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 incorporation or organization)	*(I.R.S. Employer Identification No.)*

919 Milam, Suite 2100,

Houston, TX 77002

(Address of principal executive offices) (Zip code)

(713) 860-2500

Registrant s telephone number, including area code:

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units	NYSE

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

NONE

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

Table of Contents

GENESIS ENERGY, L.P.

2011 FORM 10-K ANNUAL REPORT

Table of Contents

		Page
	Part I	
Item 1	Business	5
Item 1A.	Risk Factors	21
Item 1B.	Unresolved Staff Comments	36
Item 2.	Properties	36
Item 3.	Legal Proceedings	36
Item 4.	Mine Safety Disclosures	36
	Part II	
Item 5.	Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	36
Item 6.	Selected Financial Data	38
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	39
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	64
Item 8.	Financial Statements and Supplementary Data	65
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	65
Item 9A.	Controls and Procedures	66
Item 9B.	Other Information	67
	Part III	
Item 10.	Directors, Executive Officers and Corporate Governance	67
Item 11.	Executive Compensation	72
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	86
Item 13.	Certain Relationships and Related Transactions, and Director Independence	89
Item 14.	Principal Accountant Fees and Services	90
	Part IV	
Item 15.	Exhibits and Financial Statement Schedules	91

Table of Contents

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;*

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

12

Table of Contents

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.

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.

Table of Contents

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.

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

17

Table of Contents

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

Table of Contents

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

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.

Table of Contents

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.

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;

- 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.

Table of Contents

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 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.

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.

Table of Contents

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.

Table of Contents

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.

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

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.

Table of Contents

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 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.

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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

Table of Contents

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.

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.

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

50

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

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.

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.

Table of Contents

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	$ 1,281
Supply and logistics assets	2,790	901	1,667
Refinery services assets	1,200	1,433	1,246
Other assets			232
Total maintenance capital expenditures	4,237	2,856	4,426
Growth capital expenditures:			
Pipeline transportation assets	7,382	573	1,762
Supply and logistics assets	11,056	839	19,099
Refinery services assets	646		1,326
Information technology systems upgrade project	4,128	10,613	
Total growth capital expenditures	23,212	12,025	22,187
Total	27,449	14,881	26,613
Capital expenditures for business combinations:			
Black oil barge transportation business of FMT	143,479		
Wyoming refinery and related pipeline	20,000		
Acquisition of intangible assets			2,500
Total	163,479		2,500
Capital expenditures related to equity investees and other investments	194	332,462(1)	83
Total	194	332,462	83
Total capital expenditures	$ 191,122	$ 347,343	$ 29,196

(1) Represents the investment to acquire our interest in CHOPS.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital. We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows.

Acquisitions

We continue to pursue a growth strategy that requires significant capital. 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. The acquisition is intended to complement 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 in Texas and Louisiana. 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). That 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 described above, whereby we raised approximately $185 million in net proceeds of equity capital.

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.

See Notes 3 and 21 to our Consolidated Financial Statements in Item 8 for further information related to the acquisitions.

Growth Capital Expenditures

In April 2011, we announced two projects to increase the services we provide to producers and refiners. We 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. We also are constructing a truck station and tankage at West Columbia, Texas 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. In addition, we have initiated construction of a 16-inch diameter loop of our existing crude oil pipeline into Texas City, supported by a term contract with one of our refining customers, which will allow us to significantly expand our total service capabilities into the Texas City area by the second quarter of 2013.

In connection with our activities in Texas, we also constructed interconnecting pipeline and other required facilities to provide transportation services for all of the crude oil production from the Hastings field, near Alvin, Texas, which is in the very early stages of a CO_2 tertiary recovery program. This connection was completed in December 2011.

During 2011, we also entered into an agreement to install a new sour gas processing facility at Holly Refining and Marketing s refinery complex located in Tulsa, Oklahoma. The new facility, expected to be completed in the fourth quarter of 2012, will remove a portion of the sulfur from the crude oil refined at Holly s complex and is expected to result in potential additional capacity of 24,000 DST per year of NaHS.

We recently began construction of a new crude-by-rail unloading terminal connected to our existing crude oil pipeline at Walnut Hill, Florida. This facility will be capable of handling unit train shipments of oil for direct deliveries to one refinery customer and indirect delivery, through third-party common carriers, to potentially multiple other markets in the southeast. We anticipate this facility to be fully operational in the third quarter of 2012.

We anticipate the total costs of these projects above to be approximately $80 million in total, of which we have spent $11.4 million during 2011. We expect the remaining costs for the projects will be spent primarily in 2012.

In connection with the refinery and pipeline acquisition in Wyoming, we anticipate spending approximately $33 million to upgrade the facilities and bring the pipeline back in service.

Capital Expenditures Related to Equity Investees

In December 2011, we created SEKCO with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. The new pipeline is expected to begin service by mid-2014. We expect to spend approximately $200 million for our share of the pipeline construction through 2014 and to reimburse Enterprise Products for our portion of previously incurred costs. Approximately $80 million of the total estimate is expected to be paid in 2012. Most cost overruns and other costs incurred associated with weather related delays will be the responsibility of the producers that have entered into transportation agreements with us.

Maintenance Capital Expenditures

Maintenance capital expenditures for 2012 are anticipated to total approximately $5 million to $6 million. We would expect to spend similar amounts annually on maintenance capital projects in future years.

Distributions to Unitholders and Our General Partner

Our partnership agreement requires us to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last twenty-six quarters, including the distribution paid for the fourth quarter of 2011, as shown in the table below (in thousands, except per unit amounts). Each quarter, our board of directors determines the distribution amount per unit, or Available Cash, based upon various factors such as our operating performance, cash on hand, future cash requirements and the economic environment. As a result, the historical trend of distribution increases may not be a good indicator of future increases.

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount (1)	General Partner Incentive Distribution Amount (1)	Total Amount
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579
First quarter 2010	May 2010	$ 0.3675	$ 14,548	$ 297	$ 2,339	$ 17,184
Second quarter 2010	August 2010	$ 0.3750	$ 14,845	$ 303	$ 2,642	$ 17,790
Third quarter 2010	November 2010	$ 0.3875	$ 15,339	$ 313	$ 3,147	$ 18,799
Fourth quarter 2010	February 2011	$ 0.4000	$ 25,846	$	$	$ 25,846
First quarter 2011	May 2011	$ 0.4075	$ 26,343	$	$	$ 26,343
Second quarter 2011	August 2011	$ 0.4150	$ 29,878	$	$	$ 29,878
Third quarter 2011	November 2011	$ 0.4275	$ 30,777	$	$	$ 30,777
Fourth quarter 2011	February 2012 (2)	$ 0.4400	$ 31,664	$	$	$ 31,664

(1) Prior to our IDR Restructuring in December 2010, our general partner received a 2% interest and incremental incentive cash distributions when unitholder s cash distributions exceeded certain target thresholds. Our IDR Restructuring is described further in Note 11 to our Consolidated Financial Statements in Item 8.

(2) This distribution was paid on February 14, 2012 to unitholders of record as of February 1, 2012.

Non-GAAP Reconciliation

This annual report includes the financial measure of Available Cash before Reserves, which is a non-GAAP measure because it is not contemplated by or referenced in accounting principles generally accepted in the U.S., also referred to as GAAP. The accompanying schedule provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure. Our non-GAAP financial measure should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts, and other market participants.

Available Cash before Reserves, also referred to as distributable cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures, or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because Available Cash before Reserves excludes some, but not all, items that affect net income or loss and because these measures may vary among other companies, the Available Cash before Reserves data presented in this Annual Report on Form 10-K may not be comparable to similarly titled measures of other companies. The GAAP measure most directly comparable to Available Cash before Reserves is net cash provided by operating activities.

Table of Contents

Available Cash before Reserves is a financial measure used by our management to compare cash flows generated by us to the cash distribution paid to our limited partners. This is an important financial measure to our public unitholders since it is an indicator of our ability to provide a cash return on their investment. Specifically, this financial measure aids investors in determining whether or not we are generating cash flows at a level that can support a quarterly cash distribution to the partners. Lastly, Available Cash before Reserves is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships.

The reconciliation of Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) is as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Net cash flows provided by operating activities (GAAP measure)	$ 58,307	$ 90,463	$ 90,079
Adjustments to reconcile operating cash flows to Available Cash before Reserves:			
Maintenance capital expenditures	(4,237)	(2,856)	(4,426)
Proceeds from sales of certain assets	6,424	1,146	873
Amortization and write-off of debt issuance fees	(2,940)	(3,082)	(2,503)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	11,436	1,017	101
Net loss of DG Marine in excess of distributable cash		(848)	(4,475)
Expenses related to acquiring or constructing assets that provide new sources of cash flow	4,376	11,260	
Other items affecting available cash	(2,098)	(1,088)	1,768
Net effect of changes in operating accounts not included in calculation of Available Cash [1]	66,931	5,487	9,569
Available Cash before Reserves	$ 138,199	$ 101,499	$ 90,986

(1) See Note 14 to our Consolidated Financial Statements in Item 8 for information regarding the net changes in components of operating assets and liabilities.

Table of Contents

Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Commercial Commitments

In addition to our credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil and petroleum products. The table below summarizes our obligations and commitments at December 31, 2011.

Commercial Cash Obligations and Commitments	Payments Due by Period: Less than one year	1 -3 years	3 - 5 Years	More than 5 years	Total
			(in thousands)		
Contractual Obligations:					
Long-term debt and notes payable [1]	$	$	$ 409,300	$ 250,000	$ 659,300
Estimated interest payable on long-term debt and notes payable [2]	39,236	78,259	49,070	37,056	203,621
Operating lease obligations	12,529	16,808	9,683	20,801	59,821
Unconditional purchase obligations [3]	200,458				200,458
Other Cash Commitments:					
Asset retirement obligations [4]				14,508	14,508
Liabilities associated with unrecognized tax benefits and associated interest [5]	2,599	3,642	1,964		8,205
Total	$ 254,822	$ 98,709	$ 470,017	$ 322,365	$ 1,145,913

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of June 30, 2015. Our senior unsecured notes are due November 18, 2018.

(2) Interest on our long-term debt under our credit facility is at market-based rates. The interest rate on our senior unsecured notes is 7.875%. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2011 under our credit facility remained outstanding through the final maturity date of June 30, 2015 and interest rates remained at the December 31, 2011 market levels through the final maturity date. Also included is the interest on our senior unsecured notes through the maturity date.

(3) Unconditional purchase obligations include agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at December 31, 2011, were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.

(4) Represents the estimated future asset retirement obligations on an undiscounted basis. The recorded asset retirement obligation on our balance sheet at December 31, 2011 was $5.9 million and is further discussed in Note 6 to our Consolidated Financial Statements.

(5) The estimated liabilities associated with unrecognized tax benefits and related interest will be settled as a result of expiring statutes or audit activity. The timing of any particular settlement will depend on the length of the tax audit and related appeals process, if any, or an expiration of statute. If a liability is settled due to a statute expiring or a favorable audit result, the settlement of the tax liability would not result in a cash payment.

Table of Contents

In connection with our 50% interest in SEKCO as described above we have committed to share the required funding with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. We expect to spend approximately $200 million for our share of the pipeline construction through 2014 and to reimburse Enterprise Products for our portion of previously incurred costs. Approximately $80 million of the total estimate is expected to be paid in 2012. Most cost overruns and other costs incurred associated with weather related delays will be the responsibility of the producers that have entered into transportation agreements with us. See Significant Events above for more information.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under Contractual Obligations and Commercial Commitments above.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We base these estimates and assumptions on historical experience and other information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be determined with certainty, and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the business environment in which we operate changes. Significant accounting policies that we employ are presented in the Notes to our Consolidated Financial Statements in Item 8 (see Note 2 Summary of Significant Accounting Policies).

We have defined critical accounting policies and estimates as those that are most important to the portrayal of our financial results and positions. These policies require management s judgment and often employ the use of information that is inherently uncertain. Our most critical accounting policies pertain to measurement of the fair value of assets and liabilities in business acquisitions, depreciation, amortization and impairment of long-lived assets, equity plan compensation accruals and contingent and environmental liabilities. We discuss these policies below.

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

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, trade names, and non-compete agreements involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired, and to the extent available, third party assessments. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. Uncertainties associated with these estimates include fluctuations in economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Note 3 to our Consolidated Financial Statements in Item 8 regarding further discussion regarding our acquisitions.

Depreciation and Amortization of Long-Lived Assets and Intangibles

In order to calculate depreciation and amortization we must estimate the useful lives of our fixed assets at the time the assets are placed in service. We compute depreciation using the straight-line method based on these estimated useful lives. The actual period over which we will use the asset may differ from the assumptions we have made about the estimated useful life. We adjust the remaining useful life as we become aware of such circumstances.

Intangible assets with finite useful lives are required to be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are recording amortization of our customer and supplier relationships, licensing agreements and trade names based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. Our favorable lease and other intangible assets are being amortized on a straight-line basis over their expected useful lives.

Impairment of Long-Lived Assets including Intangibles and Goodwill

When events or changes in circumstances indicate that the carrying amount of a fixed asset or intangible asset with finite lives may not be recoverable, we review our assets for impairment. We compare the carrying value of the fixed asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset s unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase costs and expenses at that time. Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment on October 1 of each fiscal year, and more frequently, if indicators of impairment are present.

During 2011, we adopted new accounting guidance, which provides the option to make a qualitative evaluation about the likelihood of goodwill impairment. After performing a qualitative assessment of relevant events and circumstances, if it is deemed more likely than not the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit s fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management s estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates, and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value. One of our monitoring procedures is the comparison of our market capitalization to our book equity on a quarterly basis to determine if there is an indicator of impairment. As of December 31, 2011, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform an interim assessment as of December 31, 2011. We did not have any goodwill impairments in 2011, 2010 or 2009.

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

Equity Compensation Plan Accruals

We accrue for the fair value of our liability for the stock appreciation rights, or SAR, awards we have issued to our employees and directors. Under our SAR plan, grantees receive cash for the difference between the market value of our common units and the strike price of the award at the time of exercise. We estimate the fair value of SAR awards at each balance sheet date using the Black-Scholes option pricing model. The Black-Scholes valuation model requires the input of somewhat subjective assumptions, including expected stock price volatility and expected term. Other assumptions required for estimating fair value with the Black-Scholes model are the expected risk-free interest rate and our expected distribution yield. The risk-free interest rates used are the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. We recognize the equity-based compensation expense on a straight-line basis over the requisite service period for the awards. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate at each balance sheet date based on prior experience. As of December 31, 2011, there was $0.2 million of total compensation cost to be recognized in future periods related to non-vested SARs. The cost is expected to be recognized over a weighted-average period of

Table of Contents

approximately one year. We also record compensation cost for changes in the estimated liability for vested SARs. The liability recorded for vested SARs fluctuates with the market price of our common units. Changes in our assumptions may impact our liabilities and expenses related to these awards.

Our 2010 Long-Term Incentive Plan provides for grantees, which may include key employees and directors, to receive cash at the vesting of the phantom units equal to the average of the closing market price of our common units for the twenty trading days prior to the vesting date. Our phantom units are comprised of both service-based and performance-based awards. Until the vesting date, we calculate estimates of the fair value of the awards and record that value as compensation expense during the vesting period on a straight-line basis. These estimates are based on the current trading price of our common units and an estimate of the forfeiture rate we expect may occur. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award. At December 31, 2011, we had 212,732 phantom units outstanding and recorded $1.9 million of expense during 2011. The liability recorded for phantom units expected to vest fluctuates with the market price of our common units. At the date of vesting, any difference between the estimates recorded and the actual cash paid to the grantee will be charged to expense. At December 31, 2011, we estimated approximately $4 million of compensation costs to be recognized over a weighted average period of approximately 2 years for these awards. Changes in our assumptions may impact our liabilities and expenses related to these awards.

See Note 15 to our Consolidated Financial Statements in Item 8 for further discussion regarding our equity compensation plans.

Liability and Contingency Accruals

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

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

At December 31, 2011, we were not aware of any contingencies or liabilities that would have a material effect on our financial position, results of operations, or cash flows.

Recent Accounting Pronouncements

Recent and Proposed Accounting Pronouncements

Recently Issued

In December 2011, the Financial Accounting Standards Board (FASB) issued guidance requiring new disclosures for financial instruments and derivative instruments that are eligible for offset in the statement of financial position or subject to a master netting arrangement. The new guidance is effective for us beginning January 1, 2013 and is not expected to have a significant impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance that modified how comprehensive income is presented in an entity s financial statements. The guidance issued requires an entity to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and eliminates the option to present the components of other comprehensive income as part of the statement of equity. The revised financial statement presentation for comprehensive income will be effective for us beginning January 1, 2012, with early adoption permitted. The guidance pertaining to reclassifying items out of accumulated other comprehensive income has been deferred and will be effective for us beginning January 1, 2013. The adoption of this guidance is not expected to have a significant impact on our financial position, results of operations or cash flows.

Table of Contents

Recently Adopted

In September 2011, the FASB issued guidance that simplified how an entity tests goodwill for impairment. The revised guidance provides an entity the option to make a qualitative evaluation about the likelihood of goodwill impairment. Under the revised guidance, an entity is permitted to first assess qualitative factors to determine whether goodwill impairment exists prior to performing analyses comparing the fair value of a reporting unit to its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. We early adopted the guidance effective October 1, 2011, which did not have a material impact on our Consolidated Financial Statements.

In December 2010, the FASB revised its guidance for disclosure requirements of supplementary pro forma information for business combinations. The objective of the revised guidance is to address diversity in practice regarding pro forma disclosures for revenues and earnings of an acquired entity. The amendments, which went into effect on January 1, 2011, will be adhered to any future material business combinations.

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. The guidance was effective for us beginning January 1, 2011, and there was no material impact on our Consolidated Financial Statements.

In July 2010, the FASB issued guidance, which requires companies that hold financing receivables, which include loans, lease receivables, and the other long-term receivables to provide more information in their disclosures about the credit quality of their financing receivables and the credit reserves held against them. The adoption of this accounting guidance on January 1, 2011 pertaining to disclosures about activity that occurs during a reporting period did not have a material impact on our Consolidated Financial Statements.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as Level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. This new guidance requires additional disclosures regarding transfers into and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. We adopted the guidance relating to Level 1 and Level 2 transfers as of January 1, 2010, and we adopted the guidance relating to Level 3 measurements on January 1, 2011. Our adoption had no material impact on our Consolidated Financial Statements.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, primarily related to volatility in crude oil and petroleum products prices, NaHS and NaOH prices, and interest rates. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the Segment Margin we receive. We do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes.

Our primary price risk relates to the effect of crude oil and petroleum products price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. Our risk management policies are designed to monitor our physical volumes, grades, and delivery schedules to ensure our hedging activities address the market risks that are inherent in our gathering and marketing activities.

We utilize NYMEX commodity based futures contracts and option contracts to hedge our exposure to these market price fluctuations as needed. All of our open commodity price risk derivatives at December 31, 2011 were categorized as non-trading. On December 31, 2011 we had entered into NYMEX future contracts that will settle between January and March 2012 and NYMEX options contracts that will settle during February and March 2012. This accounting treatment is discussed further in Note 17 to our Consolidated Financial Statements.

Table of Contents

The table below presents information about our open derivative contracts at December 31, 2011. Notional amounts in barrels or mmBtus, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars of our open positions are presented below. Fair values were determined by using the notional amount in barrels or mmBtus multiplied by the December 31, 2011 quoted market prices on the NYMEX. All of the hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the table below.

	Unit of Measure for Volume	Contract Volumes (in 000 s)	Unit of Measure for Price	Weighed Average Market Price	Contract Value (in 000 s)	Mark-to Market Change (in 000 s)	Settlement Value (in 000 s)
NYMEX Futures Contracts							
Sell (Short) Contracts:							
Crude Oil	Bbl	169	Bbl	$ 96.16	$ 16,251	$ 470	$ 16,721
Heating Oil	Bbl	178	Gal (1)	$ 2.86	$ 21,409	$ 345	$ 21,754
RBOB Gasoline	Bbl	15	Gal (1)	$ 2.66	$ 1,677	$ (2)	$ 1,675
#6 Fuel Oil	Bbl	489	Bbl	$ 93.73	$ 45,832	$ 1,273	$ 47,105
Buy (Long) Contracts:							
Crude Oil	Bbl	90	Bbl	$ 98.83	$ 8,894	$ 9	$ 8,903
Heating Oil	Bbl	60	Bbl	$ 2.83	$ 7,141	$ 182	$ 7,323
NYMEX Option Contracts (2)							
Written Call Contracts:							
Crude Oil	Bbl	355	Bbl	$ 2.05	$ 727	$ (123)	$ 604
Heating Oil	Bbl	30	Gal (1)	$ 0.09	$ 112	$ (64)	$ 48
Written Put Contracts:							
Crude Oil	Bbl	75	Bbl	$ 0.56	$ 42	$ (9)	$ 33

(1) Prices and volumes are presented as quoted on the NYMEX. To calculate the total contract value the price per unit in gallons should be multiplied by 42 gallons to convert into a price per barrel.

(2) Weighted average premium received/paid.

We manage our risks of volatility in NaOH prices by indexing prices for the sale of NaHS to the market price for NaOH in most of our contracts.

We are also exposed to market risks due to the floating interest rates on our credit facility. Obligations under our senior secured credit facility bear interest at the LIBOR rate or alternate base rate (which approximates the prime rate), at our option, plus the applicable margin. We have not, historically hedged our interest rates. On December 31, 2011, we had $409.3 million of debt outstanding under our credit facility. For the year ended December 31, 2011, a 10% change in LIBOR would have resulted in approximately a $1.2 million change in net income.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the Index to Consolidated Financial Statements on page 97.

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

None.

Table of Contents

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K and have determined that such disclosure controls and procedures are effective in providing assurance of the timely recording, processing, summarizing and reporting of information, and in accumulation and communication to management on a timely basis material information relating to us (including our consolidated subsidiaries) required to be disclosed in this annual report.

Changes in Internal Controls over Financial Reporting

There were no changes during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control over Financial Reporting

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

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

Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2011, the Partnership s internal control over financial reporting is effective based on those criteria.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2011. Deloitte & Touche LLP, the Company s independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company s internal control over financial reporting. Deloitte & Touche s attestation report on the Partnership s internal control over financial reporting appears in Item 8. Financial Statements and Supplementary Data.

Table of Contents

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

We are a Delaware limited partnership. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. Our general partner, Genesis Energy, LLC, a wholly-owned subsidiary that owns a non-economic general partner interest in us, has sole responsibility for conducting our business and managing our operations. Our general partner does not receive a management fee or other compensation in connection with its management of our business.

As is common with MLPs, our partnership structure does not allow our unitholders (of our Class A and Class B Units and Waiver Units) to directly or indirectly participate in our management or operations. The board of directors of our general partner must approve significant matters (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 distributions.) The holders of our Waiver Units are not, generally, entitled to vote on any matters. The holders of Class B Units are entitled to (i) vote in the election of the board of directors of our general partner (which we refer to as our board of directors), subject to the Davison family s rights described below, as well as (ii) vote on substantially all other matters on which our Class A holders are entitled to vote. The holders of our Class A Units are not entitled to vote in the election of directors, but they are entitled to vote in a very limited number of other circumstances, including the removal of our general partner (or the director election rights of our Class B unitholders) under specified circumstances. For example, our unitholders may remove our general partner by a vote of the holders of not less than a majority of the outstanding common units, excluding units held by our general partner and its affiliates. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units.

The Robertson Group owns approximately 12% of our Class A Units and 74% of our Class B Units. Consequently, through its Class B Units, the Robertson Group is able to elect at least a majority of the members of our board of directors. The Davison family is entitled to elect up to three directors under terms of its unitholders rights agreement. If members of the Davison family own (i) 15% or more of our common units, they have the right to appoint three directors, (ii) less than 15% but more than 10%, they have the right to appoint two directors, and (iii) less than 10%, they have the right to appoint one director. So long as the Davison family has the right to elect three directors, our board of directors cannot have more than 11 directors without the Davison family s consent. EIV Capital Fund LP, a former stakeholder in our general partner, has the right to vote for directors due to its ownership of Class B units. Additionally, pursuant to his employment agreement, Mr. Sims is entitled to be a director.

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

Our board of directors currently consists of the Robertson Group appointees: Robert C. Sturdivant, Donald L. Evans, Corbin J. Robertson III, William K. Robertson, Kenneth M. Jastrow, II and S. James Nelson; the Davison family appointees: James E. Davison, James E. Davison, Jr. and Sharilyn S. Gasaway; the EIV Capital Fund LP appointee Carl A. Thomason; and Mr. Sims. Each of Ms. Gasaway and Messrs. Jastrow, Nelson, and Thomason are considered independent directors.

Table of Contents

Board Leadership Structure and Risk Oversight

Board Leadership Structure

Our board of directors has no policy that requires that the positions of the Chairman of the Board, or the Chairman, and the Chief Executive Officer be held by the same or different persons or that we designate a lead or presiding independent director. Our board of directors believes that those determinations should be based on circumstances existing from time to time, including the composition, skills and experience of our board of directors and its members, specific challenges faced by the company or the industry in which it operates, and governance efficiency. Presently, Mr. Sturdivant, a representative of the Robertson Group, serves as the Chairman, and Mr. Sims serves as Chief Executive Officer and a director of our board of directors. We have not designated anyone as a presiding or lead independent director. We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders. We believe independent directors are a key element for strong governance, although we have exercised our right as a limited partnership under the listing standards of the NYSE, not to comply with certain requirements of the NYSE. For example, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that our board of directors be comprised of a majority of independent directors. In addition, among other things, we have elected not to comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require our board of directors to maintain a nominating/corporate governance committee and a compensation committee, each consisting entirely of independent directors.

Risk Oversight

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

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

Independence Determinations and Audit Committee

The audit committee of our board of directors generally oversees our accounting policies and financial reporting and the audit of our financial statements. The audit committee assists our board of directors in its oversight of the quality and integrity of our financial statements and our compliance with legal and regulatory requirements. Our independent registered public accounting firm is given unrestricted access to the audit committee. Our board of directors has determined that the members of the audit committee meet the independence and experience standards established by NYSE and the Securities Exchange Act of 1934, as amended. In accordance with the NYSE rules and the Securities Exchange Act of 1934, as amended, our board of directors has named three of its members to serve on the audit committee. Sharilyn S. Gasaway, S. James Nelson and Carl A. Thomason serve as the members of the audit committee. Ms. Gasaway is the chairperson. Our board of directors believes that Ms. Gasaway and Mr. Nelson qualify as audit committee financial experts as such term is used in the rules and regulations of the SEC. The charter of the audit committee is available on our website (www.genesisenergy.com) free of charge. Our board of directors considered the fact that Mr. Nelson is a member of the audit committees of three other public companies, and determined that such simultaneous service will not, and does not, impair his ability to effectively serve on our audit committee.

Table of Contents

Governance, Compensation and Business Development Committee

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

Conflicts Committee

To the extent requested by our board of directors, the conflicts committee of our board of directors reviews specific matters in connection with the resolution of conflicts of interest and potential conflicts of interest between our general partner or any of its affiliates and us. Our conflicts committee is comprised solely of independent directors, Messrs. Nelson, Thomason and Jastrow and Ms. Gasaway. Mr. Nelson is the chairperson. See Item 13. Certain Relationships and Related Transactions, and Director Independence Review or Special Approval of Material Transactions with Related Persons.

Executive Sessions of Non-Management Directors

Our board of directors holds executive sessions in which non-management directors meet without any members of management present in connection with regular board meetings. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. Mr. Sturdivant serves as the presiding director at those executive sessions. In accordance with NYSE rules, interested parties can communicate directly with non-management directors by mail in care of the General Counsel and Secretary or in care of the chairperson of the audit committee at 919 Milam, Suite 2100, Houston, TX 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded. We have established a toll-free, confidential telephone hotline so that interested parties may communicate with the chairperson of the audit committee or with all the non-management directors as a group. All calls to this hotline are reported to the chairperson of the audit committee who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential hotline is (800) 826-6762.

Directors and Executive Officers

Set forth below is certain information concerning our directors and executive officers, effective as of February 22, 2012. All executive officers serve at the discretion of our general partner.

Name	Age	Position
Robert C. Sturdivant	66	Director and Chairman of the Board
Grant E. Sims	56	Director and Chief Executive Officer
James E. Davison	74	Director
James E. Davison, Jr.	45	Director
Donald L. Evans	65	Director
Sharilyn S. Gasaway	43	Director
Kenneth M. Jastrow II	64	Director
S. James Nelson	69	Director
Corbin J. Robertson III	41	Director
William K. Robertson	36	Director
Carl A Thomason	59	Director
Steven R. Nathanson	56	President and Chief Operating Officer
Robert V. Deere	57	Chief Financial Officer
Stephen M. Smith	35	Vice President
Karen N. Pape	53	Senior Vice President and Controller

Robert C. Sturdivant has served as a director of our general partner since February 5, 2010. Mr. Sturdivant currently serves as Vice President Finance and Managing Director Risk Management of certain affiliates of Quintana Capital Group II, L.P. and has served in various roles with Quintana and its affiliates since 1974. Mr.

Table of Contents

Sturdivant represents Quintana s interests as a director on the boards of several private entities. We believe that Mr. Sturdivant s background and knowledge coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to our board of directors.

Grant E. Sims has served as a director and Chief Executive Officer of our general partner since August 2006. Mr. Sims had been a private investor since 1999. He was affiliated with Leviathan Gas Pipeline Partners, L.P. from 1992 to 1999, serving as the Chief Executive Officer and a director beginning in 1993 until he left to pursue personal interests, including investments. Leviathan (subsequently known as El Paso Energy Partners, L.P. and then GulfTerra Energy Partners, L.P.) was an NYSE-listed MLP that merged with Enterprise Products Partners, L.P. on September 30, 2004. Mr. Sims provides leadership skills, executive management experience and significant knowledge of our business environment, which he has gained through his vast experience with other MLPs.

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

James E. Davison, Jr. has served as a director of our general partner since July 2007. Mr. Davison is also a director of Community Trust Bank and serves on its executive, audit, finance and compensation committees. Mr. Davison is the son of James E. Davison. Mr. Davison s executive and leadership experience enable him to make valuable contributions to our board of directors.

Donald L. Evans has served as a director of our general partner since February 5, 2010. Mr. Evans has served as President of The Don Evans Group, Ltd. since 2005 and served as the 34th Secretary of the U.S. Department of Commerce from 2001 to 2005. Since 2007, Mr. Evans has also served as the Non-Executive Chairman of Energy Future Holdings Corp., a provider of electricity and related services. We believe that Mr. Evans background and knowledge coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to our board of directors.

Sharilyn S. Gasaway has served as a director of our general partner since March 1, 2010, and serves as chairperson of the audit committee and as a member of our conflicts committee. Ms. Gasaway is a private investor and was Executive Vice President and Chief Financial Officer of Alltel Corporation, a wireless communications company, from 2006 to 2009. She served as Controller of Alltel Corporation from 2002 through 2006. Ms. Gasaway is a director of two other public companies, JB Hunt Transport Services, Inc. and Waddell and Reed Financial, Inc., serving on the audit committee of both companies. Additionally, Ms. Gasaway serves on the nominating committee of JB Hunt and the nominating and corporate governance committee and investment committees of Waddell and Reed. Ms. Gasaway provides our board of directors valuable management and financial expertise, including an understanding of the accounting and financial matters that we address on a regular basis.

Kenneth M. Jastrow, II, has served as a director of our general partner since March 1, 2010, and serves as chairperson of the G&C Committee and as a member of our conflicts committee. Mr. Jastrow is Non-Executive Chairman of Forestar Group, Inc., a real estate and natural resources company. He served as Chairman and Chief Executive Officer of Temple-Inland, Inc., a manufacturing company and the former parent of Forestar Group, from 2000 to 2007. Prior to that, Mr. Jastrow served in various roles at Temple-Inland, including President and Chief Operating Officer, Group Vice President and Chief Financial Officer. Mr. Jastrow is also a director of KB Home and MGIC Investment Corporation, where he also serves on the compensation committee. Mr. Jastrow s executive experience and service as director of other companies enable him to make valuable contributions to our board of directors.

S. James Nelson has served as a director of our general partner since March 1, 2010, and serves as chairperson of our conflicts committee and as a member of the audit committee. In 2004, Mr. Nelson retired after 15 years of service from Cal Dive International, Inc. (now known as Helix Energy Solutions Group, Inc.), a marine contractor and operator of offshore oil and natural gas properties and production facilities, where he was a founding shareholder, the Chief Financial Officer from 1990 to 2000, Vice Chairman from 2000 to 2004, and a director. Mr. Nelson is also a director of three other public companies: W&T Offshore, Inc., Oil States International, Inc. and ION Geophysical (formerly Input/Output, Inc.). Mr. Nelson also serves on the audit committee of the board of directors of each such company. In addition, from 2005 through the company s sale in 2008, Mr. Nelson was a member of the board of directors of Quintana Maritime LLC where he was also chairman of the audit committee and a member of the compensation committee. Mr. Nelson s role as a director of multiple public companies and energy industry experience enables him to provide our board of directors with valuable insight and guidance.

Table of Contents

Corbin J. Robertson III has served as a director of our general partner since February 5, 2010. Mr. Robertson has served as Managing Director, Coal and Downstream for Quintana since 2006, and is a principal in that organization. Prior to joining Quintana, Mr. Robertson was a Managing Director of Spring Street Partners, a hedge fund focused on undervalued small cap securities, a position he held from 2002 to 2007. Prior to joining Spring Street, Mr. Robertson worked for three years as a Vice President of Sandefer Capital Partners LLC, a private investment partnership focused on energy related investments, and two years as a management consultant for Deloitte and Touche LLP. We believe that Mr. Robertson s experience with investment in a variety of energy businesses provides a valuable resource to our board of directors.

William K. Robertson has served as a director of our general partner since February 5, 2010. Mr. Robertson is Managing Member of Quintana Infrastructure and Development, LLC. Mr. Robertson served as a Managing Director for Quintana Capital Group GP, Ltd. from 2005 to 2010 and continues to serve as a director of its general partner and management company. Since October 31, 2007, Mr. Robertson has served as president of Quintana Minerals Corporation, a privately-held management company. Prior to joining Quintana, Mr. Robertson worked in private investments with The CapStreet Group, LLC, and, prior to that, in the energy and power investment banking department of Merrill Lynch, Pierce, Fenner & Smith Inc. Mr. Robertson is the brother of Corbin J. Robertson III. We believe that Mr. Robertson brings to our board of directors experience investing in and operating energy assets.

Carl A. Thomason has served as a director of our general partner since March 1, 2010, and serves on the audit committee and conflicts committee. Mr. Thomason has been a marketing consultant to Yessup Oil Corp., a crude oil marketing company, since 2004 and prior to that he served for over thirty years in various roles in the crude oil gathering business, including as an owner of a regional crude oil gathering and transportation company. Mr. Thomason is a director of Forestar Group, Inc., a real estate and natural resources company, serving on the audit and nominating and governance committees. Mr. Thomason s experience in the crude oil gathering business and familiarity with the energy industry enhances his contributions to our board of directors.

Steven R. Nathanson became President and Chief Operating Officer in December 2010 and an executive officer of our general partner in February 2010. He had served as President of our refinery services subsidiary, TDC, LLC since 2002.

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

Stephen M. Smith has served as Vice President of our general partner since February 2010. Mr. Smith is responsible for commercial development and the commercial aspects of our Supply and Logistics segment. Since 2009, Mr. Smith has served in various capacities within our commercial development and finance groups. He was a Principal for the energy investment banking group at Banc of America Securities from 2006 to 2009.

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

Code of Ethics

We have adopted a code of ethics that is applicable to, among others, the principal financial officer and the principal accounting officer. The Genesis Energy Financial Employee Code of Professional Conduct is posted at our website (www.genesisenergy.com), where we intend to report any changes or waivers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our officers and directors of our general partner and persons who own more than ten percent of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC and the NYSE. Based solely on our review of the copies of such reports received by us, or written representations from certain reporting persons to us, we are aware of no filings that were not timely made.

Item 11. Executive Compensation

Genesis Energy, LLC, our general partner, directs and manages all of our activities. Our executive officers and most of our employees are employed by Genesis Energy, LLC. Under the terms of our partnership agreement, we are required to reimburse our general partner for expenses relating to managing our operations, including salaries and bonuses of employees employed on our behalf, as well as the costs of providing benefits to such persons under employee benefit plans. We own 100% of Genesis Energy, LLC.

The Compensation Discussion and Analysis below discusses our compensation process, objectives and philosophy with respect to our Named Executive Officers (NEOs), for the fiscal year ended December 31, 2011.

Compensation Discussion and Analysis

Named Executive Officers

Our NEOs for 2011 were:

- Grant E. Sims, Chief Executive Officer;
- Steven R. Nathanson, President and Chief Operating Officer;
- Robert V. Deere, Chief Financial Officer;
- Stephen M. Smith, Vice President; and
- Karen N. Pape, Senior Vice President and Controller.

Board and Governance, Compensation and Business Development Committee

Our board of directors is responsible for, and effectively determines, compensation matters. Our board of directors has delegated to the G&C Committee, the authority and responsibility to regularly analyze and reconsider our compensation policies, to determine the annual compensation of our employees, and to make recommendations to our board of directors with respect to such matters. As described in more detail below, the G&C Committee engaged BDO USA, LLP, or BDO, as its independent compensation advisor. We also utilize committees comprised solely of certain of our independent directors (i.e., the audit committee, conflicts committee or special committees) to review and make recommendations with respect to certain matters such as obtaining exemptions from the insider trading trading rules under Section 16 of the Exchange Act in connection with certain acquisitions. Because the G&C Committee is comprised of all the members of our board of directors, excluding our CEO, determinations by the G&C Committee are effectively determinations by our board of directors. For a more detailed discussion regarding the purposes and composition of board committees, please see Item 10. Directors, Executive Officers and Corporate Governance.

Committee/Board Process

Following the end of each calendar year, our CEO reviews the compensation of all the other NEOs and makes a proposal to the G&C Committee as to the compensation of the other NEOs, which proposal is based on (among other things) our financial results for the prior year, the individual executive s areas of responsibility, as well as recommendations from that executive s supervisor (if other than our CEO). The G&C Committee reviews the compensation of our CEO and the proposal of our CEO regarding the compensation of the other NEOs and makes a final determination with our board of directors regarding compensation of our NEOs. Depending on the nature and quantity of changes made to that proposal, there may be additional G&C Committee meetings and discussions with our CEO in advance of that determination.

Committee/Board Approval

The G&C Committee determines compensation and long-term awards for executive officers, taking into consideration the CEO s recommendation regarding the NEOs. Following approval of the entire annual compensation program in the first quarter of each year, any applicable salary increases and long-term incentive awards are made or granted. Bonuses are paid in March.

Role of Compensation Consultant

The G&C Committee s charter authorizes the committee to retain independent compensation consultants from time to time to serve as a resource in support of its efforts to carry out certain duties. In 2011, the G&C Committee engaged BDO, an independent compensation consultant, to assist the Committee in assessing and structuring

Table of Contents

competitive compensation packages for the executive officers that are consistent with our compensation philosophy. At the request of the G&C Committee, BDO reviewed and provided input on the compensation of our NEOs, trends in executive compensation, meeting materials prepared for and circulated to the G&C Committee and management s proposed executive compensation plans. BDO also developed assessments of market levels of compensation through an analysis of peer data and information disclosed in our peer companies public filings.

The peer group used for this analysis consisted of the following 18 companies in the energy industry: Blueknight Energy Partners, Buckeye Partners, Copano Energy, LLC, Crosstex Energy Partners, DCP Midstream Partners, Eagle Rock Energy Partners, Holly Energy Partners, Magellan Midstream Partners, NuStar Energy, LP, Penn Virginia Resource Partners, Regency Energy Partners, Sunoco Logistics, LP, Targa Resource Partners, Amerigas Partners, Calumet Specialty Products Partners, Frontier Oil, Natural Resource Partners and Western Refining. These companies were selected as the compensation peer group because: 1) they reflect our industry competitors for products and services; 2) operate in similar markets or have comparable geographical reach; 3) are of similar size and maturity to us; or 4) are companies that had similar credit profiles, comparable debt and equity markets or similar growth or capital programs to us. The information that BDO compiled included compensation trends for MLPs, and levels of compensation for similarly-situated executive officers of companies within this peer group and in other companies with revenues generally comparable to ours. We believe that compensation levels of executive officers in our peer group are relevant to our compensation decisions because we compete with those companies for executive management talent.

Compensation Objectives and Philosophy

The primary objectives of our compensation program are to:

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

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

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

As described in more detail below, we believe that the combination of base salaries, cash bonuses and long-term incentive plans provide an appropriate balance of short-term and long-term incentives, cash and non-cash based compensation and an alignment of the incentives for our executives, including our NEOs, with the interests of our common unitholders. Compensation that is earned over the long-term through service and performance-based opportunities aims to assure an alignment between executives and investors in the organization. The amount of compensation contingent on performance is weighted appropriately as a percentage of total compensation to ensure business decisions and actions lead to the long-term growth and sustainability of the organization. Our bonus plan is driven by the generation of Available Cash before Reserves (which is an important metric of value for our unitholders) and our safety record. Our long term incentive plan is linked primarily to the appreciation in our common unit price and increases in the distribution rate on our common units, which we believe links pay with performance and creates an alignment of interest between our NEOs and our unitholders.

Table of Contents

Elements of Our Compensation Program and Compensation Decisions for 2011

The primary elements of our compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the year ended December 31, 2011, the elements of our compensation program for the NEOs consisted of the following:

- annual cash base salary;
- discretionary annual cash bonus awards; and
- annual grants under long-term incentive arrangements.

Base Salaries

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

In May 2011, the G&C Committee reviewed the assessments of market levels of compensation developed by BDO in conjunction with a discussion of individual performance and responsibilities and, as a result, approved market adjustments for the following NEOs: Mr. Sims salary was increased 3% to $475,000, Mr. Smith s salary was increased 10% to $220,000 and Ms. Pape s salary was increased 7% to $240,000. The G&C Committee determined that such increases were necessary to align salaries to comparable market levels and were warranted in light of their individual performance and increased levels of responsibility related to the management of the company. Two other NEOs salaries were not adjusted because their salary levels were judged to be sufficiently consistent with market norms. The decision not to make salary adjustments for those individuals was not the result of a negative evaluation of their performance.

Bonuses

Our NEOs participate in a bonus program, or the Bonus Plan, in which all company employees participate. As designed by the G&C Committee, each NEO has an annual bonus target based on a stated percentage of his or her base salary. The targeted amount for the NEOs is set following the analysis of market practices of the peer group and consideration of the level of salary and targeted long-term incentives for each NEO. For 2011, the G&C Committee set each NEO s bonus target as a percentage of salary as follows:

Name	2011 Bonus Target (% of base salary)
Grant E. Sims	100%
Steven R. Nathanson	100%
Robert V. Deere	40%
Stephen M. Smith	100%
Karen N. Pape	75%

The Bonus Plan is designed to reward employees on a basis that is aligned with the interests of our unitholders. We believe the Plan generates a bonus that represents a meaningful level of compensation for the employee population and encourages employees to operate as a unified team to generate results that are aligned with the interests of our unitholders. The G&C Committee therefore designed the Bonus Plan to enhance our financial performance by rewarding our NEOs and other employees for achieving (i) financial performance and (ii) safety objectives. Attainment of these two goals is measured by Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) and company-wide safety incident rates. Available Cash before Reserves is an important factor in determining the amount of distributions to our unitholders and is a significant factor in the market s perception of the value of common units of an MLP. Safety objectives encourage our employees to focus on the impact their job performance has on the environment in which we operate. Both of these measures are used to calculate the recommended bonus payout (or general bonus pool) described below. However, bonuses are paid at the discretion of the G&C Committee based on quantitative and qualitative measures relating to: our financial and operational performance relative to our peers; industry expectations; progress in attaining strategic goals; and

Table of Contents

individual performance. Because the determination of whether bonuses will be paid each year and in what amounts they will be paid is determined by the G&C Committee on a company-wide basis, NEOs only receive bonuses if other employees receive bonuses. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation for a description of Available Cash before Reserves.

The general bonus pool is weighed and calculated as follows: the level of Available Cash before Reserves generated for the year as a percentage of a target set by the G&C Committee was weighted 90% and the achieved level of the safety incident rate was weighted 10%. The sum of the weighted percentage achievement of these targets was multiplied by the eligible compensation and the target percentages established by the G&C Committee for the various levels of our employees to determine the maximum general bonus pool.

The total 2011 pool approved for such bonuses, inclusive of other discretionary downward adjustments, was approximately $6.2 million. From the general bonus pool amount, the G&C Committee approved 2011 bonuses of $450,000, $420,000, $130,000, $220,000 and $130,000 to Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape, respectively. The bonuses were approved based on the G&C Committee s review of the operational and financial performance of the company, industry expectations and individual performance. The bonuses will be paid in March 2012.

Long-Term Incentive Compensation

We provide equity-based, long-term compensation for employees, including executives and directors, through our 2010 Long-Term Incentive Plan, or the 2010 LTIP. The 2010 LTIP is designed to promote a sense of proprietorship and personal involvement in our development and financial success among our employees and directors through awards of phantom units and distribution equivalent rights, or DERs. The 2010 LTIP also allows for providing flexible incentives to employees and directors. The 2010 LTIP provides for the awards of phantom units and DERs to directors of our general partner, and employees and other representatives of our general partner and its affiliates who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. DERs are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on the phantom units had they been limited partner units issued by us.

The G&C Committee administers the 2010 LTIP. Under the 2010 LTIP, the G&C Committee (at its discretion) has the authority to determine the terms and conditions of any awards granted under the 2010 LTIP and to adopt, alter and repeal rules, guidelines and practices relating to the 2010 LTIP. The G&C Committee has full discretion to administer and interpret the 2010 LTIP and to establish such rules and regulations as it deems appropriate and to determine, among other things, the time or times at which the awards may be exercised and whether and under what circumstances an award may be exercised. The G&C Committee designates participants in the 2010 LTIP, determines the types of awards to grant to participants and determines the number of units to be covered by any award. Our board of directors can terminate the 2010 LTIP at any time.

Long-term incentive awards are expressed as a percentage of base salary. This percentage reflects the expected fair value of the awards to be granted in aggregate each year. The targeted amount for the NEOs is set following the analysis of market practices of the peer group and consideration of the level of salary and targeted bonus for each NEO. For 2011, the G&C Committee established the following long-term incentive target percentages (expressed as a percent of base salary) for each of our NEOs:

Name	2011 Long-Term Incentive Target (% of base salary)
Grant E. Sims	175%
Steven R. Nathanson	150%
Robert V. Deere	100%
Stephen M. Smith	100%
Karen N. Pape	75%

In April 2011, phantom units were granted to our NEOs and certain non-officer employees under the 2010 LTIP. The phantom units will be paid in cash upon vesting based on the average closing price of the common units for the 20 trading days immediately prior to the date of vesting. The phantom units granted to our NEOs in April 2011 were all performance-based awards while phantom units granted to our non-officer employees, were apportioned 60% to performance-based awards and 40% to service-based awards. The service-based awards vest on the third year anniversary from the date of grant.

Between 50% and 150% of the number of performance-based awards granted to our NEOs and non-officer employees will vest on the third anniversary of issuance if certain quarterly cash distribution targets are achieved in the 2013 fourth quarter. These awards will vest as follows: (i) if the quarterly cash distribution on the common units is $0.46 per unit, 50% of the phantom units granted will vest, and the remainder will be forfeited; (ii) if the quarterly cash distribution on the common units is $0.49 per unit, 100% of the phantom units granted will vest; or (iii) if the quarterly cash distribution on the common units is $0.52 per unit or greater, 150% of the phantom units granted will vest. Should the quarterly cash distribution on the common units fall between the range of $0.46 per unit and $0.52 per unit, the phantom units will vest between 50% and 150% of the number granted on a pro rata basis. If the quarterly cash distribution is below $0.46 per unit for the fourth quarter of 2013, all of the performance-based phantom units granted will be forfeited. The distribution targets are based on targeted distribution annual growth rates ranging between approximately 5% and 9%.

The phantom units also include distribution equivalent rights, or DERs, which are granted in tandem with all phantom units. DERs on service-based awards to our non-officer employees will be paid in connection with the vesting of the related phantom units. DERs on all granted performance-based awards are accumulated and paid upon vesting when the number of phantom units earned is determined.

Termination or Change of Control Benefits

We consider maintaining a stable and effective management team to be essential to protecting and enhancing the best interests of us and our unitholders. To that end, we recognize that the possibility of a change of control or other acquisition event may raise uncertainty and questions among management, and that this uncertainty may adversely affect our ability to retain our key employees, which would be to our unitholders detriment. Because our management team was built over time, as described above, and our NEOs became NEOs under different circumstances, the compensation and benefits awarded to our individual NEOs in the event of termination or a change of control varies. The employment agreements of Messrs. Sims, Deere and Nathanson provide certain compensation and benefits as an incentive for the executive to remain in our employ and enhance our ability to call on and rely upon the executive in the event of a change of control. None of these NEOs would be entitled to severance benefits if terminated by our general partner for cause. In extending these benefits, we considered a number of factors, including the prevalence of similar benefits adopted by other publicly traded MLPs. See Employment Agreements below for further discussion of employment agreements, including the definitions of certain terms such as change of control and cause.

We believe that the interests of unitholders will best be served if the interests of our management and unitholders are aligned. We believe the termination and change of control benefits described above strike an appropriate balance between the potential compensation payable and the objectives described above and should reduce any possible reluctance to pursue transactions that may be in the best interests of our unitholders.

For more details on the benefits and payouts under various termination scenarios, including in connection with a change of control, see Potential Payments upon Termination or Change of Control.

Other Compensation and Benefits

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

Tax and Accounting Implications

Because we are a partnership and not a corporation for federal income tax purposes, we are not subject to the limitations of Internal Revenue Code Section 162(m) with respect to tax-deductible executive compensation. However, if such tax laws related to executive compensation change in the future, the G&C Committee will consider the implication of such changes to us.

For our equity-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 15 of our Consolidated Financial Statements in Item 8.

Table of Contents

Compensation Committee Report

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

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

Kenneth M. Jastrow, II, Chairman

S. James Nelson

James E. Davison

James E. Davison, Jr.

Sharilyn S. Gasaway

Donald L. Evans

Corbin J. Robertson III

William K. Robertson

Robert C. Sturdivant

Carl A. Thomason

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

Compensation Risk Assessment

Our board of directors does not believe that our compensation policies and practices for employees are reasonably likely to have a material adverse effect on us. We compensate all employees with a combination of competitive base salary and incentive compensation. Our board of directors believes that the mix and design of the elements of employee compensation do not encourage employees to assume excessive or inappropriate risk taking.

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

- the company has strong internal financial controls;
- base salaries are consistent with employees responsibilities so that they are not motivated to take excessive risks to achieve a reasonable level of financial security;
- the determination of incentive awards is based on a review of a variety of indicators of performance as well as a meaningful subjective assessment of personal performance, thus diversifying the risk associated with any single indicator of performance;

goals are appropriately set to avoid targets that, if not achieved, result in a large percentage loss of compensation;

incentive awards are capped by the G&C Committee;

compensation decisions include discretionary authority to adjust annual awards and payments, which further reduces any business risk associated with our plans; and

long-term incentive awards are designed to provide appropriate awards for dedication to a corporate strategy that delivers long-term returns to unitholders.

Table of Contents

2011 SUMMARY COMPENSATION TABLE

The following Summary Compensation Table summarizes the total compensation paid or accrued to our NEOs in 2011, 2010 and 2009.

Name & Principal Position	Year	Salary ($)	Bonus (1) ($)	Stock Awards (2) ($)	All Other Compen-sation (3) ($)	Total ($)
Grant E. Sims	2011	460,962	450,000	839,346	74,978	1,825,286
Chief Executive Officer	2010	440,000	446,200	4,186,488	72,262	5,144,950
(Principal Executive Officer)	2009	340,000			50,904	390,904
Steven R. Nathanson (4)	2011	323,654	420,000	499,807	58,087	1,301,548
President & Chief Operating Officer	2010	320,067	320,100	2,259,069	66,187	2,965,423
Robert V. Deere	2011	411,923	130,000	424,085	37,285	1,003,293
Chief Financial Officer	2010	413,167	101,850	805,066	61,696	1,381,779
(Principal Financial Officer)	2009	369,600			52,574	422,174
Stephen M. Smith (5)	2011	209,231	220,000	222,149	23,091	674,471
Vice President	2010	226,247	194,000	1,097,914	38,766	1,556,927
Karen N. Pape	2011	230,481	130,000	181,751	36,692	578,924
Senior Vice President &	2010	225,000	218,250	400,877	44,227	888,354
Controller (Principal Accounting Officer)	2009	225,000	170,000	58,408	20,238	473,646

(1) Bonuses for 2011 were approved in February 2012 and will be paid in March 2012. Bonuses for 2010 were paid in March 2011. The amounts in this column for Ms. Pape for 2009 represent bonuses paid in March 2010 relative to 2009 under our bonus program that was effective for 2009.

(2) The amounts shown in this column for 2011 and 2010 represent the aggregate grant date fair value for each NEO s phantom units granted under our 2010 Long-Term Incentive Plan. Amounts in 2010 also include the aggregate grant date fair value for each NEO s Series B Award. The Series B Awards provided for the conversion into Series A units in our general partner under certain conditions. These awards were ultimately exchanged for our Class A Units and Waiver Units in connection with our IDR Restructuring. For additional information on these awards and our IDR Restructuring see Note 15 to our Consolidated Financial Statements in Item 8. Amounts in this column for Ms. Pape in 2009 represent the aggregate grant date fair value of the phantom units granted under our 2007 Long Term Incentive Plan, or 2007 LTIP. The grant date fair value of each award was determined in accordance with accounting guidance for equity-based compensation and is based on the probable outcome of any underlying performance conditions. Assumptions used in the calculation of these amounts are included in Note 15 to our Consolidated Financial Statements in Item 8.

(3) Information on the amounts included in this column is included in the table below.

(4) Mr. Nathanson became an executive officer of our general partner on February 5, 2010.

(5) Mr. Smith became an executive officer of our general partner on December 28, 2010.

78

Table of Contents

		2011 All Other Compensation			
Name	Year	401(k) Matching and Profit Sharing Contributions (a)	Insurance Premiums (b)	Other Compensation (c)	Totals
Grant E. Sims	2011	$ 7,350	$ 2,700	$ 64,928	$ 74,978
	2010	$ 7,350	$	$ 64,912	$ 72,262
	2009	$ 7,350	$	$ 43,554	$ 50,904
Steven R. Nathanson	2011	$ 19,976	$ 2,700	$ 35,411	$ 58,087
	2010	$ 19,677	$ 207	$ 46,303	$ 66,187
Robert V. Deere	2011	$ 7,350	$ 2,700	$ 27,235	$ 37,285
	2010	$ 7,350	$	$ 54,346	$ 61,696
	2009	$ 7,350	$	$ 45,224	$ 52,574
Stephen M. Smith	2011	$ 7,350	$ 1,881	$ 13,860	$ 23,091
	2010	$ 6,870	$ 138	$ 31,758	$ 38,766
Karen N. Pape	2011	$ 22,050	$ 2,070	$ 12,572	$ 36,692
	2010	$ 20,606	$ 155	$ 23,466	$ 44,227
	2009	$ 18,375	$ 1,863	$	$ 20,238

The amounts in this table represent:

(a) Contributions by us to our 401(k) plan on each NEO s behalf.

(b) Term life insurance premiums paid by us on each NEO s behalf.

(c) For 2011 and 2010, this column includes cash distributions paid in connection with granted DERs. For 2010 and 2009, this column also includes reimbursements for additional benefit costs and taxes paid by our NEOs. Prior to December 2010, our NEOs as owners of our general partner were reimbursed for the additional benefit costs and taxes they paid or owed individually related to their medical, dental, disability and life insurance, as well as self-employment taxes (see Note 11 to our Consolidated Financial Statements for further information regarding our IDR Restructuring). During 2011, NEOs did not receive reimbursement for additional benefits costs and taxes paid. Reimbursements for additional benefits costs in 2010 were $14,605, $16,112, $17,163, $13,201 and $7,267 for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape, respectively. Reimbursements for taxes in 2010 were $31,329, $21,117, $31,409, $15,811, and $13,108 for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape, respectively. Amounts paid for DERs in 2010 were $18,978, $9,074, $5,774, $2,746 and $3,091 for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape, respectively. In 2009, the amount for Mr. Sims was $16,127 for reimbursements for additional benefits costs and $27,427 for tax reimbursements. The amount for Mr. Deere in 2009 was $16,160 for reimbursements for additional benefits costs and $29,064 for tax reimbursements.

Table of Contents

GRANTS OF PLAN-BASED AWARDS IN FISCAL YEAR 2011

The following table shows equity incentive plan awards granted to our NEOs in 2011.

Grants of Plan-based Awards In Fiscal Year 2011

Name	Grant Date	Estimated Future Payouts (Phantom Units) Under Equity Incentive Plan Awards (1) Threshold	Target	Maximum	Market Price of Common Units on Award Date (2)	Grant Date Fair Value of Stock and Option Awards (3)
Grant E. Sims	4/29/2011	14,887	29,773	44,660	$ 27.92	$ 839,346
Steven R. Nathanson	4/29/2011	8,865	17,729	26,594	$ 27.92	$ 499,807
Robert V. Deere	4/29/2011	7,522	15,043	22,565	$ 27.92	$ 424,085
Stephen M. Smith	4/29/2011	3,940	7,880	11,820	$ 27.92	$ 222,149
Karen N. Pape	4/29/2011	3,224	6,447	9,671	$ 27.92	$ 181,751

(1) Represents the number of phantom units that each NEO can earn of the initial grant awarded on April 29, 2011, if the company meets certain performance conditions (threshold, target and maximum) during the 2013 fourth quarter. Upon achieving either the threshold, target or maximum levels during the fourth quarter of 2013 the NEO earns either 50% of the initial grant, 100% of the initial grant or 150% of the initial grant, respectively. The target level represents the number of phantom units initially issued on the grant date. The performance targets are as follows: (i) at threshold, if the quarterly cash distribution on the common units is $0.46 per unit, 50% of the phantom units granted will vest and the remainder will be forfeited; (ii) at target, if the quarterly cash distribution on the common units is $0.49 per unit, 100% of the phantom units granted will vest); or (iii) at maximum, if the quarterly cash distribution on the common units is $0.52 per unit or greater, 150% of the phantom units granted will vest. Should the quarterly cash distribution on the common units fall between the range of $0.46 per unit and $0.52 per unit, the phantom units will vest between 50% and 150% of the number granted on a pro rata basis. If the quarterly cash distribution is below $0.46 per unit for the fourth quarter of 2013, all of the phantom units granted will be forfeited.

(2) Represents the closing market price of our common units on the date of the phantom unit award on April 29, 2011.

(3) The amounts in this column for each NEO represent the fair value of the award on the date of the grant, based on a target performance payout (as calculated in accordance with accounting guidance for equity-based compensation) using the twenty day average closing price of our common units through the date of grant ($28.19).

Table of Contents

Employment Agreements

Grant E. Sims and Robert V. Deere

In December 2008, the stakeholders of our general partner, our general partner and Messrs. Sims and Deere finalized a compensation philosophy and structure for our executive officers; at which time Messrs. Sims and Deere entered into four-year employment agreements. Those employment agreements automatically terminate on December 31, 2012 unless terminated earlier in accordance with the terms thereof. In February 2010, in connection with the change of control in our general partner, Messrs. Sims and Deere (i) entered into waiver agreements that amended the change of control and severance payment rights under their 2008 employment agreements and (ii) agreed to enter into a new employment agreement and a related release agreement with different terms in the future if requested by our general partner subject to the G&C Committee s approval and, if needed, the approval of our board of directors. Unless and until Messrs. Sims and Deere enter into new employment agreements, their 2008 employment agreements (as amended by their waiver agreements) will remain in effect until December 31, 2012. Currently, the annual base salaries of Messrs. Sims and Deere are $475,000 and $420,000, respectively.

Each 2008 employment agreement contains customary non-solicitation and non-competition provisions that prohibit the executive from competing with us after termination, including working for, supervising, assisting, or participating in any competing business in any capacity in the states of Louisiana, Mississippi, and Texas during the term of the employment agreement and for a period of two years after termination if the employment agreement is terminated by our general partner for cause or by the executive without good reason, and for a period of one year after termination if the employment agreement is terminated by our general partner for reasons other than cause or by the executive with good reason. Under those employment agreements, Messrs. Sims and Deere are entitled to specified severance benefits under certain circumstances described below.

Each of Messrs. Sims and Deere (or his respective family) would be entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through December 31, 2012 if he dies, if he is terminated due to a disability or if he terminates his employment for good reason. If our general partner terminates Mr. Sims or Mr. Deere (other than for cause) within two years after a change of control, he would be entitled to continued health benefits for 18 months after his termination to the extent that such benefits are subsidized by the Partnership for its active employees and to the payment of his base salary up through the third year from his date of termination. As used in the employment agreements of Messrs. Sims and Deere, the terms cause, good reason and disability are generally described below:

Cause means, in general, if an executive commits willful fraud or theft of our assets, is convicted of a felony or crime of moral turpitude, materially violates certain provisions of his employment agreement, substantially fails to perform, is grossly negligent, acts with willful misconduct, acts in a way materially injurious to us, willfully violates material written rules, regulations or policies, or fails to follow reasonable instructions from the audit committee, and such failure to follow instructions could reasonably be expected to be materially injurious to us.

Good reason means, in general, an executive s duties, responsibilities, base salary, or benefits are materially diminished, if either our principal executive office or that executive is based anywhere outside of metropolitan Houston without his consent, if our general partner fails to make a material payment under, or perform a material provision of, his employment agreement, or our general partner amends or changes certain equity interests in a manner that materially and adversely affects the executive s right to distributions or redemptions payable because of such amendment or change, subject to certain exceptions.

Disability means, in general, if the executive has been absent from his duties with us on a full-time basis for 180 out of any 220 consecutive calendar days as a result of incapacity due to mental or physical illness or injury that is determined to be total and permanent by a selected physician or if the Social Security Administration has determined that executive is totally disabled.

Steven R. Nathanson

Mr. Nathanson entered into an employment agreement in July 2007, at a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr.Nathanson is $330,000. The agreement also provides that Mr. Nathanson is eligible to participate in all other benefit programs (e.g., health, dental, disability, life and/or other insurance plans) for which executive officers are generally eligible. Mr. Nathanson s employment arrangement includes customary non-competition restrictions following his termination.

81

Table of Contents

After his termination other than for cause, including in the event of a change of control, during the initial term of Mr. Nathanson s employment agreement, Mr. Nathanson would be entitled to continued health benefits for the remainder of the term of his employment agreement for up to 18 months and to the greater of payment of his base salary for one year or the remainder of the term of his employment agreement and in no event for more than 18 months.

As used in the employment agreement of Mr. Nathanson, the terms cause and change of control are generally described below:

Cause means, in general, if the executive commits theft, embezzlement, forgery, any other act of dishonesty relating the executive s employment or violates our policies or any law, rule, or regulation applicable to us, is convicted of a felony or lesser crime having as its predicate element fraud, dishonesty, or misappropriation, fails to perform his duties under the employment agreement or commits an act or intentionally fails to act, which act or failure to act amount amounts to gross negligence or willful misconduct.

Change of control means, in general, any sale of equity of us or our general partner or substantially all of the assets of us or our general partner, merger, conversion or consolidation of us or our general partner, or other event that, in each case, results in any person or entity (or other persons or entities acting in concert) having the ability to elect a majority of the members of our board of directors.

Stephen M. Smith and Karen N. Pape

Neither Mr. Smith nor Ms. Pape has an employment agreement with us.

Table of Contents

OUTSTANDING EQUITY AWARDS AT 2011 FISCAL YEAR-END

The following table presents information regarding the outstanding equity awards to our NEOs at December 31, 2011.

		Stock Appreciation Rights				Stock Awards			
Name	Grant Date	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable (1)	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable (2)	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date	Number of Phantom Units That Have Not Vested (#) (3)	Market Value of Phantom Units That Have Not Vested ($) (4)	Equity Incentive Plan Awards: Number of Unearned Phantom Units That Have Not Vested (#) (5)	Equity Incentive P lan Awards: Market Value of Unearned Phantom Units That Have Not Vested ($) (4)
Grant E. Sims	4/29/2011							14,887	$ 396,180
	4/20/2010					16,795	$ 446,957		
Steven R. Nathanson	4/29/2011							8,865	$ 235,920
	4/20/2010					8,030	$ 213,698		
	2/14/2008	12,348	4,117	$ 20.92	2/14/2018				
Robert V. Deere	4/29/2011							7,522	$ 200,179
	4/20/2010					5,110	$ 135,990		
Stephen M. Smith	4/29/2011							3,940	$ 104,853
	4/20/2010					2,430	$ 64,668		
Karen N. Pape	4/29/2011							3,224	$ 85,799
	4/20/2010					2,735	$ 72,785		
	2/14/2008		4,790	$ 20.92	2/14/2018				
	12/29/2006	4,254		$ 19.57	12/29/2016				
	8/29/2006	767		$ 16.95	8/29/2016				
	12/31/2005	3,071		$ 11.17	12/31/2015				
	12/31/2004	2,889		$ 12.48	12/31/2014				
	12/31/2003	12,153		$ 9.26	12/31/2013				

(1) All rights in this column were vested at December 31, 2011.
(2) The unexercisable rights of each named executive officer, which vested on January 1, 2012.
(3) The phantom unit awards granted in 2010 vest on April 20, 2013.
(4) The amounts in this column were calculated by multiplying the closing market price of our units using the twenty day average at year-end by the number of applicable units outstanding.
(5) The number of performance units reflected in the table assumes a threshold performance payout during the 2013 fourth quarter (at which 50% of the initial phantom units awarded will vest on the third year anniversary from the date of grant). The phantom units will vest at the end of three years between 50% and 150% of the number granted, if certain quarterly cash distribution target levels for the 2013 fourth quarter are achieved.

Table of Contents

Potential Payments upon Termination or Change in Control

Each of Messrs. Sims, Deere and Nathanson is entitled under his employment agreement to specified severance benefits under certain circumstances as discussed above under Employment Agreements. Under a change in control and certain termination circumstances, our NEOs also will vest in any outstanding awards under our 2010 LTIP.

Based upon a hypothetical termination date of December 31, 2011, the termination benefits for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape for voluntary termination or termination for cause would be zero.

Based upon a hypothetical termination date of December 31, 2011, the termination benefits for of Messrs. Sims, Nathanson and Deere for termination without cause or for good reason, including death or disability would have been:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere
Severance payment pursuant to employment agreement	$ 475,000	$ 330,000	$ 420,000
Healthcare	24,180	20,551	30,826
Total	$ 499,180	$ 350,551	$ 450,826

If termination occurs due to death or disability, Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape would vest in outstanding phantom unit awards under our 2010 LTIP. Utilizing the closing price of our common units for the twenty trading days prior to December 31, 2011 would result in payments under the 2010 LTIP of the following amounts upon death or disability:

Grant E. Sims	$ 1,239,291
Steven R. Nathanson	$ 685,511
Robert V. Deere	$ 536,322
Stephen M. Smith	$ 274,375
Karen N. Pape	$ 244,356

Based on a hypothetical termination date of December 31, 2011, the change of control termination benefits for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape would have been as follows:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere	Stephen M. Smith	Karen N. Pape
Severance payment pursuant to employment agreement	$ 1,425,000	$ 330,000	$ 1,260,000	$	$
Healthcare	24,180	20,551	30,826		
Cash payment for vested phantom units under 2010 LTIP	1,239,291	685,511	536,322	274,375	244,356
Total	$ 2,688,471	$ 1,036,062	$ 1,827,148	$ 274,375	$ 244,356

Table of Contents

DIRECTOR COMPENSATION FOR FISCAL YEAR 2011

The table below reflects compensation for the directors.

Director Compensation in Fiscal 2011

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($) (2) (3)	All Other Compensation ($)(4)	Total
James E. Davison	$ 76,500	$ 75,000	$ 7,396	$ 158,896
James E. Davison, Jr.	$ 76,500	$ 75,000	$ 7,396	$ 158,896
Donald L. Evans (5)	$ 75,000	$ 75,000	$ 7,396	$ 157,396
Sharilyn S. Gasaway	$ 95,500	$ 85,000	$ 8,379	$ 188,879
Kenneth M. Jastrow, II	$ 83,000	$ 80,000	$ 7,865	$ 170,865
S. James Nelson	$ 90,500	$ 80,000	$ 7,793	$ 178,293
Corbin J. Robertson III (5)	$ 76,500	$ 75,000	$ 7,396	$ 158,896
William K. Robertson (5)	$ 75,000	$ 75,000	$ 7,396	$ 157,396
Robert C. Sturdivant (5)	$ 76,500	$ 75,000	$ 7,396	$ 158,896
Carl A. Thomason	$ 85,500	$ 75,000	$ 7,396	$ 167,896

(1) Amounts include annual retainer fees and fees for attending meetings.

(2) Amounts in this column represent the fair value of the awards of phantom units under our 2010 LTIP on the date of grant, as calculated in accordance with accounting guidance for equity-based compensation.

(3) Outstanding awards to directors at December 31, 2011 consist of phantom units granted under our 2010 LTIP and stock appreciation rights pursuant to our SAR Plan. Messrs. James Davison and James Davison Jr. each hold 5,578 outstanding phantom units and 1,000 stock appreciation rights. Messrs. Jastrow, Nelson and Thomason and Ms. Gasaway hold 5,949, 5,946, 5,578 and 6,319 outstanding phantom units, respectively. Each of Messrs. Evans, C. Robertson, W. Robertson and Sturdivant hold 5,578 phantom units, of which all proceeds will be paid to an affiliate of Quintana.

(4) Amounts in this column represent the amounts paid for tandem DERs related to outstanding phantom units granted under our 2010 LTIP. DERs for each of Messrs. Evans, C. Robertson, W. Robertson and Sturdivant were paid to an affiliate of Quintana.

(5) These directors have agreed to give all compensation for their services as directors to an affiliate of Quintana. All fees paid and amounts paid for DERs related to phantom unit awards in 2011 for these directors were paid to an affiliate of Quintana.

Directors who are not officers of our general partner are entitled to a base compensation of $150,000 per year, with $75,000 paid in cash and $75,000 paid in phantom units. Cash is paid, and phantom units are awarded, on the first day of each calendar quarter. All phantom units awarded to directors are service-based and vest on the third anniversary from the date of grant. The determination of the number of phantom units awarded is determined by dividing the closing market price of our units on the date of the award into the quarterly amount to be paid in phantom units. So long as he or she is a director on the relevant date of determination, each director will receive: (i) a quarterly distribution equal to the number of phantom units held by such director multiplied by the quarterly distribution amount we will pay in respect of each of our outstanding common units on such distribution date, and (ii) on the third anniversary of each award date for such director, an amount equal to the number of phantom units granted to such director on such award date multiplied by the average closing price of our common units for the 20 trading days ending on the day immediately preceding such anniversary date.

Table of Contents

Chairpersons of the audit, and conflicts committees as well as the G&C Committee receive an additional amount of base compensation split equally between cash and phantom units, which compensation is paid in equal quarterly installments. Such additional amount is $20,000 for the chair of the audit committee and $10,000 for the chair of the G&C Committee and conflicts committee.

In addition, each director receives additional cash compensation for each Additional Meeting (board and/or committee) in which he or she participates. Participation by a director in-person will entitle her/him to additional compensation of $2,000 per meeting, and participation by a director by means of telecommunication will entitle her/him to additional compensation of $1,500 per meeting. Such payments are made in connection with the quarterly payments of base compensation. Additional Meetings consist of (i) with respect to our board of directors any meetings (in-person or by telecommunication) other than (x) the four pre-set meetings of our board of directors for each calendar year and (y) brief follow-up telecommunication conferences relating to the Annual Report on Form 10-K or any Quarterly Report on Form 10-Q the company files with the SEC, and (ii) any committee meeting.

Compensation Committee Interlocks and Insider Participation

None of the members of the G&C Committee has at any time been an officer or employee of our general partner or us. None of our executive officers serves, or in the past year has served, as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving on our G&C Committee.

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

Securities Authorized for Issuance Under Equity Compensation Plans

	Number of securities remaining available for future issuance under equity compensation plans securities
Equity Compensation plans approved by security holders:	
2007 Long-term Incentive Plan (2007 LTIP)	832,928

There are no outstanding phantom units under this plan as of December 31, 2011. For additional discussion of our 2007 LTIP, see Note 15 to our Consolidated Financial Statements in Item 8.

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 15, 2012, regarding the beneficial ownership of our Class A Common Units and Class B Common Units by beneficial owners of 5% or more of such units, by directors and the executive officers of our general partner and by all directors and executive officers as a group. This information is based on data furnished by the persons named.

Table of Contents

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class	2010 LTIP Phantom Units [1]
James E. Davison [2]	Class A Common Units	2,826,610	3.9	5,578
James E. Davison, Jr. [3]	Class A Common Units	4,209,973	5.9	5,578
Donald L. Evans [4] [9]	Class A Common Units	96,547	*	5,578
Sharilyn S. Gasaway	Class A Common Units [5]	174,374	*	6,319
	Class B Common Units	526	1.3	
Kenneth M. Jastrow, II	Class A Common Units		*	5,949
S. James Nelson	Class A Common Units		*	5,946
Corbin J. Robertson III [6] [9]	Class A Common Units	1,269,693	1.8	5,578
William K. Robertson [7] [9]	Class A Common Units	1,290,628	1.8	5,578
Robert C. Sturdivant [8] [9]	Class A Common Units	18,281	*	5,578
Carl A. Thomason	Class A Common Units		*	5,578
Grant E. Sims	Class A Common Units [10]	2,270,690	3.2	46,568
	Class B Common Units	3,421	8.6	
Robert V. Deere	Class A Common Units [11]	555,235	*	20,153
	Class B Common Units	1,052	2.6	
Steven R. Nathanson [12]	Class A Common Units	746,419	1.0	25,759
Stephen M. Smith [13]	Class A Common Units	308,256	*	10,310
Karen N. Pape [14]	Class A Common Units	116,515	*	9,182
All directors and executive officers as a group (15 in total)	Class A Common Units	13,883,221	19.3	169,232
	Class B Common Units	4,999	12.5	
Quintana [15]	Class A Common Units	859,572	1.2	
	Class B Common Units	29,735	74.3	
EIV Capital Fund LP [16]	Class A Common Units	1,599,009	2.2	
	Class B Common Units	5,263	13.2	

* Less than 1%

(1) Represents outstanding phantom units awarded to named person under our 2010 LTIP. Proceeds of awards to Messrs. Evans, C. Robertson, W. Robertson and Sturdivant will be paid to an affiliate of Quintana upon vesting. See Item 11 Executive Compensation -2010 Long-Term Incentive Plan and Director Compensation in Fiscal 2011.

(2) James E. Davison is the sole stockholder of Davison Terminal Service, Inc., which directly owns 1,010,835 units. Additionally, Mr. Davison holds 91,823 of each class of our Waiver Units.

(3)

972,091 of these units are held by the James E Davison, Jr. Grantor Retained Annuity Trust. Additionally this trust holds 91,823 of each class of our Waiver Units. Mr. Davison pledged 700,000 of these units as collateral for a loan from a bank.

(4) Includes 87,101 units held by Donald L. Evans. The Don Evans Group Ltd holds 7,652 of each class of our Waiver Units.

(5) Includes 526 Class B Units. Ms. Gasaway also holds 15,303 of each class of our Waiver Units.

(6) Includes 147,117 units held by The Corbin J. Roberston III 2009 Family Trust and 5,743 unit held by Corby & Brooke Robertson 2006 Family Trust. The Corbin J. Roberston III 2009 Family Trust holds 12,917 of each class of our Waiver Units, and Corbin J. Roberston III holds 97,484 of each class of our Waiver Units.

(7) Includes 147,117 units held by The William Keen Robertson 2009 Family Trust and 1,110 units held by The William K Robertson 2007 Family Trust. The William Keen Robertson 2009 Family Trust holds 12,917 of each of our Waiver Units, and William K. Robertson holds 97,484 of each class of our Waiver Units.

(8) Robert C. Sturdivant holds 1,530 of each class of our Waiver Units.

(9) Mr. Evans is a member of the board of managers of QEP Management Co. GP, LLC, a Delaware limited liability company (Management Co GP), a member of the board of directors and senior partner of Quintana Capital Group GP, Ltd., a Cayman Islands company (QCG GP), and partner of Quintana Capital Group II, L.P., a Cayman Islands limited partnership (QCG II); The Don Evans Group Ltd is a member of Q GEI Holdings, LLC, a Delaware limited liability company (Q GEI). Each of Quintana Energy Partners II, L.P., a Cayman Islands limited partnership (QEP II), and QEP II Genesis TE Holdco, LP, a Delaware limited partnership (Holdco), has (i) QCG II as its general partner (with QCG GP as the general partner of QCG II), (ii) management services provided by QEP Management Co., L.P., a Delaware limited partnership (QEP Management) (with Management Co GP as the general partner of QEP Management) and (iii) membership interests in Q GEI. Mr. Robertson is a member of the board of managers of Management Co GP, a member of the board of directors and managing director of QCG GP, a member of Q GEI and a partner in QCG II; The William Keen Robertson 2009 Family Trust is a member of Q GEI. Mr. Robertson, III is the chief executive officer, president and a member of the board of managers of Q GEI, a manager of Management Co GP, a member of the board of directors and managing director of QCP GP, a member of Q GEI and a partner in QCG II; The Corbin J. Robertson III 2009 Family Trust is a member of Q GEI. Mr. Sturdivant is a partner of QCG II and a member of Q GEI. Each such person disclaims beneficial ownership of all the units reported by such entities. See note (15) below.

(10) 1,000 of these common units are held by Mr. Sims father. Mr. Sims disclaims beneficial ownership of these units. Includes 3,421 of our Class B Units. Mr. Sims also holds 198,459 of each class of our Waiver Units. Mr. Sims pledged 250,000 of these units as collateral for a loan from a bank.

(11) Includes 1,052 of our Class B Units. Mr. Deere also holds 48,675 of each class of our Waiver Units.

(12) Mr. Nathanson also holds 53,944 of each class of our Waiver Units.

(13) Mr. Smith also holds 26,972 of each class of our Waiver Units. 50,000 of these units are pledged in a margin brokerage account.

(14) Ms. Pape also holds 8,904 of each class of our Waiver Units.

(15) QEP II is the beneficial owner of 746,804 Class A Units it holds directly, including 7,534 Class A Units issuable upon conversion of an identical number of Class B Units. QEP II holds 305,908 of each class of our Waiver Units. Holdco is the beneficial owner of 75,313 Class A Units it holds directly, including 885 Class A Units issuable upon conversion of an identical number of Class B Units. Holdco holds 30,780 of each class of our Waiver Units. QCG GP is the beneficial owner of 1,618 Class A Units it holds directly. Q GEI is the beneficial owner of 28,270 Class A Units it holds directly, including 21,316 Class A Units issuable upon conversion of an identical number of Class B Units. QCG II is the beneficial owner of 3,338 Class A Units it holds directly. Each of QEP II, Holdco, QCG GP, Q GEI and QCG II may be deemed to have sole voting and dispositive power over the units held directly by them. By the nature of their relationship or interests in QEP II, Holdco and QEP Management, Management Co GP, QCG II and QCG GP may be deemed to have shared voting and dispositive power over the Class A Units held directly by QEP II, Holdco and Q GEI. QCG Series A Holdings, LLC holds 4,229 Class A Units directly. The principal business and office address of each entity is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(16) The principal business and office address of EIV Capital Fund LP is 1616 South Voss Road, Suite 940, Houston, Texas 77057.

Table of Contents

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

The mailing address for Genesis Energy, LLC and all officers and directors is 919 Milam, Suite 2100, Houston, Texas, 77002.

Beneficial Ownership of General Partner Interest

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

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

Transactions with Related Persons

In February 2010, new investors, including certain of our executives, affiliates of the Robertson Group and members of the Davison family, acquired all of the equity interest in our general partner. See Item 10. Directors, Executive Officers and Corporate Governance for a discussion of certain arrangements with the Robertson Group and members of the Davison family to appoint directors and Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for a description of such investors ownership interest in us. In December 2010, we acquired all of the equity interests in our general partner.

During 2011, we sold $1.2 million of petroleum products to businesses owned and operated by members of the Davison family in the ordinary course of our operations.

Our CEO, Mr. Sims owns an aircraft, which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. In connection with this arrangement, we made payments to Mr. Sims totaling $0.3 million, during 2011, the initial year of the arrangement. Based on current market rates for chartering of private aircraft, we believe that the terms of this arrangement are no worse than what we could have obtained in an arms-length transaction.

Family members of certain of our executive officers and directors may work for us from time to time. In 2011, each of Messrs. Sims (our CEO and a director) and James Davison, Sr. (a director) had a son (in the case of James Davison, Sr., who is also a brother of James E. Davison, Jr. a director), that worked as a non-executive employee in our finance and supply and logistics departments, respectively, and received total W-2 compensation of greater than $120,000 but less than $300,000.

Review or Special Approval of Material Transactions with Related Persons

Before we consider entering into a material transaction with our general partner or any of its affiliates, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, (3) would comply with our partnership agreement, and (4) would be fair to us and our limited partners. For transactions that are not material, we use review and approval procedures that we believe are commensurate with the size and nature of the underlying transaction, which could involve obtaining appraisals from third parties, having informal discussions with board members and/or management or other process that we determine suitable. In addition, our board of directors may request our conflicts committee to review specific matters that our board of directors believes may involve conflicts of interest between our general partner or any of its affiliates and us. Messrs. Nelson, Thomason and Jastrow and Ms. Gasaway serve as the members of our conflicts committee. In which case, our conflicts committee:

- evaluates and, where appropriate, negotiates certain material terms of the proposed transaction;
- engages an independent legal counsel and, if it deems appropriate, an independent financial advisor to assist with its evaluation of the proposed transaction; and
- determines whether to reject or approve and recommend the proposed transaction.

For example, our conflicts committee approved our acquisition of the 51% economic interest in DG Marine that we did not own in July 2010. Additionally our conflicts committee, excluding Ms. Gasaway who recused herself, approved our IDR Restructuring (see Note 11 to our Consolidated Financial Statements in Item 8).

Table of Contents

Director Independence

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

Under NYSE listing standards, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants. Our board of directors has determined that Messrs. Nelson, Thomason and Ms. Gasaway, who are all of the members of the audit committee, are independent under applicable NYSE rules. The board of directors also determined Mr. Jastrow was independent under such rules. See Item 10. Directors, Executive Officers and Corporate Governance for additional discussion of director independence.

Item 14. Principal Accounting Fees and Services

The following table summarizes the fees for professional services rendered by Deloitte & Touche LLP for the years ended December 31, 2011 and 2010.

	2011	2010
	(in thousands)	
Audit Fees [1]	$ 2,555	$ 3,001
Audit-Related Fees [2]	220	241
Tax Fees [3]	938	421
All Other Fees [4]	4	4
Total	$ 3,717	$ 3,667

(1) Includes fees for the annual audit and quarterly reviews (including internal control evaluation and reporting), SEC registration statements and accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles. Also includes separate audits of certain of our joint ventures.
(2) Includes fees for the audit of our employee benefit plan and review of correspondence with the SEC. Also includes fees related to reviewing our documentation of controls and process for conversion related to our project to upgrade our information technology systems.
(3) Includes fees for tax return preparation and tax consultations.
(4) Includes fees associated with licenses for accounting research software.

Pre-Approval Policy

The services by Deloitte in 2011 and 2010 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. This policy describes the permitted audit, audit-related, tax and other services, which we refer to collectively as the Disclosure Categories that the independent auditor may perform. The policy requires that each fiscal year, a description of the services, or the Service List expected to be performed by the independent auditor in each of the Disclosure Categories in the following fiscal year be presented to the audit committee for approval.

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

In considering the nature of the non-audit services provided by Deloitte in 2011 and 2010, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed these services with Deloitte and management of our general partner to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

See Index to Consolidated Financial Statements and Financial Statement Schedules set forth on page 97.

(a)(2) Financial Statement Schedules.

See Index to Consolidated Financial Statements and Financial Statement Schedules set forth on page 97.

(a)(3) Exhibits

2.1	Purchase and Sale Agreement by and between Valero Energy Corporation, Valero Services, Inc., Valero Unit Investments, LLC, Genesis Energy, LP, Genesis CHOPS I, LLC and Genesis CHOPS II, LLC dated October 22, 2010 (incorporated by reference to Exhibit 2.2 to Form 10-Q for the quarter ended September 30, 2010).
2.2	Agreement and Plan of Merger by and among Genesis Energy, L.P., Genesis Acquisition, LLC and Genesis Energy, LLC dated as of December 28, 2010 (incorporated by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
2.3	Purchase and Sale Agreement by and among Florida Marine Transporters, Inc., FMT Heavy Oil Transportation, LLC, FMT Industries, LLC, JAR Assets, Inc., Pasentine Family Enterprises, LLC, PBC Management, Inc., and GEL Marine, LLC dated June 24, 2011 (incorporated by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K dated June 30, 2011, File No. 001-12295).
2.4	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interest in Poseidon Oil Pipeline Company, L.L.C. (incorporated by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.5	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interest in Odyssey Pipeline L.L.C. (incorporated by reference to Exhibit 2.2 to the Company s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.6	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interests in Eugene Island Pipeline System and certain related pipelines (incorporated by reference to Exhibit 2.3 to the Company s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.7	Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Free State Pipeline, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K dated June 5, 2008, File No. 001-12295).
3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 of the Registration Statement on Form S-1, File No. 333-11545).
3.2	Amendment to the Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 001-12295).
3.3	Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
3.4	Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009, File No. 001-12295).

Table of Contents

3.5 Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295).

3.6 Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295).

4.1 Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-12295).

4.2 Indenture dated November 18, 2010 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K dated November 23, 2010, File No. 001-12295).

4.3 Supplemental Indenture, dated as of November 24, 2010, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

4.4 Second Supplemental Indenture, dated as of December 27, 2010, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

4.5 Third Supplemental Indenture, dated as of February 28, 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

4.6 Fourth Supplemental Indenture, dated as of June 30, 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

4.7 Fifth Supplemental Indenture, dated as of September 13, 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

4.8 Sixth Supplemental Indenture, dated as of September 22, 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.7 to the Company s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).

* 4.9 Seventh Supplemental Indenture, dated as of December 5, 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.

* 4.10 Eighth Supplemental Indenture, dated as of January 3, 2012 2011, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.

*	4.11	Ninth Supplemental Indenture, dated as of January 27, 2012, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee.
	4.12	Registration Rights Agreement, dated as of December 28, 2010, by and among Genesis Energy, L.P. and the former unitholders of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
	4.13	Registration Rights Agreement dated February 1, 2012 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and Deutsche Bank Securities Inc., BMO Capital Markets Corp., Citigroup Global Markets Inc., RBC Capital Markets, LLC, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several initial purchasers (incorporated by reference to the Company s Current Report on Form 8-K dated February 2, 2012, File No. 001-12295).
	4.14	Davison Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K dated July 31, 2007, File No. 001-12295).
	4.15	Amendment No. 1 to the Davison Registration Rights Agreement dated November 16, 2007 (incorporated by reference to Exhibit 10.1 the Company s Current Report on to Form 8-K dated November 16, 2007, File No. 001-12295).
	4.16	Amendment No. 2 to the Davison Registration Rights Agreement dated December 6, 2007 (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated December 12, 2007, File No. 001-12295).
	4.17	Amendment No. 3 to the Davison Registration Rights Agreement, dated as of December 28, 2010 (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
	4.18	Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K dated July 31, 2007, File No. 001-12295).
	4.19	Amendment No. 1 to the Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K dated October 19, 2007, File No. 001-12295).
	4.20	Amendment No. 2 to the Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
	10.1	Second Amended and Restated Credit Agreement dated as of June 29, 2010 among Genesis Energy, L.P., as borrower, BNP Paribas as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated July 2, 2010, File No. 001-12295).
	10.2	First Amendment to Second Amended and Restated Credit Agreement, dated November 17, 2010, among Genesis Energy, L.P. as borrower, BNP Paribas, as administrative agent, and each of the other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated November 23, 2010, File No. 001-12295).
	10.3	Second Amendment to Second Amended and Restated Credit Agreement, dated as of August 19, 2011, among Genesis Energy, L.P. as borrower, BNP Paribas as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated August 23, 2011, File No. 001-12295).

Table of Contents

10.4		Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC, as Lessor and Denbury Onshore, LLC, as Lessee for the North East Jackson Dome Pipeline dated May 30, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated June 5, 2008, File No. 001-12295).
10.5		Transportation Services Agreement between Genesis Free State Pipeline, LLC, as Lessor and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K dated June 5, 2008, File No. 001-12295).
10.6		Form of Indemnity Agreement, among Genesis Energy, L.P., Genesis Energy, LLC and Quintana Energy Partners II, L.P. and each of the Directors of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated March 5, 2010, File No. 001-12295).
10.7		Amendment No. 1 to the Indemnity Agreement dated March 4, 2010 (incorporated by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
10.8	+	Genesis Energy, LLC First Amended and Restated Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.24 to the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-12295).
10.9	+	Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.25 to the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-12295).
10.10	+	Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).
10.11	+	Genesis Energy, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295).
10.12	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Directors Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295).
10.13	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Executive Phantom Unit with DERs Award Officers (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-12295).
10.14	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Employee Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295).
10.15	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Graded) (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).
10.16	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Cliff) (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).
10.17	+	Employment Agreement by and between Genesis Energy, LLC and Grant E. Sims, dated December 31, 2008 (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).

	10.18	+	Employment Agreement by and between Genesis Energy, LLC and Robert V. Deere, dated December 31, 2008 (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).
	10.19	+	Employment Agreement by and between Genesis Energy, Inc. and Steve Nathanson dated July 25, 2007 (incorporated by reference to Exhibit 10.30 to the Company s Current Report on Form 10-K for the year ended December 31, 2009, File No. 001-12295).
	10.20	+	Waiver Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K dated February 11, 2010, File No. 001-12295).
	10.21	+	Waiver Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K dated February 11, 2010, File No. 001-12295).
	10.22		Purchase Agreement dated November 12, 2010 relating to 7.875% Senior Notes due 2018 (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated November 18, 2010, File No. 001-12295).
	10.23		Purchase Agreement dated February 1, 2012 relating to 7.875% Senior Notes due 2018 (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K dated February 2, 2012, File No. 001-12295).
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 11 of the Notes to the Consolidated Financial Statements).
*	21.1		Subsidiaries of the Registrant.
*	23.1		Consent of Deloitte & Touche LLP.
*	23.2		Consent of Deloitte & Touche LLP.
*	31.1		Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
*	31.2		Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
*	32.1		Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	32.2		Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	101.INS		XBRL Instance Document.
*	101.SCH		XBRL Schema Document.
*	101.CAL		XBRL Calculation Linkbase Document.
*	101.LAB		XBRL Label Linkbase Document.
*	101.PRE		XBRL Presentation Linkbase Document.
*	101.DEF		XBRL Definition Linkbase Document.

* Filed herewith
\+ A management contract or compensation plan or arrangement.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

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

By: GENESIS ENERGY, LLC,
as General Partner

Date: February 29, 2012

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

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

NAME	TITLE (OF GENESIS ENERGY, LLC)*	DATE
/s/ GRANT E. SIMS	Director and Chief Executive Officer	February 29, 2012
Grant E. Sims	(Principal Executive Officer	
/s/ ROBERT V. DEERE	Chief Financial Officer,	February 29, 2012
Robert V. Deere	(Principal Financial Officer)	
/s/ KAREN N. PAPE	Senior Vice President and Controller	February 29, 2012
Karen N. Pape	(Principal Accounting Officer)	
/s/ ROBERT C. STURDIVANT	Chairman of the Board and	February 29, 2012
Robert C. Sturdivant	Director	
/s/ JAMES E. DAVISON	Director	February 29, 2012
James E. Davison		
/s/ JAMES E. DAVISON, JR.	Director	February 29, 2012
James E. Davison, Jr.		
/s/ DONALD L. EVANS	Director	February 29, 2012
Donald L. Evans		
/s/ SHARILYN S. GASAWAY	Director	February 29, 2012

Sharilyn S. Gasaway		
/s/ KENNETH M. JASTROW, II	Director	February 29, 2012
Kenneth M. Jastrow, II		
/s/ S. JAMES NELSON	Director	February 29, 2012
S. James Nelson		
/s/ CORBIN J. ROBERTSON, III	Director	February 29, 2012
Corbin J. Robertson, III		
/s/ WILLIAM K. ROBERTSON	Director	February 29, 2012
William K. Robertson		
/s/ CARL A. THOMASON	Director	February 29, 2012
Carl A. Thomason		

* Genesis Energy, LLC is our general partner.

Table of Contents

Item 8. Financial Statements and Supplementary Data

GENESIS ENERGY, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

AND FINANCIAL STATEMENT SCHEDULES

	Page
Financial Statements of Genesis Energy, L.P.	
Report of Independent Registered Public Accounting Firm	F-1
Consolidated Balance Sheets, December 31, 2011 and 2010	F-2
Consolidated Statements of Operations for the Years Ended December 31, 2011, 2010 and 2009	F-3
Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2011, 2010 and 2009	F-4
Consolidated Statements of Partners Capital for the Years Ended December 31, 2011, 2010 and 2009	F-5
Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009	F-6
Notes to Consolidated Financial Statements	F-7
Financial Statements of Significant Equity Investee Cameron Highway Oil Pipeline Company[(1)]	
Balance Sheet, December 31, 2011	F-48
Statement of Operations for the Year Ended December 31, 2011	F-49
Statement of Cash Flows for the Year Ended December 31, 2011	F-50
Statement of Partners Capital for the Year Ended December 31, 2011	F-51
Notes to Financial Statements	F-52
Financial Statements of Significant Equity Investee Cameron Highway Oil Pipeline Company	
Independent Auditors Report	F-58
Balance Sheet, December 31, 2010	F-59
Statement of Operations for the Period from November 23, 2010 to December 31, 2010	F-60
Statement of Cash Flows for the Period from November 23, 2010 to December 31, 2010	F-61
Statement of Partners Capital for the Period from November 23, 2010 to December 31, 2010	F-62
Notes to Financial Statements	F-63

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the Consolidated Financial Statements or the Notes to the Consolidated Financial Statements.

(1) The financial statements as of and for the year ended December 31, 2011 were included for informational purposes but did not meet the significance test under Regulation S-X Rule 3-09.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, LLC and Unitholders of

Genesis Energy, L.P.

Houston, Texas

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. and subsidiaries (the Partnership) as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive (loss) income, partners capital, and cash flows for each of the three years in the period ended December 31, 2011. We also have audited the Partnership s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Partnership s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Genesis Energy, L.P. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 28, 2012

Table of Contents

GENESIS ENERGY, L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,817	$ 5,762
Accounts receivable trade, net	237,989	171,550
Inventories	101,124	55,428
Other	26,174	19,798
Total current assets	376,104	252,538
FIXED ASSETS, at cost	541,138	373,339
Less: Accumulated depreciation	(124,213)	(108,283)
Net fixed assets	416,925	265,056
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	162,460	168,438
EQUITY INVESTEES	326,947	343,434
INTANGIBLE ASSETS, net of amortization	93,356	120,175
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	30,006	32,048
TOTAL ASSETS	$ 1,730,844	$ 1,506,735
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable trade	$ 199,357	$ 165,978
Accrued liabilities	50,071	40,736
Total current liabilities	249,428	206,714
SENIOR SECURED CREDIT FACILITIES	409,300	360,000
SENIOR UNSECURED NOTES	250,000	250,000
DEFERRED TAX LIABILITIES	12,549	15,193
OTHER LONG-TERM LIABILITIES	16,929	5,564
COMMITMENTS AND CONTINGENCIES (Note 19)		
PARTNERS CAPITAL:		
Common unitholders, 71,965 and 64,615 units issued and outstanding at December 31, 2011 and 2010, respectively	792,638	669,264
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,730,844	$ 1,506,735

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per unit amounts)

	Year Ended December 31, 2011	2010	2009
REVENUES:			
Supply and logistics	$ 2,825,768	$ 1,894,612	$ 1,243,044
Refinery services	201,711	151,060	141,365
Pipeline transportation services	62,190	55,652	50,951
Total revenues	3,089,669	2,101,324	1,435,360
COSTS AND EXPENSES:			
Supply and logistics product costs	2,643,687	1,761,161	1,115,809
Supply and logistics operating costs	123,121	97,701	88,087
Refinery services operating costs	126,782	88,094	88,910
Pipeline transportation operating costs	16,964	14,777	13,024
General and administrative	34,473	113,406	40,413
Depreciation and amortization	61,926	53,557	62,581
Net loss on disposal of surplus assets	264	12	160
Impairment expense			5,005
Total costs and expenses	3,007,217	2,128,708	1,413,989
OPERATING INCOME (LOSS)	82,452	(27,384)	21,371
Equity in earnings of equity investees	3,347	2,355	1,547
Interest expense	(35,767)	(22,924)	(13,660)
Income (loss) before income taxes	50,032	(47,953)	9,258
Income tax benefit (expense)	1,217	(2,588)	(3,080)
NET INCOME (LOSS)	51,249	(50,541)	6,178
Net loss attributable to noncontrolling interests		2,082	1,885
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 51,249	$ (48,459)	$ 8,063
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:			
Basic and Diluted	$ 0.75	$ 0.49	$ 0.51
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
Basic and Diluted	67,938	40,560	39,471

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$ 51,249	$ (50,541)	$ 6,178
Change in fair value of derivatives:			
Current period reclassification to earnings interest rate swaps		2,112	784
Changes in derivative financial instruments interest rate swaps		(424)	(508)
Comprehensive income (loss)	51,249	(48,853)	6,454
Comprehensive loss attributable to noncontrolling interests		1,223	1,742
Comprehensive income (loss) attributable to Genesis Energy, L.P.	$ 51,249	$ (47,630)	$ 8,196

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands)

		Partners Capital				
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interests	Total Capital
Partners capital, December 31, 2008	39,457	$ 616,971	$ 16,649	$ (962)	$ 24,804	$ 657,462
Comprehensive income:						
Net income (loss)		21,469	(13,406)		(1,885)	6,178
Interest rate swap losses reclassified to interest expense				383	401	784
Interest rate swap loss				(250)	(258)	(508)
Cash contributions			9			9
Contribution for management compensation (Note 11)			14,104			14,104
Cash distributions		(53,876)	(6,204)		(6)	(60,086)
Issuance of units under LTIP	31	990				990
Partners capital, December 31, 2009	39,488	585,554	11,152	(829)	23,056	618,933
Comprehensive income:						
Net income (loss)		17,933	(66,392)		(2,082)	(50,541)
Interest rate swap losses reclassified to interest expense				1,035	1,077	2,112
Interest rate swap loss				(206)	(218)	(424)
Cash contributions			2,528		13	2,541
Contribution for management compensation (Note 11)			76,923			76,923
Cash distributions		(58,983)	(11,369)		(7)	(70,359)
Acquisition of noncontrolling interest in DG Marine (Note 3)		(4,920)	(100)		(21,268)	(26,288)
Issuance of units for cash	5,175	116,347				116,347
Issuance of units in exchange for general partner interest (Note 11)	19,854	13,313	(12,742)		(571)	
Issuance of units under LTIP	98	20				20
Partners capital, December 31, 2010	64,615	669,264				669,264
Comprehensive income:						
Net income		51,249				51,249
Cash distributions		(112,844)				(112,844)
Issuance of units for cash	7,350	184,969				184,969
Partners capital, December 31, 2011	71,965	$ 792,638	$	$	$	$ 792,638

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31, 2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 51,249	$ (50,541)	$ 6,178
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, amortization and impairment	61,926	53,557	67,586
Amortization and write-off of debt issuance costs	2,940	3,082	2,503
Amortization of unearned income and initial direct costs on direct financing leases	(17,237)	(17,651)	(18,095)
Payments received under direct financing leases	21,852	21,854	21,853
Equity in earnings of investments in equity investees	(3,347)	(2,355)	(1,547)
Cash distributions of earnings of equity investees	8,592	3,623	950
Non-cash effect of equity-based compensation plans	(15)	4,706	4,248
Non-cash compensation charge		76,923	14,104
Deferred and other tax (benefits) liabilities	(2,075)	1,337	1,914
Unrealized losses (gains) on derivative transactions	1,002	1,562	(649)
Other, net	351	(147)	603
Net changes in components of operating assets and liabilities, net of acquisitions (See Note 14)	(66,931)	(5,487)	(9,569)
Net cash provided by operating activities	58,307	90,463	90,079
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(27,992)	(12,400)	(30,332)
Cash distributions received from equity investees return of investment	11,436	2,859	
Investments in equity investees and other investments	(194)	(332,462)	(83)
Acquisitions	(163,479)		
Proceeds from asset sales	6,424	1,146	873
Other, net	1,508	119	309
Net cash used in investing activities	(172,297)	(340,738)	(29,233)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Bank borrowings	777,600	691,829	255,300
Bank repayments	(728,300)	(698,729)	(263,700)
Proceeds from issuance of senior unsecured notes		250,000	
Credit facility and senior unsecured notes issuance costs	(3,018)	(14,586)	(422)
Issuance of common units for cash, net	184,969	116,347	
General partner contributions		2,528	9
Noncontrolling interests contributions, net of distributions		6	(6)
Distributions to common unitholders	(112,844)	(58,983)	(53,876)
Distributions to general partner interest		(11,369)	(6,204)
Acquisition of noncontrolling interest in DG Marine		(26,288)	
Other, net	638	1,134	(6,784)
Net cash provided by (used in) financing activities	119,045	251,889	(75,683)

Net increase (decrease) in cash and cash equivalents	5,055	1,614	(14,837)
Cash and cash equivalents at beginning of period	5,762	4,148	18,985
Cash and cash equivalents at end of period	$ 10,817	$ 5,762	$ 4,148

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

We are a growth-oriented limited partnership 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 assets, including pipelines, refinery-related plants, storage tanks and terminals, barges and trucks. We were formed in 1996 and are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. We manage our businesses through the following three divisions that constitute our reportable segments:

- Pipeline transportation of crude oil and carbon dioxide (or CO_2);

- Refinery services involving processing of high sulfur (or sour) gas streams for refineries to remove the sulfur, and sale of the related by-product, sodium hydrosulfide (or NaHS , commonly pronounced nash); and

- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting crude oil, and petroleum products and, on a smaller scale, CO_2.

On December 28, 2010, we permanently eliminated our incentive distribution rights (IDRs) and converted our 2% general partner interest into a non-economic interest, which we refer to as our IDR Restructuring. We issued Class A Units, Class B Units and Waiver Units to the former stakeholders of our general partner in exchange for the elimination of our IDRs. See Note 11 for additional discussion of our capital structure.

2. Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2011 and 2010 and our results of operations, cash flows and changes in partners capital for the years ended December 31, 2011, 2010 and 2009. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries, and Genesis Energy, LLC. The inclusion of Genesis Energy, LLC in our Consolidated Financial Statements was effective December 28, 2010 due to our IDR Restructuring (see Notes 1 and 11).

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Joint Ventures

We participate in several joint ventures, including Cameron Highway Oil Pipeline Company (CHOPS) and Southeast Keathley Canyon Pipeline Company, LLC (SEKCO). We account for our investments in these joint ventures by the equity method of accounting. See Notes 3 and 8.

CHOPS

In November 2010, we acquired a 50% equity interest in CHOPS, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. Enterprise Products Partners, L.P. indirectly owns the remaining 50% interest in, and operates, the joint venture.

Table of Contents

SEKCO

In December 2011, we entered into a joint venture forming 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. We own 50% of SEKCO, and Enterprise Products owns the remaining 50% interest. Enterprise Products serves as construction manager and will be the operator of the new pipeline. The 149-mile, 18-inch diameter pipeline, would connect the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the Poseidon pipeline system, in which we recently acquired an ownership interest (see Note 21). The new pipeline is expected to begin service by mid-2014. At December 31, 2011, we had not yet made any investment in this joint venture.

Noncontrolling Interests

During the years ended December 31, 2010 and 2009, we held less than 100% interests in two consolidated subsidiaries, DG Marine and Genesis Crude Oil, L.P. During 2010, we acquired the interests in those subsidiaries that we did not already own. In July 2010, we acquired the 51% interest in DG Marine from TD Marine LLC (TD Marine), a related party. In connection with our IDR Restructuring in December 2010, when we acquired our general partner, we also acquired the 0.01% general partner s interest in Genesis Crude Oil, L.P. We reclassified the acquired noncontrolling interests in Genesis Crude Oil, L.P. and DG Marine to Genesis Energy, L.P. partners capital during 2010.

Use of Estimates

The preparation of our Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. We based these estimates and assumptions on historical experience and other information that we believed to be reasonable under the circumstances. Significant estimates that we make include: (1) liability and contingency accruals, (2) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (3) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, and (4) estimates of future asset retirement obligations. Additionally, for purposes of the calculation of the fair value of awards under equity-based compensation plans, we make estimates regarding the expected life of the rights, expected forfeiture rates of the rights, volatility of our unit price and expected future distribution yield on our units. While we believe these estimates are reasonable, actual results could differ from these estimates. Changes in facts and circumstances may result in revised estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. We have no requirement for compensating balances or restrictions on cash. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal.

Accounts Receivable

We review our outstanding accounts receivable balances on a regular basis and record an allowance for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Inventories

Our inventories are valued at the lower of cost or market. Cost is determined principally under the average cost method within specific inventory pools.

Fixed Assets

Property and equipment are carried at cost. Depreciation of property and equipment is provided using the straight-line method over the respective estimated useful lives of the assets. Asset lives are 5 to 15 years for pipelines and related assets, 20 to 25 years for marine vessels, 10 to 20 years for machinery and equipment, 3 to 7 years for transportation equipment, and 3 to 10 years for buildings and improvements, office equipment, furniture and fixtures and other equipment.

Interest is capitalized in connection with the construction of major facilities. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset s estimated useful life.

Table of Contents

Maintenance and repair costs are charged to expense as incurred. Costs incurred for major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset.

Certain volumes of crude oil are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil volumes are carried at their weighted average cost.

Long-lived assets are reviewed for impairment. An asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to be generated from the use and ultimate disposal of the asset. If the carrying value is determined to not be recoverable under this method, an impairment charge equal to the amount the carrying value exceeds the fair value is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Asset Retirement Obligations

Some of our assets have contractual or regulatory obligations to perform dismantlement and removal activities, and in some instances remediation, when the assets are abandoned. In general, our future asset retirement obligations relate to future costs associated with the removal of our oil and CO_2 pipelines, barge decommissioning, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. Accretion of the discount increases the liability and is recorded to expense. See Note 6.

Direct Financing Leasing Arrangements

When a direct financing lease is consummated, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in pipeline transportation services revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets.

We review our direct financing lease arrangements for credit risk. Such review includes consideration of the credit rating and financial position of the lessee. See Note 7.

CO_2 Assets

Our CO_2 assets include three volumetric production payments, which are amortized on a units-of-production method. These assets are included in Other Assets in our Consolidated Balance Sheets. See Note 9.

Intangible and Other Assets

Intangible assets with finite useful lives are amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are amortizing our customer and supplier relationships, licensing agreements and trade name based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The favorable lease and other intangible assets are being amortized on a straight-line basis.

We test intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. No impairment has occurred of intangible assets in any of the periods presented.

Costs incurred in connection with the issuance of long-term debt and certain amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization. Fully-amortized debt issuance costs and the related accumulated amortization are written-off in conjunction with the refinancing or termination of the applicable debt arrangement.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We test goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. During 2011, we adopted new accounting guidance, which provides the option to make a qualitative evaluation about the likelihood of goodwill impairment. After performing a qualitative assessment of relevant events and circumstances, if it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not necessary. If the calculated fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings may be necessary to reduce the carrying value of the goodwill to its implied fair value. In the event that we determine that goodwill has become impaired, we will incur a charge for the amount of impairment during the period in which the determination is made. No goodwill impairment has occurred in any of the periods presented. See Recent and Proposed Accounting Pronouncements below and Note 9 for further information.

Environmental Liabilities

We provide for the estimated costs of environmental contingencies when liabilities are probable to occur and a reasonable estimate of the associated costs can be made. Ongoing environmental compliance costs, including maintenance and monitoring costs, are charged to expense as incurred.

Equity-Based Compensation

Our stock appreciation rights plan and phantom units issued under our 2010 Long-Term Incentive Plan result in the payment of cash to our employees or directors of our general partner upon exercise or vesting of the related award. The fair values of our equity-based awards are re-measured at the end of each reporting period and are recorded as liabilities. The liability and related compensation cost for our stock appreciation rights are calculated using a Black-Scholes option pricing model that takes into consideration the expected future value of the rights at their expected exercise dates and management s assumptions about expectation of forfeitures prior to vesting. The fair value of our phantom units is equal to the market price of our common units. Our phantom units include both service-based and performance-based awards. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award. See Note 15 for more information on these plans.

Revenue Recognition

Product Sales Revenues from the sale of crude oil, petroleum products and CO_2 by our supply and logistics segment, and caustic soda and NaHS by our refinery services segment are recognized when title to the inventory is transferred to the customer, collectability is reasonably assured and there are no further significant obligations for future performance by us. Most frequently, title transfers upon our delivery of the inventory to the customer at a location designated by the customer, although in certain situations, title transfers when the inventory is loaded for transportation to the customer. Our crude oil and petroleum products are typically sold at prices based off daily or monthly published prices. Many of our contracts for sales of NaHS incorporate the price of caustic soda in the pricing formulas.

Pipeline Transportation Revenues from transportation of crude oil by our pipelines are based on actual volumes at a published tariff. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to the specifications outlined in our regulated tariffs.

In order to compensate us for bearing the risk of volumetric losses in volumes that occur to crude oil in our pipelines due to temperature, crude quality and the inherent difficulties of measurement of liquids in a pipeline, our tariffs include the right for us to make volumetric deductions from the shippers for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances.

We compare these allowances to the actual volumetric gains and losses of the pipeline and the net gain or loss is recorded as revenue or a reduction of revenue, based on prevailing market prices at that time. When net gains occur, we have crude oil inventory. When net losses occur, we reduce any recorded inventory on hand and record a liability for the purchase of crude oil that we must make to replace the lost volumes. We reflect inventories in the Consolidated Financial Statements at the lower of the recorded value or the market value at the balance sheet date. We value liabilities to replace crude oil at current market prices. The crude oil in inventory can then be sold, resulting in additional revenue if the sales price exceeds the inventory value.

Income from direct financing leases is being recognized ratably over the term of the leases and is included in pipeline revenues.

Cost of Sales and Operating Expenses

Supply and logistics costs and expenses include the cost to acquire the product and the associated costs to transport it to our terminal facilities or to a customer for sale. Other than the cost of the products, the most significant costs we incur relate to transportation utilizing our fleet of trucks and barges, including personnel costs, fuel and maintenance of our equipment.

When we enter into buy/sell arrangements concurrently or in contemplation of one another with a single counterparty, we reflect the amounts of revenues and purchases for these transactions on a net basis in our Consolidated Statements of Operations as supply and logistics revenues.

The most significant operating costs in our refinery services segment consist of the costs to operate NaHS plants located at various refineries, caustic soda used in the process of processing the refiner s sour gas stream, and costs to transport the NaHS and caustic soda.

Pipeline operating costs consist primarily of power costs to operate pumping equipment, personnel costs to operate the pipelines, insurance costs and costs associated with maintaining the integrity of our pipelines.

Excise and Sales Taxes

We collect and remit excise and sales taxes to state and federal governmental authorities on its sales of fuels. These taxes are presented on a net basis, with any differences due to rebates allowed by those governmental entities reflected as a reduction of product cost in the Consolidated Statements of Operations.

Income Taxes

We are a limited partnership, organized as a pass-through entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our Consolidated Statements of Operations, is included in the federal income tax returns of each partner.

Some of our corporate subsidiaries pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized. Penalties and interest related to income taxes will be included in income tax expense in the Consolidated Statements of Operations.

Derivative Instruments and Hedging Activities

When we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative s fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income (AOCI) and reclassified into earnings when the underlying position affects earnings. See Note 17.

Fair Value of Current Assets and Current Liabilities

The carrying amount of other current assets and other current liabilities approximates their fair value due to their short-term nature.

Net Income Per Common Unit

Basic and diluted net income per common unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding common units during the period. Prior to our IDR Restructuring, income available to common unit holders was allocated

98% to our limited partners and 2% to the general partner, including general partner allocations for incentive distributions and certain equity-based compensation costs, which our general partner agreed to pay.

Table of Contents

Recent and Proposed Accounting Pronouncements

Recently Issued

In December 2011, the Financial Accounting Standards Board (FASB) issued guidance requiring new disclosures for financial instruments and derivative instruments that are eligible for offset in the statement of financial position or subject to a master netting arrangement. The new guidance is effective for us beginning January 1, 2013 and is not expected to have a significant impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance that modified how comprehensive income is presented in an entity s financial statements. The guidance issued requires an entity to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and eliminates the option to present the components of other comprehensive income as part of the statement of equity. The revised financial statement presentation for comprehensive income will be effective for us beginning January 1, 2012, with early adoption permitted. The guidance pertaining to reclassifying items out of accumulated other comprehensive income has been deferred and will be effective for us beginning January 1, 2013. The adoption of this guidance is not expected to have a significant impact on our financial position, results of operations or cash flows.

Recently Adopted

In September 2011, the FASB issued guidance that simplified how an entity tests goodwill for impairment. The revised guidance provides an entity the option to make a qualitative evaluation about the likelihood of goodwill impairment. Under the revised guidance, an entity is permitted to first assess qualitative factors to determine whether goodwill impairment exists prior to performing analyses comparing the fair value of a reporting unit to its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. We adopted the guidance early as permitted, effective October 1, 2011, which did not have a material impact on our Consolidated Financial Statements.

In December 2010, the FASB revised its guidance for disclosure requirements of supplementary pro forma information for business combinations. The objective of the revised guidance is to address diversity in practice regarding pro forma disclosures for revenues and earnings of an acquired entity. The amendments, which went into effect on January 1, 2011, will be adhered to any future material business combinations.

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. The guidance was effective for us beginning January 1, 2011, and there was no material impact on our Consolidated Financial Statements.

In July 2010, the FASB issued guidance, which requires companies that hold financing receivables, which include loans, lease receivables, and the other long-term receivables to provide more information in their disclosures about the credit quality of their financing receivables and the credit reserves held against them. The adoption of this accounting guidance on January 1, 2011 pertaining to disclosures about activity that occurs during a reporting period did not have a material impact on our Consolidated Financial Statements.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as Level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. This new guidance requires additional disclosures regarding transfers into and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. We adopted the guidance relating to Level 1 and Level 2 transfers as of January 1, 2010, and we adopted the guidance relating to Level 3 measurements on January 1, 2011. Our adoption had no material impact on our Consolidated Financial Statements.

Table of Contents

3. Acquisitions

FMT Black Oil Barge Transportation Business

In August 2011, we completed the acquisition of the black oil barge transportation business of Florida Marine Transporters, Inc. and its affiliates (FMT). The purchase price was $143.5 million (including $2.5 million for fuel inventory and other costs). The acquired business is comprised of 30 barges (seven of which are sub-leased under similar terms of an existing FMT lease) and 14 push/tow boats which transport heavy refined products, primarily 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. The acquisition and related transaction costs were funded with a portion of the net proceeds from the July 2011 public offering of our common units, whereby we raised approximately $185 million in net proceeds of equity capital. See Note 11 for additional information regarding the common unit offering.

The financial results of the acquired business are included in the supply and logistics segment from the date of acquisition. The acquisition is intended to complement and further integrate certain existing operations, including our inland barge business (comprised of 20 barges and 8 push/tow boats), storage and blending terminals and crude oil pipeline systems. Our expanded fleet of 50 barges is capable of transporting heavy refined products, including asphalt, and with minor modifications, half of the barges (representing 750,000 barrels of capacity) will be capable of transporting crude oil as well.

Wyoming Refinery and Pipeline Assets

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. Those assets are located near the emerging Powder River Basin portion of the Niobrara Shale. The purchase price was $20 million, which included $1.3 million for product inventories. We funded the acquisition with cash available under our credit facility. The Consolidated Financial Statements reflect the preliminary purchase price allocation, pending completion of independent appraisals and other evaluations.

The financial results of the refinery assets are included in the supply and logistics segment and the pipeline assets have been included in the pipeline transportation segment from the date of acquisition.

CHOPS Investment

In November 2010, we acquired a 50% equity interest in CHOPS, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. The purchase price was approximately $330 million plus approximately $2.5 million of purchase price adjustments.

The funding for this acquisition consisted of $330 million in cash from the issuance of 5,175,000 common units at $23.58 per common unit and the issuance of $250 million of senior unsecured notes. Total net proceeds from the common units offering, after deducting underwriting discounts and commissions and estimated offering expenses and including our general partner s proportionate capital contribution to maintain its 2% general partner interest, were approximately $119 million.

CHOPS is a 380-mile 24- and 30-inch diameter pipeline constructed in 2004, with capacity to deliver up to 500,000 barrels per day of crude oil from developments in the Gulf of Mexico to major refining markets along the Texas Gulf Coast located in Port Arthur and Texas City. Enterprise Products Partners, L.P. indirectly owns the remaining 50% interest in, and operates, the joint venture.

The following table presents selected unaudited pro forma financial information incorporating the historical 50% equity interest in CHOPS. The effective closing date of our purchase of a 50% equity interest in CHOPS was November 23, 2010. As a result, our Consolidated Statements of Operations for the year ended December 31, 2010 includes our 50% equity investment in CHOPS for the last five weeks of 2010. The pro forma financial information has been prepared as if the acquisition had been completed on the first day of each period presented rather than the actual closing date. The pro forma financial information has been prepared based upon assumptions deemed appropriate by us and may not be indicative of actual results.

Table of Contents

	Year Ended December 31, 2010	2009
Pro forma earnings data:		
Equity in earnings of equity investees	$ 15,322	$ 15,699
Net loss attributable to Genesis Energy, L.P.	$ (55,001)	$ (538)
Basic and diluted earnings per unit:		
As reported units outstanding	40,560	39,471
Pro forma units outstanding	44,969	44,646
As reported net income per unit	$ 0.49	$ 0.51
Pro forma net income per unit	$ 0.30	$ 0.26

Acquisition of Remaining Noncontrolling Interest in DG Marine

In July 2010, we acquired from TD Marine, a related party, their 51% interest in DG Marine for $25.5 million in cash, resulting in DG Marine becoming wholly-owned by us. We funded the acquisition with proceeds from our credit agreement, including (i) paying off DG Marine s stand-alone credit facility, which had an outstanding principal balance of $44.4 million, and (ii) settling DG Marine s interest rate swaps, which resulted in $1.3 million being reclassified from Accumulated Other Comprehensive Loss (AOCL) to interest expense in the third quarter of 2010.

Prior to the acquisition, DG Marine was consolidated as a variable interest entity as certain of our voting rights were not proportional to our 49% economic interest. As a result of the acquisition, we reclassified the acquired noncontrolling interest in DG Marine of $21.3 million to Genesis Energy, L.P. partners capital. Additionally, we reduced our partners capital by $26.3 million for the costs related to the transaction ($25.5 million paid to TD Marine and $0.8 million in direct transaction costs associated with the acquisition). The net effect of Genesis Energy, L.P. partners capital in our Consolidated Balance Sheet for December 31, 2010 was a decrease of $5 million.

4. Receivables

Accounts receivable trade, net consisted of the following:

	December 31, 2011	2010
Accounts receivable - trade	$ 239,033	$ 172,857
Allowance for doubtful accounts	(1,044)	(1,307)
Accounts receivable - trade, net	$ 237,989	$ 171,550

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	December 31, 2011	2010	2009
Balance at beginning of period	$ 1,307	$ 1,372	$ 1,132
Charged to costs and expenses	373	491	558
Amounts written off	(636)	(556)	(320)
Recoveries			2
Balance at end of period	$ 1,044	$ 1,307	$ 1,372

Table of Contents

5. Inventories

The major components of inventories were as follows:

	December 31, 2011	December 31, 2010
Crude oil	$ 11,701	$ 6,128
Petroleum products	70,769	38,588
Caustic soda	11,312	6,309
NaHS	7,337	4,387
Other	5	16
Total inventories	$ 101,124	$ 55,428

At December 31, 2011 and 2010, market values of our inventory exceeded recorded costs.

6. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following:

	December 31, 2011	December 31, 2010
Land, buildings and improvements	$ 13,140	$ 14,335
Pipelines and related assets	167,865	156,805
Machinery and equipment	46,233	29,433
Transportation equipment	21,732	29,249
Marine vessels	262,216	122,992
Office equipment, furniture and fixtures	3,778	3,742
Construction in progress	14,236	4,493
Other	11,938	12,290
Subtotal	541,138	373,339
Accumulated depreciation	(124,213)	(108,283)
Total	$ 416,925	$ 265,056

Depreciation expense was $27.3 million, $22.5 million and $25.2 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Asset Retirement Obligations

A reconciliation of our liability for asset retirement obligations is as follows:

Asset retirement obligations as of December 31, 2009	$ 4,838
Accretion expense	341

Asset retirement obligations as of December 31, 2010	5,179
Liabilities incurred and assumed in the current period	349
Accretion expense	372
Asset retirement obligations as of December 31, 2011	$ 5,900

7. Net Investment in Direct Financing Leases

Our direct financing leases include a lease of the Northeast Jackson Dome (NEJD) Pipeline. Under the terms of the agreement, we are paid quarterly payments, which commenced August 30, 2008. These quarterly payments are fixed at approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term in 2028, we will convey all of our interests in the NEJD Pipeline to the lessee for a nominal payment.

The following table lists the components of the net investment in direct financing leases:

	December 31, 2011	December 31, 2010
Total minimum lease payments to be received	$ 341,917	$ 365,169
Estimated residual values of leased property (unguaranteed)	1,287	1,287
Unamortized initial direct costs	1,992	2,184
Less unearned income	(176,726)	(195,586)
Net investment in direct financing leases	168,470	173,054
Less current portion (included in other current assets)	(6,010)	(4,616)
Long-term portion of net investment in direct financing leases	$ 162,460	$ 168,438

At December 31, 2011, minimum lease payments to be received for each of the five succeeding fiscal years are $21.8 million for 2012, $21.3 million for 2013, $21.2 million for 2014 and $20.7 million per year for 2015 and 2016.

8. Equity Investees and Other Investments

Equity Investees

We are accounting for our ownership in our joint ventures under the equity method of accounting (see Note 2 for a description of these investments). The price we pay to acquire an ownership interest in a company may exceed the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our equity investees. At December 31, 2011 and 2010, the unamortized excess cost amounts totaled $97.8 million and $101.9 million, respectively. We amortize the excess cost as a reduction in equity earnings in a manner similar to depreciation. The table below reflects information included in our Consolidated Financial Statements related to our equity investees.

	Year Ended December 31, 2011	2010	2009
Genesis share of operating earnings	$ 7,910	$ 3,224	$ 1,262
Amortization of excess purchase price	(4,563)	(869)	285
Net equity in earnings	$ 3,347	$ 2,355	$ 1,547
Distributions received	$ 20,028	$ 6,482	$ 950

Table of Contents

The combined balance sheet information for the last two years and results of operations data for the last three years for our equity investees was as follows:

	December 31, 2011	December 31, 2010
BALANCE SHEET DATA:		
Current Assets	$ 12,732	$ 16,402
Fixed Assets, net	441,894	459,490
Other Assets	18,000	15,424
Total Assets	$ 472,626	$ 491,316
Current Liabilities	$ 5,891	$ 5,509
Other Liabilities	8,536	3,876
Equity	458,199	481,931
Total Liabilities and Combined Equity	$ 472,626	$ 491,316

	Year Ended December 31, 2011	2010	2009
INCOME STATEMENT DATA:			
Revenues	$ 56,353	$ 20,013	$ 14,793
Operating Income	$ 16,363	$ 5,881	$ 775
Net Income	$ 16,322	$ 5,843	$ 749

The 2010 income statement data above includes CHOPS since the date of acquisition. We have included in this filing on Form 10-K (i) unaudited financial statements for CHOPS as of December 31, 2011 and for the year ended December 31, 2011 and (ii) audited financial statements as of December 31, 2010 and the period from November 23, 2010 to December 31, 2010.

Other Investments

In 2006, we invested in the Faustina Project, a petroleum coke to ammonia project that is in the development stage. As a result of a review of the financing alternatives for the project, requirements for continued funding for the project, and the change in control of our general partner in February 2010, we decided not to fund our share of further development in the project. We further determined that the likelihood of a recovery of our investment was remote, and the fair value of the investment was zero. In 2009, we recorded a $5 million impairment charge related to our investment in the Faustina Project, reducing the value of that investment to zero.

Table of Contents

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

The following table reflects the components of intangible assets being amortized at December 31, 2011 and 2010:

		December 31, 2011			December 31, 2010		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery services customer relationships	5	$ 94,654	$ 62,111	$ 32,543	$ 94,654	$ 53,139	$ 41,515
Supply and logistics customer relationships	5	35,430	23,584	11,846	35,430	19,981	15,449
Refinery services supplier relationships	2	36,469	34,105	2,364	36,469	31,476	4,993
Refinery services licensing agreements	6	38,678	19,476	19,202	38,678	15,786	22,892
Supply and logistics trade names	4	18,888	17,048	1,840	18,888	7,530	11,358
Intangibles associated with supply and logistics lease	15	13,260	2,092	11,168	13,260	1,618	11,642
Other	5	17,292	2,899	14,393	13,776	1,450	12,326
Total		$ 254,671	$ 161,315	$ 93,356	$ 251,155	$ 130,980	$ 120,175

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The supply and logistics lease relates to a terminal facility in Shreveport, Louisiana.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The supply and logistics lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $30.9 million, $26.8 million and $33.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

	2012	2013	2014	2015	2016
Refinery services customer relationships	$ 7,056	$ 7,116	$ 5,597	$ 4,405	$ 3,471
Supply and logistics customer relationships	2,819	2,165	1,660	1,275	981
Refinery services supplier relationships	2,364				
Refinery services licensing agreements	3,416	3,163	2,928	2,711	2,510
Supply and logistics trade names	1,840				
Supply and logistics lease	474	474	474	474	474
Other	2,155	1,514	1,514	1,500	1,467
Total	$ 20,124	$ 14,432	$ 12,173	$ 10,365	$ 8,903

In the first quarter of 2011, we adjusted the useful lives of our supply and logistics trade names. As a result of this change in the amortization period of our assets, operating income and net income attributable to us for 2011 decreased $7.7 million, or $0.11 per common unit. The impact of this change on net income is not expected to be material in future periods. The table of estimated future amortization expense above reflects this change.

Goodwill

The carrying amount of goodwill by business segment at both December 31, 2011 and 2010 was $301.9 million in refinery services and $23.1 million in supply and logistics. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Other Assets

Other assets consisted of the following:

	December 31,	
	2011	2010
CO2 volumetric production payments, net of amortization	$ 12,158	$ 15,852
Other deferred costs and deposits	17,848	16,196
Other assets, net of amortization	$ 30,006	$ 32,048

The CO_2 assets are being amortized on a units-of-production method. We recorded amortization of $3.7 million in 2011, and $4.3 million in both 2010 and 2009. We have 77.2 Bcf of CO_2 remaining under the volumetric production payments at December 31, 2011.

10. Debt

At December 31, 2011 and 2010, our obligations under debt arrangements consisted of the following:

	December 31,	
	2011	2010
Senior Secured Credit Facility	$ 409,300	$ 360,000
7.875% Senior Unsecured Notes Due 2018	250,000	250,000
Total Long-Term Debt	$ 659,300	$ 610,000

We believe the amounts included in our Consolidated Balance Sheets for the debt outstanding under our revolving credit agreement approximates fair value as the stated rate of interest approximates current market rates of interest for similar instruments with comparable maturities. At December 31, 2011 and 2010, the fair value of our senior unsecured notes was approximately $253.1 million and $250.3 million, respectively.

Senior Secured Credit Facility

In August 2011, we amended our senior secured 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, subject to obtaining lender approval. The amendment also increased the inventory financing sublimit tranche that we may use to finance the purchase and sale of certain petroleum products subject to sales contracts or hedging agreements and related storage and transportation costs from $75 million to $125 million.

At December 31, 2011, we had $409.3 million borrowed under our credit agreement, with $69.6 million of that amount designated as a loan under the inventory sublimit. Additionally, up to $100 million of the credit facility can be used for letters of credit. We had $9 million in letters of credit outstanding at December 31, 2011. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of June 30, 2015. The total amount available for borrowings at December 31, 2011 was $356.7 million under our credit facility.

Table of Contents

The key terms for rates under our credit facility are as follows:

The interest rate on borrowings may be based on an alternate base rate or a Eurodollar rate, at our option. The alternate base rate is equal to the sum of (a) the greatest of (i) the prime rate as established by the administrative agent for the credit facility, (ii) the federal funds effective rate plus $^{1}/2$ of 1% and (iii) the LIBOR rate for a one-month maturity plus 1% and (b) the applicable margin. The Eurodollar rate is equal to the sum of (a) the LIBOR rate for the applicable interest period multiplied by the statutory reserve rate and (b) the applicable margin. The applicable margin varies from 1.0% to 2.0% for alternate base rate borrowings and from 2.0% to 3.0% for Eurodollar rate borrowings, depending on our leverage ratio. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2011, the applicable margins on our borrowings were 1.5% for alternate base rate borrowings and 2.5% for Eurodollar rate borrowings.

Letter of credit fees will range from 2.50% to 3.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2011, our letter of credit rate was 2.5%.

We pay a commitment fee on the unused portion of the $775 million maximum facility amount. The commitment fee varies from 0.375% to 0.500% per annum depending on our leverage ratio (0.375% at December 31, 2011).

Our credit facility is secured by liens on a substantial portion of our assets, and by guarantees by all of our restricted subsidiaries (as defined in the credit facility).

Our credit facility contains customary covenants (affirmative, negative and financial) that could limit the manner in which we may conduct our business. As defined in our credit facility, we are required to meet three primary financial metrics a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. Our credit agreement provides for the temporary inclusion of certain pro forma adjustments to the calculations of the required ratios following material acquisitions. In general, our leverage ratio calculation compares our consolidated funded debt (including outstanding notes we have issued) to EBITDA (as defined and adjusted in accordance with the credit facility) and cannot exceed 5.00 to 1.00 (5.50 to 1.00 in an acquisition period). Our senior secured leverage ratio excludes outstanding debt under senior unsecured notes and cannot exceed 3.75 to 1.00 (4.25 to 1.00 in an acquisition period). Our interest coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense and must be greater than 2.75 to 1.00 (3.00 to 1.00 during an acquisition period.

7.875% Senior Unsecured Notes Due 2018

In November 2010, we issued $250 million in aggregate principal amount of 7.875% senior unsecured notes due December 15, 2018. The notes were sold at face value. Interest payments are due on June 15 and December 15 of each year, beginning June 15, 2011. We used the net proceeds from this offering to finance in part the purchase price and related transaction costs for the acquisition of a 50% equity interest in CHOPS.

The notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the notes at any time after December 15, 2013 at a premium to the face amount of the notes that varies based on the time remaining to maturity of the notes. Prior to December 15, 2013, we may also redeem up to 35% of the principal amount for 107.875% of the face amount with the proceeds from an equity offering of our common units.

See Note 21 for more information on issuance of additional notes under this indenture.

Table of Contents

Covenants and Compliance

Our credit agreement and the indenture governing the senior notes contain cross-default provisions. Our credit documents prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, those agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

A default under our credit documents would permit the lenders thereunder to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit facility, our ability to make distributions of available cash is not restricted. As of December 31, 2011, we were in compliance with the financial covenants contained in our credit facility and indenture.

11. Partners Capital and Distributions

At December 31, 2011, our outstanding equity consisted of 71,925,065 Class A Units, 39,997 Class B Units and 6,949,004 Waiver Units. The Class A Units are traditional common units in us. The Class B Units are identical to the Class A Units and, accordingly, have voting and distribution rights equivalent to those of the Class A Units, and, in addition, the Class B Units have the right to elect all of our board of directors and are convertible into Class A Units under certain circumstances, subject to certain exceptions. The Waiver Units are non-voting securities entitled to a minimal preferential quarterly distribution and are comprised of four classes (designated Class 1, Class 2, Class 3 and Class 4) of 1,750,000 authorized units each. Each class of Waiver Units has the right to convert into Genesis common units in the calendar quarter during which each of our common units receives a quarterly distribution per unit of at least $0.43, $0.46, $0.49 and $0.52, respectively, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times. On February 14, 2012, we paid a distribution of $0.44 per common unit and we satisfied the conversion coverage ratio requirement. Consequently, our Class 1 Waiver Units are convertible into common units. The Waiver Units convert into common units no later than six months from the date they become convertible.

IDR Restructuring

Prior to our IDR Restructuring our partners capital consisted of common units (Class A Units), representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving effect to the general partner interest), a 2% general partner interest, and incentive distribution rights (IDRs). Our general partner owned all of our general partner interest, all of our IDRs, and all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which was reflected as a noncontrolling interest in the Consolidated Statements of Partners Capital at December 31, 2009.) IDRs provided our general partner incremental incentive cash distributions when the quarterly cash distribution amount per common unit exceeded certain target thresholds.

In December 2010, the IDRs held by our general partner were eliminated and the 2% general partner interest in us that our general partner held was converted into a non-economic general partner interest. In exchange, we issued to the former owners of our general partner approximately 27,000,000 units, consisting of: (i) approximately 19,960,000 Class A Units, (ii) approximately 40,000 Class B Units and (iii) approximately 7,000,000 Waiver Units.

Table of Contents

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We paid distributions in 2010 and 2011 as follows:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount [(1)]	General Partner Incentive Distribution Amount [(1)]	Total Amount
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579
First quarter 2010	May 2010	$ 0.3675	$ 14,548	$ 297	$ 2,339	$ 17,184
Second quarter 2010	August 2010	$ 0.3750	$ 14,845	$ 303	$ 2,642	$ 17,790
Third quarter 2010	November 2010	$ 0.3875	$ 15,339	$ 313	$ 3,147	$ 18,799
Fourth quarter 2010	February 2011	$ 0.4000	$ 25,846	$	$	$ 25,846
First quarter 2011	May 2011	$ 0.4075	$ 26,343	$	$	$ 26,343
Second quarter 2011	August 2011	$ 0.4150	$ 29,878	$	$	$ 29,878
Third quarter 2011	November 2011	$ 0.4275	$ 30,777	$	$	$ 30,777
Fourth quarter 2011	February 2012	$ 0.4400	$ 31,664	$	$	$ 31,664

(1) Prior to our IDR Restructuring in December 2010, our general partner received a 2% interest and incremental incentive cash distributions when unitholder s cash distributions exceeded certain target thresholds.

Net Income per Common Unit

The following table sets forth the computation of basic and diluted net income per common unit.

	Year Ended December 31, 2011	2010	2009
Numerators for basic and diluted net income per common unit:			
Net income (loss) attributable to Genesis Energy, L.P	$ 51,249	$ (48,459)	$ 8,063
Less: General partner's incentive distribution paid or to be paid for the period		(8,128)	(6,318)
Add: Expense allocable to our general partner		76,923	18,853
Subtotal	51,249	20,336	20,598
Less: General partner 2% ownership		(407)	(412)
Income available for common unitholders	$ 51,249	$ 19,929	$ 20,186
Denominator for basic and diluted per common unit	67,938	40,560	39,471
Basic and diluted net income per common unit	$ 0.75	$ 0.49	$ 0.51

Table of Contents

Equity Issuances and Contributions

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

In July 2011, we issued 7,350,000 common units in a public offering. We received proceeds, net of underwriting discounts and offering costs, of $185 million from the offering. The proceeds were used to fund our acquisition of the black oil barge transportation business of FMT (see Note 3) and other corporate purposes, including the repayment of borrowings outstanding under our credit facility. In November 2010, we issued 5,175,000 common units in a public offering in connection with the acquisition of a 50% equity interest in CHOPS. Our general partner also contributed capital of $2.5 million in November 2010 to maintain its 2% capital account. The new common units issued in 2011 and 2010 to the public for cash were as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Issuance Value	GP Contributions	Costs	Net Proceeds
July 2011	Public	7,350	$ 26.30	$ 193,305	$	$ (8,336)	$ 184,969
November 2010	Public	5,175	$ 23.58	$ 122,027	$ 2,490	$ (5,680)	$ 118,837

During 2010 and 2009, we recorded non-cash contributions of $76.9 million and $14.1 million, respectively, from our general partner related to incentive compensation arrangements with our senior executives. As the purpose of these arrangements was to incentivize these individuals to grow the partnership, the expense was recognized as compensation by us and a capital contribution by our general partner. These amounts relate to arrangements representing an equity interest in our general partner for which our general partner did not seek reimbursement under our partnership agreement.

12. Business Segment Information

Our operations consist of three operating segments: (1) Pipeline Transportation interstate, intrastate and offshore crude oil, and to a lesser extent, CO_2 pipeline transportation; (2) Refinery Services processing high sulfur (or sour) gas streams as part of refining operations to remove the sulfur and sale of the related by-product, and (3) Supply and Logistics purchasing, transporting, storing, blending and marketing of crude oil and petroleum products (primarily fuel oil, asphalt, and other heavy refined products). Substantially all of our revenues are derived from, and substantially all of our assets are located in the United States. We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash 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.

Table of Contents

	Pipeline Transportation	Refinery Services	Supply & Logistics	Total
Year Ended December 31, 2011				
Segment margin [a]	$ 67,908	$ 74,618	$ 59,975	$ 202,501
Capital expenditures [b]	$ 14,501	$ 1,846	$ 170,647	$ 186,994
Net fixed and other long-term assets [c]	$ 594,102	$ 384,340	$ 376,298	$ 1,354,740
Revenues:				
External customers	$ 50,391	$ 210,394	$ 2,828,884	$ 3,089,669
Intersegment [d]	11,799	(8,683)	(3,116)	
Total revenues of reportable segments	$ 62,190	$ 201,711	$ 2,825,768	$ 3,089,669
Year Ended December 31, 2010				
Segment margin [a]	$ 48,305	$ 62,923	$ 38,336	$ 149,564
Capital expenditures [b]	$ 333,557	$ 1,433	$ 1,740	$ 336,730
Net fixed and other long-term assets [c]	$ 604,572	$ 400,164	$ 221,932	$ 1,226,668
Revenues:				
External customers	$ 45,367	$ 158,456	$ 1,897,501	$ 2,101,324
Intersegment [d]	10,285	(7,396)	(2,889)	
Total revenues of reportable segments	$ 55,652	$ 151,060	$ 1,894,612	$ 2,101,324
Year Ended December 31, 2009				
Segment margin [a]	$ 42,162	$ 51,844	$ 40,484	$ 134,490
Capital expenditures [b]	$ 3,043	$ 2,572	$ 23,581	$ 29,196
Net fixed and other long-term assets [c]	$ 279,574	$ 409,556	$ 269,753	$ 958,883
Revenues:				
External customers	$ 44,461	$ 147,240	$ 1,243,659	$ 1,435,360
Intersegment [d]	6,490	(5,875)	(615)	
Total revenues of reportable segments	$ 50,951	$ 141,365	$ 1,243,044	$ 1,435,360

Table of Contents

(a) A reconciliation of Segment Margin to income (loss) before income taxes for each year presented is as follows:

	Year Ended December 31,		
	2011	2010	2009
Segment margin	$ 202,501	$ 149,564	$ 134,490
Corporate general and administrative expenses	(31,685)	(110,058)	(36,475)
Depreciation, amortization and impairment	(61,926)	(53,557)	(67,586)
Net loss on disposal of surplus assets	(264)	(12)	(160)
Interest expense	(35,767)	(22,924)	(13,660)
Distributable cash from equity investees in excess of equity in earnings	(16,681)	(2,284)	496
Non-cash items not included in segment margin	(1,531)	(4,479)	(4,089)
Cash payments from direct financing leases in excess of earnings	(4,615)	(4,203)	(3,758)
Income before income taxes	$ 50,032	$ (47,953)	$ 9,258

(b) Capital expenditures include fixed asset additions and acquisitions of businesses.

(c) Net fixed and other long-term assets is a measure used by management in evaluating the results of our operations on a segment basis. Current assets are not allocated to segments as the amounts are not meaningful in evaluating the success of the segment s operations. Amounts for our Pipeline Transportation segment include our investment in CHOPS totaling $314.7 million and $329.7 million at December 31, 2011 and 2010, respectively. Amounts for our Supply and Logistics segment include investments in equity investees totaling $12.2 million, $13.7 million and $15.1 million at December 31, 2011, 2010 and 2009, respectively.

(d) Intersegment sales were conducted on an arm s length basis.

13. Transactions with Related Parties

Sales, purchases and other transactions with affiliated companies, in the opinion of management, are conducted under terms no more or less favorable than then-existing market conditions. The transactions with related parties were as follows:

	Year Ended December 31,		
	2011	2010 (1)	2009
Petroleum products sales to an affiliate of the Robertson Group (2)	$ 20,888	$ 3,740	$
Marine operating fuel and expenses provided by an affiliate of the Robertson Group(2)	3,568	2,443	
Sales of CO_2 to Sandhill Group, LLC (3)	2,481	2,706	2,867
Petroleum products sales to Davison family businesses (2)	1,207	1,081	757
Amounts paid to our CEO in connection with the use of his aircraft	300		
Operations, general and administrative services provided by our general partner(4)		47,035	50,417
Pipeline tranportation and supply and logistics services provided to Denbury		3,059	35,957
Supply and logistics products and services provided by Denbury		373	7,229

(1) Affiliates of Denbury Resources, Inc. sold its interests in our general partner in February 2010. Transactions with Denbury are included in the table as a related party through that date.

(2) The Robertson Group owned 12% of our Class A Units and 74% of our Class B Units at December 31, 2011. The Davison family owned 18% of our Class A Units at December 31, 2011.

(3) We own a 50% interest in Sandhill Group, LLC.

(4) Our general partner became a wholly-owned subsidiary in December 2010.

Table of Contents

Our CEO, Mr. Sims owns an aircraft, which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. In connection with this arrangement, we made payments to Mr. Sims totaling $0.3 million, during 2011, the initial year of the arrangement. Based on current market rates for chartering of private aircraft, we believe that the terms of this arrangement are no worse than what we could have obtained in an arms-length transaction.

In July 2010, we acquired from TD Marine its 51% interest in DG Marine. TD Marine is owned by members of the Davison family.

Amounts due to and from Related Parties

At December 31, 2011 and 2010, an affiliate of the Robertson Group owed us $1.9 million and $1.4 million, respectively. We owed the affiliate $0.1 million and $0.2 million, at December 31, 2011 and 2010, respectively. At both December 31, 2011 and 2010, Sandhill owed us $0.2 million for purchases of CO_2.

Financing

We guarantee 50% of Sandhill s outstanding credit facility loan. At December 31, 2011 and 2010, the total amount of Sandhill s obligation to the bank was $1.7 million and $2.2 million, respectively; therefore, our guarantee was for $0.9 million and $1.1 million for the respective periods.

As discussed in Note 11, our general partner made capital contributions in order to maintain its capital account totaling $2.5 million and less than $0.1 million in 2010 and 2009, respectively. In 2010 and 2009, we recorded a capital contribution from our general partner of $76.9 million and $14.1 million, respectively, related to compensation recognized for our executive management team (see Note 15).

14. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities.

	Year Ended December 31,		
	2011	2010	2009
(Increase) decrease in:			
Accounts receivable	$ (66,208)	$ (41,648)	$ (7,979)
Inventories	(46,151)	(16,870)	(16,559)
Other current assets	(3,598)	(4,036)	(2,712)
Increase (decrease) in:			
Accounts payable	33,049	47,401	19,203
Accrued liabilities	15,977	9,666	(1,522)
Net changes in components of operating assets and liabilities	$ (66,931)	$ (5,487)	$ (9,569)

Payments of interest and commitment fees, net of amounts capitalized, were $32.9 million, $25.1 million and $13.3 million, during the years ended December 31, 2011, 2010 and 2009, respectively.

Cash paid for income taxes during the years ended December 31, 2011, 2010 and 2009 was $1 million, $2.4 million and $0.2 million, respectively.

At December 31, 2011, 2010 and 2009, we had incurred liabilities for fixed and intangible asset additions totaling $2 million, $2.6 million and $0.5 million, respectively, which had not been paid at the end of the year. Therefore, these amounts were not included in the caption Payments to acquire fixed and intangible assets on the Consolidated Statements of Cash Flows.

15. Equity-Based Compensation Plans and Employee Benefit Plans

2010 Long Term Incentive Plan

In 2010, we adopted the 2010 Long-Term Incentive Plan (the 2010 Plan). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to members of our board of directors, and employees who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights (DERs) are tandem rights to receive on a quarterly basis a cash amount per phantom unit equal to the amount of cash distributions paid per common unit. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the G&C Committee) of our board of directors. The G&C Committee (at its discretion) designates participants in the 2010 Plan, determines the types of awards to grant to participants, determines the number of units to be covered by any award, and determines the conditions and terms of any award including vesting, settlement and forfeiture conditions.

The compensation cost associated with the phantom units is re-measured each reporting period based on the market value of our common units, and is recognized over the vesting period. The liability recorded for the estimated amount to be paid to the participants under the 2010 LTIP is adjusted to recognize changes in the estimated compensation cost and vesting. Management s estimates of the fair value of these awards granted in 2011 are adjusted for assumptions about expected forfeitures of units prior to vesting. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award.

During 2011, we granted 151,916 phantom units with tandem DERs. The phantom units granted during 2011 were both service-based and performance-based awards. The service-based awards vest on the third anniversary of the date of grant. Between 50% and 150% of the number of performance-based phantom units awarded will vest on the third anniversary of the date of grant, if certain quarterly cash distribution per common unit targets are achieved in the 2013 fourth quarter. If the quarterly cash distribution per common unit is below the threshold target, all of the performance-based phantom units granted will be forfeited. During 2010, we granted 62,927 phantom units that were service-based awards at a weighted average grant date fair value of $20.64 per unit. These phantom units will vest on the third anniversary of the date of grant. A summary of our phantom unit activity for our service-based and performance-based awards is set forth below:

	Service-Based Awards			Performance-Based Awards		
	Number of Phantom Units	Average Grant Date Fair Value	Total Value	Number of Phantom Units	Average Grant Date Fair Value	Total Value
Unvested at December 31, 2010	62,927	$ 20.64	$ 1,299		$	$
Granted	47,680	$ 27.03	1,289	104,236	$ 28.19	2,938
Forfeited	(845)	$ 28.19	(24)	(1,266)	$ 28.19	(36)
Unvested at December 31, 2011	109,762	$ 23.36	$ 2,564	102,970	$ 28.19	$ 2,902

At December 31, 2011, we estimated the unrecognized compensation cost of our phantom awards to be approximately $4 million to be recognized over a weighted average period of approximately 2 years. We recorded $1.9 million and $0.4 million of compensation expense for the years ended December 31, 2011 and 2010, respectively. Our liability for these awards totaled $2 million and $0.3 million at December 31, 2011 and 2010, respectively.

2007 Long Term Incentive Plan

As a result of the sale of our general partner in February 2010, all outstanding phantom units issued pursuant to our 2007 Long Term Incentive Plan vested. As a result of this acceleration of the vesting period, we recorded non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested. In 2009, we recorded compensation expense of $1 million related to this plan. This expense is primarily included in general and administrative expenses. At December 31, 2011 and 2010, there were no awards outstanding under this plan.

Stock Appreciation Rights Plan

Our Stock Appreciation Rights Plan is administered by the G&C Committee, who determines, in its full discretion, who shall receive awards under the Plan, the number of rights to award, the grant date of the units and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit.

Table of Contents

The rights have a term of 10 years from the date of grant. If the right has not been exercised at the end of the ten year term and the participant has not terminated his employment with us, the right will be deemed exercised as of the date of the right s expiration and a cash payment will be made as described below.

Upon vesting, the participant may exercise his rights and receive a cash payment calculated as the difference between the average of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. If the G&C Committee determines, in its full discretion, that it would cause significant financial harm to the Partnership to make cash payments to participants who have exercised rights under the Stock Appreciation Rights Plan, then the G&C Committee may authorize deferral of the cash payments until a later date.

Termination for any reason other than death, disability or normal retirement (as these terms are defined in the Stock Appreciation Rights Plan) will result in the forfeiture of any non-vested rights. Upon death, disability or normal retirement, all rights will become fully vested. If a participant is terminated for any reason within one year after the effective date of a change in control (as defined in the plan) all rights will become fully vested.

The compensation cost associated with our Stock Appreciation Rights plan, which upon exercise will result in the payment of cash to the employee, is re-measured each reporting period based on the fair value of the rights. Under accounting guidance, the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

The liability amount accrued on the balance sheet is adjusted to the fair value of the outstanding awards at each balance sheet date with the adjustment reflected in the Consolidated Statement of Operations. The fair value is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting).

The estimates that we make each period to determine the fair value of these rights include the following assumptions:

Assumptions Used for Fair Value of Rights	December 31, 2011	December 31, 2010	December 31, 2009
Expected life of rights (in years)	0.00 - 3.41	0.00 - 4.41	0.25 - 5.50
Risk-free interest rate	0.00% to 0.58%	0.12% - 1.73%	0.05% - 2.52%
Expected unit price volatility	40.6%	41.9%	43.8%
Expected future distribution yield	6.00%	6.00%	8.50%

The following table reflects rights activity under our Stock Appreciation Rights Plan as of January 1, 2011, and changes during the year ended December 31, 2011:

Stock Appreciation Rights	Rights	Weighted Average Strike Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at December 31, 2010	913,690	$ 17.65		
Exercised during 2011	(230,069)	$ 16.57		
Forfeited or expired during 2011	(21,137)	$ 17.00		
Outstanding at December 31, 2011	662,484	$ 17.97	5.7	$ 6,778
Exercisable at December 31, 2011	532,816	$ 18.34	5.5	$ 5,287

The total intrinsic value of rights exercised during 2011, 2010 and 2009 was $2.4 million, $1.3 million and $0.1 million, respectively, which was paid in cash to the participants.

At December 31, 2011, there was $0.2 million of total unrecognized compensation cost related to rights that we expect will vest under the Stock Appreciation Rights Plan. This amount was calculated as the fair value at December 31, 2011 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet date until the rights are exercised, forfeited or expire. For the awards outstanding at December 31, 2011, the remaining cost will be recognized over a weighted average period of less than one year.

Table of Contents

We recorded compensation expense related to our stock appreciation rights of $0.6 million, $5.2 million and $3.4 million in 2011, 2010 and 2009, respectively.

Equity-Based Compensation Plan Expense

Equity-based compensation expense related to the 2010 Plan, 2007 Long Term Incentive Plan and Stock Appreciation Rights Plan during the three years ended December 31, 2011 was as follows:

		$000000000000		$000000000000		$000000000000
	Expense Related to Equity-Based Compensation Plans					
Statement of Operations		2011		2010		2009
Supply and logistics operating costs	$	181	$	2,611	$	1,467
Refinery services operating costs		226		833		445
Pipeline operating costs		135		575		364
General and administrative expenses		2,013		2,098		2,132
Total	$	2,555	$	6,117	$	4,408

Series B Units

Pursuant to restricted unit agreements entered into with Genesis Energy, LLC, our general partner, on February 5, 2010, certain members of our management team received an aggregate of 767 Series B units in our general partner. These awards provided for the conversion of the Series B units into Series A units in our general partner on the seventh anniversary of the issuance date of the awards or at the time of certain events including a change in control of our general partner. As a result of our IDR Restructuring on December 28, 2010, the Series B units converted into Series A units. The Series A units were then exchanged for a total of 2,364,279 Class A Units and 827,484 Waiver Units. See Note 11 for a discussion of our IDR Restructuring and our equity securities.

Although the Series B Units represented an equity interest in our general partner and our general partner did not seek reimbursement under our partnership agreement for the value of these compensation arrangements, we recorded non-cash expense for the estimated fair value of the awards. For the year ended December 31, 2010, we recorded non-cash expense of $79.1 million related to these Series B awards with an offsetting entry to the capital account of our general partner. As the awards are fully-vested, no further compensation expense for these awards remains to be recorded.

Class B Membership Interests

As part of finalizing the compensation arrangements for our senior executives on December 31, 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. The Class B membership interests awarded to our senior executives were accounted for as liability awards under the guidance for equity-based compensation.

All of the Class B membership interests in our general partner held by our management team at December 31, 2009 were either (i) converted into Series A units in our general partner or (ii) redeemed by our general partner on February 5, 2010. In total, the value of the Series A units issued and cash payments made by our general partner to settle its obligations under the Class B membership interests and related deferred compensation totaled $14.9 million. This value, when combined with amounts previously paid to our management team during 2009 related to the Class B membership interests, resulted in total compensation expense of $15.4 million. Upon settlement by our general partner of these arrangements with our management team, we recorded a reduction in expense of $2.1 million in the first quarter of 2010. In the year ended December 31, 2009, we recorded expense related to these arrangements of $14.1 million.

Bonus Program

Bonuses under our bonus plan are paid at the discretion of the G&C Committee to our employees and executive officers. In 2011, the G&C Committee based bonus amounts primarily on the amount of cash we generated for distributions to our unitholders, measured on a calendar-year basis. Two metrics were used to determine the general bonus pool the level of Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) that we generated and our company-wide safety record improvement which included a targeted reduction in our company-wide incident injury rate. The level of Available Cash before Reserves generated for the year as a percentage of a target set by the G&C Committee is weighted 90% and the achieved level of the targeted improvement in our safety record is weighted 10%. The sum of the weighted percentage achievement of these targets is multiplied by the eligible compensation and the target percentages established by the G&C Committee for the various levels of our employees to determine the maximum general bonus pool. At December 31, 2011, we accrued $6.1 million for estimated bonuses to be paid in March 2012. For 2010 and 2009, we paid bonuses totaling $5.2 million and $3.9 million, respectively, to our executive officers and employees.

Employee Benefit Plans

In order to encourage long-term savings and to provide additional funds for retirement to its employees, we sponsor a tax qualified profit-sharing and retirement savings plan. Under this plan, our matching contribution is calculated as an equal match of the first 6% of each employee s annual pretax contribution. Our profit-sharing plan targets a 3% contribution of each eligible employee s total compensation (subject to IRS limitations). The expenses included in the Consolidated Statements of Operations for costs relating to this plan were $2.6 million, $2.7 million, and $2.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

We also provided certain health care and survivor benefits for our active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. We plan to continue self-insuring these plans in the future. The expenses included in the Consolidated Statements of Operations for these benefits were $8.1 million, $6.5 million, and $6.2 million in 2011, 2010 and 2009, respectively.

16. Major Customers and Credit Risk

Due to the nature of our supply and logistics operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and large independent energy companies with stable payment experience. The credit risk related to contracts which are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

During 2011, 2010 and 2009, our largest customer was Shell Oil Company, which accounted for 16%, 13% and 12.5% of total revenues respectively. The revenues from Shell Oil Company in all three years relate primarily to our supply and logistics operations.

17. Derivatives

Commodity Derivatives

We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (primarily futures and options contracts traded on the NYMEX) to hedge our exposure to commodity prices, primarily crude oil, fuel oil and petroleum products; however, only a portion of these instruments are designated as hedges under the accounting guidance. Our decision as to whether to designate derivative instruments as fair value hedges for accounting purposes relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under accounting guidance in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil that we supply cannot be hedged with a high degree of effectiveness with derivative contracts available on the NYMEX; therefore, we do not designate derivative contracts utilized to limit our price risk related to these products as hedges for accounting purposes. Typically we utilize crude oil and natural gas futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges for accounting purposes can occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged. Therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.

Table of Contents

We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the accounting guidance. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss in the Consolidated Statements of Operations.

In accordance with NYMEX requirements, we fund the margin associated with our loss positions on commodity derivative contracts traded on the NYMEX. The amount of the margin is adjusted daily based on the fair value of the commodity contracts. The margin requirements are intended to mitigate a party s exposure to market volatility and the associated contracting party risk. We offset fair value amounts recorded for our NYMEX derivative contracts against margin funding as required by the NYMEX in Other current assets in our Consolidated Balance Sheets.

At December 31, 2011, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

	Sell (Short) Contracts	Buy (Long) Contracts
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	169	90
Weighted average contract price per bbl	$ 96.16	$ 98.83
Heating oil futures:		
Contract volumes (1,000 bbls)	178	60
Weighted average contract price per gal	$ 2.86	$ 2.83
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	15	
Weighted average contract price per gal	$ 2.66	$
# 6 Fuel oil futures:		
Contract volumes (1,000 bbls)	489	
Weighted average contract price per bbl	$ 93.73	$
Crude oil options:		
Contract volumes (1,000 bbls)	355	75
Weighted average premium received	$ 2.05	$ 0.56
Heating oil options:		
Contract volumes (1,000 bbls)	30	
Weighted average premium received	$ 0.09	$

Interest Rate Derivatives

During 2010 and 2009, our DG Marine subsidiary utilized swap contracts with financial institutions to hedge interest payments for its outstanding debt. DG Marine expected these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates; therefore, we designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represented the change in fair value of the hedge that offset the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts was reported as a component of Accumulated Other Comprehensive Loss (AOCL) and was reclassified into future earnings contemporaneously, as interest expense associated with the underlying debt was recorded. In the third quarter of 2010, we settled the DG Marine interest rate swaps in connection with our acquisition of the 51% interest of DG Marine that we did not own (see Note 3).

Table of Contents

Financial Statement Impacts

The following table summarizes the accounting treatment and classification of our derivative instruments on our Consolidated Financial Statements.

		Impact of Unrealized Gains and Losses	
		Consolidated	Consolidated
Derivative Instrument	Hedged Risk	Balance Sheets	Statements of Operations
Designated as hedges under accounting guidance:			
Crude oil futures contracts (fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in Other current assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventories	Excess, if any, over effective portion of hedge is recorded in Supply and logistics costs - product costs Effective portion is offset in cost of sales against change in value of inventory being hedged
Interest rate swaps (cash flow hedge) (through July 2010)	Changes in interest rates	Not applicable	Expect hedge to fully offset hedged risk; no ineffectiveness recorded. Effective portion is recorded to AOCL and ultimately reclassified to Interest expense
Not qualifying or not designated as hedges under accounting guidance:			
Commodity hedges consisting of crude oil, heating oil and natural gas futures and forward contracts and call options	Volatility in crude oil and petroleum products prices - effect on market value of inventory or purchase commitments	Derivative is recorded in Other current assets (offset against margin deposits) or Accrued liabilities	Entire amount of change in fair value of derivative is recorded in Supply and logistics costs - product costs

Unrealized gains are subtracted from net income and unrealized losses are added to net income in determining cash flows from operating activities. Additionally, the offsetting change in the fair value of inventory that is recorded for our fair value hedges is also eliminated from net income in determining cash flows from operating activities. Changes in margin deposits necessary to fund unrealized losses also affect cash flows from operating activities.

Table of Contents

The following tables reflect the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at December 31, 2011 and 2010:

Fair Value of Derivative Assets and Liabilities

	Asset Derivatives		
	Consolidated Balance Sheets Location	Fair Value December 31, 2011	Fair Value December 31, 2010
Commodity derivatives futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$	$ 14
Undesignated hedges	Other Current Assets	306	493
Total asset derivatives		$ 306	$ 507

	Liability Derivatives		
	Consolidated Balance Sheets Location	Fair Value December 31, 2011	Fair Value December 31, 2010
Commodity derivatives forwards futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$	$ (191) (1)
Undesignated hedges	Other Current Assets	(2,820) (1)	(2,283) (1)
Total liability derivatives		$ (2,820)	$ (2,474)

(1) These derivative liabilities have been funded with margin deposits recorded in our Consolidated Balance Sheets in other current assets.

Effect on Consolidated Statements of Operations and Other Comprehensive Income (Loss)

	Amount of Gain (Loss) Recognized in Income					
	Supply & Logistics Product Costs Year Ended December 31,		Interest Expense Reclassified from AOCL Year Ended December 31,		Other Comprehensive Loss Effective Portion Year Ended December 31,	
	2011	2010	2011	2010	2011	2010
Commodity derivatives futures and call options:						
Contracts designated as hedges under accounting guidance	$ (173) (1)	$ 307 (1)	$	$	$	$
Contracts not considered hedges under accounting guidance	(17,419)	(4)				
Total commodity derivatives	(17,592)	303				
Interest rate swaps designated as cash flow hedges under accounting guidance				(2,112)		(424)

Total derivatives	$ (17,592)	$ 303	$	$ (2,112)	$	$ (424)

(1) Represents the amount of gain (loss) recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $0.8 million and $1 million for the year ended 2011 and 2010, respectively.

We have no derivative contracts with credit contingent features.

Table of Contents

18. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	$000000000	$000000000	$000000000	$000000000	$000000000	$000000000
	Fair Value at December 31, 2011			Fair Value at December 31, 2010		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$ 306	$	$	$ 507	$	$
Liabilities	$ (2,820)	$	$	$ (2,474)	$	$

Level 1

Included in Level 1 of the fair value hierarchy as commodity derivative contracts are exchange-traded futures and exchange-traded option contracts. The fair value of these exchange-traded derivative contracts is based on unadjusted quoted prices in active markets and is, therefore, included in Level 1 of the fair value hierarchy.

Level 2 and Level 3

At December 31, 2011 and 2010, we had no Level 2 or Level 3 fair value measurements. During 2010, we settled our interest rate swaps, which were classified as Level 3 fair value measurements. The following table provides a reconciliation of changes in fair value of our interest rate swaps during 2010 and 2009:

	$000000000	$000000000
	Year Ended December 31,	
	2010	2009
Balance at beginning of period	$ (1,688)	$ (1,964)
Realized and unrealized gains (losses)-		
Reclassified into interest expense for settled contracts	2,112	784
Included in other comprehensive income (loss)	(424)	(508)
Balance at end of period	$	$ (1,688)

We generally apply fair value techniques on a non-recurring basis associated with (1) valuing the potential impairment loss related to goodwill and (2) valuing potential impairment loss related to long-lived assets.

See Note 17 for additional information on our derivative instruments.

19. Commitments and Contingencies

Commitments and Guarantees

Our office lease for our corporate headquarters extends until January 31, 2017. To transport products, we lease tractors, trailers, and railcars. In addition, we lease tanks and terminals for the storage of crude oil, petroleum products, NaHS and caustic soda. Additionally, we lease a segment of pipeline where under the terms we make payments based on throughput. We have no minimum volumetric or financial requirements remaining on our pipeline lease.

The future minimum rental payments under all non-cancelable operating leases as of December 31, 2011, were as follows (in thousands):

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2012	$ 885	$ 6,183	$ 5,461	$ 12,529
2013	910	5,510	3,076	9,496
2014	940	5,345	1,027	7,312
2015	956	4,495	1,027	6,478
2016	933	1,245	1,027	3,205
2017 and thereafter	65	1,654	19,082	20,801
Total minimum lease obligations	$ 4,689	$ 24,432	$ 30,700	$ 59,821

Total operating lease expense was as follows (in thousands):

Year ended December 31, 2011	$ 18,331
Year ended December 31, 2010	$ 15,692
Year ended December 31, 2009	$ 12,023

In connection with our 50% interest in SEKCO as described in Note 2, we have committed to share in the required funding 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.

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities; however no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material effect on our financial position, results of operations or cash flows.

20. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. Other than with respect to our corporate subsidiaries and the Texas Margin Tax, our taxable income or loss is includible in the federal income tax returns of each of our partners.

A few of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. We pay federal and state income taxes on these operations. In May 2006, the State of Texas enacted a law which requires us to pay a tax of 0.5% on our margin, as defined in the law. The margin to which the tax rate is applied generally is calculated as our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax purposes), in the State of Texas.

Table of Contents

Our income tax (benefit) expense is as follows:

	Year Ended December 31, 2011	2010	2009
Current:			
Federal	$ 2,147	$ 1,664	$ 1,458
State	676	1,494	1,442
Total current income tax expense	2,823	3,158	2,900
Deferred:			
Federal	(3,714)	(573)	168
State	(326)	3	12
Total deferred income tax (benefit) expense	(4,040)	(570)	180
Total income tax (benefit) expense	$ (1,217)	$ 2,588	$ 3,080

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the balance sheet date. Deferred tax assets and liabilities consist of the following:

	December 31, 2011	2010
Deferred tax assets:		
Current:		
Other current assets	$ 351	$ 445
Other	8	8
Total current deferred tax asset	359	453
Net operating loss carryforwards	2,363	862
Total long-term deferred tax asset	2,363	862
Valuation allowances	(428)	(416)
Total deferred tax assets	2,294	899
Deferred tax liabilities:		
Current:		
Other	(211)	(213)
Long-term:		
Fixed assets	(5,744)	(7,807)
Intangible assets	(6,805)	(7,386)
Total long-term liability	(12,549)	(15,193)

Total deferred tax liabilities		(12,760)		(15,406)
Total net deferred tax liability	$	(10,466)	$	(14,507)

We record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character in the future and in the appropriate taxing jurisdictions. We have provided a valuation allowance for state net operating loss carryforwards.

Table of Contents

Our income tax (benefit) expense varies from the amount that would result from applying the federal statutory income tax rate to income (loss) before income taxes as follows:

	$00000000000	$00000000000	$00000000000
	Year Ended December 31,		
	2011	2010	2009
Income (loss) before income taxes	$ 50,032	$ (47,953)	$ 9,258
Partnership (income) loss not subject to tax	(60,304)	47,357	(7,822)
Income (loss) subject to income taxes	(10,272)	(596)	1,436
Tax (benefit) expense at federal statutory rate	$ (3,595)	$ (209)	$ 503
State income taxes, net of federal benefit	123	583	991
Effects of unrecognized tax positions, federal and state	1,964	1,909	1,733
Return to provision, federal and state	72	257	(224)
Other	219	48	77
Income tax expense (benefit)	$ (1,217)	$ 2,588	$ 3,080
Effective tax rate on income (loss) before income taxes	(1)	(1)	33%

(1) Income tax expense is related to taxable income generated by our corporate subsidiaries and Texas Margin Tax. Due to the income tax benefit in 2011 and the loss before income taxes in 2010, the effective tax rate as a percentage of our total income (loss) before income taxes is not meaningful.

A reconciliation of the beginning and ending amount of our unrecognized tax positions was as follows:

	$00000000000
Balance at January 1, 2009	$ 2,599
Additions based on tax positions related to current year	1,733
Balance at December 31, 2009	4,332
Additions based on tax positions related to current year	1,909
Balance at December 31, 2010	6,241
Additions based on tax positions related to current year	1,964
Balance at December 31, 2011	$ 8,205

If the unrecognized tax positions at December 31, 2011 were recognized, $8.2 million would affect our effective income tax rate. At December 31, 2011, our unrecognized tax positions are included in other liabilities.

21. Subsequent Events (Unaudited)

Interests in Gulf of Mexico Crude Oil Pipelines

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. The acquisition is intended to complement 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 in 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. 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. 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.

Table of Contents

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.

22. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2011 and 2010.

	2011 Quarters				Total
	First	Second	Third	Fourth	Year
Revenues	$ 689,798	$ 762,790	$ 830,200	$ 806,881	$ 3,089,669
Operating income	$ 12,832	$ 25,931	$ 28,632	$ 15,057	$ 82,452
Net income attributable to Genesis Energy, L.P.	$ 7,030	$ 17,358	$ 19,088	$ 7,773	$ 51,249
Net income per common unit basic and diluted	$ 0.11	$ 0.27	$ 0.27	$ 0.10	$ 0.75
Cash distributions per common unit [(1)]	$ 0.4000	$ 0.4075	$ 0.4150	$ 0.4275	$ 1.6500

	2010 Quarters				Total
	First	Second	Third	Fourth [(2)]	Year
Revenues	$ 466,531	$ 456,538	$ 576,012	$ 602,243	$ 2,101,324
Operating income (loss)	$ 10,038	$ 18,299	$ 10,183	$ (65,904)	$ (27,384)
Net income (loss)	$ 6,325	$ 13,921	$ 3,863	$ (74,650)	$ (50,541)
Net income (loss) attributable to Genesis Energy, L.P.	$ 6,885	$ 14,238	$ 5,068	$ (74,650)	$ (48,459)
Net income per common unit basic and diluted	$ 0.06	$ 0.29	$ 0.12	$ 0.02	$ 0.49
Cash distributions per common unit [(1)]	$ 0.3600	$ 0.3675	$ 0.3750	$ 0.3875	$ 1.4900

(1) Represents cash distributions declared and paid in the applicable period.
(2) Includes executive compensation expense related to Series B and Class B awards borne entirely by our general partner in the amounts of $75.6 million (see Note 15).

Table of Contents

23. Condensed Consolidating Financial Information

Our Senior Unsecured Notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P. s subsidiaries, except Genesis Free State Pipeline, LLC, Genesis NEJD Pipeline, LLC and certain other minor subsidiaries. Genesis NEJD Pipeline, LLC is 100% owned by Genesis Energy, L.P., the parent company. The remaining non-guarantor subsidiaries are owned by Genesis Crude Oil, L.P., a guarantor subsidiary. Genesis Energy Finance Corporation has no independent assets or operations. See Note 10 for additional information regarding our consolidated debt obligations.

As a result of our IDR Restructuring in December 2010 (see Note 11), each subsidiary guarantor and the subsidiary co-issuer are 100% owned, directly or indirectly, by Genesis Energy, L.P.

The following is condensed consolidating financial information for Genesis Energy, L.P. and subsidiary guarantors:

Table of Contents

	December 31, 2011					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$ 3	$	$ 9,182	$ 1,632	$	$ 10,817
Other current assets	597,966		341,131	31,897	(605,707)	365,287
Total current assets	597,969		350,313	33,529	(605,707)	376,104
Fixed Assets, at cost			444,262	96,876		541,138
Less: Accumulated depreciation			(114,655)	(9,558)		(124,213)
Net fixed assets			329,607	87,318		416,925
Goodwill			325,046			325,046
Other assets, net	14,773		276,450	162,373	(167,774)	285,822
Equity investees and other investments			326,947			326,947
Investments in subsidiaries	841,725		96,303		(938,028)	
Total assets	$ 1,454,467	$	$ 1,704,666	$ 283,220	$ (1,711,509)	$ 1,730,844
LIABILITIES AND PARTNERS CAPITAL						
Current liabilities	$ 2,529	$	$ 835,013	$ 17,562	$ (605,676)	$ 249,428
Senior secured credit facilities	409,300					409,300
Senior unsecured notes	250,000					250,000
Deferred tax liabilities			12,549			12,549
Other liabilities			14,673	169,842	(167,586)	16,929
Total liabilities	661,829		862,235	187,404	(773,262)	938,206
Partners capital	792,638		842,431	95,816	(938,247)	792,638
Total liabilities and partners capital	$ 1,454,467	$	$ 1,704,666	$ 283,220	$ (1,711,509)	$ 1,730,844

Table of Contents

	December 31, 2010					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$ 1	$	$ 5,082	$ 679	$	$ 5,762
Other current assets	584,967		245,240	20,620	(604,051)	246,776
Total current assets	584,968		250,322	21,299	(604,051)	252,538
Fixed Assets, at cost			297,832	75,507		373,339
Less: Accumulated depreciation			(101,472)	(6,811)		(108,283)
Net fixed assets			196,360	68,696		265,056
Goodwill			325,046			325,046
Other assets, net	14,695		310,808	166,616	(171,458)	320,661
Equity investees and other investments			343,434			343,434
Investments in subsidiaries	682,641		83,323		(765,964)	
Total assets	$ 1,282,304	$	$ 1,509,293	$ 256,611	$ (1,541,473)	$ 1,506,735
LIABILITIES AND PARTNERS CAPITAL						
Current liabilities	$ 3,040	$	$ 805,381	$ 2,172	$ (603,879)	$ 206,714
Senior secured credit facilities	360,000					360,000
Senior unsecured notes	250,000					250,000
Deferred tax liabilities			15,193			15,193
Other liabilities			5,564	171,266	(171,266)	5,564
Total liabilities	613,040		826,138	173,438	(775,145)	837,471
Partners capital	669,264		683,155	83,173	(766,328)	669,264
Total liabilities and partners capital	$ 1,282,304	$	$ 1,509,293	$ 256,611	$ (1,541,473)	$ 1,506,735

Table of Contents

	Year Ended December 31, 2011					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$	$	$ 2,824,524	$ 14,883	$ (13,639)	$ 2,825,768
Refinery services			197,928	20,548	(16,765)	201,711
Pipeline transportation services			36,281	25,909		62,190
Total revenues			3,058,733	61,340	(30,404)	3,089,669
COSTS AND EXPENSES:						
Supply and logistics costs			2,766,084	14,363	(13,639)	2,766,808
Refinery services operating costs			122,724	20,968	(16,910)	126,782
Pipeline transportation operating costs			16,174	790		16,964
General and administrative			34,473			34,473
Depreciation and amortization			59,175	2,751		61,926
Net loss on disposal of surplus assets			264			264
Total costs and expenses			2,998,894	38,872	(30,549)	3,007,217
OPERATING INCOME			59,839	22,468	145	82,452
Equity in earnings of equity investees			3,347			3,347
Equity in earnings of subsidiaries	86,958		5,333		(92,291)	
Interest (expense) income, net	(35,709)		16,933	(16,991)		(35,767)
Income before income taxes	51,249		85,452	5,477	(92,146)	50,032
Income tax benefit (expense)			1,555	(338)		1,217
NET INCOME	51,249		87,007	5,139	(92,146)	51,249
Net loss attributable to noncontrolling interests						
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 51,249	$	$ 87,007	$ 5,139	$ (92,146)	$ 51,249

Table of Contents

`

	Year Ended December 31, 2010					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$	$	$ 1,894,612	$	$	$ 1,894,612
Refinery services			146,570	14,544	(10,054)	151,060
Pipeline transportation services			29,497	26,155		55,652
Total revenues			2,070,679	40,699	(10,054)	2,101,324
COSTS AND EXPENSES:						
Supply and logistics costs			1,858,862			1,858,862
Refinery services operating costs			85,250	12,672	(9,828)	88,094
Pipeline transportation operating costs			14,301	476		14,777
General and administrative			113,406			113,406
Depreciation and amortization			50,961	2,596		53,557
Net loss on disposal of surplus assets			12			12
Total costs and expenses			2,122,792	15,744	(9,828)	2,128,708
OPERATING (LOSS) INCOME			(52,113)	24,955	(226)	(27,384)
Equity in earnings of equity investees			2,355			2,355
Equity in (losses) earnings of subsidiaries	(34,988)		7,401		27,587	
Interest (expense) income, net	(13,471)		7,884	(17,337)		(22,924)
(Loss) income before income taxes	(48,459)		(34,473)	7,618	27,361	(47,953)
Income tax expense			(2,175)	(413)		(2,588)
NET (LOSS) INCOME	(48,459)		(36,648)	7,205	27,361	(50,541)
Net loss attributable to noncontrolling interests			2,083		(1)	2,082
NET LOSS (INCOME) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ (48,459)	$	$ (34,565)	$ 7,205	$ 27,360	$ (48,459)

F-43

Table of Contents

	Year Ended December 31, 2009					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
REVENUES:						
Supply and logistics	$	$	$ 1,243,044	$	$	$ 1,243,044
Refinery services			138,438	9,527	(6,600)	141,365
Pipeline transportation services			25,004	25,947		50,951
Total revenues			1,406,486	35,474	(6,600)	1,435,360
COSTS AND EXPENSES:						
Supply and logistics costs			1,203,896			1,203,896
Refinery services operating costs			86,346	9,320	(6,756)	88,910
Pipeline transportation operating costs			12,542	482		13,024
General and administrative			40,402	11		40,413
Depreciation and amortization			59,992	2,589		62,581
Net loss on disposal of surplus assets			160			160
Impairment expense			5,005			5,005
Total costs and expenses			1,408,343	12,402	(6,756)	1,413,989
OPERATING (LOSS) INCOME			(1,857)	23,072	156	21,371
Equity in earnings of equity investees			1,547			1,547
Equity in earnings of subsidiaries	8,063		5,614		(13,677)	
Interest income (expense), net			3,998	(17,658)		(13,660)
Income before income taxes	8,063		9,302	5,414	(13,521)	9,258
Income tax expense			(3,080)			(3,080)
NET INCOME	8,063		6,222	5,414	(13,521)	6,178
Net loss attributable to noncontrolling interests			1,885			1,885
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ 8,063	$	$ 8,107	$ 5,414	$ (13,521)	$ 8,063

F-44

Table of Contents

	Year Ended December 31, 2011					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$ (41,392)	$	$ 99,360	$ 17,696	$ (17,357)	$ 58,307
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets			(27,417)	(575)		(27,992)
Cash distributions received from equity investees return of investment	107,956		11,436		(107,956)	11,436
Investments in equity investees and other investments	(184,969)		(20,193)		204,968	(194)
Acquisitions			(142,692)	(20,787)		(163,479)
Repayments on loan to non-guarantor subsidiary			3,685		(3,685)	
Other, net			7,194	738		7,932
Net cash (used in) provided by investing activities	(77,013)		(167,987)	(20,624)	93,327	(172,297)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Bank borrowings	777,600					777,600
Bank repayments	(728,300)					(728,300)
Proceeds from issuance of senior unsecured notes						
Credit facility issuance fees	(3,018)					(3,018)
Issuance of ownership interests to partners for cash	184,969		184,969	19,999	(204,968)	184,969
Distributions to partners/owners	(112,844)		(112,844)	(12,500)	125,344	(112,844)
Other, net			602	(3,618)	3,654	638
Net cash provided by (used in) financing activities	118,407		72,727	3,881	(75,970)	119,045
Net increase in cash and cash equivalents	2		4,100	953		5,055
Cash and cash equivalents at beginning of period	1		5,082	679		5,762
Cash and cash equivalents at end of period	$ 3	$	$ 9,182	$ 1,632	$	$ 10,817

Table of Contents

	Year Ended December 31, 2010					
	Genesis Energy, L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$ (569,824)	$	$ 680,974	$ 3,746	$ (24,433)	$ 90,463
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets			(12,372)	(28)		(12,400)
Cash distributions received from equity investees return of investment	45,889		2,859		(45,889)	2,859
Investments in equity investees and other investments	(118,875)		(332,462)		118,875	(332,462)
Repayments on loan to non-guarantor subsidiary			3,331		(3,331)	
Other, net			1,265			1,265
Net cash used in investing activities	(72,986)		(337,379)	(28)	69,655	(340,738)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Bank borrowings	449,729		242,100			691,829
Bank repayments	(455,629)		(243,100)			(698,729)
Transfer of senior secured credit facility to Parent	364,772		(364,772)			
Proceeds from issuance of senior unsecured notes	250,000					250,000
Credit facility and senior unsecured notes issuance fees	(14,586)					(14,586)
Issuance of ownership interests to partners for cash	118,875		118,888		(118,888)	118,875
Noncontrolling interests contributions, net of distributions					6	6
Acquisition of noncontrolling interest in DG Marine			(26,288)			(26,288)
Distributions to partners/owners	(70,352)		(70,359)		70,359	(70,352)
Other, net			1,134	(3,301)	3,301	1,134
Net cash provided by (used in) financing activities	642,809		(342,397)	(3,301)	(45,222)	251,889
Net (decrease) increase in cash and cash equivalents	(1)		1,198	417		1,614
Cash and cash equivalents at beginning of period	2		3,884	262		4,148
Cash and cash equivalents at end of period	$ 1	$	$ 5,082	$ 679	$	$ 5,762

	Year Ended December 31, 2009					
	Genesis Energy L.P. (Parent and Co-Issuer)	Genesis Energy Finance Corporation (Co-Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Genesis Energy, L.P. Consolidated
Net cash (used in) provided by operating activities	$ (1)	$	$ 86,926	$ 11,128	$ (7,974)	$ 90,079
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets			(30,270)	(62)		(30,332)
Cash distributions received from equity investees return of investment	60,080				(60,080)	
Investments in equity investees and other investments	(9)		(83)		9	(83)
Repayments on loan to non-guarantor subsidiary			3,010		(3,010)	
Other, net			1,182			1,182
Net cash provided by (used) in investing activities	60,071		(26,161)	(62)	(63,081)	(29,233)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Bank borrowings			255,300			255,300
Bank repayments			(263,700)			(263,700)
Credit facility issuance fees			(422)			(422)
Issuance of ownership interests to partners for cash	9		9		(9)	9
Noncontrolling interests contributions, net of distributions					(6)	(6)
Distributions to partners/owners	(60,080)		(60,086)	(8,000)	68,086	(60,080)
Other, net			(6,784)	(2,984)	2,984	(6,784)
Net cash used in financing activities	(60,071)		(75,683)	(10,984)	71,055	(75,683)
Net (decrease) increase in cash and cash equivalents	(1)		(14,918)	82		(14,837)
Cash and cash equivalents at beginning of period	3		18,802	180		18,985
Cash and cash equivalents at end of period	$ 2	$	$ 3,884	$ 262	$	$ 4,148

Table of Contents

Financial Statements of Significant Equity Investee

CAMERON HIGHWAY OIL PIPELINE COMPANY

BALANCE SHEET

AT DECEMBER 31, 2011

(Dollars in thousands)

		000000000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$	1,220
Accounts receivable trade		3,818
Accounts receivable affiliates		6
Prepaid and other current assets		295
Total current assets		5,339
PROPERTY, PLANT AND EQUIPMENT, NET		438,421
Total assets	$	443,760
LIABILITIES AND PARTNERS EQUITY		
CURRENT LIABILITIES		
Accounts payable trade	$	882
Accounts payable affiliates		541
Accrued product payables		462
Accrued ad valorem taxes		535
Other current liabilities		133
Total current liabilities		2,553
OTHER LIABILITIES		1,616
COMMITMENTS AND CONTINGENCIES		
PARTNERS EQUITY		439,591
Total liabilities and partners equity	$	443,760

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2011

(Dollars in thousands)

		000000000000
REVENUES		
Crude oil handling revenues	$	42,454
Total revenues		42,454
COSTS AND EXPENSES		
Depreciation and accretion		16,742
Other operating costs and expenses		11,933
General and administrative costs		90
Total costs and expenses		28,765
NET INCOME	$	13,689

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2011

(Dollars in thousands)

OPERATING ACTIVITIES	
Net income	$ 13,689
Reconciliation of net income to net cash flows provided by operating activities:	
Depreciation and accretion	16,742
Non-cash asset impairment charge	591
Loss on sale of asset	26
Effect of changes in operating accounts	
Accounts receivable	4,482
Prepaid and other current assets	623
Accounts payable	(2,118)
Accrued product payables	462
Accrued ad valorem taxes	(34)
Other current liabilities	45
Net cash provided by operating activities	34,508
INVESTING ACTIVITIES	
Capital expenditures	(593)
Proceeds on sale of asset	58
Cash used in investing activities	(535)
FINANCING ACTIVITIES	
Distributions to partners	(35,340)
Cash used in financing activities	(35,340)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,367)
CASH AND CASH EQUIVALENTS, JANUARY 1	2,587
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 1,220

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF PARTNERS EQUITY

FOR THE YEAR ENDED DECEMBER 31, 2011

(Dollars in thousands)

	Cameron Highway Pipeline I, L.P. 50%	Cameron Highway Pipeline II, L.P. 25%	Cameron Highway Pipeline III, L.P. 25%	Total
BALANCE AT JANUARY 1, 2011	$ 230,620	$ 115,311	$ 115,311	$ 461,242
Net income	6,845	3,422	3,422	13,689
Distributions to partners	(17,670)	(8,835)	(8,835)	(35,340)
BALANCE AT DECEMBER 31, 2011	$ 219,795	$ 109,898	$ 109,898	$ 439,591

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Partnership Organization

Cameron Highway Oil Pipeline Company (Cameron Highway) is a Delaware general partnership formed in June 2003 to construct, install, own and operate a 374-mile crude oil pipeline (the Pipeline) located in deepwater areas of the central Gulf of Mexico offshore Texas and Louisiana. Unless the context requires otherwise, references to we, us , our or the Company, within these notes are intended to mean the Cameron Highway joint venture.

We are owned (i) 50% by Cameron Highway Pipeline I, L.P. (CHOPS I), a subsidiary of Enterprise GTM Holdings L.P. (Enterprise), (ii) 25% by Cameron Highway Pipeline II, L.P. (CHOPS II), a subsidiary of Genesis Energy LP (Genesis), and (iii) 25% by Cameron Highway Pipeline III, L.P. (CHOPS III), another subsidiary of Genesis. CHOPS I, CHOPS II and CHOPS III are referred to individually as a Partner , or collectively as the Partners. Genesis acquired its indirect 50% equity interest in Cameron Highway from Valero Energy Corporation (Valero) on November 23, 2010.

2. Summary of Significant Accounting Policies

Our financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles (GAAP). Except as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Business Segment

We operate in a single business segment, Offshore Pipeline & Services, which consists of a 374-mile pipeline used in the transportation of crude oil. The following table summarizes our revenues and long-lived assets for this business segment for the period indicated:

	For Year Ended December 31, 2011
Segment assets	$ 443,760
Segment revenues	42,454
Segment operating income	13,689
Segment net income	13,689

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition and/or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

Table of Contents

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. There were no loss contingency accruals at December 31, 2011.

Crude Oil Imbalances

Crude oil imbalances arise in the course of providing crude oil handling services, where we receive volumes of crude oil that differ from the volumes committed to be redelivered. These differences result in imbalances that are settled in-kind (i.e., with crude oil volumes instead of cash) the following month. We value our crude oil imbalances using contractual settlement prices. Imbalance receivables and payables are classified on our balance sheet within accounts receivable and payable, respectively. At December 31, 2011, our imbalance receivables were $0.6 million and our imbalance payables were $8 thousand.

Environmental Costs

Our operations are subject to extensive federal and state environmental regulations. Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. There were no environmental remediation liabilities incurred as of December 31, 2011.

Estimates

Preparing our financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the unaudited financial statements. Our most significant estimates relate to (i) the useful lives of fixed assets, (ii) impairment testing of fixed assets, (iii) contingencies and (iv) revenue and expense accruals. Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our unaudited financial statements.

Fair Value Information

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair values based on their short-term nature.

Impairment Testing For Long-Lived Assets

Long-lived assets such as property, plant and equipment are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset s carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset s carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. We recorded $0.6 million of non-cash asset impairment charges in 2011 related to construction in progress balances that were written off.

Table of Contents

Income Taxes

We are organized as a pass-through entity for federal income tax purposes and our Partners are individually responsible for their allocable share of our taxable income for federal income tax purposes. As a result, our financial statements do not provide for such taxes.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the periods it benefits. Our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. See Note 3 for additional information regarding our property, plant and equipment.

Asset retirement obligations (AROs) are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. See Note 3 for additional information regarding our AROs.

Recently Issued Accounting Standards

The Financial Accounting Standards Board has recently issued various new accounting standards that may impact our future financial statements. We have evaluated these new standards and have determined that the adoption of these rules will not have a material impact on us.

Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer s price is fixed or determinable and (iv) collectibility is reasonably assured.

Crude oil handling revenues are generated from purchase and sale arrangements whereby we purchase crude oil from shippers at various receipt points along the Pipeline for an index-based price (less a price differential) and sell the crude oil back to the same shippers at various redelivery points at the same index-based price. Since these are purchase and sales transactions with the same counterparty and are entered into in contemplation of one another, we recognize net revenue from such arrangements based upon the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. We net the corresponding receivables and payables from such transactions on our balance sheet for consistency of presentation.

Table of Contents

Subsequent Events

We have evaluated subsequent events through February 16, 2012, which is the date our Financial Statements and Notes were available to be issued, and have determined that there were no material subsequent events.

3. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life	December 31, 2011
Pipeline (1)	30 years	$ 329,368
Platforms and facilities (2)	30 years	169,973
Crude oil line fill (3)	n/a	34,053
Construction in progress	n/a	18,215
Total		551,609
Less accumulated depreciation		113,188
Property, plant and equipment, net		$ 438,421

(1) Pipeline includes the Pipeline and related assets.
(2) Platforms and facilities include offshore platforms and related facilities that are an integral part of the Pipeline.
(3) Crude oil line fill is carried at original cost and is not depreciated, but it is subject to impairment considerations.

Depreciation expense was $16.6 million for the year ended December 31, 2011.

In 2011, we had an impairment charge of $591 thousand resulting from the writeoff of construction costs (carried in Construction in progress) related to an unfinished lateral pipeline begun in 2004 and subsequently put on hold until potential use could be identified. Our management determined in 2011 there was no longer a specific plan to complete the pipeline. This impairment loss is included in Other operating costs and expenses on the Statement of Operations.

Our pipeline and related platforms and facilities are subject to the Bureau of Safety and Environment Enforcement (BSEE) regulations governing the abandonment or retirement of certain offshore facilities. Our AROs result from right-of-way agreements associated with our pipeline operations and regulatory requirements of the BSEE. None of our assets are legally restricted for purposes of settling AROs. The following table presents information regarding our asset retirement obligations for the periods noted.

Balance, January 1, 2011	$ 1,475
Accretion expense	120
Revisions in estimated cash flows	21
Balance, December 31, 2011	$ 1,616

Property, plant and equipment at the year ended December 31, 2011 includes $1.2 million of estimated ARO costs capitalized as an increase in the associated long-lived asset. The following table presents our accretion expense forecasts for AROs for the periods presented:

2012	2013	2014	2015	2016
	$000,000,000,0	$000,000,000,0	$000,000,000,0	$000,000,000,0
$ 130	$ 140	$ 151	$ 164	$ 177

Table of Contents

4. Partners Equity

Income or loss amounts are allocated to Partners based on their respective partnership interests. Distributions to Partners are also made in accordance with each Partner s respective partnership interests. We make cash distributions to Partners on a quarterly basis to the extent that our cash balance exceeds our normal working capital and any outstanding invoices.

5. Related Party Transactions

We have an Operation and Management Agreement (the Agreement) with Manta Ray Gathering Company L.L.C. (Manta Ray) for the operation and management of the Pipeline. Manta Ray is a subsidiary of Enterprise. Pursuant to the agreement, we pay Manta Ray $350,000 per month (adjusted annually for changes in an average weekly earnings index as defined in the Agreement) for routine operating services. During 2011, such amount was approximately $459,000 per month. We reimburse Manta Ray for all non-routine operations-related services.

The Agreement may be terminated or canceled by us if Manta Ray (i) defaults in the performance of any of its obligations; (ii) dissolves, liquidates or terminates its separate corporate existence; (iii) makes a general assignment for the benefit of creditors or admits in writing its inability to pay its debts; or (iv) if Manta Ray is in default under the performance standards set forth in the Agreement. The Agreement may be terminated or canceled by Manta Ray without cause at any time with at least 180 days notice if (i) we are in default in the performance of any payment obligations; (ii) we dissolve, liquidate or terminate our separate corporate existence; (iii) we make a general assignment for the benefit of creditors or admit in writing our inability to pay our debts generally as they become due; or (iv) we sell or lease our Pipeline to a third party. For the year ended December 31, 2011, other operating costs and expenses include payments to Manta Ray for operation and management services rendered to us totaling $5.5 million.

We rent offshore platform space from an affiliate of Enterprise and a third party. Total rent paid to the affiliate of Enterprise was $0.7 million for the year ended December 31, 2011. See Note 6 for additional information regarding this operating lease.

6. Commitments and Contingencies

Operating Leases

Lease and rent expense included in operating income was $1.8 million for the year ended December 31, 2011.

We rent offshore platform space from an affiliate of Enterprise and a third party. Total rent paid for this platform space was $1.3 million for the year ended December 31, 2011. The agreement has an indefinite term and will continue until the platform is abandoned. However, we can terminate the agreement at any time if we cease operations on the platform. As a result, there are no future minimum payment obligations attributable to this agreement.

We also have right-of-way leases held in connection with our Pipeline. In general, our payments for right-of-way easements are determined by the underlying contracts, which typically include a stated fixed fee. Certain of our right-of-way leases contain rent escalation clauses whereby the rent is adjusted periodically for inflation. Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit.

Table of Contents

The following table presents our minimum payment obligations under operating leases for right-of-way:

2012	$ 22
2013	22
2014	22
2015	22
2016	22
Thereafter	213
Total	$ 323

Regulatory and Legal

As part of our normal business activities, we are subject to various laws and regulations, including those related to environmental matters. In the opinion of management, compliance with existing laws and regulations will not materially affect our financial position, results of operations or cash flows. Also, in the normal course of business, we may be a party to lawsuits and similar proceedings before various courts and governmental agencies involving, for example, contractual disputes, environmental issues and other matters. We are not aware of any such matters at December 31, 2011. As new information becomes available or relevant developments occur, we will establish accruals and/or make disclosures as appropriate.

7. Significant Risks

Production and credit risk due to customer concentration

Offshore crude oil pipeline systems such as ours are affected by oil exploration and production activities. Crude oil reserves are depleting assets. Our Pipeline must access additional reserves to offset either (i) the natural decline in production from existing connected wells or (ii) the loss of any production to a competitor. We actively seek to offset the loss of volumes due to depletion by adding connections to new customers and fields.

The pipeline has a throughput capacity of 500,000 barrels per day and is designed to gather production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon and Walker Ridge areas, for delivery to refineries and terminals in southeast Texas. The Pipeline is supported by life of lease dedications by BP Exploration and Production Inc. (BP), BHP Billiton Ltd. (BHP) and Chevron USA Inc. in connection with their production from Holstein, Mad Dog and Atlantis fields and by Anadarko US Offshore Corporation in connection with its production from the Constitution and Ticonderoga fields. Additionally, we have contracted with Petrobras America Inc. to transport crude oil production from the Cottonwood field. BP accounted for 42% of our revenues for the year ended December 31, 2011. BHP accounted for 41% of our revenues for the year ended December 31, 2011.

Additionally, in April 2010, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill that significantly impacted ecological resources in the Gulf of Mexico. As a result, in May 2010, a federal offshore drilling moratorium went into effect which halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. The moratorium was lifted in October 2010; however, it is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected. A continued decline in oil and natural gas production volumes and/or a failure to achieve anticipated future production due to limitations caused by the federal moratorium and additional regulatory compliance could have a material adverse effect on our financial position, results of operations or cash flows.

Weather-Related Risks

Our assets are located offshore Texas and Louisiana in the Gulf of Mexico, an area that is prone to tropical weather events such as hurricanes. Our Partners are required to maintain certain levels of insurance with respect to our assets. If we were to experience a significant weather-related loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows.

Financial Statements of Significant Equity Investee Cameron Highway Oil Pipeline Company

INDEPENDENT AUDITORS REPORT

To the Management Committee of

Cameron Highway Oil Pipeline Company

Houston, Texas

We have audited the accompanying balance sheet of Cameron Highway Oil Pipeline Company (the Company) as of December 31, 2010, and the related statements of operations, partners equity, and cash flows for the period from November 23, 2010 through December 31, 2010. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2010, and the results of its operations and its cash flows for the period from November 23, 2010 through December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 4, 2011

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

BALANCE SHEET

December 31, 2010

(Dollars in thousands)

ASSETS	
CURRENT ASSETS	
Cash and cash equivalents	$ 2,587
Accounts receivable trade	8,172
Accounts receivable affiliates	218
Prepaid and other current assets	918
Total current assets	11,895
PROPERTY, PLANT AND EQUIPMENT, NET	455,424
Total assets	$ 467,319
LIABILITIES AND PARTNERS EQUITY	
CURRENT LIABILITIES	
Accounts payable trade	$ 2,420
Accounts payable affiliates	1,525
Other current liabilities	657
Total current liabilities	4,602
OTHER LIABILITIES	1,475
COMMITMENTS AND CONTINGENCIES	
PARTNERS EQUITY	461,242
Total liabilities and partners equity	$ 467,319

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF OPERATIONS

Period from November 23, 2010 through December 31, 2010

(Dollars in thousands)

REVENUES	
Crude oil handling revenues	$ 5,636
Total revenues	5,636
COSTS AND EXPENSES	
Depreciation and accretion	1,797
Other operating costs and expenses (see Note 5)	1,159
General and administrative costs	16
Total costs and expenses	2,972
NET INCOME	$ 2,664

See Notes to Financial Statements

F-60

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF CASH FLOWS

Period from November 23, 2010 through December 31, 2010

(Dollars in thousands)

OPERATING ACTIVITIES	
Net income	$ 2,664
Adjustments to reconcile net income to net cash flows provided by operating activities:	
Depreciation and accretion	1,797
Effect of changes in operating accounts	
Accounts receivable	129
Prepaid and other current assets	100
Accounts payable	388
Other current liabilities	(27)
Net cash provided by operating activities	5,051
INVESTING ACTIVITIES	
Capital expenditures	(104)
Cash used in investing activities	(104)
FINANCING ACTIVITIES	
Distributions to partners	(7,800)
Cash used in financing activities	(7,800)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,853)
CASH AND CASH EQUIVALENTS, NOVEMBER 23	5,440
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 2,587

See Notes to Financial Statements

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

STATEMENT OF PARTNERS EQUITY

Period from November 23, 2010 through December 31, 2010

(Dollars in thousands)

	Cameron Highway Pipeline I, L.P. (Enterprise) 50%	Cameron Highway Pipeline II, L.P. (Genesis) 25%	Cameron Highway Pipeline III, L.P. (Genesis) 25%	Total
BALANCE AT NOVEMBER 23, 2010	$ 233,188	$ 116,595	$ 116,595	$ 466,378
Net income	1,332	666	666	2,664
Distributions to partners	(3,900)	(1,950)	(1,950)	(7,800)
BALANCE AT DECEMBER 31, 2010	$ 230,620	$ 115,311	$ 115,311	$ 461,242

See Notes to Financial Statements

F-62

Table of Contents

CAMERON HIGHWAY OIL PIPELINE COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Partnership Organization

Cameron Highway Oil Pipeline Company (Cameron Highway) is a Delaware general partnership formed in June 2003 to construct, install, own and operate a 374-mile crude oil pipeline (the Pipeline) located in deepwater areas of the central Gulf of Mexico offshore Texas and Louisiana. Unless the context requires otherwise, references to we, us , our or the Company, within these notes are intended to mean the Cameron Highway joint venture.

At December 31, 2010, we were owned (i) 50% by Cameron Highway Pipeline I, L.P. (CHOPS I), a subsidiary of Enterprise GTM Holdings L.P. (Enterprise), (ii) 25% by Cameron Highway Pipeline II, L.P. (CHOPS II), a subsidiary of Genesis Energy, L.P. (Genesis), and (iii) 25% by Cameron Highway Pipeline III, L.P. (CHOPS III), another subsidiary of Genesis. CHOPS I, CHOPS II and CHOPS III are collectively referred to as the Partners. Genesis acquired its indirect 50% equity interest in Cameron Highway from Valero Energy Corporation on November 23, 2010.

2. Summary of Significant Accounting Policies

Our financial statements are prepared on the accrual basis of accounting in conformity with U.S. generally accepted accounting principles (GAAP). Except as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Business Segment

We operate in a single business segment, Offshore Pipeline & Services, which consists of a 374-mile pipeline used in the transportation of crude oil.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase. Our Statements of Cash Flows are prepared using the indirect method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Crude Oil Imbalances

Crude oil imbalances arise in the course of providing crude oil handling services, where we receive volumes of crude oil that differ from the volumes committed to be redelivered. These differences result in imbalances that are settled in-kind (i.e., with crude oil volumes instead of cash) the following month. We value our crude oil imbalances using contractual settlement prices. Imbalance receivables and payables are classified on our balance sheet within accounts receivable and payable, respectively. At December 31, 2010, our imbalance receivables were $0.3 million, and our imbalance payables were $0.5 million.

Environmental Costs

Our operations include activities subject to federal and state environmental regulations. Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. There were no environmental remediation liabilities incurred as of December 31, 2010.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

Financial Instruments

Cash and cash equivalents, accounts receivable and accounts payable are carried at amounts which reasonably approximate their fair values due to their short-term nature.

Impairment Testing For Long-Lived Assets

Long-lived assets such as property, plant and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if the carrying value exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset s carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset s carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. No asset impairment charges were recognized for any of the periods presented.

Income Taxes

We are organized as a pass-through entity for federal income tax purposes and our Partners are individually responsible for their allocable share of our taxable income for federal income tax purposes. As a result, our financial statements do not provide for such taxes.

Table of Contents

Partnership Equity

We allocate income or loss and pay cash distributions to Partners in accordance with their respective partnership interests.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized. Minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in results of operations for the respective period. See Note 3 for additional information regarding our property, plant and equipment.

Asset retirement obligations (AROs) are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (through accretion expense) and the capitalized cost is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. See Note 3 for additional information regarding our AROs.

Recently Issued Accounting Standards

The accounting standard setting organizations, including the U.S. Securities and Exchange Commission, have recently issued various new accounting standards. We have evaluated these new standards and have determined that the adoption of these rules will not have a material impact on us.

Revenue Recognition

Crude oil handling revenues are generated from purchase and sale arrangements whereby we purchase crude oil from shippers at various receipt points along the Pipeline for an index-based price (less a price differential) and sell the crude oil back to the same shippers at various redelivery points at the same index-based price. Since these are purchase and sales transactions with the same counterparty and are entered into in contemplation of one another, we recognize net revenue from such arrangements based upon the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. We net the corresponding receivables and payables from such transactions on our balance sheet for consistency of presentation.

Subsequent Events

We have evaluated subsequent events through March 4, 2011, which is the date our Audited Financial Statements and Notes were available to be issued, and have determined that there were no material subsequent events.

Table of Contents

3. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life	December 31, 2010
Pipeline (1)	30 years	$ 329,093
Platforms and facilities (2)	30 years	169,789
Crude oil line fill (3)	n/a	34,053
Construction in progress	n/a	19,056
Total		551,991
Less accumulated depreciation		96,567
Property, plant and equipment, net		$ 455,424

(3) Includes the Pipeline and related assets.
(4) Platforms and facilities include offshore platforms and related facilities that are an integral part of the Pipeline.
(5) Crude oil line fill is carried at original cost and is not depreciated, but it is subject to impairment considerations.

The Pipeline has a throughput capacity of 500,000 barrels per day and is designed to gather production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon and Walker Ridge areas, for delivery to refineries and terminals in southeast Texas. The Pipeline is supported by life of lease dedications by BP, BHP Billiton Ltd. and Chevron in connection with their production from the Holstein, Mad Dog and Atlantis fields and by Anadarko in connection with its production from the Constitution and Ticonderoga fields. Additionally, we have contracted with Petrobras to transport crude oil production from the Cottonwood field.

Our AROs primarily result from right-of-way agreements associated with our pipeline operations and regulatory requirements triggered by the abandonment or retirement of certain offshore facilities. None of our assets are legally restricted for purposes of settling AROs.

Property, plant and equipment at December 31, 2010 includes $1.2 million of estimated ARO costs capitalized as an increase in the associated long-lived asset. Based on information currently available, we estimate that accretion expense will approximate $0.1 million annually for 2011 through 2014 and $0.2 million for 2015.

4. Related Party Transactions

We have an Operation and Management Agreement (the Agreement) with Manta Ray Offshore Gathering Co LLC (Manta Ray) for the operation and management of the Pipeline. Manta Ray is a subsidiary of Enterprise. Pursuant to the agreement, we pay Manta Ray $350,000 per month (adjusted annually for changes in an average weekly earnings index as defined in the Agreement) for routine operating services. During 2010, such amount was approximately $462,000 per month. We reimburse Manta Ray for all non-routine operations-related services.

The Agreement may be terminated or canceled by us if Manta Ray (i) defaults in the performance of any of its obligations; (ii) dissolves, liquidates or terminates its separate corporate existence; (iii) makes a general assignment for the benefit of creditors or admits in writing its inability to pay its debts; or (iv) if Manta Ray is in default under the performance standards set forth in the Agreement. The Agreement may be terminated or canceled by Manta Ray without cause at any time with at least 180 days notice if (i) we are in default in the performance of any payment obligations; (ii) we dissolve, liquidate or terminate our separate corporate existence; (iii) we make a general assignment for the benefit of creditors or admit in writing our inability to pay our debts generally as they become due; or (iv) we sell or lease our Pipeline to a third party. Other operating costs and expenses for the period from November 23, 2010 through December 31, 2010 include payments to Manta Ray totaling $0.6 million for operation and management services rendered to us.

Table of Contents

We rent offshore platform space from an affiliate of Enterprise and a third party. Total rent paid to the affiliate of Enterprise was $69 thousand for the period from November 23, 2010 through December 31, 2010. See Note 5 for additional information regarding this operating lease.

5. Commitments and Contingencies

Operating Leases

Lease and rent expense included in operating income was $224 thousand for the period from November 23, 2010 to December 31, 2010.

We rent offshore platform space from an affiliate of Enterprise and a third party. Total rent paid for this platform space was $138 thousand for the period from November 23, 2010 through December 31, 2010. The agreement has an indefinite term and will continue until the platform is abandoned. However, we can terminate the agreement at any time if we cease operations on the platform. As a result, there are no future minimum payment obligations attributable to this agreement.

We lease right-of-way held in connection with our Pipeline. In general, our payments for right-of-way easements are determined by the underlying contracts, which typically include a stated fixed fee. Certain of our right-of-way leases contain rent escalation clauses whereby the rent is adjusted periodically for inflation. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. The following table presents our minimum payment obligations under operating leases for right-of-way:

2011	$ 21
2012	21
2013	22
2014	22
2015	22
Thereafter	233
Total	$ 341

Other Matters

We are subject to potential loss contingencies arising from the course of our regular business operations. These may result from federal, state and local environmental, health and safety laws and regulations and third-party litigations. There are no matters currently which, in the opinion of our management, will have a material adverse effect on the financial position or results of our operations.

6. Significant Risks

Nature of Operations

Offshore crude oil pipeline systems such as ours are affected by oil exploration and production activities. Crude oil reserves are depleting assets that will produce over a finite period. Our Pipeline must access additional reserves to offset either (i) the natural decline in production from existing connected wells or (ii) the loss of any production to a competitor. We actively seek to offset the loss of volumes due to depletion by adding connections to new customers and fields.

In April 2010, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill that has significantly impacted ecological resources in the Gulf of Mexico. As a result, in May 2010, a federal offshore drilling moratorium went into effect which halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. The moratorium was lifted in October 2010; however, it is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected. A continued decline in oil and natural gas production volumes and or a failure to achieve anticipated future production due to limitations caused by the federal moratorium could have a material adverse effect on our financial position, results of operations or cash flows.

Table of Contents

Weather-Related Risks

Our assets are located offshore Texas and Louisiana in the Gulf of Mexico, which is prone to tropical weather events such as hurricanes. Our Partners are required to maintain certain levels of insurance with respect to our assets. If our assets were materially damaged in a storm, it could have a material impact on our financial position and results of operations.