GENESIS ENERGY LP
Form 10-K
February 29, 2012
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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, 2011

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	*(I.R.S. Employer*
incorporation or organization)	*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 Exchange Act. Yes x No ¨

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

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 ¨

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. x

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	¨	Smaller reporting company	¨

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

The aggregate market value of the Class A common units held by non-affiliates of the Registrant on June 30, 2011 (the last business day of Registrant s most recently completed second fiscal quarter) was approximately $968,047,470 based on $27.26 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 15, 2012, the Registrant had 71,925,065 Class A 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 or like terms refer to Ge 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 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. 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, o 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, NaHS and 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;*

throughput levels and rates;

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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;

shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, petroleum products, or CO_2 *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, 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 indenture governing our notes, which contain various affirmative and negative covenants;

loss of key personnel;

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;

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;*
- *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 and any other risk factors contained in our Current Reports on Form 8-K 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, or MLP, focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida and in the Gulf of Mexico. Formed in Delaware in 1996, 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, 2011.

We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, barges and trucks. We provide an integrated suite of services to oil producers, refineries, and industrial and commercial enterprises that use NaHS and caustic soda. Our business activities are primarily focused on providing services around and within refinery complexes. Upstream of the refineries, we provide gathering and transportation of crude oil. Within the refineries, we provide services to assist in their sulfur balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for their finished refined products. Substantially all of our revenues are derived from providing services to integrated oil companies, large independent oil and gas or refinery companies, and large 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. Since our acquisition of all of the equity interest in our general partner in December 2010, our outstanding common units and waiver units representing limited partner interest constitute all of the economic equity interest in us.

We manage our businesses through three divisions that constitute our reportable segments Pipeline Transportation, Refinery Services, and Supply and Logistics.

Pipeline Transportation Segment

Overview

We own interests in approximately 1,500 miles of crude oil pipelines (including the pipeline interests we acquired in January 2012) located in the Gulf Coast region of the U.S. We also own two CO_2 pipelines. Our pipelines generate cash flows from fees charged to customers or substantially similar arrangements that otherwise limit our exposure to changes in commodity prices.

Crude Oil Pipelines

We own interests in three onshore crude oil pipeline systems, with approximately 460 miles of pipe located primarily in Alabama, Florida, Mississippi and Texas. The FERC regulates the rates charged by two of our onshore systems to their customers. The rates for the other onshore pipeline are regulated by the Railroad Commission of Texas. We also own interests in various offshore crude oil pipeline systems, with approximately 1,050 miles of pipe and an aggregate design capacity of approximately 1,400 MBbls per day (including the pipeline interests we acquired in January 2012), located offshore in the Gulf of Mexico, a producing region representing approximately 30% of the crude oil production in the United States during each of 2011, 2010 and 2009. By way of example, we own interests in the Poseidon pipeline system (28%) and the Cameron Highway pipeline system (50%), or CHOPS, which is the largest crude oil pipeline (in terms of both length and design capacity) located in the Gulf of Mexico. We acquired our interest in Poseidon, along with certain other pipeline interests, on January 3, 2012. See Recent Developments for information regarding these acquisitions.

CO_2 Pipelines

We own interests in two CO_2 pipelines with approximately 270 miles of pipe. We have leased our NEJD System, comprised of 183 miles of pipe, to an affiliate of a large, independent oil company through 2028. 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. We receive a fixed quarterly payment under the NEJD arrangement. Payments on the Free State Pipeline are dependent on throughput.

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Refinery Services Segment

We primarily (i) provide services to nine refining operations located primarily in Texas, Louisiana, Arkansas and Utah; (ii) operate significant storage and transportation assets in relation to those services; and (iii) sell NaHS and 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 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 four years. NaHS is a by-product derived from our refinery 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 ConocoPhillips, CITGO, Holly 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.

Supply and Logistic Segment

We provide services primarily to Gulf Coast oil and gas producers and refineries 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 portfolio of logistical assets consisting of trucks, terminals, pipelines and barges. We have access to a suite of more than 250 trucks, 350 trailers, and terminals and other tankage with 1.5 million barrels of storage capacity in multiple locations along the Gulf Coast as well as capacity associated with our three common carrier crude oil pipelines. Our marine operations include access to 50 barges with a combined transportation capacity of 1.5 million barrels of heavy refined products, including asphalt, and 22 push/tow boats. Approximately half of our barges would be capable of transporting crude oil if we were to make minor modifications. Usually, our supply and logistics segment experiences limited 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. On a smaller scale, we also provide CO_2 and certain other industrial gases and related services to industrial and commercial enterprises.

Our Objectives and Strategies

Our primary business objectives are to generate stable cash flows that allow us to make quarterly cash distributions to our unitholders and to increase those distributions over time. We plan to achieve those objectives by executing the following business and financial strategies.

Business Strategy

Our primary business strategy is to provide an integrated suite of services to oil and gas producers, refineries and other customers. Successfully executing this strategy should enable us to generate and grow sustainable cash flows. 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 refinery services and supply and logistics segments;
- 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 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:

- *Our businesses encompass a balanced, diversified portfolio of customers, operations and assets*. We operate three business segments and own and operate assets that enable us to provide a number of services to oil and CO_2 producers; refinery owners; industrial and commercial enterprises that use NaHS and caustic soda; and businesses that use CO_2 and other industrial gases. Our business lines complement each other by allowing us to offer an integrated suite of services to common customers across segments.
- *Through our NaHS sales, we have indirect exposure to fast-growing, developing economies outside of the U.S.* We sell NaHS a by-product of our refinery services process to the mining and pulp and paper industries. Copper and other mined materials as well as paper products are sold in the global market.
- *We have lower commodity price risk exposure.* The volumes of crude oil, refined products or intermediate feedstocks that we purchase are either subject to back-to-back sales contracts or are hedged with NYMEX derivatives to limit our exposure to movements in the price of the commodity. Our risk management policy requires that we monitor the effectiveness of the hedges to maintain a value at risk of such hedged inventory that does not exceed $2.5 million. In addition, our service contracts with refiners allow us to adjust our processing rates to maintain a balance between NaHS supply and demand.
- *Our businesses provide consistent consolidated financial performance.* Our consistent and improving financial performance combined with our conservative capital structure has allowed us to increase our distribution for twenty-six consecutive quarters as of our most recent distribution declaration. During this period, twenty-one of those quarterly increases have been 10% or greater year-over-year.
- *Our pipeline transportation and related assets are strategically located.* Our crude oil pipelines are located in the Gulf Coast region and provide our customers access to multiple delivery points. 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.

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 refinery services market can provide us with an advantage when evaluating new opportunities and/or markets.

Our supply and logistics business is operationally flexible. Our portfolio of trucks, 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.

We are financially flexible and have significant liquidity. As of December 31, 2011, we had $356.7 million available under our $775 million credit agreement, including up to $55.4 million available under the $125

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million petroleum products inventory loan sublimit, and $91 million available for letters of credit. Our inventory borrowing base was $69.6 million at December 31, 2011. In January 2012, we borrowed $205.9 million under our credit agreement to acquire interests in several pipeline systems, and in February 2012 we issued $100 million under our existing 7.875% senior unsecured notes indenture for which the net proceeds were used to repay borrowings under our credit agreement (see Recent Developments below for more information).

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 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 senior executive management team is incentivized to create value by increasing cash flows.

Recent Developments

The following is a brief listing of developments since December 31, 2010. Additional information regarding most of these items may be found elsewhere in this report.

Acquisition of Interests in Gulf of Mexico Crude Oil Pipeline Systems

On January 3, 2012, we acquired from Marathon Oil Company, interests in several Gulf of Mexico crude oil pipeline systems, including its 28% interest in the Poseidon pipeline system, its 29% interest in the Odyssey pipeline system, and its 23% interest in the Eugene Island pipeline system. The purchase price was $205.9 million, including crude oil linefill of approximately $26 million (net to us), subject to post-closing adjustments. We funded the purchase price with cash available under our credit facility.

This acquisition complements our existing infrastructure in the Gulf of Mexico and enhances our ability to provide capacity and market optionality to producers for their existing and future developments as well as our refining customers onshore Texas and Louisiana. The Poseidon system is comprised of a 367-mile network of crude oil pipelines, varying in diameter from 16 to 24 inches, with capacity to deliver approximately 400,000 barrels per day of crude oil from developments in the central and western offshore Gulf of Mexico to other pipelines and terminals onshore and offshore Louisiana. Affiliates of Enterprise Products Partners, L.P. and Shell Oil Company each own a 36% interest in Poseidon. An affiliate of Enterprise Products will continue in its role as operator of Poseidon. The Odyssey system is comprised of a 120-mile network of crude oil pipelines, varying in diameter from 12 to 20 inches, with capacity to deliver up to 300,000 barrels per day of 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, and an affiliate of Shell will continue to serve as the operator of Odyssey. The Eugene Island system is comprised of a 183-mile network of crude oil pipelines, the main pipeline of which is 20 inches in diameter, with capacity to deliver approximately 200,000 barrels per day of 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-Texaco, ConocoPhillips and Shell. An affiliate of Shell will continue to serve as the operator of Eugene Island.

Deepwater Gulf of Mexico Pipeline Joint Venture

In December 2011, we entered into a joint venture, forming Southeast Keathley Canyon Pipeline Company LLC, or SEKCO, with Enterprise Products Partners, L.P. to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. SEKCO has entered into crude oil transportation agreements with six Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Apache Deepwater Development LLC, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Plains Offshore Operations, Inc. These producers have dedicated their production from Lucius to the pipeline for the life of the reserves. We expect the pipeline to provide capacity for additional projects in the deepwater Gulf of Mexico. Enterprise Products serves as construction manager and will be the operator of the new pipeline.

The 149-mile, 18-inch diameter pipeline, designed to have a 115,000 barrel per day capacity, would connect the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the recently acquired Poseidon pipeline system described above. The new pipeline is expected to begin service by mid-2014. See additional discussion regarding this project in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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Barge Transportation Business Acquisition

In August 2011, we completed the acquisition of the black oil barge transportation business of Florida Marine Transporters, Inc, or FMT, for $143.5 million (including $2.5 million for fuel inventory and other costs). The transaction added 30 barges (seven of which are leased) and 14 push/tow boats to our marine fleet, which transport heavy refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Intracoastal Canal and western river systems of the United States, including the Red, Ouachita and Mississippi Rivers. We funded the acquisition through a public offering of our common units, whereby we raised approximately $185 million in net proceeds of equity capital.

Wyoming Refinery and Pipeline Assets Acquisition

In November 2011, we acquired a 90% interest in a 3,500 barrel per day refinery located in Converse County, Wyoming, including 300 miles of abandoned 3 6 pipeline. We believe the pipeline can be economically returned to crude oil service as an early delivery service system of production from the emerging Powder River Basin portion of the Niobrara Shale. The purchase price was $20 million, which included $1.3 million for products inventories. We funded the acquisition with cash available under our credit facility.

Other Growth Initiatives

In April 2011, we began construction on a new sour gas processing facility to be installed at a refining complex in Tulsa, Oklahoma. The new facility is expected to result in potential additional capacity of 24,000 DST per year of NaHS. The construction of the facility is expected to be completed in the fourth quarter of 2012. We also acquired three above-ground storage tanks, located in Texas City, Texas and an existing barge dock at the same location, all approximately 1.5 miles from our existing Texas pipeline system. At West Columbia, Texas, we are constructing a truck station and tankage to provide incremental transportation service for the Eagle Ford Shale and other Texas production through our pipeline system to refining markets in the greater Houston/Texas City area. Once the refurbishment, tie-in and all interconnecting pipe is completed, estimated to be in the second quarter of 2012, we will be able to handle approximately 40,000 barrels per day of crude oil through the Texas City terminal.

Common Units Offering

In July 2011, we issued 7,350,000 Class A common units at $26.30 per unit, providing total net proceeds of approximately $185 million, after deducting underwriting discounts and commissions and offering expenses. We used those proceeds to fund the acquisition of the barge transportation business described above and for other corporate purposes, including the repayment of borrowings outstanding under our credit facility.

Credit Facility Amendment

In August 2011, we amended our senior secured revolving credit facility to, among other things, increase the committed amount from $525 million to $775 million and the accordion feature from $125 million to $225 million, giving us the ability to expand the size of the facility up to an aggregate $1 billion for acquisitions or internal growth projects, subject to obtaining lender approval. The amendment also increased from $75 million to $125 million the inventory financing sublimit tranche, which was designed to more efficiently finance crude oil and petroleum products inventory.

Senior Unsecured Notes Issuance

On February 1, 2012, we issued an additional $100 million of aggregate principal amount of senior unsecured notes under our existing 7.875% senior unsecured notes due 2018 indenture. The notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes will be treated as a single class with our outstanding notes and have identical terms and conditions as our outstanding notes for all purposes, including, without limitation, waivers, amendments, redemptions and offers to purchase. The notes mature on December 15, 2018. The net proceeds were used to repay borrowings under our credit agreement.

Twenty-Six Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for twenty-six consecutive quarters. During this period, twenty-one of those quarterly increases have been 10% or greater year-over-year. On February 14, 2012, we paid a quarterly cash distribution of $0.44 (or $1.76 annually) per unit to unitholders of record as of February 1, 2012, an

increase per unit of $0.0125 (or 2.9%) from the distribution in the prior quarter, and an increase of 10% from the distribution in February 2011. 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.

Organizational Structure

The following chart depicts our organizational structure at December 31, 2011.

Description of Segments and Related Assets

We conduct our business through three primary segments: Pipeline Transportation, Refinery Services 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.

Pipeline Transportation

Overview

We own three onshore crude oil common carrier pipelines, interests in several offshore crude oil pipeline systems in the Gulf of Mexico and two CO_2 pipelines. Our core pipeline transportation business is the transportation of crude oil for others for a fee.

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Crude Oil Pipelines

Onshore Crude Oil Pipelines.

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

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

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

	Mississippi System	Jay System	Texas System
Product	Crude oil	Crude Oil	Crude oil
Interest Owned	100%	100%	100%
System miles	235	100	90
Approximate owned and leased tankage storage capacity	247,500 Bbls	230,000 Bbls	220,000 Bbls
Location	Soso, Mississippi to Liberty, Mississippi	Southern Alabama/Florida to Mobile, Alabama	West Columbia, Texas to Webster, Texas Webster, Texas to Texas City, Texas Webster, Texas to Houston, Texas
Rate Regulated	Yes - FERC	Yes - FERC	Yes - TXRRC

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. The system is adjacent to several 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.

Jay System. Our Jay System provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. The system also includes gathering connections to approximately 35 wells, additional oil storage capacity of 20,000 barrels in the field and a delivery connection to a refinery in Alabama.

Texas System. Our Texas System transports crude oil from West Columbia to several delivery points near Houston. The Texas System receives all of its volume from connections to other pipeline carriers. 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.

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Offshore Crude Oil Pipelines.

We own interests in several crude oil pipelines located offshore in the Gulf of Mexico, a producing region representing approximately 30% of the crude oil production in the United States during each of 2011, 2010 and 2009. CHOPS is the largest crude oil pipeline (in terms of both length and design capacity) located in the Gulf of Mexico. In January 2012, we acquired interests in several Gulf of Mexico pipeline systems, including the Poseidon pipeline system, Odyssey pipeline system and Eugene Island pipeline system. The table below reflects our interests in our operating offshore crude oil pipelines.

	CHOPS (1)	**Poseidon**	**Odyssey**	**Eugene Island Pipeline and certain related pipelines**
Product	Crude oil	Crude Oil	Crude Oil	Crude Oil
Interest owned	50%	28%	29%	23%
System miles	380	367	120	183
Location	Gulf of Mexico (primarily offshore of Texas and Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)
FERC Rate Regulated	No	No	No	Yes
In-service date	2004	1996	1998	1983
Approximate Capacity (Bbls/day)	500,000	400,000	300,000	200,000
2011 Throughput (Bbls/day)	120,723	(1)	(1)	(1)

(1) We acquired our interests in CHOPS in November 2010 and our interests in our other offshore pipelines in January 2012.

CHOPS. CHOPS is comprised of 24- and 30- inch diameter pipelines to deliver crude oil from developments 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. Enterprise Products owns the remaining 50% interest in, and operates, the joint venture. The pipeline has significant available capacity to accommodate future growth in the fields from which the production is dedicated to the pipeline as well as to transport volumes from non-dedicated fields both currently in production and to be developed in the future.

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. Affiliates of Enterprise Products and Shell each own a 36% interest in Poseidon. An affiliate of Enterprise Products serves as the operator.

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, and an affiliate of Shell serves as the operator.

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-Texaco, ConocoPhillips and Shell Oil Company. An affiliate of Shell serves as the operator.

SEKCO Pipeline. As described in Recent Developments we entered into a joint venture with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. The pipeline is expected to begin service by mid-2014.

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CO_2 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	NEJD System *
Product	CO_2	CO_2
Interest owned	100%	100%
System miles	86	183
Pipeline diameter	20	20
Location	Jackson Dome near Jackson, Mississippi to East Mississippi	Jackson Dome near Jackson, Mississippi to Donaldsonville, Louisiana
FERC Rate Regulated	No	No

* Subject to fixed payment agreement.

Our Free State Pipeline extends from CO_2 source fields near Jackson, Mississippi to oil fields in eastern Mississippi. We have a twenty-year transportation services agreement (through 2028) related to the transportation of CO_2 on our Free State Pipeline.

Denbury Resources, Inc. has leased the NEJD System from us through 2028. Our NEJD System transports CO_2 to tertiary oil recovery operations in southwest Mississippi.

Customers

Our customers on our Mississippi, Jay and Texas systems are primarily large, energy companies. Denbury has exclusive use of the NEJD Pipeline System and is responsible for all operations and maintenance on that system and will bear and assume all obligations and liabilities with respect to that system. Currently, Denbury also has rights to exclusive use of our Free State Pipeline.

Due to the cost of finding, developing and producing oil properties in the deepwater regions of the Gulf of Mexico, most of our offshore pipeline customers are integrated oil companies and other large producers, and those producers desire to have longer-term arrangements ensuring that their production can access the markets. The anchor customers for CHOPS (including subsidiaries of BP p.l.c., BHP Billiton Group and Chevron Corporation) dedicated their production from approximately 86,400 acres to CHOPS for the life of the reserves underlying such acreage, which dedications included Mad Dog and Atlantis fields as well as other deepwater oil discoveries. Those producer agreements include both firm and, to the extent CHOPS has any remaining capacity, interruptible capacity arrangements. Since its formation, CHOPS has entered into handling arrangements with numerous other producers pursuant to both firm and interruptible capacity arrangements covering deepwater discoveries, including Constitution, Ticonderoga, K2, Shenzi, Front Runner, Cottonwood and Tahiti. Our primary customers for our Poseidon system include BHP Billiton Group, Repsol, Hess and Anadarko Petroleum Corporation primarily from the Shenzi, Allegheny and K2 Complex developments in addition to other deepwater developments. Anadarko, Chevron, ENI, Marathon, Murphy, Statoil and Hess have dedicated their production to Poseidon from the Allegheny, Marco Polo, Droshky, Bald Plate, Front Runner and Lobster fields.

Usually, our offshore 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 pipeline transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to production, refineries 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.

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Our offshore pipelines principal competition includes other crude oil 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, 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 its customer and the amount and term of the reserve commitment by that customer.

Refinery Services

Our refinery services segment (i) provides sulfur-extraction services to nine refining operations primarily located in Texas, Louisiana, Arkansas and Utah, (ii) operates significant storage and transportation assets in relation to our business and (iii) sells NaHS and caustic soda (or NaOH) to large industrial and commercial companies. Our refinery services activities involve processing 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 ConocoPhillips, CITGO, Holly, and Ergon.

Our refinery services footprint includes terminals in the Gulf Coast, Midwest, Montana, Utah, British Columbia and South America. We also utilize railcars, ships, barges and trucks to transport product. In conjunction with our supply and logistics segment, we sell and deliver NaHS and caustic soda to over 100 customers. We believe we are one of the largest marketers of NaHS in North and South America. By minimizing our costs by utilizing our own logistical assets and leased storage sites, we believe we have a competitive advantage over other suppliers of NaHS. Our refinery services contracts are typically long-term in nature. The average remaining life of our refinery services contracts is four years. 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 onsite services utilizing NaHS units at nine refining locations, and we manage sulfur removal by exclusive rights to market NaHS produced at three third-party sites. While some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. These NaHS facilities are located primarily in the southeastern United States.

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 United States, Canada and Mexico. We also export the NaHS to South America for sale to customers for mining in Peru and Chile. No customer of the refinery services segment is responsible for more than ten percent of our consolidated revenues. Approximately 10% of the revenues of the refinery services segment in 2011 resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc. 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.

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

Competition

Our competitors for the supply of NaHS consist primarily of parties who produce NaHS as a by-product of processes involved with agricultural pesticide products, plastic additives and lubricant viscosity. Typically our competitors for the production of NaHS have only one manufacturing location and they do not have the logistical infrastructure that we have to supply customers. Our primary competitor has been AkzoNobel, a chemical manufacturing company that produces NaHS primarily in its pesticide operations.

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 NaOH 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 NaOH from one source.

Supply and Logistics

Through our supply and logistics segment we provide a wide array of services to oil producers and refiners in the Gulf Coast region. In connection with these services, we utilize our portfolio of logistical assets consisting of trucks, terminals, pipelines and barges. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by truck to pipeline injection points and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via truck, railcar or barge, and sell refined products to customers in wholesale markets. For these services, we generate fee-based income and 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 oil and products, minus the associated costs of aggregation and transportation. Our industrial gases supply and logistics operations (i) supply CO_2 to industrial customers, (ii) process raw CO_2 and sell that processed CO_2, and (iii) manufacture and sell syngas, a combination of carbon monoxide and hydrogen.

Our crude oil supply and logistics operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations help to ensure (among other things) a base supply source for our oil pipeline systems and our refinery customers while providing our producer customers with a market outlet for their production. Usually, our supply and logistics segment experiences limited commodity price risk because it involves back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis. Unsold volumes are hedged with NYMEX derivatives to offset the remaining price risk. By utilizing our network of trucks, terminals and pipelines, we are able to provide transportation related services to crude oil producers and refiners as well as enter into back-to-back gathering and marketing arrangements with these same parties. Additionally, our crude oil gathering and marketing expertise and knowledge base, provides us with an ability to capitalize on opportunities that arise from time to time in our market areas. We gather and transport approximately 40,000 barrels per day of crude oil, much of which is produced from large and growing resource basins throughout Texas and the Gulf Coast. Given our network of terminals, we have the ability to store crude oil during periods of contango (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 limit commodity price risk by simultaneously entering into a contract to sell the inventory in a future period, either with a counterparty or in the crude oil futures market. The most substantial component of the costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks.

Our refined products supply and logistics operations are concentrated in the Gulf Coast region, principally Texas and Louisiana. Through our footprint of owned and leased trucks, leased railcars, terminals and barges, we are able to provide Gulf Coast area refineries with transportation services as well as market outlets for their 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 as well as paper mills and utilities. By utilizing our broad network of relationships and logistics assets, including our terminal accessibility, 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. Alternatively, our refinery customers may choose to manufacture such refined products depending on a number of economic and operating factors, and therefore we cannot predict the timing of contribution margins related to our blending services. Our industrial gases supply and logistics operations supply CO_2 to industrial customers currently under five long-term contracts, with an average remaining contract life of five years. Our industrial customers treat the CO_2 and sell it to end users for use in beverage carbonation and chilling and freezing food. Our profitability is determined by the difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our volumetric production payments (also known as VPPs), minus transportation costs. Our existing customer contracts expire between 2012 and 2023. At December 31, 2011, we had approximately 77.2 Bcf of CO_2 remaining under the VPPs. All of our CO_2 supply is currently from our interests our VPPs in fields producing naturally occurring CO_2. We do not expect to renew or replace our CO_2 supply agreements.

Within our supply and logistics business segment, we employ many types of logistically flexible assets. These assets include 250 trucks, 350 trailers, 50 barges with approximately 1.5 million barrels of refined products transportation capacity, 22 push/tow boats, and terminals and other tankage with 1.5 million barrels of leased and owned storage capacity in multiple locations along the Gulf Coast, accessible by truck, rail or barge. Our marine fleet 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 United States, including the Red, Ouachita and Mississippi Rivers. Approximately half of our barges would be capable of transporting crude oil if we were to make minor modifications.

Customers

Our supply and logistics business encompasses hundreds of producers and customers, for which we provide transportation related services, as well as gather from and market to crude oil, refined products and CO_2. During 2011, more than ten percent of our consolidated revenues were generated from Shell. We do not believe that the loss of any one customer for crude oil, petroleum products or CO_2 would have a material adverse effect on us as these products are readily marketable commodities.

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 areas in which they operate. In our refined products supply and logistics operations, we compete primarily with regional companies. 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 United States. Additionally, we transport and sell NaHS to customers in South America and Canada. Revenues from customers in foreign countries totaled approximately $19.7 million, $14.5 million and $9.5 million in 2011, 2010 and 2009, respectively. The remainder of our revenues was generated from sales to customers in the United States.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies, independent refiners, and mining and other industrial companies that purchase NaHS. This energy industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and independent energy companies with stable payment experience. 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 and petroleum products and NaHS, 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 pipeline transportation segment.

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Employees

To carry out our business activities, we employed approximately 740 employees at December 31, 2011. 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 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 the 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 the 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 portion of the rate increase resulting from application of the index is substantially in excess of the 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, or agreements between shippers and the oil pipeline company that the rate is acceptable, or Settlement Rates. The pipeline tariff rates on our Mississippi and Jay Systems are either rates that were grandfathered and have been changed 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 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. Most of the volume on our Texas System is now shipped under joint tariffs with Enterprise Products and Exxon. 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 tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues. Federal regulations also require that all tank barges engaged in the transportation of oil and petroleum in the U.S. be double hulled by 2015. All of our barges are double-hulled.

Jones Act. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States 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 United States-flag vessel operations compared to foreign-flag vessel operations. Further, the USCG and American Bureau of Shipping, or ABS, maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for

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United States-flag operators than for owners of vessels registered under foreign 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 that provides that, upon proclamation by the president of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States 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.

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 require the acquisition of and compliance with permits for regulated activities, limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness areas or areas inhabited by endangered or threatened species, result in capital expenditures to limit or prevent emissions or discharges, and place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup, and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements 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

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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 oil and gas exploration and production wastes as hazardous wastes. 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

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 oil, into navigable waters of the United States, 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 OPA, is the primary federal law for oil spill liability. OPA contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States, 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 United States. A responsible party includes the owner or operator of an onshore facility.

Noncompliance with the Clean Water Act or 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, 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 June 2009, the U.S. House of Representatives passed the American Clean Energy and Security (ACES) Act that, among other things, would have established a cap-and-trade system to regulate greenhouse gas (GHG) emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to again consider a climate change bill in the future. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the

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planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Any laws or regulations that may be adopted to restrict or reduce emissions of GHG emissions could require us to incur increased operating costs, and could have an adverse affect on demand for the refined products produced by our refining customers.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as air pollutants under the Clean Air Act, or the CAA. Thereafter, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because, according to the EPA, emissions of such gases contribute to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA recently adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in May 2010 and it became effective January 2011 and applies to vehicles manufactured in model years 2012 2016. The EPA adopted the stationary source rule in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in October 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

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. Due to the proximity of all of our pipelines to water crossings and populated areas, we have designated all of our pipelines as affecting HCAs. 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 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 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 United States 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. Additionally, these documents are available at the SEC s website (www.sec.gov). Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of them.

Item 1A. Risk Factors

Risks Related to Our Business

We may not be able to fully execute our growth strategy if we are unable to raise debt and equity capital at an affordable price.

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.

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.

The capital and credit markets have been, and may continue to be, disrupted and volatile as a result of adverse conditions. The government response to the disruptions in the financial markets may not adequately restore investor or customer confidence, stabilize such markets, or increase liquidity and the availability of credit to businesses. If the credit markets continue to experience volatility and the availability of funds remains limited, we may experience difficulties in accessing capital for significant growth projects or acquisitions which could adversely affect our strategic plans.

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.

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Economic developments in the United States and worldwide in credit markets and concerns about economic growth could impact our operations and materially reduce our profitability and cash flows.

Continued uncertainty in the credit markets and concerns about local and global economic growth have had a significant adverse impact on global financial markets. If these disruptions, which have occurred over the last several years, reappear, they could negatively impact our cash flows and profitability. Tightening of the credit markets, lower levels of liquidity in many financial markets, and extreme volatility in fixed income, credit and equity markets could limit our access to capital.

Additionally, significant decreases in our operating cash flows could affect the fair value of our long-lived assets and result in impairment charges. At December 31, 2011, we had $325 million of goodwill recorded on our Consolidated Balance Sheet.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our credit facility ($409 million outstanding at December 31, 2011) 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 refinery services, pipeline transportation, and supply and logistics businesses, which fluctuate from quarter to quarter based on, among other things:

- the volumes and prices at which we purchase and sell crude oil, 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 trucking, barge and pipeline transportation services;
- the demand for our terminal storage services;
- 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;

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- 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.

Our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and 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 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, 2011, we had approximately $409 million outstanding of senior secured indebtedness and an additional $250 million of senior unsecured indebtedness.

We must comply with various affirmative and negative covenants contained in our credit facilities. Among other things, these covenants 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; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow 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 facilities, 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 facility or under arrangements which may have terms and conditions at least as restrictive as those contained in our existing credit facilities. 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 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.

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity oil, refined products, NaHS and caustic soda volumes, which often depends 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 oil, refined products, NaHS and caustic soda volumes. We access commodity volumes through two sources, producers and service providers (including gatherers, shippers, marketers and other aggregators). 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 transportation operations) or we can purchase the commodity from our customer and resell it to another party.

Our source of volumes depends on successful exploration and development of additional oil reserves by others; continued demand for our refinery 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 oil and refined products available to us 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. Thus, oil production in our market area may not rise to sufficient levels to allow us to maintain or increase the commodity volumes we are experiencing.

Our ability to access NaHS depends primarily on the demand for our proprietary refinery services 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 refinery services 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 refinery services operations are dependent upon the supply of caustic soda and the demand for NaHS, as well as the operations of the refiners for whom we process sour gas.

Caustic soda is a major component of the proprietary sour gas 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 product from our refinery services 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 sour gas treatment 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. The refineries

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need for our sour gas services is also 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.

Our pipeline transportation operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast.

Any decrease in this demand for crude oil by those refineries or connecting carriers to which we deliver could adversely affect our cash flows. Those refineries need 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.

We face intense competition to obtain oil and refined products commodity volumes.

Our competitors gatherers, transporters, marketers, brokers and other aggregators include independents and major integrated 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 and other 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 producers or refiners to gather, refine, market, transport, store or otherwise handle any of these crude oil 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;
- costs of connection;
- available capacity;
- rates;
- logistical efficiency in all of our operations;
- operational efficiency in our refinery services 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 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 and trucks can result in less demand for our transportation services. 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 or transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

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Fluctuations in commodity prices could adversely affect our business.

Oil, natural gas, other petroleum products, NaHS and caustic soda prices are volatile and could have an adverse effect on our profits and cash flow. Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Price reductions in those commodities can cause material long and short term reductions in the level of throughput, volumes and, in some cases, margins.

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 any of 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 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.

We sell petroleum products to many wholesalers and end-users that are not large companies and are privately-owned operations. While those sales are not large volume sales, they tend to be frequent transactions such that a large balance can develop quickly. 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, and we could continue to experience losses in dealings with other parties.

Additionally, many of our customers were impacted by the weakened economic conditions 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.

Our refinery services division is dependent on contracts with less than fifteen 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 refinery services revenue 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 2011, approximately 65% of our refinery services division NaHS by-product volumes was attributable to ConocoPhillips s refinery located in Westlake, Louisiana. That contract requires Conoco to make available minimum volumes of sour gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if, for any reason, Conoco 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.

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 and other commodities, involves a risk that crude oil and related hydrocarbons or other substances may be released into the environment, which may result in substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption. These costs and liabilities could rise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we are unable to recover such resulting costs through increased rates or insurance reimbursements, our cash flows and distributions to our unitholders could be materially affected.

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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere and other climate changes. In response to such studies, the United States Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. As an alternative to reducing emission of greenhouse gases under cap and trade programs, Congress may consider the implementation of a program to tax the emission of carbon dioxide and other greenhouse gases. In December 2009, the EPA issued an endangerment finding that greenhouse gases may reasonably be anticipated to endanger public health and welfare and are a pollutant to be regulated under the Clean Air Act. In response to these findings, the EPA adopted and finalized, among other things, the motor vehicle rule in May 2010 and it became effective January 2011 and applies to vehicles manufactured in model years 2012-2016. The motor vehicle rule purports to regulate emissions of GHGs from motor vehicles and subjects stationary sources to additional requirements if certain emissions levels are exceeded, including current recordkeeping and future permitting obligations.

Passage of climate change legislation or other regulatory initiatives by Congress or various states of the United States or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases in areas in which we conduct business, could result in changes to the demand for the products we store, transport and sell, and could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

Regulation of the rates, terms and conditions of services and a changing regulatory environment could affect our cash flow.

The FERC regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state 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 flows.

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Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

We may be unable to integrate successfully businesses we acquire. We may incur substantial expenses, delays or other problems in connection with our growth strategy that could negatively impact our results of operations. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment also likely would result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation and amortization expenses. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our business, as discussed above.

The 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.

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

We use financial derivative 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.

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.

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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 United States 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.

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 four members, only two 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 participant and/or the lenders of our joint ventures, 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.

Due to our significant relationships with Denbury adverse developments concerning them could adversely affect us, even if we have not suffered any similar developments.

We have some important relationships with Denbury. It is the operator of our largest CO_2 pipeline and the operator of the fields that produce our CO_2 reserves. We are also parties to agreements with Denbury, including the lease of our NEJD System and the transportation arrangements related to the Free State Pipeline. Denbury ships substantially all of the crude oil that is shipped on our Mississippi System. We could be adversely affected if Denbury experiences any adverse developments or fails to pay us for our services on a timely basis or fails to meet its obligations to us.

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 United States only to vessels operating under the U.S. flag, built in the United States, 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 oil and gas industry in response to the Deepwater Horizon drilling rig incident in the U.S. Gulf of Mexico and subsequent 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 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 United States coastwise trade and significantly increase competition with our fleet, which could have an adverse effect on our business. Events within the oil and 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 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 oil and gas industry, including us, to additional regulatory scrutiny and result in additional regulations and restrictions adversely affecting the U.S. oil and 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.

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 United States and manned by U.S. crews. This has made it less expensive for certain areas of the United States 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 United States and transporting them on U.S. flag vessels, demand for our vessels and the charter rates for them could decrease.

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, 2011, we have a number of significant unitholders. For example, Corbin J. Robertson, Jr., together with members of his family and certain of their affiliates, or the Robertson Group, certain members of the Davison family (including their affiliates) and management owned approximately 25 million or 35% of our common units. We also have other unitholders that may 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, the sale could reduce the market price of common units. In connection with converting our 2% general partner interest into a non-economic interest and permanently eliminating the incentive distribution rights held by our general partner in December 2010, which we refer to as our

IDR Restructuring, and certain other transactions, we have put in place a resale shelf registration statement, which allows those unit holders 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.

The Robertson Group exerts significant influence over us and may have conflicts of interest with us and may be permitted to favor its interests to the detriment of our other unitholders.

The Robertson Group owns approximately 12% of our Class A Units and 74% of our Class B Units. Consequently, the Robertson Group is able to exert substantial influence over us, including electing at least a majority of the members of our board of directors and controlling most matters requiring board approval, such as business strategies, mergers, business combinations, acquisitions or dispositions of significant assets, issuances of common stock, incurrence of debt or other financing and the payment of dividends. In addition, the existence of a controlling group 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 units. Further, directors elected by the Robertson Group who are also directors and/or officers of other entities may have a fiduciary duty to make decisions based on the best interests of the equity holders of such other entities.

The Robertson Group owns, controls and has an interest in a wide array of companies, some of which may compete directly or indirectly with us. As a result, that group s interests may not always be consistent with our interests or the interests of our other unitholders. The Robertson Group may also pursue acquisitions or business opportunities that may be complementary to our business. Our organizational documents allow the Robertson Group 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 members of the Robertson Group, 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 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 Units have the right to elect our board of directors. Holders of our Class B Units may transfer such units to a third party without the consent of the unitholders. The new holders of our Class B 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.

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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, 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.

The interruption of distributions to us from our subsidiaries and joint ventures may 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, other than CHOPS are subject to the discretion of their respective management committees. Further, each joint venture s charter documents typically vest in its management committee sole discretion regarding 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

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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.

Your 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. You could be liable for any and all of our obligations as if you 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

- your 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.

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.

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.

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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. The current Administration and members of Congress have recently considered substantive changes to the existing U.S. federal income tax laws that would adversely affect the tax treatment of certain publicly traded partnerships. 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 flow.

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 United States 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. 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

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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-1 s) 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.

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 Stockholder Matters and Issuer Purchases of Equity Securities

Our Class A common units are listed on the New York Stock Exchange (NYSE) under the symbol GEL . Until September 15, 2010, our common units were listed on the NYSE Amex LLC. 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)
2011			
Fourth Quarter	$ 28.33	$ 21.82	$ 0.4275
Third Quarter	$ 28.12	$ 20.85	$ 0.4150
Second Quarter	$ 29.08	$ 25.35	$ 0.4075
First Quarter	$ 29.83	$ 25.03	$ 0.4000
2010			
Fourth Quarter	$ 27.24	$ 22.77	$ 0.3875
Third Quarter	$ 23.52	$ 18.43	$ 0.3750
Second Quarter	$ 20.64	$ 15.47	$ 0.3675
First Quarter	$ 21.67	$ 17.94	$ 0.3600

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

At February 22, 2012, we had 71,925,065 Class A common units outstanding. As of December 31, 2011, the closing price of our common units was $28.04 and we had approximately 30,000 record holders of our common units, which include holders who own units through their brokers in street name.

After holders of our Waiver Units receive a minimal preferential quarterly distribution, we distribute all of our available cash, as defined in our partnership agreement, within 45 days after the end of each quarter to unitholders of record. Available cash consists generally of all of our cash receipts less cash disbursements, adjusted for net changes to cash reserves. Cash reserves are the amounts deemed necessary or appropriate, in the reasonable discretion of our general partner, to provide for the proper conduct of our business or to comply with applicable law, any of our debt instruments or other agreements. 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 General Partner and Note 10 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, 2011, 2010, 2009, 2008, and 2007 *(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.

	$000000000	$000000000	$000000000	$000000000	$000000000
			Year Ended December 31,		
	2011 (1)	2010 (1)	2009	2008 (1)	2007 (1)
Income Statement Data:					
Revenues:					
Supply and logistics	$ 2,825,768	$ 1,894,612	$ 1,243,044	$ 1,870,063	$ 1,110,347
Refinery services	201,711	151,060	141,365	225,374	62,095
Pipeline transportation	62,190	55,652	50,951	46,247	27,211
Total revenues	$ 3,089,669	$ 2,101,324	$ 1,435,360	$ 2,141,684	$ 1,199,653
Net income (loss) (2)	$ 51,249	$ (50,541)	$ 6,178	$ 25,825	$ (13,551)
Net income (loss) attributable to Genesis Energy, L.P. (2)	$ 51,249	$ (48,459)	$ 8,063	$ 26,089	$ (13,550)
Net income (loss) available to Common Unitholders	$ 51,249	$ 19,929	$ 20,186	$ 23,006	$ (13,608)
Net income (loss) attributable to Genesis Energy, L.P. per Common Unit: Basic and Diluted	$ 0.75	$ 0.49	$ 0.51	$ 0.59	$ (0.66)
Cash distributions declared per Common Unit	$ 1.6500	$ 1.4900	$ 1.3650	$ 1.2225	$ 0.9300
Balance Sheet Data (at end of period):					
Current assets	$ 376,104	$ 252,538	$ 189,244	$ 168,127	$ 214,240
Total assets	1,730,844	1,506,735	1,148,127	1,178,674	908,523
Long-term liabilities	688,778	630,757	387,766	394,940	101,351
Partners capital:					
Genesis Energy, L.P.	792,638	669,264	595,877	632,658	631,804
Noncontrolling interests			23,056	24,804	570
Total partners capital	792,638	669,264	618,933	657,462	632,374
Other Data:					
Maintenance capital expenditures (3)	4,237	2,856	4,426	4,454	3,840
Volumes continuing operations:					
Onshore crude oil pipeline (barrels per day)	82,712	67,931	60,262	64,111	59,335
Offshore crude oil pipeline (barrels per day) (4)	120,723	149,270			
CO_2 pipeline (Mcf per day) (5)	169,962	167,619	154,271	160,220	
NaHS sales (DST) (6)	147,670	145,213	107,311	162,210	69,853
NaOH sales (DST) (6)	99,702	93,283	88,959	68,647	20,946

(1) Our operating results and financial position have been affected by acquisitions, most notably the acquisition of the black oil barge business of Florida Marine Transporters, Inc. in August 2011, the 50% equity interest acquisition in CHOPS in November 2010, the acquisition of the remaining 51% ownership interest in DG Marine in July 2010, the Grifco acquisition in July 2008 and the Davison acquisition in July 2007. The results of these operations are included in our financial results prospectively from the acquisition date. For additional information regarding our acquisitions during 2011 and 2010, see Note 3 to our Consolidated Financial Statements included in Item 8.

(2)

Includes executive compensation expense related to Series B and Class B awards borne entirely by our general partner in the amounts of $76.9 million for 2010, $14.1 million for 2009 and $3.4 million for 2007 (see Note 15 to our Consolidated Financial Statements in Item 8).

(3) Maintenance capital expenditures are capital expenditures to replace or enhance partially or fully depreciated assets to sustain the existing operating capacity or efficiency of our assets and extend their useful lives.

(4) Includes barrels per day for CHOPS for the period we owned the pipeline in 2010.

(5) Volume per day for the period we owned the Free State CO_2 pipeline in 2008.

(6) Volumes relate to operations acquired in July 2007.

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

Introduction

We are a growth-oriented MLP focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida and in the Gulf of Mexico. We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, barges and trucks. We provide an integrated suite of services to oil producers, refineries, and industrial and commercial enterprises that use NaHS and caustic soda. Our business activities are primarily focused on providing services around and within refinery complexes. 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. Since our acquisition of all of the equity interest in our general partner in December 2010 (which we refer to as the incentive distribution rights (IDR) Restructuring), our outstanding common units and waiver units representing limited partner interest constitute all of the economic equity interest in us.

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

- Significant Events
- Financial Measures
- Overview of 2011 Results
- Results of Operations
- Other Consolidated Results
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

Significant Events

Acquisition of Interests in Gulf of Mexico Crude Oil Pipeline Systems

On January 3, 2012, we acquired from Marathon oil Company, interests in several Gulf of Mexico crude oil pipeline systems, including its 28% interest in the Poseidon pipeline system, its 29% interest in the Odyssey pipeline system, and its 23% interest in the Eugene Island pipeline system. The purchase price was $205.9 million, including crude oil linefill of approximately $26 million (net to us), subject to post-closing adjustments. We funded the purchase price with cash available under our credit facility.

This acquisition complements our existing infrastructure in the Gulf of Mexico and enhances our ability to provide capacity and market optionality to producers for their existing and future developments as well as our refining customers onshore Texas and Louisiana. The Poseidon system is comprised of a 367-mile network of crude oil pipelines, varying in diameter from 16 to 24 inches, with capacity to deliver approximately 400,000 barrels per day of crude oil from developments in the central and western offshore Gulf of Mexico to other pipelines and terminals onshore and offshore Louisiana. Affiliates of Enterprise Products and Shell each own a 36% interest in Poseidon. An affiliate of Enterprise Products will continue in its role as operator of Poseidon. The Odyssey system is comprised of a 120-mile network of crude oil pipelines, varying in diameter from 12 to 20 inches, with capacity to deliver up to 300,000 barrels per day of 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, and an affiliate of Shell will continue to serve as the operator of Odyssey. The Eugene Island system is comprised of a 183-mile network of crude oil pipelines, the main pipeline of which is 20 inches in diameter, with capacity to deliver approximately 200,000 barrels per day of 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-Texaco, ConocoPhillips and Shell. An affiliate of Shell will continue to serve as the operator of Eugene Island.

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Deepwater Gulf of Mexico Pipeline Joint Venture

In December 2011, we entered into a joint venture, forming SEKCO with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. SEKCO has entered into crude oil transportation agreements with six Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Apache Deepwater Development LLC, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Plains Offshore Operations, Inc. These producers have dedicated their production from Lucius to the pipeline for the life of the reserves. We expect the pipeline to provide capacity for additional projects in the deepwater Gulf of Mexico. Enterprise Products serves as construction manager and will be the operator of the new pipeline.

The 149-mile, 18-inch diameter pipeline, designed to have a 115,000 barrel per day capacity, would connect the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the recently acquired Poseidon pipeline system described above. The new pipeline is expected to begin service by mid-2014.

Barge Transportation Business Acquisition

In August 2011, we completed the acquisition of the black oil barge transportation business of FMT for $143.5 million (including $2.5 million for fuel inventory and other costs). The transaction added 30 barges (seven of which are leased) and 14 push/tow boats to our marine fleet, which transport heavy refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Intracoastal Canal and western river systems of the United States, including the Red, Ouachita and Mississippi Rivers. We funded the acquisition through a public offering of our common units, whereby we raised approximately $185 million in net proceeds of equity capital.

Wyoming Refinery and Pipeline Assets Acquisition

In November 2011, we acquired a 90% interest in a 3,500 barrel per day refinery located in Converse County, Wyoming, including 300 miles of abandoned 3 6 pipeline. We believe the pipeline can be economically returned to crude oil service as an early delivery service system of production from the emerging Powder River Basin portion of the Niobrara Shale. The purchase price was $20 million, which included $1.3 million for products inventories. We funded the acquisition with cash available under our credit facility.

Other Growth Initiatives

In April 2011, we began construction on a new sour gas processing facility to be installed at a refining complex in Tulsa, Oklahoma. The new facility is expected to result in potential additional capacity of 24,000 DST per year of NaHS. The construction of the facility is expected to be completed in the fourth quarter of 2012. We also acquired three above-ground storage tanks, located in Texas City, Texas and an existing barge dock at the same location, all approximately 1.5 miles from our existing Texas pipeline system. At West Columbia, Texas, we are constructing a truck station and tankage to provide incremental transportation service for the Eagle Ford Shale and other Texas production through our pipeline system to refining markets in the greater Houston/Texas City area. Once the refurbishment, tie-in and all interconnecting pipe is completed, estimated to be in the second quarter of 2012, we will be able to handle approximately 40,000 barrels per day of crude oil through the Texas City terminal.

Common Units Offering

In July 2011, we issued 7,350,000 Class A common units at $26.30 per unit, providing total net proceeds of approximately $185 million, after deducting underwriting discounts and commissions and offering expenses. We used the proceeds to fund the acquisition of the barge transportation business described above and for other corporate purposes, including the repayment of borrowings outstanding under our credit facility.

Credit Facility Amendment

In August 2011, we amended our senior secured revolving credit facility to, among other things, increase the committed amount from $525 million to $775 million and the accordion feature from $125 million to $225 million, giving us the ability to expand the size of the facility up to an aggregate $1 billion for acquisitions or internal growth projects, subject to obtaining lender approval. The amendment also increased from $75 million to $125 million the inventory sublimit tranche, which was designed to more efficiently finance crude oil and petroleum products inventory.

Senior Unsecured Notes Issuance

On February 1, 2012, we issued an additional $100 million of aggregate principal amount of senior unsecured notes under our existing 7.875% senior unsecured notes due 2018 indenture. The notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes will be treated as a single class with our outstanding notes and have identical terms and conditions as our outstanding notes for all purposes, including, without limitation, waivers, amendments, redemptions and offers to purchase. The notes mature on December 15, 2018. The net proceeds were used to repay borrowings under our credit agreement.

Distribution Increase

On January 11, 2012, we declared our twenty-sixth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2011. During this period, twenty-one of those quarterly increases have been 10% or greater year-over-year. This distribution of $0.44 per unit (paid in February 2012) represents a 10% increase from our distribution of $0.40 per unit for the fourth quarter of 2010.

Financial Measures

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. Those two measures are Segment Margin and Available Cash before Reserves.

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes where relevant, and maintenance capital investment. A reconciliation of Segment Margin to income before income taxes is included in our segment disclosures in Note 12 to our Consolidated Financial Statements in Item 8.

Available Cash before Reserves (a non-GAAP measure) is net income as adjusted for specific items, the most significant of which are the addition of non-cash expenses (such as depreciation and amortization), the substitution of distributable cash generated by our equity investees in lieu of our equity income attributable to our equity investees, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) and unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows, the elimination of earnings of DG Marine in excess of distributable cash until July 2010 when DG Marine s credit facility was repaid, and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows.

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Available Cash before Reserves for the years ended December 31, 2011, 2010 and 2009 was as follows:

	Year Ended December 31, 2011	2010	2009
		(in thousands)	
Net income (loss) attributable to Genesis Energy, L.P.	$ 51,249	$ (48,459)	$ 8,063
Depreciation, amortization and impairment	61,926	53,557	67,586
Cash received from direct financing leases not included in income	4,615	4,203	3,758
Cash effects of sales of certain assets	6,688	1,158	873
Effects of distributable cash generated by equity method investees not included in income	16,681	2,285	(495)
Cash effects of equity-based compensation plans	(2,394)	(1,350)	(121)
Non-cash tax (benefit) expense	(2,075)	1,337	1,914
Earnings of DG Marine in excess of distributable cash		(848)	(4,475)
Non-cash equity-based compensation expense	311	82,979	18,512
Expenses related to acquiring or constructing assets that provide new sources of cash flow	4,376	11,260	
Unrealized loss on derivative transactions excluding fair value hedges	724	59	1,298
Other items, net	335	(1,826)	(1,501)
Maintenance capital expenditures	(4,237)	(2,856)	(4,426)
Available Cash before Reserves	$ 138,199	$ 101,499	$ 90,986

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flows from operating activities (the most comparable GAAP measure) for the each of the periods in the table above in Liquidity and Capital Resources Non-GAAP Reconciliation below. For the years ended December 31, 2011, 2010 and 2009, net cash provided by operating activities was $58.3 million, $90.5 million and $90.1 million, respectively. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see Liquidity and Capital Resources Non-GAAP Reconciliation below.

Overview of 2011 Results

We reported net income of $51.2 million, or $0.75 per common unit, in 2011 compared to a net loss (attributable to us) of $48.5 million in 2010. The loss in 2010 included $76.9 million of non-cash compensation charges which were borne entirely by our general partner. As a result, net income attributable to our common units for 2010 was $19.9 million, or $0.49 per common unit.

Segment Margin was $202.5 million in 2011, an increase of $52.9 million, or 35%, as compared to 2010. This increase resulted from improvements in Segment Margin of approximately 41%, 19% and 56% in our pipeline transportation, refinery services and supply and logistics segments, respectively. The contribution to Segment Margin from our investment in CHOPS for a full twelve months, combined with increased throughput on our onshore pipelines, were the primary factors increasing pipeline transportation Segment Margin. Our refinery services Segment Margin increased as a result of several factors, including operating efficiencies realized at several of our sour gas processing facilities as well as our favorable management of the acquisition and utilization of caustic soda in our operations. Our supply and logistics segment benefited from increased volumes, operating efficiencies and modifications to our existing crude oil and petroleum products commercial arrangements. Segment Margin generated by the operations of the recently acquired black oil barge transportation business also increased the results of our supply and logistics segment.

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Results of Operations

Revenues, Costs and Expenses and Net Income

Our revenues for the year ended December 31, 2011 increased $988.3 million, or 47% from 2010. Additionally, our costs and expenses increased $878.5 million or 41% between the two periods. The majority of our revenues and our costs are derived from the purchase and sale of crude oil and petroleum products. The significant increase in our revenues and costs between 2011 and 2010 is primarily attributable to the fluctuations in the market prices for crude oil and petroleum products. For example, prices for West Texas Intermediate, or WTI, crude oil on the New York Mercantile Exchange averaged $95.12 per barrel in 2011, as compared to $79.53 per barrel in 2010, or a 20% increase. Net income (attributable to us) increased $99.7 million in 2011 to $51.2 million from a net loss (attributable to us) of $48.5 million in 2010. The increase in net income during 2011 primarily reflects the non-cash charges of $76.9 million we recorded in 2010 for executive and equity-based compensation borne by our general partner. In addition, segment results for all of our segments improved during 2011 as volumes increased. Our increased segment results were partially offset by increases in depreciation and amortization expense and interest costs.

Revenues in 2010 increased $666 million or 46% from 2009. Excluding non-cash charges for executive compensation borne by our general partner, our costs and expenses increased $652 million, or 47%, between the periods. The increase in revenues and cost expenses primarily reflects a 29% increase in the per barrel price of WTI crude oil in 2010 as compared to 2009. Also contributing to the impact was an increase in volumes in all of our segments, particularly in our supply and logistics segment where volumes increased by almost 30% between 2010 and 2009. Net income (attributable to us) declined $56.5 million in 2010 from 2009 primarily reflecting an increase in non-cash charges of $62.8 million included in general and administrative expenses related to executive and equity-based compensation

Included below is additional detailed discussion of the results of our operations focusing on Segment Margin and other costs including general and administrative expense, depreciation, amortization and impairment, 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,		
	2011	2010	2009
		(in thousands)	
Pipeline transportation	$ 67,908	$ 48,305	$ 42,162
Refinery services	74,618	62,923	51,844
Supply and logistics	59,975	38,336	40,484
Total Segment Margin	$ 202,501	$ 149,564	$ 134,490

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Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Pipeline Transportation Segment

Operating results and volumetric data for our pipeline transportation segment were as follows:

	Year Ended December 31, 2011	2010
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases onshore crude oil pipelines	$ 24,870	$ 20,351
CO2 tariffs and revenues from direct financing leases of CO_2 pipelines	26,334	26,413
Sales of crude oil pipeline loss allowance volumes	7,756	5,519
Pro-rata share of distributable cash generated by Cameron Highway	17,670	2,384
Pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(14,120)	(11,522)
Payments received under direct financing leases not included in income	4,615	4,202
Other	783	958
Segment Margin	$ 67,908	$ 48,305

In 2011, we owned three onshore common carrier crude oil pipeline systems, a 50% interest in CHOPS and two CO_2 pipelines. Our core pipeline transportation business is the transportation of crude oil for others for a fee. We refer to these pipelines as our Mississippi System, Jay System, Texas System, Free State Pipeline and CHOPS. Volumes shipped on these systems for the last two years are as follows (barrels or Mcf per day):

Pipeline System	2011	2010
Mississippi-Bbls/day	20,629	23,537
Jay Bbls/day	16,900	15,646
Texas Bbls/day	45,183	28,748
Free State Mcf/day	169,962	167,619
CHOPS Bbls/day	120,723	149,270[1]

(1) Daily average since our acquisition date in November 2010.

During 2011, crude oil volumes shipped on our Texas System increased 16,435 barrels per day (or 57%) primarily as a result of increased demand by one of the refiners connected to our system with capabilities for processing light crude oil such as that being produced in the Eagle Ford Shale area. On CHOPS, crude oil volumes declined 28,547 barrels per day (or 19%) during 2011 due to planned improvements to offshore field facilities by producers with fields connected to CHOPS that were performed in the last three quarters of 2011. These field improvements by the producers are expected to increase volumes on CHOPS in the future.

We deliver CO_2 on our Free State Pipeline for use in tertiary recovery operations in east Mississippi. Denbury currently has rights to exclusive use of the pipeline and is required to use the pipeline to supply CO_2 to its current and certain of its other tertiary operations in east Mississippi. We have a twenty-year financing lease (through 2028) with Denbury for their use of our NEJD System. Denbury makes fixed quarterly base rent payments to us of $5.2 million per quarter or approximately $20.7 million per year.

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Pipeline transportation Segment Margin increased $19.6 million in 2011 as compared to 2010. The primary factors in this increase are summarized below.

Our share of the distributable cash generated by CHOPS increased $15.3 million during 2011 as a result of owning our 50% interest for a full year in 2011. Despite the increase, planned improvements by producers of offshore field facilities from the second quarter of 2011 through the fourth quarter of 2011 negatively impacted our revenue generating volumes during the year.

Crude oil tariff revenues of onshore crude oil pipelines increased $4.5 million reflecting increased volumes of 14,781 barrels per day transported on our onshore crude oil pipelines as described above.

An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $2.2 million related to the significant increase (an average of $16 per barrel) in crude oil prices.

Pipeline operating costs, excluding non-cash charges increased $2.6 million, primarily due to increased insurance costs (related to our investment in CHOPS) and employee compensation and related benefit costs.

As is common in the industry, our onshore crude oil tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The increase in market prices for crude oil increased the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices increased approximately $16 per barrel between the two periods. Based on historic volumes, a change in crude oil market prices of $10 per barrel has the effect of decreasing or increasing our pipeline loss allowance revenues by approximately $0.1 million per month.

Refinery Services Segment

Operating results from our refinery services segment were as follows (in thousands, except average index price):

	Year Ended December 31, 2011	2010
Volumes sold:		
NaHS volumes (Dry short tons DST)	147,670	145,213
NaOH (caustic soda) volumes (DST)	99,702	93,283
Total	247,372	238,496
Revenues (in thousands):		
NaHS revenues	$ 152,422	$ 119,688
NaOH (caustic soda) revenues	47,339	29,578
Other revenues	10,633	9,190
Total external segment revenues	$ 210,394	$ 158,456
Segment Margin	$ 74,618	$ 62,923
Average index price for NaOH per DST (1)	$ 513	$ 353
Raw material and processing costs as % of segment revenues	48%	37%

(1) Source: Harriman Chemsult Ltd.

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Refinery services Segment Margin for the year ended 2011 increased $11.7 million, or 19% from 2010. The significant components of this change were as follows:

Revenues increased primarily as a function of the increase in the average index price for caustic soda. Average index prices of caustic soda increased to an average of $513 per DST during 2011 as compared to $353 per DST in 2010. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to mitigate the effects of changes in index prices for caustic on our operating costs.

The pricing in our sales contracts for NaHS includes adjustments for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments are applied varies by contract, geographic region and supply point. Our raw material costs related to NaHS increased correspondingly to the rise in the average index price for caustic soda, although operating efficiencies at several of our sour gas processing facilities as well as our favorable management of the acquisition and utilization of caustic soda in our operations and our logistics management, as discussed below, helped offset these costs.

NaHS sales volumes during 2011 increased 2% from 2010. Although there have been decreased levels of activity by our pulp and paper customers, the return of industrialization and urbanization in the world s emerging economies has increased the demand for products requiring copper and molybdenum. These trends have led to a noticeable increase in NaHS demand from our mining customers primarily in North America in 2011 as compared to 2010.

Caustic soda sales volumes increased 7%. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. Consequently, we are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively purchase caustic soda for re-sale to third parties. Our ability to purchase caustic soda volumes is currently sufficient to meet the demands of our refinery services operations and third-party sales.

Supply and Logistics Segment

Our supply and logistics segment is focused on utilizing our knowledge of the crude oil and petroleum markets and our logistics capabilities from our terminals, trucks and barges to provide suppliers and customers with a full suite of services. These services include:

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

supplying petroleum products (primarily fuel oil, asphalt, and other heavy refined products) to wholesale markets and some end-users such as paper mills and utilities;

purchasing products from refiners, transporting the products to one of our terminals and blending the products to a quality that meets the requirements of our customers;

utilizing our fleet of trucks and trailers and barges to take advantage of logistical opportunities primarily in the Gulf Coast states and inland waterways; and industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture.

We also 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.

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. Despite crude oil being considered a somewhat homogenous commodity, many refiners are very particular about the quality of crude oil feedstock they process. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources meeting their requirements, and to purchase the crude oil and transport it to the refineries for sale. The imbalances and inefficiencies relative to meeting the refiners requirements can provide opportunities for us to utilize our purchasing and logistical skills to meet their demands. The pricing in the majority of our purchase contracts contain a market price component and a deduction to cover the cost of transporting the crude oil and to provide us with a

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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 petroleum 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. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tend to be higher than the same percentage attributable to our recurring operations. We utilize our fleet of 250 trucks, 350 trailers, 50 barges, 22 push/tow boats, and 1.5 million barrels of leased and owned storage capacity to service our refining customers and to store and blend the intermediate and finished refined products.

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

	Year Ended December 31, 2011	2010
	(in thousands)	
Supply and logistics revenue	$ 2,825,768	$ 1,894,612
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(2,642,964)	(1,761,161)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(122,925)	(95,011)
Other	96	(104)
Segment Margin	$ 59,975	$ 38,336
Volumes of crude oil and petroleum products (barrels per day)	69,305	61,012

As discussed above in Revenues, Costs and Expenses and Net Income, the average market prices of crude oil increased by approximately $16 per barrel, or approximately 20% between the two periods. Similarly, market prices for petroleum products increased significantly between 2011 and 2010. Fluctuations in these prices, however, have a limited impact on our Segment Margin. The increase in Segment Margin during 2011 versus 2010 resulted primarily from several factors, including:

- increased volumes of approximately 14% from 2010 primarily due to a greater availability of volumes of crude oil and heavy-end petroleum products resulting from increased refinery utilization in our operating area;
- increased production from new sources of crude oil, principally shale oil production, has increased demand for our services;
- higher foreign demand for fuel oil and other heavy-end petroleum products helped sustain the price environment for the products we sell;
- operating efficiencies and modifications to our existing crude oil and petroleum products commercial arrangements; and
- the contribution from the additional black oil barges we acquired in August 2011.

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Other Costs and Interest

General and Administrative Expenses

	Year Ended December 31, 2011	2010
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$ 19,466	$ 17,276
Segment	2,682	3,193
Bonus plan expense	6,186	5,007
Equity-based compensation plan expense	1,763	1,955
Third party costs related to IDR Restructuring, business development activities and growth projects	4,376	7,290
Expenses related to change in owner of our general partner		1,762
Non-cash compensation expense related to management team		76,923
Total general and administrative expenses	$ 34,473	$ 113,406

General and administrative expenses decreased $78.9 million in 2011 from 2010 primarily due to non-cash compensation charges of $76.9 million in the prior year related to equity-based compensation arrangements between executive management and our general partner. The decrease in general and administrative expenses was partially offset primarily by an increase in personnel resulting in greater salaries and benefits expenses. In addition, our bonus plan expenses increased $1.2 million during 2011 as a result of improvements in our operating results.

The non-cash compensation charges recorded in 2010 reflect the exchange of certain equity interests in our general partner held by our executives for new common units (including waiver units). These charges were incurred in connection with our IDR Restructuring. Although the compensation under these arrangements ultimately came from our general partner, we recorded the fair value of the related compensation expense in our Consolidated Statements of Operations in general and administrative expenses. See Note 15 to our Consolidated Financial Statements in Item 8 for more information concerning the non-cash compensation costs incurred in connection with our IDR Restructuring.

Depreciation and Amortization Expense

	Year Ended December 31, 2011	2010
	(in thousands)	
Depreciation on fixed assets	$ 27,280	$ 22,498
Amortization of intangible assets	30,952	26,805
Amortization of CO_2 volumetric production payments	3,694	4,254
Total depreciation and amortization expense	$ 61,926	$ 53,557

Depreciation and amortization expense increased $8.4 million between 2011 and 2010 primarily as a result of an adjustment in the useful lives of certain of our intangible assets in the first quarter of 2011 and depreciation expense related to our black oil barge assets acquisition. In the first quarter of 2011, we adjusted the useful lives of our supply and logistics trade names, which resulted in an increase of amortization expense of $7.7 million during the year. The impact of this change is not expected to be material in future periods.

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Interest Expense, Net

	Year Ended December 31, 2011	2010
	(in thousands)	
Genesis Facility and Notes:		
Interest expense, credit facility (including commitment fees)	$ 12,880	$ 10,540
Interest expense, senior unsecured notes	19,961	2,406
Bridge financing fees		3,219
Amortization of credit facility and notes issuance costs	2,940	1,551
Write-off of facility fees		402
DG Marine Facility:		
Interest expense and commitment fees		2,512
Interest rate swaps settlement		1,553
Write-off of facility fees		794
Interest income	(14)	(53)
Net interest expense	$ 35,767	$ 22,924

Net interest expense increased $12.8 million during 2011, primarily reflecting increased interest expense on our senior unsecured notes, which were outstanding for an entire year during 2011. Interest expense on our credit facility also increased during 2011 as our average debt balance increased $8.1 million. The increase in the average outstanding balance under our credit facility is attributable primarily to growth initiative projects during 2011, including expansion of our Texas pipeline infrastructure and the acquisition of the Wyoming refinery and pipeline assets. The increase in net interest expense during 2011 was partially offset by the repayment of the DG Marine credit facility in July 2010.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Pipeline Transportation Segment

Operating results and volumetric data for our pipeline transportation segment were as follows.

	Year Ended December 31, 2010	2009
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases onshore crude oil pipelines	$ 20,351	$ 17,202
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	26,413	26,279
Sales of crude oil pipeline loss allowance volumes	5,519	4,462
Pro-rata share of distributable cash generated by Cameron Highway	2,384	
Pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(11,522)	(10,477)
Payments received under direct financing leases not included in income	4,202	3,758
Other	958	938
Segment Margin	$ 48,305	$ 42,162

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Volumes shipped on our pipeline systems in 2010 and 2009 were as follows (barrels or Mcf per day):

Pipeline System	2010	2009
Mississippi-Bbls/day	23,537	24,092
Jay Bbls/day	15,646	10,523
Texas Bbls/day	28,748	25,647
CHOPS Bbls/day	149,270 (1)	
Free State Mcf/day	167,619	154,271

(1) Daily average for the period we owned the pipeline beginning on November 23, 2010.

Pipeline Segment Margin increased $6.1 million in 2010 as compared to 2009. This increase is primarily attributable to the following factors:

Our share of distributable cash generated by CHOPS beginning in the latter part of November 2010 added $2.4 million to Segment Margin.

An increase in volumes transported on our crude oil pipelines between the two periods increased Segment Margin by $2.1 million.

Tariff rate changes in July 2009 and July 2010 resulted in an increase of approximately $0.4 million between the two periods.

An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $1.1 million. This revenue increase is due primarily to increased crude oil market prices, although the increase in volumes transported in our onshore pipelines also contributed to the additional revenue.

Pipeline operating costs increased approximately $1 million due to an increase in pipeline integrity tests and other maintenance costs. In the first quarter of 2010 pipeline integrity tests on a segment of our Texas System cost approximately $0.6 million.

Refinery Services Segment

Operating results from our refinery services segment were as follows (in thousands, except average index price):

	Year Ended December 31, 2010	2009
Volumes sold:		
NaHS volumes (Dry short tons DST)	145,213	107,311
NaOH (caustic soda) volumes (DST)	93,283	88,959
Total	238,496	196,270
Revenues (in thousands):		
NaHS revenues	$ 119,688	$ 97,962
NaOH (caustic soda) revenues	29,578	38,773

Other revenues	9,190	10,505
Total external segment revenues	$ 158,456	$ 147,240
Segment Margin	$ 62,923	$ 51,844
Average index price for NaOH per DST [1]	$ 353	$ 424
Raw material and processing costs as % of segment revenues	37%	44%

(1) Source: Harriman Chemsult Ltd.

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Refinery services Segment Margin for the year ended 2010 was $62.9 million, an increase of $11.1 million, or 21% from the year ended 2009. The significant components of this change were as follows:

An increase in NaHS volumes of 35%. As the world economies, particularly outside of the United States and European Union, recovered from the depths of the greatest recession in the last 70 years, the demand for base metals such as copper and molybdenum increased over the prior period. As a result, we experienced a noticeable increase in the demand for NaHS from our mining customers in North and South America. Additionally, with the return of industrialization and urbanization in the world s more underdeveloped economies, the demand for paper products and packaging materials increased. This trend led to an increase in demand for NaHS from our pulp/paper customers primarily in North America. The pricing in the majority of our sales contracts for NaHS includes an adjustment for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments can be applied varies by geographic region and supply point.

An increase in NaOH (or caustic soda) sales volumes of 5%. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. We are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties. Fluctuations in volumes sold are affected by the demand we have in our operations that consume caustic soda.

Index prices for caustic soda averaged approximately $424 per DST in 2009. Market index prices of caustic soda decreased to an average of approximately $353 per DST during 2010. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers.

Somewhat mitigating the increase in Segment Margin was an increase in delivery logistics costs. Although our logistics costs per unit increased only modestly, our logistics costs expressed as a percentage of revenues increased by 3% (to 15%) primarily because our sales price per unit, along with our cost per unit declined. Quantities delivered to customers also increased. Freight demand and fuel prices increased modestly in 2010 as economic conditions improved, increasing demand for transportation services and the increase in crude oil prices increased the cost of fuel used in transporting these products.

Supply and Logistics Segment

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

	Year Ended December 31, 2010	2009
	(in thousands)	
Supply and logistics revenue	$ 1,894,612	$ 1,243,044
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(1,761,161)	(1,115,809)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(95,011)	(84,967)
Other	(104)	(1,784)
Segment Margin	$ 38,336	$ 40,484
Volumes of crude oil and petroleum products (barrels per day)	61,012	48,117

As discussed above in Revenues, Costs and Expenses and Net Income, the average market prices of crude oil increased by approximately $18 per barrel, or approximately 29% between the two periods. Similarly, market prices for petroleum products increased significantly between 2009 and 2010. Fluctuations in these prices, however, have a limited impact on our Segment Margin.

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The key factors affecting the change in Segment Margin between 2010 and 2009 were as follows:

- The contango price market narrowed beginning late in the fourth quarter of 2009 and extended through most of 2010 decreasing the effects on contribution to Segment Margin of our crude oil activities.

- Fluctuations in differentials related to heavy end petroleum products decreased Segment Margin from our petroleum products marketing activities.

When crude oil markets are in contango (oil prices for future deliveries are higher than for current deliveries), we may purchase and store crude oil as inventory for delivery in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period for a higher price, either with a counterparty or in the crude oil futures market. The storage capacity we own for use in this strategy is approximately 420,000 barrels, although maintenance activities on our pipelines can impact the availability of a portion of this storage capacity. We generally account for this inventory and the related derivative hedge as a fair value hedge under the accounting guidance. See Notes 17 and 18 to our Consolidated Financial Statements in Item 8.

Beginning late in 2008 and throughout most of 2009, the crude oil market was in wide contango. In 2009, we took advantage of contango conditions, holding an average of 174,000 barrels of crude oil in storage throughout the year. In 2010, contango market conditions had narrowed and we reduced the volumes of crude oil stored to take advantage of the contango conditions to an average of 101,000 barrels of crude oil throughout the year. This change in contango market conditions was the primary factor in the $1.1 million decrease in the contribution to Segment Margin of our crude oil gathering and marketing activities.

Our petroleum products activities involve handling volumes from the heavy end of the refined barrel. Our access to logistical assets (owned and leased trucks, leased railcars and barges) as well as our access to terminals (owned and leased), provided us with greater opportunities in 2010 to acquire increased volumes of petroleum products for sale or for blending. However, fluctuations in the differentials between crude oil and fuel oils combined with variances in the values of other products we sell or utilize in our blending activities reduced the margins between the costs at which we obtained the heavy end products from refiners and the sales prices for those products. The contribution to Segment Margin in 2010 decreased by $2.2 million, as compared to 2009, as a result of these activities.

Other Costs and Interest

General and Administrative Expenses

	Year Ended December 31, 2010	2009
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$ 17,276	$ 16,418
Segment	3,193	3,859
Bonus plan expense	5,007	3,900
Equity-based compensation plan expense	1,955	2,132
Third party costs related to IDR Restructuring, business development activities and growth projects	7,290	
Expenses related to change in owner of our general partner	1,762	
Non-cash compensation expense related to management team	76,923	14,104
Total general and administrative expenses	$ 113,406	$ 40,413

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Although our general and administrative expenses increased substantially, 86% of the increase during 2010 was due to non-cash compensation expense related to our management team and borne by the former owners of our general partner, in connection with our IDR Restructuring described above. During 2010, we incurred transaction costs related to the restructuring of our IDRs and growth projects including the acquisition of our 50% interest in CHOPS totaling $7.3 million, or 10% of the remaining increase in general and administrative expenses. These transaction costs consisted primarily of fees paid to legal and financial advisors for their assistance in the evaluation and completion of these transactions.

During 2009, we recorded compensation expense of $14.1 million related to certain equity-based arrangements, and we recorded a reduction in compensation expense of $2.1 million in 2010 upon vesting of the arrangements when a change in control occurred in February 2010 in which a group of investors acquired all of the equity interest in our general partner.

Depreciation, Amortization and Impairment Expense

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Depreciation on fixed assets	$ 22,498	$ 25,208
Amortization of intangible assets	26,805	33,099
Amortization of CO_2 volumetric production payments	4,254	4,274
Impairment expense		5,005
Total depreciation, amortization and impairment expense	$ 53,557	$ 67,586

Depreciation and amortization expense (excluding impairment expense) decreased $9 million between 2010 and 2009 primarily as a result of lower amortization expense recognized on intangible assets. As discussed above, we amortize our intangible assets over the period, which we expect them to contribute to our future cash flows, and that amortization has declined since we acquired the assets. During 2009, we recorded a $5 million impairment charge during 2009 related to our Faustina Project based upon a review of the financing alternatives available for the project to use as construction financing and a determination not to continue making investments in the projects (see Note 8 to our Consolidated Financial Statements in Item 8).

Interest Expense, Net

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Genesis Facilities and Notes:		
Interest expense, credit facility (including commitment fees)	$ 10,540	$ 8,036
Interest expense, senior unsecured notes	2,406	
Bridge financing fees	3,219	
Amortization of credit facility and notes issuance fees	1,551	662
Write-off of facility fees	402	
DG Marine Facility:		
Interest expense and commitment fees	2,512	4,446
Interest rate swaps settlement	1,553	
Write-off of facility fees	794	586
Interest income	(53)	(70)
Net interest expense	$ 22,924	$ 13,660

Our average outstanding credit facility balance (excluding interest on DG Marine s stand-alone facility), was $31.4 million higher in 2010 than 2009. The increase in the credit facility balance is attributable primarily to the acquisition of the 51% ownership interest in DG Marine we did not own and the elimination of the DG Marine credit facility with borrowings under our credit facility. The increase during 2010 also reflects the issuance of $250 million of senior unsecured notes in November 2010 to partially finance our acquisition of a 50% equity interest in CHOPS and incurred fees of $3.2 million for bridge financing related to the acquisition.

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Net interest expense was also affected by interest on the DG Marine credit facility during the seven months it was outstanding, costs to settle the DG Marine interest rate swaps and the write-off of facility fees related to the repayment of the DG Marine credit facility.

Other Consolidated Results

Income Taxes

A portion of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, a substantial portion of the income tax expense we record relates to the operations of those corporations, and will vary from period to period as a percentage of our income before taxes based on the percentage of our income or loss that is derived from those corporations. The balance of the income tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles. During 2011, we recorded an income tax benefit of $1.2 million, and in 2010 and 2009 we recorded income tax expense of $2.6 million and $3.1 million, respectively. The benefit during 2011 reflects a net loss for those wholly-owned corporate subsidiaries that are taxable as corporations.

Liquidity and Capital Resources

General

As of December 31, 2011, we believe our balance sheet and liquidity position remained strong. We had $356.7 million of borrowing capacity available under our $775 million senior secured revolving credit facility. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our typical capital needs. Our primary sources of liquidity have been cash flows from operations and borrowing availability under our credit facility.

Our primary cash requirements consist of:

- Working capital, primarily inventories;
- Routine operating expenses;
- Capital expansion and maintenance projects;
- Acquisitions of assets or businesses;
- Interest payments related to outstanding debt; and
- Quarterly cash distributions to our unitholders.

Capital Resources

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

In August 2011, we amended our senior secured revolving credit facility to increase the committed amount from $525 million to $775 million and the accordion feature from $125 million to $225 million, giving us the ability to expand the size of the facility up to an aggregate $1 billion for acquisitions or internal growth projects, subject to obtaining lender approval. The amendment also increased the inventory sublimit tranche from $75 million to $125 million. This inventory tranche is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Our credit facility does not include a borrowing base limitation except with respect to our inventory loans. Fourteen lenders participate in our credit facility, and we do not anticipate any of them being unable to satisfy their obligations under the credit facility.

In July 2011, we issued 7,350,000 Class A common units at $26.30 per unit, providing net proceeds of $185 million, after deducting underwriting discounts and commissions and offering expenses. We used $143.5 million of the proceeds from this offering to fund the acquisition of the black oil barge transportation business. The remaining net proceeds of the offering were used for other corporate purposes, including the repayment of borrowings outstanding under our credit facility.

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At December 31, 2011, long-term debt totaled $659.3 million, consisting of $409.3 million outstanding under our credit facility (including $69.6 million borrowed under the inventory sublimit tranche) and $250 million of senior unsecured notes due in 2018.

In January 2012, we borrowed $205.9 million under our credit agreement to acquire interests in several pipeline systems. In February 2012 we issued $100 million under our existing 7.875% senior unsecured notes indenture for which the net proceeds were used to repay borrowings under our credit agreement. The notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes will be treated as a single class with our outstanding notes and have identical terms and conditions as our outstanding notes for all purposes, including, without limitation, waivers, amendments, redemptions and offers to purchase. The notes mature on December 15, 2018.

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

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our working capital needs. Excess funds that are generated are used to repay borrowings from our credit facilities and to fund capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

We typically sell our crude oil in the same month in which we purchase it and we do not rely on borrowings under our credit facility to pay for the crude oil. During such periods, our accounts receivable and accounts payable generally move in tandem as we make payments and receive payments for the purchase and sale of oil. However, when the crude oil markets are in contango, we may store crude for future delivery utilizing futures contracts to hedge our risk to fluctuations in prices.

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

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

Net cash flows provided by our operating activities were $58.3 million and $90.5 million for 2011 and 2010, respectively. The decrease during 2011 reflects increased working capital requirements related to increases in accounts receivable and inventories due to higher crude oil prices. As discussed above, changes in the cash requirements related to payment for petroleum products or collection of receivables from the sale of inventory impact the cash provided by operating activities. Additionally, changes in the market prices for crude oil and petroleum products can result in fluctuations in our operating cash flows between periods as the cost to acquire a barrel of oil or products will require more cash. At December 31, 2011, the cost of inventories on our balance sheet increased by $45.7 million from December 31, 2010.

Capital Expenditures and Distributions Paid to Our Unitholders

We use cash primarily for our acquisition activities, internal growth projects and distributions we pay to our unitholders. We finance small acquisitions and internal growth projects and distributions primarily with cash generated by our operations. We have historically funded large acquisition activities and internal growth projects with borrowings under our credit facility, equity issuances and the issuance of senior unsecured notes.

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Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets, business and other asset acquisitions in the years ended 2011, 2010 and 2009 is as follows:

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Capital expenditures for fixed and intangible assets:			
Maintenance capital expenditures:			
Pipeline transportation assets	$ 247	$ 522	