and $18 million in 2016, 2015 and 2014, respectively. These amounts exclude sales to certain customers where the title to certain NaHS shipments is transferred in the U.S. prior to the NaHS being transported to South America or Canada. The remainder of our revenues was generated from sales to customers in the U.S.

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,

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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, most of which have stable payment histories. The credit risk related to contracts that are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

When we market crude oil, petroleum products and NaHS 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, our largest customers include Shell, Exxon Mobil Corporation, BP PLC, Marathon Petroleum Corporation and Anadarko Petroleum Corporation.

Employees

To carry out our business activities, we employed approximately 1,200 employees at December 31, 2016. None of our employees are represented by labor unions, and we believe that relationships with our employees are good.

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 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.

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, Louisiana, and Wyoming 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 Railroad Commission of Texas. 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.

Our CO_2 pipelines are subject to regulation by the state agencies in the states in which they are located.

Marine Regulations

Maritime Law. 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

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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.

We believe that additional security and environmental related regulations may be imposed on the marine industry in the form of contingency planning requirements. Generally, we endorse the anticipated additional regulations and believe we are currently operating to standards at least equal to anticipated additional regulations.

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 loading and 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.

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 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

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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 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.

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. It has until March 2019 to determine whether any revisions are necessary. 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. 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, or the OPA, is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to oil spills into waters of the U.S., including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on “responsible parties” 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 and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the U.S.. A “responsible party” includes the owner or operator of an onshore facility.

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Noncompliance with the Clean Water Act or the OPA may result in substantial civil and criminal penalties. 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.

NEPA

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.

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. These findings served as a statutory prerequisite for EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA also adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective in July 2010. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA (“UARG v. EPA”), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in UARG v. EPA. In its preliminary guidance, EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., beginning in 2011 for emissions occurring in 2010. Further, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore crude oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of crude oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. As a result of this continued regulatory focus, future GHG regulations of the crude oil and natural gas industry remain a possibility. The EPA has continued to adopt GHG regulations of other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals.

Further, the U.S. Congress has considered various proposals to reduce GHG emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, 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. The net effect of this legislation is to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products

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and natural gas. Our compliance with any future legislation or regulation of GHGs, if it occurs, may result in materially increased compliance and operating costs.

In addition, in December 2015, the United States joined the international community at 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

The effect on our operations of CAA regulations, 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 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, 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 may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. 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.

Safety and Security Regulations

Our crude oil and CO_2 pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation, or DOT, and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration under DOT 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 195. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. 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 are subject to the DOT Integrity Management, or IM, regulations, which require that we perform baseline assessments of all pipelines that could affect a High Consequence Area, or HCA, including certain populated areas and environmentally sensitive areas. After completing a baseline assessment, we continue to assess all pipelines at specified intervals and 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.

The IM regulations required us to prepare 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. The regulations also require periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address pipeline integrity issues. 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.

We have developed a Risk Management Plan required by the EPA 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 refinery 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.

States are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to hazardous liquids pipelines, including crude oil, natural gas and CO_2 pipelines. In practice, states vary

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considerably in their authority and capacity to address pipeline safety. 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.

Available Information

The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. 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

Risks Related to Our Business

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

We have outstanding debt and the ability to incur more debt. As of December 31, 2016, we had approximately $1.3 billion outstanding of senior secured indebtedness and an additional $1.8 billion of senior unsecured indebtedness. We must comply with various affirmative and negative covenants contained in our credit agreement and the indentures 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; access capital markets (debt and equity); or to otherwise fully realize the value of our assets and opportunities because of the need to

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- 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 capital 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 credit agreement or under arrangements that may have terms and conditions at least as restrictive as those contained in our existing credit agreement and the indentures 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 credit facility, that would be an event of default, unless our creditors agreed otherwise, and, under our 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 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 from time to time disrupted and volatile as a result of adverse conditions, including recessionary pressures, bubble-affects 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 impaired for long.

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 could limit or prohibit our ability to execute significant portions of our business plan, such as executing our growth strategy, refinancing our debt and/or optimizing our capital structure.

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 energy infrastructure 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, and are currently contemplating, additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business, 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:

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- 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.

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 energy infrastructure 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 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 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.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our credit facility ($1.3 billion outstanding at December 31, 2016) are 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.

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.

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

The amount of cash we distribute on our units 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, that we receive for our refinery services and the prices at which we sell NaHS;
- 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 will depend on other factors that include:

- the level of capital expenditures 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;
- our ability to borrow under our working capital facility to pay distributions; and

- the amount of cash reserves required in the conduct of our business.

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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, NaHS and caustic soda-volumes, which often depend on actions and commitments by parties beyond our control.

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, NaHS, and caustic soda-volumes. We access commodity volumes through various sources, such as 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 either provide a service for a fee (as in the case of our pipeline, marine vessel and railcar transportation operations) or we can acquire the commodity from our customer and resell it to another party.

Our source of volumes depends on successful exploration and development of additional crude oil and natural gas reserves by others; 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 precipitous decline in crude oil and natural gas prices beginning in late 2014 and continuing into 2016 has forced most producers to significantly 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 sources 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.

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 NaOH 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.

Our sulfur removal operations are dependent upon the supply of caustic soda, the demand for NaHS, and the continuing operations of the refiners for whom we process sour natural gas.

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

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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.

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.

Many of our crude oil and natural gas transportation customers are producers who’s drilling activity levels and spending for transportation have been, and may continue to be, impacted by the current deterioration 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. 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. Additionally, many of our customers' equity values have substantially declined. 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. For example, prices for crude oil and natural gas declined precipitously since late 2014 and have remained depressed in 2016 (which could continue further into 2017). As a

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result, the onshore crude oil rig count in the U.S. has declined from 1,499 rigs at December 31, 2014 to 525 rigs at December 31, 2016.

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

Because we purchase (or otherwise acquire) and sell crude oil, refined petroleum products, NaHS 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, such as our leased railcars, 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, 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 rail 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 to take or not to take certain actions unless some or all of the joint venture 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 include a corporate governance structure that consists of a management committee composed of members, 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 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.

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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 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 and caustic soda to customers in a variety of industries. Many of these customers are in industries that have been 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.

Further, many of our customers were impacted by the weakened economic conditions, and precipitous decline in commodity prices, such as crude oil, natural gas, copper, molybdenum, and aluminum experienced in recent years in a manner that influenced the need for our products and services and their ability to pay us for those products and services. It is uncertain if commodity prices will increase in the near future.

Our sulfur removal operations are dependent on contracts with less than ten refineries and much of its revenue is attributable to a few refineries.

If one or more of our refinery customers that, individually or in the aggregate, generate a material portion of our revenue from sulfur removal services experience financial difficulties or changes in their strategy for sulfur removal such that they do not need our services, our cash flows could be adversely affected. For example, in 2016, approximately 60% of our sulfur removal operations' NaHS by-product volumes were attributable to Phillips 66's refinery located in Westlake, Louisiana. That contract requires Phillips 66 to make available minimum volumes of sour natural gas to us (except during periods of force majeure). Although the current term of that contract extends through 2026, if, for any reason, Phillips 66 does not meet its obligations under that contract for an extended period of time, such non-performance could have a material adverse effect on our profitability and cash flow.

We may not be able to renew our marine transportation time charters and contracts when they expire at favorable rates 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, 2016, our marine transportation segment received approximately 62% 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 38% 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 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"

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

Our operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. In particular, our operations are subject to increasingly stringent environmental protection and safety laws and regulations that restrict our operations, impose consequences of varying degrees for noncompliance, and require us to expend resources in an effort to maintain compliance. 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

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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 December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other 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. These findings served as a statutory prerequisite for EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted two sets of related rules, one which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective in July 2010. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA (“UARG v. EPA”), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in UARG v. EPA. In its preliminary guidance, EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. Further, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore crude oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of crude oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. As a result of this continued regulatory focus, future GHG regulations of the crude oil and natural gas industry remain a possibility. The EPA has continued to adopt GHG regulations of other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals.

Further, the U.S. Congress has considered various proposals to reduce GHG emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, 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. The net effect of this legislation 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 it occurs, 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, or 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

The effect on our operations of CAA regulations, 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 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

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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, 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 may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. 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.

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.

A natural disaster, accident, terrorist attack or other interruption event involving us could result in severe personal injury, property damage and/or environmental damage, which could curtail our operations and 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 and 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 and earthquakes. 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. These areas can be subject to hurricanes.

If one or more facilities that are owned by us or that connect to us is damaged or otherwise affected by severe weather or any other disaster, 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 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.

On September 11, 2001, the U.S. was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future 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.

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

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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.

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 in response to the recent lifting of the crude oil export ban and the Deepwater Horizon drilling rig incident in the U.S. Gulf of Mexico and subsequent crude oil spill.

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.

In December 2015, Congress voted to lift the four decade crude oil export ban. Although the impact of this legislation is not yet determinable, increased exports of U.S. crude oil may lead to increased calls to repeal or modify the Jones Act. Even before lifting the export ban, in the past several years, interest groups have lobbied Congress to repeal or modify the Jones Act to facilitate foreign-flag competition for trades and cargoes currently reserved for U.S. flag vessels under the Jones Act. 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, such as the April 2010 fire and explosion on the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico and the resulting crude oil spill and moratorium on certain drilling activities in the U.S. Gulf of Mexico implemented by the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly, the Minerals Management Service), may adversely affect our customers' operations and, consequently, our operations. Such events 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.

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 our ability to pay cash distributions on our units.

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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.

An easing or lifting of the U.S. crude oil export ban could adversely impact our U.S. Flag Fleet.

In December 2015, Congress voted to lift the four decade crude oil export ban. Although the impact of this legislation on our U.S. Flag fleet's operations is not determinable, the easing of the crude oil export ban could result in reduced coastwise transportation of crude oil, which may have an adverse impact on our U.S. Flag segment.

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 its marine transportation customers on a timely basis.

Risks Related to Our Partnership Structure

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

As of December 31, 2016, we have a number of significant unitholders. For example, certain members of the Davison family (including their affiliates) and management owned approximately 19 million or 15.9% 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.

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 10.5% of our Class A Common Units and 76.9% 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

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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.

Unitholders with registration rights have rights to require underwritten offerings that could limit our ability to raise capital in the public equity market.

Unitholders with registration rights have rights to require us to conduct underwritten offerings of our common units. If we want to access the capital markets (debt and equity), those unitholders’ ability to sell a portion of their common units could satisfy investor’s demand for our common units or may reduce the market price for our common units, thereby reducing the net proceeds we would receive from a sale of newly issued units.

We may issue additional common units without unitholder’s 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 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.

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

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

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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. Distributions from our joint ventures are subject to the discretion of their respective management committees. Further, certain joint ventures' charter documents may vest in their management committees' certain discretion regarding cash distributions. Accordingly, our joint ventures 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 Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. A publicly-traded partnership can lose its status as a partnership for a number of reasons, including not having enough "qualifying income." If the Internal Revenue Service, or IRS, were to treat us as a corporation 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 unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common 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, referred to in this discussion as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships 90% or more of the gross income of which for every taxable year consists of “qualifying income.” If less than 90% of our gross income for any taxable year is “qualifying income” from transportation or processing of natural resources including crude oil, natural gas or products thereof, interest, dividends or similar sources, 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, and do not plan to request, 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, which is currently a maximum of 35% 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 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 common 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 the cash available for distribution to our unitholders.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common 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 the cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships 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, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us and change the character or treatment of portions of our income. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that would adversely affect the tax treatment of certain publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships. Additionally, on January 19, 2017, the U.S. Treasury Department and the IRS issued final regulations regarding qualifying income under Section 7704(d)(1)(E) of the Code . We do not believe the final regulations affect our ability to qualify as a publicly traded partnership.

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 common units.

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

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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 common 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.

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.

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. 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 common units could be more or less than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to unitholders in excess of the total net taxable income unitholders were allocated for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their 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 unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common 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. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisors before investing in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units 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.

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

In addition to federal income taxes, 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 unitholders do not live in any of those jurisdictions. 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, unitholders may be subject to penalties for failure to comply with those requirements. We 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.

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 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 prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.
We prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The Department of the Treasury and the IRS recently adopted the final Treasury regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted. Certain publicly traded partnerships, including us, may but are not required to apply the conventions provided by the Treasury regulations. If the IRS were to successfully challenge this method or new Treasury Regulations were issued, 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 sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.
We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one fiscal year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced. Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we may elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances and the manner in which the election is made and implemented has yet to be determined. If we are unable to have our general partner and our unitholders take such audit

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adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. “Business.” We also have various operating leases for rental of office space, office and field equipment and vehicles. See “Commitments and Off-Balance Sheet Arrangements” in Management’s Discussion and Analysis of Financial Condition and Results of Operations, and Note 19 to our Consolidated Financial Statements in Item 8 for the future minimum rental payments. Such information is incorporated herein by reference.

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 19 to our Consolidated Financial Statements in Item 8.

Item 4. Mine Safety Disclosures

Not applicable.

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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." The following table sets forth, for the periods indicated, the high and low sale prices per common unit and the amount of cash distributions declared and paid per common unit.

	Price Range		Cash
	High	Low	Distributions [1]
2015			
1st Quarter	$48.66	$38.65	$ 0.5950
2nd Quarter	$50.04	$43.44	$ 0.6100
3rd Quarter	$48.15	$27.40	$ 0.6250
4th Quarter	$44.32	$30.79	$ 0.6400
2016			
1st Quarter	$37.35	$19.55	$ 0.6550
2nd Quarter	$40.35	$29.19	$ 0.6725
3rd Quarter	$40.90	$33.03	$ 0.6900
4th Quarter	$38.36	$31.80	$ 0.7000

(1) Cash distributions are shown in the quarter paid and are based on the prior quarter's activities.

At February 24, 2017, we had 117,939,221 Class A common units outstanding. As of December 31, 2016, the closing price of our common units was $36.02 and we had approximately 55,000 record holders of our Class A common units, which include holders who own units through their brokers "in street name."

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 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.

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Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2016, 2015, 2014, 2013 and 2012 (in thousands, except per unit and volume data). The selected financial data should be read in conjunction with our Consolidated Financial Statements and Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,				
	2016 (1)	2015 (1)	2014 (1)	2013 (1)	2012 (1)
Income Statement Data:					
Revenues:					
Offshore pipeline transportation	334,679	140,230	3,296	3,923	5,508
Refinery services	171,503	177,880	207,401	205,985	196,017
Marine transportation	213,021	238,757	229,282	152,542	118,204
Supply and logistics	993,290	1,689,662	3,406,185	3,772,380	3,047,632
Total revenues	$1,712,493	$2,246,529	$3,846,164	$4,134,830	$3,367,361
Equity of earnings of equity investees	$47,944	$54,450	$43,135	$22,675	$14,345
Income (loss) from continuing operations after income taxes	$111,082	$421,585	$106,202	$84,004	$97,337
Net income attributable to Genesis Energy, L.P.	$113,249	$422,528	$106,202	$86,109	$96,319
Net income (loss) attributable to Genesis Energy, L.P. per Common Unit: Basic and Diluted	$1.00	$4.10	$1.18	$1.03	$1.23
Cash distributions declared per Common Unit	$2.7175	$2.4700	$2.2300	$2.0150	$1.8225
Balance Sheet Data (at end of period):					
Current assets	$359,569	$306,316	$355,366	$535,223	$404,034
Total assets (2)	$5,702,592	$5,459,599	$3,210,624	$2,848,528	$2,101,902
Long-term liabilities (2)	$3,321,739	$3,136,712	$1,618,276	$1,304,238	$872,756
Partners' capital:					
Common unitholders	2,130,331	2,029,101	1,229,203	1,097,737	916,495
Noncontrolling interests	(10,281)	(8,350)	—	—	—
Total partners’ capital	$2,120,050	$2,020,751	$1,229,203	$1,097,737	$916,495
Other Data:					
Volumes:					
Offshore crude oil pipeline (barrels per day) (3)	657,105	579,977	446,548	404,787	359,387
Onshore crude oil pipeline (barrels per day)	114,130	144,084	116,225	104,026	92,897
Natural gas transportation volumes (MMBtus/d)	679,862	708,556	—	—	—
CO_2 pipeline (Mcf per day)	97,955	161,409	173,770	190,274	186,479
NaHS sales (DST)	125,766	127,063	150,038	147,297	142,712
NaOH sales (DST)	80,021	86,914	94,693	87,463	77,492
Crude oil and petroleum products sales (barrels per day)	62,484	91,074	99,139	99,651	79,174

(1) Our operating results and financial position have been affected by acquisitions. For additional information regarding our acquisitions and divestitures during 2016, 2015 and 2014, see Note 3 to our Consolidated Financial Statements included in Item 8.

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(2) As relating to new accounting guidance issued by the FASB which we adopted in 2015, our long-term liabilities and total assets for all years presented reflect changes in presentation of debt issuance costs as a direct reduction of related debt liabilities with amortization of debt issuance costs reported as interest expense.

(3) Volume data is inclusive of the SEKCO pipeline.

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

Introduction

We are a growth-oriented master limited partnership formed in Delaware in 1996 and focused on the midstream segment of the crude oil and natural gas industry primarily in the Gulf Coast region of the United States and Wyoming. We have a diverse portfolio of assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, trucks, barges and a product tanker. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises. We currently have two distinct, complimentary types of operations: (i) our refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on a suite of services primarily to refiners (as reported in our refinery services, marine transportation and supply and logistics business segments), and (ii) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, which focus on providing a suite of services primarily to integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties. We conduct our operations and own our operating assets through our subsidiaries and joint ventures.

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

- Overview of 2016 Results
- Acquisitions, Divestitures and Growth Initiatives
- Results of Operations
- Other Consolidated Results
- Financial Measures
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

Overview of 2016 Results

We reported Net Income Attributable to Genesis Energy, L.P. of $113.2 million, or $1.00 per common unit, in 2016 compared to Net Income Attributable to Genesis Energy, L.P. of $422.5 million, or $4.10 per common unit, in 2015. The large decrease was principally due to the $332.4 million non-cash gain we recognized during 2015 resulting from a step up in basis to fair value of our historical interests in certain of our equity investees (CHOPS and SEKCO) as a result of our acquiring the remaining interest in those equity investees when we completed our Enterprise acquisition in July 2015. Exclusive of that 2015 non-cash gain, our net income attributable to Genesis Energy, L.P. of $113.2 million for 2016 would be compared to net income attributable to Genesis Energy, L.P. of $90.1 million for 2015, representing an increase of $23.1 million, or 26%.

That $23.1 million increase in our net income (as well as Segment Margin) was principally due to increases attributable to our offshore pipeline transportation segment (primarily resulting from contributions from our offshore Gulf of Mexico assets we acquired from Enterprise in July 2015) as partially offset by smaller decreases in our other segments. In addition, a portion of the increase is attributable to a non-cash loss on debt extinguishment recognized during 2015 of $19.2 million, as well as a $19.4 million decrease in general and administrative expenses relating to certain third party costs in 2015 (primarily financing, legal and accounting) primarily related to financing the offshore Gulf of Mexico assets we acquired from Enterprise.

The above factors benefiting Net Income Attributable to Genesis Energy, L.P. were partially offset by a $39.4 million increase in interest expense attributable to additional long term debt outstanding and a $72.1 million increase in depreciation and amortization expense. Both of these items are the result of the effect of recently acquired and constructed assets placed in service (and the associated financing of these items), in particular those offshore pipelines and services assets acquired as a result of our Enterprise acquisition.

Cash flow from operating activities was $298.3 million for the 2016 compared to $289.5 million for 2015.

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Available Cash before Reserves (as defined below in "Financial Measures") increased $52.8 million in 2016 to $384.2 million as compared to 2015 Available Cash before Reserves of $331.4 million. See "Financial Measures" below for additional information on Available Cash before Reserves.

Segment Margin (as defined below in "Financial Measures") was $569.6 million in 2016, an increase of $93.0 million, or 20%, as compared to 2015. Consistent with net income, this increase resulted primarily from increases attributable to our offshore pipeline transportation segment partially offset by smaller decreases in our other segments.

Given the continuing challenging operating environment in the energy midstream space, we continue to be pleased with the financial performance of our diversified, yet increasingly integrated, businesses.

Our significant infrastructure projects in the Baton Rouge area were substantially completed in the fourth quarter, and we anticipate completing our repurposing project in Texas in the second quarter of 2017. We would expect to see contributions from these projects to continue to ramp throughout this year and into 2018. At Raceland, we would expect to see volumes start to ramp in mid-2017 as we will be fully capable of receiving and terminaling heavy crudes via rail and medium sour crudes via pipeline.

While we are a bit behind schedule and might arguably have a slightly slower ramp from these major investments, we are very excited and have many reasons to believe that we will ultimately exceed our average base case economics across the projects. The momentum for the rest of this year and into 2018 positions us to do reasonably well even if things don’t improve in late 2017 or 2018. Given our recent and continuing actions to increase liquidity and strengthen our balance sheet, we believe we are well positioned to continue to deliver long term value to all of our stakeholders without ever losing our absolute commitment to safe, reliable and responsible operations.

Our primary objective continues to be to deliver the best value to our unitholders while never wavering from our commitment to safe and responsible operations. A lot has changed, we recognize, in how the market apparently values unit prices for MLPs or other midstream entities over the last year and a half to two years. The move to eliminate our IDR’s over six years ago and our track record of delivering annualized double-digit growth in distributions were historically rewarded. However, we have recently concluded the valuation metrics demanded by the markets have changed in recent times, especially in light of numerous freezes, cuts or total elimination of distributions over the recent energy business cycle by other entities in our space with which we compete commercially and/or for external capital.

We now believe the best way to promote unit price appreciation under current conditions is to exercise strong financial discipline designed primarily to maintain and enhance our financial flexibility across the business cycle. We believe prospectively we can naturally restore our financial flexibility with cash flows from operations. During 2016, we accelerated that process by issuing additional equity and lowering the future growth rate of quarterly distributions. On July 27, 2016, we closed a public offering of 8,000,000 common units generating net proceeds of approximately $298.0 million. As a practical matter, we would have issued such additional equity a year ago at the time of closing our Enterprise acquisition had markets been stronger at that point. This 2016 equity raise instantly improved our liquidity and credit metrics.

We believe our increased liquidity and even stronger balance sheet resulting from such actions should combine to give us the flexibility to continue to pursue acquisitions and/or organic projects that we feel are consistent with delivering long term value to all of our stakeholders. We also believe that our improved credit profile has the potential to significantly lower the future costs of refinancing our public debt when certain tranches become due beginning in 2021 or callable beginning in 2017.

A more detailed discussion of our segment results and other costs is included below in "Results of Operations".

Distribution Increase

In January 2017, we declared our forty-sixth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2016. In February 2017, we paid a distribution of $0.7100 per unit related to the fourth quarter of 2016, representing an 8.4% increase from our distribution of $0.6550 per unit related to the fourth quarter of 2015.

Segment Reporting Change

In the fourth quarter of 2016, we reorganized our operating segments as a result of the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. The results of our onshore pipeline transportation segment, formerly reported under its own segment, are now reported in our supply and logistics segment. This change is consistent with the increasingly integrated nature of our onshore operations.

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As a result of the above changes, we currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, refinery services, marine transportation, and supply and logistics. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

Acquisitions, Divestitures and Growth Initiatives

Houston Area Crude Oil Pipeline and Terminal Infrastructure

We are constructing new, and expanding existing, crude oil pipeline and terminal facilities in Webster, Texas and Texas City, Texas as a result of expanding our crude oil pipeline and terminal infrastructure in the Houston area. We are constructing a new crude oil pipeline that will deliver crude oil received from upstream crude oil pipelines (including CHOPS, which delivers crude oil originating in the deepwater Gulf of Mexico to the Texas City area) to our new Texas City Terminal, which will ultimately connect to our existing 18-inch Webster to Texas City crude oil pipeline. Our new Texas City Terminal will initially include approximately 750,000 barrels of crude oil tankage. As a part of this project, we are also making the necessary upgrades on our existing 18-inch Webster to Texas City crude oil pipeline to reverse the direction of flow. The result of this expanded crude oil infrastructure will allow additional optionality to Houston and Baytown area refineries, including the ExxonMobil Baytown refinery, its largest refinery in the U.S.A., and provide additional delivery outlets for other crude oil pipelines. We expect these assets to become operational in the first half of 2017.

Raceland Terminal and Crude Oil Pipeline

We are constructing a new crude oil terminal and pipeline in Raceland, Louisiana that will be connected to existing midstream infrastructure that will provide further distribution to the Louisiana refining markets. Our new Raceland Terminal will consist of 515,000 barrels of crude oil tankage and unit train unloading facilities capable of unloading up to two unit trains per day. We are constructing a new crude oil pipeline that will deliver crude oil received from the Poseidon system, which currently delivers crude oil originating in the deepwater Gulf of Mexico to the Houma, Louisiana area, to our Raceland Terminal for further distribution. We expect these assets to become fully operational in the first half of 2017.

Inland Marine Barge Transportation Expansion

We ordered 28 new-build barges and 18 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 20 of those barges and 14 of those push boats through December 2016. We expect to take delivery of those remaining vessels periodically into 2017.

Baton Rouge Terminal

We constructed a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that is located near the Port of Greater Baton Rouge and is pipeline-connected to the port's existing deepwater docks on the Mississippi River. We constructed approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we constructed a new pipeline from the terminal that will allow for deliveries to existing Exxon Mobil facilities in the area, as well as connect our previously constructed 17-mile line to the terminal allowing for receipts from the Scenic Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our Baton Rouge Terminal. The Baton Rouge Terminal and related facilities became operational in the fourth quarter of 2016.

Wyoming Crude Oil Pipeline

In the third quarter of 2015, we completed construction of a new 60 mile crude oil pipeline to transport crude oil from new receipt point stations in Campbell County and Converse County, Wyoming to our existing Pronghorn Rail Facility. This new crude oil pipeline has an initial capacity of approximately 30,000 barrels per day and is supplied by truck volumes and third party gathering infrastructure in the Powder River Basin.

We also constructed a new 75 mile pipeline from our Pronghorn Rail Facility to a delivery point at our new Guernsey Station in Platte County, Wyoming. This Pronghorn to Guernsey pipeline has an initial capacity of approximately 45,000 barrels per day and will allow for connectivity to additional downstream pipeline markets at Guernsey, including regional refineries and Cushing, Oklahoma via the Pony Express Pipeline. This pipeline became operational in the first quarter of 2016.

Acquisition of Enterprise Offshore Pipelines and Services Business

In July 2015, we acquired the offshore pipeline and services business of Enterprise Products Partners, L.P. and its affiliates for approximately $1.5 billion, subject to certain adjustments. That business included interests in approximately 2,350 miles of offshore crude oil and natural gas pipelines and six offshore hub platforms that serve some of the most active drilling and development regions in the United States, including deepwater production fields in the Gulf of Mexico offshore Texas,

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Louisiana, Mississippi and Alabama. That acquisition complemented and substantially expanded our existing offshore pipelines segment and was immediately accretive to Net Income, Segment Margin and Available Cash before Reserves.

Results of Operations

In the discussions that follow, we will focus on our revenues, expenses and net income, 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 and Net Income Attributable to Genesis Energy L.P.

Our revenues for the year ended December 31, 2016 decreased $534.0 million, or 24%, from the year ended December 31, 2015. Additionally, our costs and expenses decreased $583.6 million, or 28%, between the two periods. A substantial majority of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products through our supply and logistics segment. The significant decrease in our revenues and costs between the two years is primarily attributable to decreases in market prices for such purchases and sales. In general, we do not expect fluctuations in prices for crude oil and natural gas to materially affect our net income, Available Cash before Reserves or Segment Margin to the same extent they affect our revenues and costs. We have limited our direct commodity price exposure 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 oil would generally have a proportionate impact on both our revenues and our costs, with a disproportionately smaller net impact on our Segment Margin. The same correlation would be true in the case of higher crude oil and petroleum products prices.

As discussed throughout this document, we 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 entitled “Risks Related to Our Business”.

Although prices of crude oil have partially recovered since December 31, 2015, prices were lower on average in the year ending on December 31, 2016 compared to the same period in 2015. The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") decreased 11% to $43.32 per barrel in 2016, as compared to $48.79 per barrel in 2015. 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 from those operations. However, due to the indirect exposure to changes in prices discussed above and in the discussion surrounding our supply and logistics segment, crude oil and petroleum product sales volumes decreased 31% in 2016 as compared to 2015.

We currently have two distinct, complementary types of operations: (i) our onshore-based refinery-centric crude oil and refined petroleum products transportation, supply and logistics, and handling operations, focusing predominantly on refinery-centric customers (as opposed to producers), and (ii) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, focusing on integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large reservoir, long-lived crude oil and natural gas properties. Refiners are the shippers of approximately 80% of the volumes transported on our onshore crude pipelines, and refiners contract for approximately 80% of the use of our inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. The shippers on our offshore pipelines are mostly integrated and large independent energy companies who have developed, and continue to explore for, numerous large-reservoir, long-lived crude oil properties whose production is ideally suited for the vast majority of refineries along the Gulf Coast, unlike the lighter crude oil and condensates produced from numerous onshore shale plays. Those 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 this lower commodity price environment. Given these facts, we do not expect changes in commodity prices to impact our net income, Available Cash before Reserves or Segment Margin in the same manner in which they impact our revenues and costs derived from the purchase and sale of crude oil and petroleum products.

Net Income Attributable to Genesis Energy L.P. decreased $309.3 million in 2016 from 2015. See "Overview of 2016 Results" above for additional discussion, including discussion of the one-time $332.4 million gain recognized in 2015.

Revenues in 2015 decreased $1,599.6 million, or 42%, from 2014. Additionally, our costs and expenses from decreased $1,624.0 million, or 44%, between the two periods. The significant decrease in our revenues and costs between 2015 and 2014 is primarily attributable to the decrease in market prices for crude oil and petroleum products between the two periods. The average closing prices for WTI crude oil on the NYMEX decreased 48% to $48.79 per barrel in 2015, as compared

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to $93.00 per barrel in 2014. Net Income Attributable to Genesis Energy L.P. increased $316.3 million in 2015 to $422.5 million from $106.2 million in 2014. The increase in net income during 2015 was primarily due to an increase in assets placed in service in both the offshore pipeline transportation and marine transportation segments, as well as the $332.4 million non-cash gain we recognized during 2015 resulting from a step up in basis to fair value of our historical interests in certain of our equity investees (CHOPS and SEKCO) as a result of our acquiring the remaining interest in those equity investees when we completed our Enterprise acquisition in July 2015.
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 and amortization, interest 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,		
	2016	2015	2014
	(in thousands)		
Offshore pipeline transportation	336,620	197,723	71,598
Refinery services	79,508	80,246	84,851
Marine transportation	70,079	103,222	86,239
Supply and logistics	83,364	95,394	104,576
Total Segment Margin	$569,571	$476,585	$347,264

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Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

Offshore Pipeline Transportation Segment

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

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Offshore crude oil pipeline revenue	$ 270,454	$ 115,640
Offshore natural gas pipeline revenue	64,225	24,590
Offshore pipeline operating costs, excluding non-cash expenses	(72,009)	(39,685)
Distributions from equity investments	84,321	94,361
Other	(10,371)	2,817
Offshore Pipeline Transportation Segment Margin[1]	$ 336,620	$ 197,723
Volumetric Data 100% basis:		
Crude oil pipelines (average barrels/day unless otherwise noted):		
CHOPS	204,533	172,647
Poseidon	262,829	259,568
Odyssey	106,933	72,958
GOPL [2]	7,468	13,038
Total crude oil offshore pipelines	581,763	518,211
SEKCO [3]	75,342	61,766
Natural gas transportation volumes (MMBtus/d) [4]	679,862	708,556
Volumetric Data net to our ownership interest [5]:		
Crude oil pipelines (average barrels/day unless otherwise noted):		
CHOPS	204,533	124,928
Poseidon	168,211	115,219
Odyssey	31,011	21,158
GOPL [2]	7,468	13,038
Total crude oil offshore pipelines	411,223	274,343
SEKCO [3]	75,342	47,705
Natural gas transportation volumes (MMBtus/d) [4]	398,190	420,464

(1) Offshore Pipeline Transportation Segment Margin includes approximately $84 million and $94 million of distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2016 and 2015, respectively.

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

(3) Though our SEKCO volumes flow through both SEKCO and Poseidon, we include those volumes only once in the table above.

(4) Represents volumes per day from the period the pipelines and related assets were acquired in July 2015.

(5) 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.

Offshore Pipeline Transportation Segment Margin for 2016 increased $139 million, or 70%, from 2015. This increase is primarily due to our Enterprise acquisition, which closed on July 24, 2015. As a result of our Enterprise acquisition, we obtained interests in approximately 2,350 miles of offshore crude oil and natural gas pipelines (including increasing our

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ownership interest in each of the Poseidon, SEKCO, and CHOPS pipelines) and six offshore hub platforms. The operating results of the offshore pipeline assets acquired from Enterprise continue to meet or exceed our expectations, with a net increase in volumes (compared to the year ended December 31, 2015) for the most significant of those offshore crude oil pipelines. In addition, this increase was partially the result of 2016 drilling activity which predominantly occurred near existing infrastructure due to the attractive economics in current pricing conditions. Our extensive pipeline network benefited ratably from this activity.

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31, 2016	2015
Volumes sold (in Dry short tons "DST"):		
NaHS volumes	125,766	127,063
NaOH (caustic soda) volumes	80,021	86,914
Total	205,787	213,977
Revenues (in thousands):		
NaHS revenues	$136,240	$137,825
NaOH (caustic soda) revenues	39,413	42,746
Other revenues	5,012	6,686
Total external segment revenues	$180,665	$187,257
Segment Margin (in thousands)	$79,508	$80,246
Average index price for NaOH per DST (1)	$645	$581

(1) Source: IHS Chemical

Refinery Services Segment Margin for 2016 decreased $0.7 million, or 1%, from 2015. The significant components of this fluctuation were as follows:

- During 2016, our NaHS business was able to realize more benefits from our favorable management of the purchasing (including economies of scale) and utilization of caustic soda in our (and our customers') operations and our logistics management capabilities, as compared to 2015. The fluctuation in NaHS revenues and volumes had a minimal impact on Segment Margin.
- Caustic soda revenues decreased 8% due to a decrease in caustic soda sales volumes. The impact on Segment Margin, compared to 2015, from these reduced caustic soda sales is approximately $2.4 million.
- Average index prices for caustic soda increased to $645 per DST during 2016 compared to $581 per DST during 2015. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. Typically, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because the pricing in many of our sales contracts for NaHS typically includes adjustments for fluctuations in commodity benchmarks (primarily caustic soda), freight, labor, energy costs and government indexes. The frequency at which those adjustments are applied varies by contract, geographic region and supply point. The mix of NaHS sales volumes to which we are able to apply such adjustments may vary due to timing or other factors such as competitive pressures. To the extent we are unable to pass these caustic soda price changes onto our customers, Segment Margin may be impacted. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

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Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 83 barges (74 inland and 9 offshore) with a combined transportation capacity of 2.9 million barrels, 43 push/tow boats (34 inland and 9 offshore), and a 330,000 barrel ocean going tanker, the M/T American Phoenix. Operating results for our marine transportation segment were as follows:

	Year Ended December 31,	
	2016	2015
Revenues (in thousands):		
Inland freight revenues	$88,502	$95,588
Offshore freight revenues	85,594	102,281
Other rebill revenues [1]	38,925	40,888
Total segment revenues	$213,021	$238,757
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$142,942	$135,535
Segment Margin (in thousands)	$70,079	$103,222
Fleet Utilization: [2]		
Inland Barge Utilization	91.4 %	96.7 %
Offshore Barge Utilization	90.5 %	98.7 %

(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 2016 decreased $33.1 million, or 32%, from 2015. The decrease in Segment Margin is primarily due to a combination of lower utilization and lower day rates across our various marine asset classes, excepting the M/T American Phoenix which is under long term contract through September 2020. In our offshore barge fleet, as a number of our units have come off longer term contracts, we have chosen to primarily place them in spot service or short-term (less than a year) service, as we believe the day rates currently being offered by the market are at, or approaching, cyclical lows. In addition, our offshore barge fleet has experienced some volume cannibalization due to excess capacity issues that have arisen as new tankers and barges have been placed into service in anticipation of domestic crude oil volumes that have not yet and may not materialize. Such excess capacity may require a significant amount of time to resolve. In our inland fleet, we saw somewhat of a strengthening in utilization and stabilization in spot day rates towards the end of the year, especially in the black oil, or heavy, intermediate refined products trade, the trade to which we have almost exclusively committed our inland barges.

Supply and Logistics Segment

Our supply and logistics segment utilizes an integrated set of pipelines and terminals, as well as trucks, railcars, 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, rail facilities and CO_2 pipelines operating primarily within the United States Gulf Coast and Rocky Mountain crude oil markets. In addition, we utilize our railcar and trucking fleets that support the purchase and sale of gathered and bulk purchased crude oil, as well as purchased and sold refined products. This fleet includes approximately 200 trucks, 400 trailers, 523 railcars, and 4.6 million barrels of leased and owned storage capacity. Through these assets we offer our customers a full suite of services, including the following:

- facilitating the transportation of crude oil from producers to refineries and from owned and third party terminals to refiners via pipelines;
- transporting CO2 from natural and anthropogenic sources to crude oil fields owned by our customers;
- shipping crude oil and refined products to and from producers and refiners via trucks, railcars and pipelines;

- loading and unloading railcars at our crude-by-rail terminals;
- storing and blending of crude oil and intermediate and finished refined products;

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- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining; and

- 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;

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.

In our refined products marketing operations, we supply primarily fuel oil, asphalt and other heavy refined products to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing "heavier" petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers.

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Operating results for our supply and logistics segment were as follows:

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Gathering, marketing, and logistics revenue	$930,347	$1,612,570
Crude oil and CO_2 pipeline tariffs and revenues from direct financing leases of CO_2 pipelines	58,567	68,265
Payments received under direct financing leases not included in income	6,277	5,685
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(823,780)	(1,479,972)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(94,592)	(116,842)
Other	6,545	5,688
Segment Margin	$83,364	$95,394
Volumetric Data (average barrels/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	33,814	71,906
Jay	14,815	16,828
Mississippi	10,247	15,472
Louisiana (1)	44,295	32,481
Wyoming (2)	10,959	7,397
Onshore crude oil pipelines total	114,130	144,084
CO_2 pipeline (average Mcf/day):		
Free State	97,955	161,409
Crude oil and petroleum products sales:		
Total crude oil and petroleum products sales	62,484	91,074
Rail load/unload volumes (3)	19,691	27,044

(1) Total daily volume for the twelve months ended December 31, 2016, includes 8,997 barrels per day of refined products associated with our new Port of Baton Rouge Terminal pipelines which became operational in the fourth quarter of 2016.
(2) Represents volumes per day from the period the pipeline began operations in August of 2015.
(3) Indicates total barrels for either loading or unloading at all rail facilities.

Segment Margin for our supply and logistics segment decreased $12 million, or 13% , in 2016 as compared to 2015. The most significant components of this change are discussed below.

- With respect to our crude oil and CO_2 pipelines, revenues decreased $9.7 million, or 14%, principally due to a net decrease in throughput volumes of 29,954 barrels per day, or 21%. This was primarily the result of decreased volumes on our Texas pipeline system, particularly delivery volumes to the Texas City refining market. We believe such lower volumes to historical customers will last indefinitely as those customers have made alternative arrangements as a result of our endeavors to expand, extend and repurpose our facilities into longer lived, higher value service. This decrease was partially offset by an increase in volumes on our Louisiana system, as our new Port of Baton Rouge Terminal and Anchorage Tank Farm crude oil and refined products pipelines began flowing volumes during the fourth quarter of 2016. Volume variances on our other onshore pipeline systems had a less significant impact on the decrease in tariff revenues between the respective quarters due to a mix of tariff rates amongst these systems and less significant decreases in volumes. Although volumes on our Free State CO_2 pipeline system decreased, that decrease had a much smaller effect on the contributions to Segment Margin by that pipeline given the "incentive" tariff on this system which results in fluctuations in volumes above a base level on our Free State CO2 pipeline system having a limited impact on Segment Margin.

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- The decrease in our Segment Margin is also partially due to lower demand for our services in our historical back-to-back, or buy/sell, crude oil marketing business associated with aggregating and trucking crude oil from producers' leases to local or regional re-sale points. We have found it difficult to compete with certain participants in the market who are willing to lose money on local gathering because they are attempting to minimize their losses from minimum volume or take-or-pay commitments they previously made in anticipation of new production that has not yet and is unlikely to come online.
- These decreases were partially offset by the improved performance of our now right-sized heavy fuel oil business after reducing volumes and related infrastructure to match new market realities resulting from the general lightening of refineries' crude slates which has resulted in a better supply/demand balance between heavy refined bottoms and domestic coker and asphalt requirements.
- While rail volumes were down compared to 2015, these results had a less significant impact on Segment Margin due to minimum volume commitments on certain of our facilities and our results reflect a ramp up in the fourth quarter of 2016 following the emergence from a refinery turnaround during the third quarter of 2016 by a major refinery customer supported by our Baton Rouge facilities.

Other Costs and Interest

General and administrative expenses

	Year Ended December 31, 2016	2015
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$ 35,841	$ 37,922
Segment	3,264	3,608
Equity-based compensation plan expense	4,575	4,564
Third party costs related to business development activities and growth projects	1,945	18,901
Total general and administrative expenses	$ 45,625	$ 64,995

Total general and administrative expenses decreased $19 million between 2016 and 2015. This decrease was principally due to higher third party costs, primarily financing, legal and accounting, related to business development and growth activities (primarily related to third party costs incurred for business development activities surrounding our Enterprise acquisition) incurred during 2015.

Depreciation and amortization expense

	Year Ended December 31, 2016	2015
	(in thousands)	
Depreciation on fixed assets	$ 193,976	$ 124,207
Amortization of intangible assets	24,310	20,044
Amortization of CO_2 volumetric production payments	3,910	5,889

Total depreciation and amortization expense	$ 222,196	$ 150,140

Total depreciation and amortization expense increased $72 million between 2016 and 2015 primarily as a result of acquiring assets and placing constructed assets' in service during calendar 2015 (including the offshore pipelines and services assets acquired as a result of our Enterprise acquisition) and 2016.

Interest expense, net

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	Year Ended December 31, 2016	2015
	(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$ 41,948	$ 23,072
Interest expense, senior unsecured notes	114,437	87,326
Amortization and write-off of debt issuance costs and premium	10,138	7,266
Capitalized interest	(26,576)	(17,068)
Net interest expense	$ 139,947	$ 100,596

Net interest expense increased $39 million during 2016 primarily due to an increase in our average outstanding indebtedness associated with newly acquired and constructed assets, primarily related to additional debt outstanding as a result of financing our Enterprise acquisition. In July 2015, we issued an additional $750 million of aggregate principal amount of 6.75% senior unsecured notes to fund a portion of the purchase price for our Enterprise acquisition. Capitalized interest costs increased in 2016 due to our growth capital expenditures for projects still under construction when compared to the prior year.

Other Consolidated Results

Net income included an unrealized loss on derivative positions, excluding fair value hedges, of $1.3 million in 2016 and an unrealized gain of $1.0 million in 2015. Those amounts are included in supply and logistics product costs in the Condensed Consolidated Statement of Operations and are not a component of Segment Margin. Net income in 2016 also included a charge of $6.0 million for a non-cash valuation allowance related to the collectibility of certain disputed receivables and claims.

As a result of acquiring the remaining 50% interest in CHOPS and SEKCO in our Enterprise acquisition, we recognized a $332.4 million gain during 2015 relating to the effects of the re-measurement of our pre-acquisition historical interest (prior to that acquisition, we owned 50% of each of CHOPS and SEKCO) at fair value based on accounting guidance involving step acquisitions. A more detailed discussion of our enterprise acquisition is included under "Liquidity and Capital Resources".

2015 also includes a loss of approximately $19.2 million that was recognized in relation to the early retirement of $350 million of 7.875% senior unsecured notes.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

Offshore Pipeline Transportation Segment

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

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	Year Ended December 31,	
	2015	2014
	(in thousands)	
Offshore crude oil pipeline revenue	$ 115,640	$ 3,296
Offshore natural gas pipeline revenue	24,590	—
Offshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(39,685)	(1,271)
Distributions from equity investments	94,361	71,305
Other	2,817	(1,732)
Segment Margin (1)	$ 197,723	$ 71,598
Volumetric Data 100% basis:		
Offshore crude oil pipelines (average barrels/day unless otherwise noted):		
CHOPS	172,647	183,726
Poseidon	259,568	209,647
Odyssey	72,958	46,717
GOPL(2)	13,038	6,458
Total crude oil offshore pipelines	518,211	446,548
SEKCO (3)	61,766	—
Natural gas transportation volumes (MMBtus/d) (4)	708,556	—
Volumetric Data net to our ownership interest (5):		
Offshore crude oil pipelines (average barrels/day unless otherwise noted):		
CHOPS	124,928	91,863
Poseidon	115,219	58,701
Odyssey	21,158	13,548
GOPL(2)	13,038	6,458
Total crude oil offshore pipelines	274,343	170,570
SEKCO (3)	47,705	—
Natural gas transportation volumes (MMBtus/d) (4)	420,464	—

(1) Offshore Pipeline Transportation Segment Margin includes approximately $94 million and $71 million of distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2015 and 2014, respectively.

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

(3) Our SEKCO pipeline was completed in June of 2014. Under the terms of SEKCO's transportation arrangements, its shippers commenced making minimum monthly payments at that time, even though they did not commence throughput of crude until January 2015. As our SEKCO volumes ultimately flow into Poseidon and thus are included within our Poseidon volume statistics, we have excluded them from our total for Offshore crude oil pipelines.

(4) Represents volumes per day from the period the pipelines and related assets were acquired in July 2015.

(5) 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.

Offshore Pipeline Transportation Segment Margin for 2015 increased $126.1 million, or 176%, from 2014. This increase is primarily due to our Enterprise acquisition, which closed in July 2015.

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Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31,	
	2015	2014
Volumes sold (in DST):		
NaHS volumes	127,063	150,038
NaOH (caustic soda) volumes	86,914	94,693
Total	213,977	244,731
Revenues (in thousands):		
NaHS revenues	$137,825	$161,962
NaOH (caustic soda) revenues	42,746	48,610
Other revenues	6,686	7,725
Total external segment revenues	$187,257	$218,297
Segment Margin (in thousands)	$80,246	$84,851
Average index price for NaOH per DST [1]	$581	$589
Raw material and processing costs as % of segment revenues	39 %	43 %

(1) Source: IHS Chemical

Refinery services Segment Margin for 2015 increased $4.6 million, or 5%, from 2014. The significant components of this fluctuation were as follows:

- NaHS revenues decreased 15% primarily due to a decrease in volumes. That decrease primarily resulted from lower total volumes than in 2015 attributable to the bankruptcy of one mining customer, reduced sales to a major customer as it works through an atypical ore seam as a result of a landslide, and increased prior year volumes generated from heavy turn around schedules at certain customers.
- We were able to realize benefits from our favorable management of the purchasing (including economies of scale) and utilization of caustic soda in our (and our customers') operations and our logistics management capabilities, which somewhat offset the effects on Segment Margin of decreased NaHS sales volumes.
- Caustic soda revenues decreased 12% due to a decrease in both caustic soda sales volumes and our sales price for caustic soda. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities.
- Average index prices for caustic soda decreased to $581 per DST during 2015 compared to $589 per DST during 2014. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally changes in caustic soda index prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic soda on our operating costs.

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Marine Transportation Segment

Operating results for our marine transportation segment were as follows:

	Year Ended December 31,	
	2015	2014
Revenues (in thousands):		
Inland freight revenues	$95,588	$92,311
Offshore freight revenues	102,281	82,732
Other rebill revenues [1]	40,888	54,239
Total segment revenues	$238,757	$229,282
Operating Costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$135,535	$143,043
Segment Margin (in thousands)	$103,222	$86,239