GENESIS ENERGY LP
Form 10-K
March 16, 2009

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

Form 10-K

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

For the fiscal year ended December 31, 2008

OR

o 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 (State or other jurisdiction of incorporation or organization)	76-0513049 (I.R.S. Employer Identification No.)
919 Milam, Suite 2100, Houston, TX (Address of principal executive offices)	77002 (Zip code)
Registrant's telephone number, including area code:	(713) 860-2500

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

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

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 o No þ

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

Yes o No þ

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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

o

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

Large accelerated filer o   Accelerated filer þ   Non-accelerated filer o   Smaller reporting company o

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

Yes o No þ

The aggregate market value of the common units held by non-affiliates of the Registrant on June 30, 2008 (the last business day of Registrant’s most recently completed second fiscal quarter) was approximately $280,949,000 based on $18.45 per unit, the closing price of the common units as reported on the NYSE Alternext US (formerly the American Stock Exchange.) 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 28, 2009, the Registrant had 39,456,774 common units outstanding.

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FORWARD-LOOKING INFORMATION

The statements in this Annual Report on Form 10-K that are not historical information may be "forward looking statements" within the meaning of the various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. 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," "intend," "may," "plan," "position," "projection," "strategy" or "will" or the nega terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

- demand for, the supply of, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs", sodium hydrosulfide and caustic soda in the United States, 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;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;
- shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;
- changes in laws or regulations to which we are subject;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of existing debt agreements that contain restrictive financial covenants;
- loss of key personnel;
- the effects of competition, in particular, by other pipeline systems;
- hazards and operating risks that may not be covered fully by insurance;
- the condition of the capital markets in the United States;

- loss or bankruptcy of key customers;
- the political and economic stability of the oil producing nations of the world; and
- general economic conditions, including rates of inflation and interest rates.

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. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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PART I

Item 1. Business

Unless the context otherwise requires, references in this annual report to "Genesis Energy, L.P.," "Genesis," "we," "our," "us" like terms refer to Genesis Energy, L.P. and its operating subsidiaries (including DG Marine, as defined); "DG Marine" means DG Marine Transportation, LLC and its subsidiaries; "Denbury" means Denbury Resources Inc. and its subsidiaries; "CO2" means carbon dioxide; and "NaHS", which is commonly pronounced as "nash", means sodium hydrosulfide.

DG Marine is a joint venture in which we own an effective 49% economic interest. Our joint venture partner holds a 51% economic interest and controls decision-making over most key operational matters. For financial reporting purposes, we consolidate DG Marine as discussed in Note 3 to the Consolidated Financial Statements. References in this annual report to DG Marine include 100% of the operations and activities of DG Marine unless the context indicates differently.

Except to the extent otherwise provided, the information contained in this form is as of December 31, 2008.

General

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 and Florida. We were formed in 1996 as a master limited partnership, or MLP. We have a diverse portfolio of customers, operations and assets, including refinery-related plants, pipelines, storage tanks and terminals, barges, and trucks and truck terminals. We provide services to refinery owners; oil, natural gas and CO2 producers; industrial and commercial enterprises that use CO2 and other industrial gases; and individuals and companies that use our trucking services. 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 manage our businesses through four divisions which constitute our reportable segments:

Pipeline Transportation—We transport crude oil, CO2 and, to a lesser extent, natural gas for others for a fee in the Gulf Coast region of the U.S. through approximately 590 miles of pipeline. We own and operate three crude oil common carrier pipelines, two CO2 pipelines and three small natural gas pipelines. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminaling and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and can deliver crude oil to a terminal near Mobile, Alabama. Our 90-mile Texas System transports crude oil from West Columbia to Webster, Webster to Texas City and Webster to Houston. Our crude oil pipeline systems include a total of approximately 0.7 million barrels of leased and owned tankage. In addition, we lease the NEJD Pipeline System, described below, to Denbury.

The Free State Pipeline is an 86-mile, 20" CO2 pipeline that extends from Denbury's CO2 source fields at the Jackson Dome, near Jackson, Mississippi, to Denbury's oil fields in east Mississippi. In 2008, we entered into a twenty-year transportation services agreement to deliver CO2 on the Free State pipeline for Denbury's use in its tertiary recovery operations. We also own a small CO2 pipeline in Mississippi to transport CO2 to a Denbury oil field.

In 2008, we entered into a twenty-year financing lease transaction with Denbury valued at $175 million related to Denbury's North East Jackson Dome (NEJD) Pipeline System. The NEJD Pipeline System is a 183-mile, 20" pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana, and is currently being leased and used by Denbury for its Phase I area of tertiary operations in southwest Mississippi. We recorded this lease arrangement in our consolidated financial statements as a direct financing lease.

Refinery Services—We provide services to eight refining operations located predominantly in Texas, Louisiana and Arkansas. These refineries generally are owned and operated by large companies, including ConocoPhillips, CITGO and Ergon. Our refinery services primarily involve processing high sulfur (or “sour”) natural gas streams, which are separated from hydrocarbon streams, to remove the sulfur. Our refinery services contracts, which usually have an initial term of two to ten years, have an average remaining term of five years.

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Supply and Logistics—We provide terminaling, blending, storing, marketing, gathering and transporting (by trucks and barges), and other supply and logistics services to third parties, as well as to support our other businesses. Our terminaling, blending, marketing and gathering activities are focused on crude oil and petroleum products, primarily fuel oil. We own or lease over 280 trucks, 550 trailers and 1.1 million barrels of liquid storage capacity at eight different locations. Through our investment in DG Marine, we own and operate barges used primarily for the inland marine transportation of fuel oil and similar petroleum products. We also conduct certain crude oil aggregating operations, including purchasing, gathering and transporting (by trucks and pipelines operated by us and trucks, pipelines and barges operated by others), and reselling that crude oil to help ensure (among other things) a base supply source for our crude oil pipeline systems. 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.

Industrial Gases.

- CO_2 — We supply CO_2 to industrial customers under seven long-term contracts, with an average remaining contract life of 7 years. We acquired those contracts, as well as the CO_2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with affiliates of our general partner. Our compensation for supplying CO_2 to our industrial customers is the effective 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.

- Syngas—Through our 50% interest in a joint venture, we receive a proportionate share of fees under a processing agreement covering a facility that manufactures high-pressure steam and syngas (a combination of carbon monoxide and hydrogen). Under that processing agreement, Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility. Praxair has the exclusive right to use that facility through at least 2016, and Praxair has the option to extend that contract term for two additional five year periods. Praxair also is our partner in the joint venture and owns the remaining 50% interest.

- Sandhill Group LLC – Through our 50% interest in a joint venture, we process raw CO_2 for sale to other customers for uses ranging from completing oil and natural gas producing wells to food processing. The Sandhill facility acquires CO_2 from us under one of the long-term supply contracts described above.

We conduct our operations through subsidiaries and joint ventures. As is common with publicly-traded partnerships, or MLPs, our general partner is responsible for operating our business, including providing all necessary personnel and other resources.

Our General Partner and Our Relationship with Denbury Resources Inc.

Denbury Resources Inc. (NYSE:DNR) indirectly owns more than a majority interest of the equity interest in, and controls, our general partner, which owns all of our general partner interest, all of our incentive distribution rights, and 7.2% of our outstanding common units. Another Denbury subsidiary owns an additional 3% of our outstanding common units. Denbury, a large independent energy company with an equity market capitalization of approximately $3.2 billion as of February 27, 2009, operates primarily in Mississippi, Louisiana and Texas, emphasizing the tertiary recovery of oil using CO_2 flooding. Denbury is the largest producer (based on average barrels produced per day) of oil in Mississippi, and it is one of only a handful of producers in the U.S. that possesses CO_2 tertiary recovery expertise along with large deposits of CO_2 reserves, approximately 5.6 trillion cubic feet of estimated proved CO_2 reserves as of December 31, 2008. Other than the CO_2 reserves owned by Denbury, we are not aware of any significant natural sources of CO_2 from East Texas to Florida. Denbury is conducting its CO_2 tertiary recovery operations in the Eastern Gulf Coast of the U.S., an area with many mature oil reservoirs that potentially contain substantial volumes of recoverable oil. We believe Denbury's equity ownership interests in us provide Denbury with economic and strategic incentives to occasionally utilize certain services we provide, whether through transportation agreements or other transactions.

Although Denbury is one of our customers from time to time, Denbury is not obligated to enter into any additional transactions with (or to offer any opportunities to) us or to promote our interest, and none of Denbury or any of its affiliates (including our general partner) has any obligation or commitment to contribute or sell any assets to us or enter into any type of transaction with us, and each of them, other than our general partner, has the right to act in a manner that could be beneficial to its interests and detrimental to ours. Further, Denbury may, at any time, and without notice, alter its business strategy, including determining that it no longer desires to use us as a provider of any services. Additionally, if Denbury were to make one or more offers to us, we cannot say that we would elect to pursue or consummate any such opportunity. In addition, though our relationship with Denbury is a strength, it also is a source of potential conflicts.

Our Objectives and Strategies

Our primary business objectives are to generate stable cash flows to 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 strategies:

- Maintaining a balanced and diversified portfolio of midstream energy and industrial gases assets, operations and customers. We intend to maintain a balanced and diversified portfolio of midstream energy and industrial gases assets, operations and customers. We believe our cash flows are likely to continue to be relatively stable due to the diversity of our customer base, the nature and increasing array of services we provide to both producers and refiners, and the geographic location of our operations.

- Maintaining, on average, a conservative capital structure that will allow us to execute our growth strategy while, over the longer term, enhancing our credit ratings. We intend to maintain, on average, a conservative capital structure that will allow us to execute our growth strategy while, over the longer term, enhancing our credit ratings. We intend to maintain a balanced approach to our existing capital availability by focusing on opportunities that provide stable cash flows and strategic opportunities utilizing our existing assets. We had approximately $176.5 million available to borrow under our senior secured credit facility as of December 31, 2008.

- Increasing the utilization rates for, and enhancing the profitability of, our existing assets. We intend to increase the utilization rates and, thereby, enhance the profitability of our existing assets. We own some pipelines and terminals that have available capacity and others for which we can increase the capacity at a relatively nominal cost. We also intend to enhance profitability of our existing assets through further integration of our operations.

- Increasing stable cash flows generated through fee-based services, longer-term contractual arrangements and managing commodity price risks. We intend to generate more stable cash flows, when practical, by (i) emphasizing fee-based compensation under longer term contracts, and (ii) using contractual arrangements, including back-to-back contracts and derivatives. We charge fee-based arrangements for substantially all of our services. We are able to enter into longer term contracts with most of our customers in our refinery services and industrial gases divisions. Our marketing activities do not include speculative transactions.

- Expanding our asset base through strategic and accretive acquisitions and strategic construction and development projects. We intend to expand our asset base through strategic and accretive acquisitions and strategic construction and development projects in new and existing markets. Such acquisitions or projects could be structured as, among other things, purchases, leases, tolling or similar agreements or joint ventures.

- Creating strategic arrangements and sharing capital costs and risks through joint ventures and strategic alliances. We intend to continue to create strategic arrangements with customers and other industry participants, and to share capital costs and risks, through the formation of joint ventures and strategic alliances.

- Optimizing our CO2 and other industrial gases expertise and infrastructure. We intend to continue to pursue opportunities to create growth from our experience with CO2 and other industrial gases.

- Attracting new refinery customers and expanding the services we provide those customers. We expect to attract new refinery customers as more sour crude is imported (or produced) and refined in the U.S., and we plan to expand the services we provide to our refinery customers by offering a broader array of services, leveraging our strong relationships with refinery owners and producers, and deploying our proprietary knowledge.

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Leveraging our oil handling capabilities with Denbury's tertiary recovery projects. Because we have facilities in close proximity to certain properties on which Denbury is conducting tertiary recovery operations, we believe we are likely to have the opportunity to provide some oil transportation, gathering, blending and marketing services to it and other producers as production from those properties increases.

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Our Key Strengths

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

- Diversified and Balanced Portfolio of Customers, Operations and Assets. We have a diversified and well-balanced portfolio of customers, operations and assets throughout the Gulf Coast region of the United States. Through our diverse assets, we provide stand-alone and integrated gathering, transporting, processing, blending, storing and marketing services, among others, to four distinct customer groups: refinery owners; CO2 producers; industrial and commercial enterprises that use CO2 and other industrial gases; and individuals and companies that use our transportation services. Our operations and assets are characterized by:

  - Strategic Locations. Our oil pipelines and related assets are predominantly located near areas that are experiencing increasing oil production, (in large part because of Denbury's tertiary recovery operations) or near inland refining operations that we believe are contemplating expansion of capacity or ability to handle sour gas streams.

  - Cost-Effective Expansion and Enhancement Opportunities. We own pipelines, terminals and other assets that have available capacity or that have opportunities for expansion of capacity without incurring material expenditures.

  - Cash Flow Stability. Our cash flow is relatively stable due to a number of factors, including our long-term, fee-based contracts with our refinery services and industrial gases customers; our diversified base of customers, assets and services; and our relatively low exposure to volatile fluctuations in commodity prices.

- Financial Liquidity and Flexibility. We have the financial liquidity and flexibility to pursue additional growth projects. As of December 31, 2008, we had $320 million of loans and $3.5 million in letters of credit outstanding under our $500 million credit facility, resulting in $176.5 million of remaining credit, all of which was available under our borrowing base. Our borrowing base fluctuates each quarter based on our earnings before interest, taxes, depreciation and amortization, or EBITDA. Our borrowing base may be increased to the extent of EBITDA attributable to acquisitions, with approval of the lenders. In addition we had $19.0 million of cash on hand at December 31, 2008.

- Experienced, Knowledgeable and Motivated Senior Management Team with Proven Track Record. Our senior management team has an average of more than 25 years of experience in the midstream sector. They have worked together and separately in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. To help ensure that our senior management team is incentivized to create value for our equity holders by maintaining and increasing (over time) the distribution rate we pay on our common units, our general partner has provided the members of our senior management team with long-term, incentive equity compensation that generally increases in value as our incentive distribution rights increase in value. To take advantage of this opportunity, our senior executive team must grow the distributions we pay our common unitholders.

- Supply and Logistics Division Supports Full Suite of Services. In addition to its established customers, our supply and logistics division can, from time to time, attract customers to our other divisions and/or create synergies that may not be available to our competitors. Several examples include:

  - our refinery services division can effectively compete with refineries, on a stand alone basis, to remove sulfur partially due to the synergies created from our ability to economically source, transport and store large supplies of caustic soda (the main component in the NaHS sulfur removal process), as well as our ability to store, transport and market NaHS;

- our pipeline transportation division receives throughput related to the gathering and marketing services that our supply and logistics division provides to producers;

- our supply and logistics division gives us the opportunity to bundle services in certain circumstances; for example, in the future, we hope to gather disparate qualities of oil and use our terminal and storage assets to customize blends for some of our customers needing fuel supplies; and

- our supply and logistics division gives us the opportunity to blend, store and distribute products made by our refinery customers.

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Ø Unique Platform, Limited Competition and Anticipated Growing Demand in Our Refinery Services Operations. We provide services to eight refining operations located predominantly in Texas, Louisiana and Arkansas. Our refinery services primarily involve processing sour natural gas streams, which are separated from hydrocarbon streams, to remove the sulfur. Refineries contract with us for a number of reasons, including the following:

- sulfur handling and removal is typically not a core business of our refinery customers;
- over a long period of time, we have developed and maintained strong relationships with our refinery services customers, which relationships are based on our reputation for high standards of performance, reliability and safety;
- the proprietary sulfur removal process we use -- the NaHS sulfur removal process -- is, generally, more reliable and less capital and labor intensive than the conventional "Claus" process employed at most refineries, and it generates a marketable by-product, NaHS;
- we have the scale of operations and supply and logistics capabilities to make the NaHS sulfur removal process extremely reliable as a means to remove sulfur efficiently while working in concert with the refineries to ensure uninterrupted refinery operations;
- other than the refinery owners (who remove their own sulfur), we have few competitors for our refinery services business; and
- we believe that the demand for sulfur removal at U.S. refineries will increase in the years ahead as the quality of the oil supply used by refineries in the U.S. continues to drop (or become more "sour"). As that occurs, we believe more refineries will seek economic and proven sulfur removal processes from reputable service providers that have the scale and logistical capabilities to efficiently perform such services. In addition, we have an increasing array of services we can offer to our refinery customers.

Ø Relationship with Denbury. We believe Denbury has an economic and strategic incentive to execute some business transactions with us. We also believe that we can leverage our operations (and our relationship with Denbury) into oil transportation and storage opportunities with third parties, such as other producers and refinery operators, in the areas into which Denbury expands its operations.

2008 Developments

Investment in DG Marine Transportation, LLC

On July 18, 2008, we acquired an interest in DG Marine which acquired the inland marine transportation business of Grifco Transportation, Ltd. ("Grifco") and two of Grifco's affiliates. DG Marine is a joint venture with TD Marine, LLC, an entity formed by members of the Davison family, who are owners of approximately 30% of our common units. (See discussion below on the acquisition of the Davison family businesses in 2007.). TD Marine owns (indirectly) a 51% economic interest in DG Marine, and we own (directly and indirectly) a 49% economic interest. This acquisition gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

Denbury Drop-Down Transactions

We completed two "drop-down" transactions with Denbury in 2008 involving two of their existing CO_2 pipelines - the NEJD and Free State CO_2 pipelines. We paid for these pipeline assets with $225 million in cash and 1,199,041 common units valued at $25 million based on the average closing price of our units for the five trading days surrounding the closing date of the transaction. Under the twenty-year agreements with Denbury related to the NEJD and Free State pipelines, we expect to receive approximately $30 million per annum, in the aggregate. Future payments for the NEJD pipeline are fixed at $20.7 million per year during the term of the financing lease, and the payments related to the Free State pipeline are dependent on the volumes of CO2 transported therein, with a minimum monthly payment of $0.1 million.

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Fourteen Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for fourteen consecutive quarters. On February 13, 2009, we paid a cash distribution of $0.33 per unit to unitholders of record as of February 3, 2009, an increase per unit of $0.0075 (or 2.3%) from the distribution in the prior quarter, and an increase of 15.8% from the distribution in February 2008. As in the past, future increases (if any) in our quarterly distribution rate will be dependent on our ability to execute critical components of our business strategy.

Florida Oil Pipeline System Expansion

In the second quarter of 2009, we expect to complete construction of an extension of our existing Florida oil pipeline system that would extend to producers operating in southern Alabama. That new lateral extension consists of approximately 33 miles of 8" pipeline originating in the Little Cedar Creek Field in Conecuh County, Alabama to a connection to our Florida Pipeline System in Escambia County, Alabama. That project also includes gathering connections to approximately 35 wells and oil storage capacity of 20,000 barrels in the field. Our capital costs in 2008 related to this project totaled $7.4 million, and we expect to expend $4.1 million to complete the project in 2009.

Description of Segments and Related Assets

We conduct our business through four primary segments: Pipeline Transportation, Refinery Services, Industrial Gases 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.

Pipeline Transportation

Crude Oil Pipelines

Overview. Our core pipeline transportation business is the transportation of crude oil for others for a fee. Through the 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 the Federal Energy Regulatory Commission, or FERC, or the Railroad Commission of Texas. 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 was injected into the pipeline and the delivery point. We also can 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 crude oil pipeline operations are generated by the difference between the revenues from regulated published tariffs, pipeline loss allowance revenues and the fixed and variable costs of operating and maintaining our pipelines.

We own and operate three common carrier crude oil pipeline systems. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminaling and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and extends to a point near Mobile, Alabama. Our 90-mile Texas System extends from West Columbia to Webster, Webster to Texas City and Webster to Houston.

Mississippi System. Our Mississippi System extends from Soso, Mississippi to Liberty, Mississippi and includes tankage at various locations with an aggregate owned storage capacity of 247,500 barrels. This System is adjacent to several oil fields operated by Denbury, which is the sole shipper (other than us) on our Mississippi System. As a result of its emphasis on the tertiary recovery of crude oil using CO2 flooding, Denbury has become the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi, and it owns more developed CO2 reserves than anyone in the Gulf Coast region of the U.S. As Denbury continues to implement its tertiary recovery strategy, its anticipated increased production could create increased demand for our crude oil transportation services because of the close proximity of those pipelines to Denbury's projects.

We provide transportation services on our Mississippi pipeline to Denbury under an "incentive" tariff. Under our incentive tariff, the average rate per barrel that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.

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Jay System. Our Jay System begins near oil fields in southern Alabama and the panhandle of Florida and extends to a point near Mobile, Alabama. Our Jay System includes tankage with 230,000 barrels of storage capacity, primarily at Jay station. Recent changes in ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development activities regarding those fields which we believe may lead to increases in production. As a result of new production in the area surrounding our Jay System, volumes have stabilized on that system.

We expect to complete construction of an extension of our existing Florida oil pipeline system in the second quarter of 2009 that would extend to producers operating in southern Alabama. The new lateral will consist of approximately 33 miles of 8” pipeline originating in the Little Cedar Creek Field in Conecuh County, Alabama to a connection to our Florida Pipeline System in Escambia County, Alabama. The project will also include gathering connections to approximately 35 wells and additional oil storage capacity of 20,000 barrels in the field.

Texas System. The active segments of the Texas System extend from West Columbia to Webster, Webster to Texas City and Webster to Houston. Those segments include approximately 90 miles of pipeline. 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. We entered into a joint tariff with TEPPCO Crude Pipeline, L.P. (TEPPCO) to receive oil from its system at West Columbia and a joint tariff with TEPPCO and ExxonMobil Pipeline Company to receive oil from their systems at Webster. We also continue to receive barrels from a connection with Seminole Pipeline Company at Webster. We own tankage with approximately 55,000 barrels of storage capacity associated with the Texas System. We lease an additional approximately 165,000 barrels of storage capacity for our Texas System in Webster. We have a tank rental reimbursement agreement with the primary shipper on our Texas System to reimburse us for the lease of this storage capacity at Webster.

CO2 Pipelines

We also transport CO2 for a fee. The Free State Pipeline is an 86-mile, 20” pipeline that extends from Denbury’s CO2 source fields at Jackson Dome, near Jackson, Mississippi, to Denbury’s oil fields in east Mississippi. In addition, the NEJD Pipeline System, a 183-mile, 20” CO2 pipeline that we lease to Denbury extends from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana, currently being used by Denbury for its tertiary operations in southwest Mississippi.

Denbury has exclusive use of the NEJD Pipeline 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. We are responsible for owning, operating and maintaining and making improvements to the Free State Pipeline, however Denbury has rights to exclusive use and is required to use the Free State Pipeline to supply CO2 to its current and certain of its other tertiary operations in East Mississippi.

Customers

Denbury is the sole shipper (other than us) on our Mississippi System and the Free State Pipeline. Denbury also has exclusive right to use the Free State Pipeline and the NEJD Pipeline. The customers on our Jay and Texas Systems are primarily large, energy companies. 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 pipelines, will be built in the same geographic areas in the near future.

Refinery Services

We acquired our refinery services segment in the Davison transaction in July 2007. That segment provides services to eight refining operations primarily located in Texas, Louisiana and Arkansas. In our processing, we apply proprietary technology that uses large quantities of caustic soda (the primary input used by our process). Our refinery services business generates revenue by providing a service for which it receives NaHS as consideration and by selling the NaHS, the by-product of our process, to approximately 100 customers. As such, we believe we are one of the largest marketers of NaHS in North America.

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NaHS is used in the specialty chemicals business, in pulp and paper business, in connection with mining operations and also has environmental applications. NaHS is used in various industries for applications including, but not limited to, agricultural, dyes, and other chemical processing; waste treatment programs requiring stabilization and reduction of heavy and toxic metals through precipitation; and sulfidizing oxide ores (most commonly to separate copper from molybdenum). NaHS is also used in the Kraft pulping process to prepare synthetic cooking liquor (white liquor); as a make-up chemical to replace lost sulfur values; as a scrubbing media for residual chlorine dioxide generated and consumed in mill bleach plants; and for removing hair from hides at the beginning of the tannery process.

Our refinery service contracts typically have an initial term from two to ten years. Because of our reputation, experience and logistical capability to transport, store and deliver both NaHS and caustic soda, we believe such contracts will likely be renewed upon the expiration of their primary terms. We also believe that the demand for sulfur removal at U.S. refineries will increase in the years ahead as the quality of the oil supply used by refineries in the U.S. continues to drop (or become more "sour"). As that occurs, we believe more refineries will seek economic and proven sulfur removal processes from reputable service providers that have the scale and logistical capabilities to efficiently perform such services. Because of our existing scale, we believe we will be able to attract some of these refineries as new customers for our sulfur handling/removal services.

The largest cost component of providing our sulfur removal service is acquiring and delivering caustic soda to our operations. Caustic soda, or NaOH, is the scrubbing agent introduced in the sour gas stream to remove the sulfur and generate the by-product, NaHS. Therefore the contribution to segment margin includes the revenues generated from the sales of NaHS less our total cost of providing the services, including the costs of acquiring and delivering caustic soda to our service locations. Because the activities of these service arrangements can fluctuate, we do, from time to time engage in other activities such as selling caustic soda, buying NaHS from other producers for re-sale to our customers and buying and selling sulfur, the financial results of which are also reported in our refinery services segment.

Our sulfur removal facilities consist of NaHS units that are located at sites leased at five refineries, primarily in the southeastern United States. While some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities.

Customers

Refinery Services: At December 31, 2008, we provided services to eight refining operations.

NaHS Marketing: We sell our NaHS to customers in a variety of industries, with the largest customers involved in copper mining and the production of paper. We sell to customers in the copper mining industry in the western United States as well as customers who export the NaHS to South America for mining in Peru and Chile. Many of the paper mills that purchase NaHS from us are located in the southeastern United States. No customer of the refinery services segment is responsible for more than ten percent of our consolidated revenues. Approximately 13% of the revenues of the refinery services segment in 2008 resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc. While the market price of copper and other ores has declined in 2008 creating a reduction in mining operations and economic circumstances have reduced demand of paper products from the paper mills who acquire NaHS, the provisions in our service contracts with refiners allow us to adjust our service levels to maintain a balance between NaHS supply and demand.

Competition for Refinery Services Business

We believe that the U.S. refinery industry's demand for sulfur extraction services will increase because we believe sour oil will constitute an ever-increasing portion of the total worldwide supply of crude oil. In addition, we have an increasing array of services we can offer to our refinery customers and we believe our proprietary knowledge, scale, logistics capabilities and safety and service record will encourage such customers to continue to outsource their existing refinery services needs to us. While other options exist for the removal of sulfur from sour oil, we believe our existing customers are unlikely to change to another method due to the costs involved. Other than the refinery owners (who may process sulfur themselves), we have few competitors for our refinery services business.

Industrial Gases

Overview

Our industrial gases segment is a natural outgrowth from our pipeline transportation business. Because of Denbury's tertiary recovery operations utilizing CO2 flooding around our Mississippi System, we became familiar with CO2-related activities and, ultimately, began our CO2 business in 2003. Our relationships with industrial customers who use CO2 have continued to expand, which has introduced us to potential opportunities associated with other industrial gases. We (i) supply CO2 to industrial customers, (ii) process raw CO2 and sell that processed CO2, and (iii) manufacture and sell syngas, a combination of carbon monoxide and hydrogen.

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CO2 – Industrial Customers

We supply CO2 to industrial customers under seven long-term CO2 sales contracts. We acquired those contracts, as well as the CO2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with Denbury. We purchased those contracts, along with three VPPs representing 280.0 Bcf of CO2 (in the aggregate), from Denbury. We sell our CO2 to customers who treat the CO2 and sell it to end users for use for beverage carbonation and food chilling and freezing. Our compensation for supplying CO2 to our industrial customers is the effective difference between the price at which we sell our CO2 under each contract and the price at which we acquired our CO2 pursuant to our VPPs, minus transportation costs. We expect some seasonality in our sales of CO2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. At December 31, 2008, we have 153.8 Bcf of CO2 remaining under the VPPs.

Currently, all of our CO2 supply is from our interests – our VPPs - in fields producing naturally occurring CO2. The agreements we executed with Denbury when we acquired the VPPs provide that we may acquire additional CO2 from Denbury under terms similar to the original agreements should additional volumes be needed to meet our obligations under the existing customer contracts. Based on the current volumes being sold to our customers, we believe that we will need to acquire additional volumes from Denbury in 2015. When our VPPs expire, we will have to obtain our CO2 supply from Denbury, from other sources, or discontinue the CO2 supply business. Denbury will have no obligation to provide us with CO2 once our VPPs expire, and Denbury has the right to compete with us in the CO2 supply business. See “Risks Related to Our Partnership Structure” for a discussion of the potential conflicts of interest between Denbury and us.

One of the parties that we supply with CO2 under a long-term sales contract is Sandhill Group, LLC. On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC as discussed below.

CO2 - Processing

We own a 50% partnership interest in Sandhill. Reliant Processing Ltd. owns the remaining 50% of Sandhill. Sandhill is a limited liability company that owns a CO2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, chemicals and oil industries. The facility acquires CO2 from us under a long-term supply contract. This contract expires in 2023, and provides for a maximum daily contract quantity of 16,000 Mcf per day with a take-or-pay minimum quantity of 2,500,000 Mcf per year.

Syngas

We own a 50% partnership interest in T&P Syngas. T&P Syngas is a partnership which owns a facility located in Texas City, Texas that manufactures syngas and high-pressure steam. Under a long-term processing agreement, the joint venture receives fees from its sole customer, Praxair Hydrogen Supply, Inc. during periods when processing occurs, and Praxair has the exclusive right to use the facility through at least 2016, which Praxair has the option to extend for two additional five year terms. Praxair owns the remaining 50% interest in that joint venture.

Customers

Five of our seven contracts for supplying CO2 are with large international companies. One of the remaining contracts is with Sandhill Group, LLC, of which we own 50%. The remaining contract is with a smaller company with a history in the CO2 business. Revenues from this segment did not account for more than ten percent of our consolidated revenues.

The sole customer of T&P Syngas is Praxair, a worldwide provider of industrial gases.

Sandhill sells to approximately 20 customers, with sales to three of those customers representing approximately 67% of Sandhill's total revenues of approximately $11 million in 2008. In 2008, Sandhill sold approximately $2.4 million of CO2 to affiliates of Reliant Processing, Ltd., our partner in Sandhill, as discussed above. Sandhill has long-term relationships with those customers and has not experienced collection problems with them.

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Competition

Currently, all of our CO_2 supply is from our interest – our VPPs – in fields producing naturally occurring sources. In the future we may have to obtain our CO_2 supply from manufactured processes. Naturally-occurring CO_2, like that from the Jackson Dome area, occurs infrequently, and only in limited areas east of the Mississippi River, including the fields controlled by Denbury. Our industrial CO_2 customers have facilities that are connected to the NEJD CO_2 pipeline, which makes delivery easy and efficient. Once our existing VPPs expire, we will have to obtain CO_2 from Denbury or other suppliers should we choose to remain in the CO_2 supply business, and the competition and pricing issues we will face at that time are uncertain.

With regard to our CO_2 supply business, our contracts have long terms and generally include take-or-pay provisions requiring annual minimum volumes that each customer must pay for even if the CO_2 is not taken.

Due to the long-term contract and location of our syngas facility, as well as the costs involved in establishing facilities, we believe it is unlikely that competing facilities will be established for our syngas processing services.

Sandhill has competition from the other industrial customers to whom we supply CO_2. As discussed above, the limited amounts of naturally-occurring CO_2 east of the Mississippi River makes it difficult for competitors of Sandhill to significantly increase their production or sales and, thereby, increase their market share.

Supply and Logistics

Our supply and logistics segment has the capabilities and assets to provide a wide array of services to oil producers and refiners in the Gulf Coast region. These services include gathering of crude oil at the wellhead, marketing of crude oil to refiners and other supply companies, transporting crude oil by truck to pipeline injection points or directly to the refiners, and acquiring the resulting petroleum products from the refiners for transportation by truck and barge primarily to third parties in fuels markets and some end-users. Our profit for those services is derived 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 crude oil gathering and marketing operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. Those operations help to ensure (among other things) a base supply source for our oil pipeline systems. In addition, our oil gathering and marketing activities provide us with an extensive expertise, knowledge base and skill set that facilitates our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually, this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks.

When the 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, either with a counterparty or in the crude oil futures market. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 17 of the Notes to the Consolidated Financial Statements.

With the Davison acquisition in 2007, we added trucks, trailers and existing leased and owned storage, and we expanded our activities to include transporting, storing and blending intermediate and finished refined products. In our petroleum products marketing operations, we primarily supply fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide services to refineries by purchasing their products that do not meet the specifications they desire, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. We cannot predict when the opportunities to provide this service will arise. However, when such opportunities arise, their contribution to margin as a percentage of the revenues tends to be higher than the same percentage attributable to our recurring operations.

Our supply and logistics operations utilize a variety of assets. Those assets include leased and owned tankage at terminals in our area of concentration with total storage capacity of 1.1 million barrels, over 280 trucks and over 550 trailers, as well as barges owned and operated by DG Marine. DG Marine owns nine pushboats and sixteen double hulled, hot-oil asphalt-capable barges with capacities ranging from 30,000 to 38,000 barrels each. DG Marine also will take delivery of four additional barges and acquire one additional pushboat in the first half of 2009. Several of our terminals are located on waterways in the southeastern United States that are accessible by barge.

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We believe we are well positioned to provide a full suite of logistical services to both independent and integrated refinery operators, ranging from upstream (the procurement and staging of refinery inputs) to downstream (the transportation, staging and marketing) of refined products.

Customers and Competition

In our supply and logistics segment, we sell crude oil and petroleum products and provide transportation services to hundreds of customers. During 2008, more than ten percent of our consolidated revenues were generated from Shell Oil Company. We do not believe that the loss of any one customer for crude oil or petroleum products would have a material adverse effect on us as these products are readily marketable commodities.

Our largest competitors in the purchase of leasehold crude oil production are Plains Marketing, L.P., Shell (US) Trading Company, and TEPPCO Partners, L.P. Additionally we compete with many regional and local gatherers who may have significant market share in the areas in which they operate. In our petroleum products marketing operations and our trucking and barge operations, we compete primarily with regional suppliers. Competitive factors in our supply and logistics business include price, personal relationships, 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.

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 companies that purchase NaHS. 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 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.

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 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. We use similar procedures to manage our exposure to our customers in the pipeline transportation and industrial gases segments.

Some of our customers experienced cash flow difficulties in the latter half of 2008 as a result of the tightening of the credit markets. These customers generally purchase petroleum products and NaHS from us. We have strengthened our credit monitoring procedures to perform more frequent review of our customer base. As a result of cash flow difficulties of some of our customers, we have experienced a delay in collections from these customers and have established an allowance for possible uncollectible receivables at December 31, 2008 in the amount of $1.1 million.

Employees

To carry out our business activities, our general partner employed, at February 27, 2009, approximately 610 employees. Additionally, DG Marine employed 133 employees. None of those employees are represented by labor unions, and we believe that relationships with those employees are good.

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Organizational Structure

Genesis Energy, LLC, a Delaware limited liability company, serves as our sole general partner and as our general partner of all of our subsidiaries. Our general partner is owned and controlled by Denbury Gathering & Marketing, Inc., a subsidiary of Denbury, and certain members of our Senior Management own an interest as described below. Below is a chart depicting our ownership structure.

(1)The incentive compensation arrangement between our general partner and our Senior Executives (see Item 11. Executive Compensation.), provides them long-term incentive equity compensation that generally increases in value as the incentive distribution rights held by our general partner increase in value. The maximum amount of this interest is 20% (17.2% currently awarded) and will fluctuate in value with increases or decreases in our distributions to our partners and our success in generating available cash.

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Regulation

Pipeline Tariff Regulation

The interstate common carrier pipeline operations of the Jay and Mississippi Systems are subject to rate regulation by FERC under the Interstate Commerce Act, or ICA. FERC regulations require that oil pipeline rates be posted publicly and that the rates be "just and reasonable" and not unduly discriminatory.

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 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—a cost-of-service methodology, competitive market showings ("Market-Based Rates"), or agreements between shippers and the oil pipeline company that the rate is acceptable ("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 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 be non-discriminatory and 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 TEPPCO 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 natural gas gathering pipelines and CO2 pipeline are subject to regulation by the state agencies in the states in which they are located.

Barge Regulations

DG Marine's inland marine transportation operations are subject to regulation by the United States Coast Guard (USCG), federal and state laws. The Jones Act is a federal cabotage law that restricts domestic marine transportation in the U.S. to vessels built and registered in the U.S., manned by U.S. citizens and owned and operated by U.S. citizens. The crews employed on the pushboats are required to be licensed by the USCG. Federal regulations require that all tank barges engaged in the transportation of oil and petroleum in the U.S. be double hulled by 2015. All of DG Marine's barges are double-hulled.

Environmental Regulations

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, 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, the imposition of remedial obligations, and the imposition of injunctive obligations. 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.

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, including current owners and operators of a contaminated facility, owners and operators of the facility at the time of contamination, and those parties arranging for waste disposal at a contaminated facility. Such "responsible persons" may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. 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. In cases of environmental contamination, it is also not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

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We currently own or lease, and have in the past owned or leased, properties that have been in use for many years in connection with the gathering and transportation of hydrocarbons including crude oil and other activities that could cause an environmental impact. We also generate, handle and dispose of regulated materials in the course of our operations, including some characterized as “hazardous substances” under CERCLA and “hazardous wastes” under RCRA. We may therefore be subject to liability and regulation under CERCLA, RCRA and analogous state laws for hydrocarbons or other substances that may have been disposed of or released on or under our current or former properties or at other locations where wastes have been taken for disposal. Under these laws and regulations, we could be required to undertake investigations into suspected contamination, remove previously disposed wastes, remediate environmental contamination, restore affected properties, or undertake measures to prevent future contamination.

The Federal Water Pollution Control Act, as amended, also known as the “Clean Water Act” and the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and controls regarding the discharge of pollutants, including crude oil, into federal and state waters. The Clean Water Act and OPA provide administrative, civil and criminal penalties for any unauthorized discharges of pollutants, including oil, and impose liabilities for the costs of remediation of spills. Federal and state permits for water discharges also may be required. OPA also requires operators of offshore facilities and certain onshore facilities near or crossing waterways to provide financial assurance generally ranging from $10 million in state waters to $35 million in federal waters to cover potential environmental cleanup and restoration costs. This amount can be increased to a maximum of $150 million under certain limited circumstances where the Minerals Management Service believes such a level is justified based on the worst case spill risks posed by the operations. We have developed an Integrated Contingency Plan to satisfy components of OPA as well as the federal Department of Transportation, the federal Occupational and Safety Health Act, or OSHA, and state laws and regulations. We believe this plan meets regulatory requirements as to notification, procedures, response actions, response resources and spill impact considerations in the event of an oil spill.

The 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.

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.

DG Marine is subject to many of the same regulations as our other operations, including the Clean Water Act, OPA and the Clean Air Act. OPA and CLERCA require DG Marine to obtain a Certificate of Financial Responsibility for each barge and most of its pushboats to evidence financial ability to satisfy statutory liabilities for oil and hazardous substance water pollution.

Recent scientific studies have suggested that emissions of certain gases, including CO2, methane and certain other gases may be contributing to the warming of the Earth’s atmosphere. In response to such studies, it is anticipated that the U.S. Congress will continue to actively consider legislation to restrict or further regulate the emission of greenhouse gases, primarily through the development of emission inventories and/or regional greenhouse gases cap and trade programs. Also, on April 2, 2007, the U.S. Supreme Court in Massachusetts, et al. v. EPA held that CO2 may be regulated as an “air pollutant” under the federal Clean Air Act and the EPA must consider whether it is required to regulate greenhouse gases from mobile sources such as cars and trucks. The Court's holding in Massachusetts that greenhouse gases fall under the Clean Air Act also may result in future regulation of greenhouse gas emissions from stationary sources. In July 2008, the EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in Massachusetts. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future. Thus, there may be restrictions imposed on the emission of greenhouse gases if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases.

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Operational components of our stationary facilities that require the combustion of carbon-based fuel (such as internal combustion engine-driven pumps) produce greenhouse gas emissions in the form of CO_2. Although it is not possible at this time to predict how legislation that may be enacted or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of CO_2 or other greenhouse gases that may be imposed in the areas in which we conduct business could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows.

Safety and Security Regulations

Our crude oil, natural gas and CO_2 pipelines are subject to construction, installation, operation and safety regulation by the Department of Transportation, or DOT, and various other federal, state and local agencies. The Pipeline Safety Act of 1992, among other things, amends the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, in several important respects. It requires the Pipeline and Hazardous Materials Safety Administration of DOT to consider environmental impacts, as well as its traditional public safety mandates, when developing pipeline safety regulations. In addition, the Pipeline Safety Improvement Act of 2005 mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, the development of standards and criteria to evaluate contractors' methods to qualify their employees and requires that pipeline operators provide maps and other records to the DOT. It also authorizes the DOT to require that pipelines be modified to accommodate internal inspection devices, to mandate the evaluation of emergency flow restricting devices for pipelines in populated or sensitive areas, and to order other changes to the operation and maintenance of petroleum pipelines. 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.

On March 31, 2001, the DOT promulgated Integrity Management Plan, or IMP, regulations. The IMP regulations 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 IMP regulation required us to prepare an Integrity Management Plan 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 risk factors to be considered include proximity to population areas, waterways and sensitive areas, known pipe and coating conditions, leak history, pipe material and manufacturer, adequacy of cathodic protection, operating pressure levels and external damage potential. The IMP regulations required that the baseline assessment be completed by April 1, 2008, with 50% of the mileage assessed by September 30, 2004. Reassessment is then required every five years. As testing is complete, we are required to take prompt remedial action to address all integrity issues raised by the assessment. 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 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.

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 and CO_2 pipelines, and natural gas pipelines that do not engage in interstate operations. 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.

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Our crude oil pipelines are also subject to the requirements of the federal Department of Transportation regulations requiring qualification of all pipeline personnel. The Operator Qualification, or OQ, program requires operators to develop and submit a written program. The regulations also require all pipeline operators to develop a training program for pipeline personnel and to qualify them on covered tasks at the operator's pipeline facilities. The intent of the OQ regulations is to ensure a qualified workforce by pipeline operators and contractors when performing covered tasks on the pipeline and its facilities, thereby reducing the probability and consequences of incidents caused by human error.

Our crude oil, refined products and refinery services operations are also subject to the requirements of OSHA and comparable state statutes. We believe that our operations have been operated in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. 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.

We have an operating authority issued by the Federal Motor Carrier Administration of the Department of Transportation for our trucking operations, and we are subject to certain motor carrier safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug testing, safety of operation and equipment, and many other aspects of truck operations. We are subject to federal EPA regulations for the development of written Spill Prevention Control and Countermeasure, or SPCC, Plans for our trucking facilities and crude oil injection stations. Annually, trucking employees receive training regarding the transportation of hazardous materials and the SPCC Plans.

The USCG regulates occupational health standards related to DG Marine's vessel 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 DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration (an agency of the Department of Homeland Security, which has assumed responsibility from the DOT). None of these measures or procedures should be construed as a guarantee that our assets are protected in the event of a terrorist attack.

Commodities Regulation

When we use futures and options contracts that are traded on the NYMEX, these contracts are subject to strict regulation by the Commodity Futures Trading Commission and the rules of the NYMEX.

Website Access to Reports

We make available free of charge on our internet website (www.genesisenergylp.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.

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.

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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 continue to be, disrupted and volatile as a result of adverse conditions. There can be no assurance that government response to the disruptions in the financial markets will 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.

Recent disruptions in the credit markets and concerns about local and global economic growth have had a significant adverse impact on global financial markets and commodity prices, both of which have contributed to a decline in our unit price and corresponding market capitalization. If these disruptions, which existed throughout the fourth quarter of 2008, continue, they could negatively impact our profitability. The current financial turmoil affecting the banking system and financial markets, and the possibility that financial institutions may consolidate or go out of business has resulted in a tightening of the credit markets, a low level of liquidity in many financial markets, and extreme volatility in fixed income, credit and equity markets. Our credit facility arrangements involve over fifteen different lending institutions. While none of these institutions have combined or ceased operations, further consolidation of the credit markets could result in lenders desiring to limit their exposure to an individual enterprise. Additionally, some institutions may desire to limit exposure to certain business activities in which we are engaged. Such consolidations or limitations could limit our access to capital and could impact us when we desire to extend or make changes to our existing credit arrangements.

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, 2008, 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 are variable. Global financial market conditions have reduced interest rates to unprecedented low rates, reducing our interest costs. 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.

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, including payments to our general partner.

The amount of cash we distribute on our units principally depends upon margins we generate from our refinery services, pipeline transportation, logistics and supply and industrial gases businesses which will 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;

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- the demand for our trucking, barge and pipeline transportation services;
- the volumes of CO_2 we sell and the prices at which we sell it;
- the demand for our terminal storage services;
- the level of our operating costs;
- 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 established by our general partner in its sole discretion 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, 2008, we had approximately $320 million outstanding of senior secured 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;

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- 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. If an event of default occurs under our joint ventures' credit facilities, we may be required to repay amounts previously distributed to us and our subsidiaries. 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, 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.

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 CO2 - 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 CO2— 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 (as in the case of oil marketing and CO2 operations).

Our source of volumes depends on successful exploration and development of additional oil reserves by others and other matters beyond our control.

The oil and other 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. We cannot assure unitholders that production will rise to sufficient levels to allow us to maintain or increase the commodity volumes we are experiencing.

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We face intense competition to obtain 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.

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 reserves, NaHS or refined products produced. 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, 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 transmitted by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

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Fluctuations in commodity prices could adversely affect our business.

Oil, natural gas, other petroleum products, and CO2 prices are volatile and could have an adverse effect on our profits and cash flow. Our operations are affected by price reductions in those commodities. Price reductions in those commodities can cause material long and short term reductions in the level of throughput, volumes and margins in our logistic and supply businesses. Price changes for NaHS and caustic soda affect the margins we achieve in our refinery services business.

Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

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

When we market any of our products or services, we must determine the amount, if any, of the line of credit we will extend to any given customer. Since typical sales transactions can involve very large volumes, the risk of nonpayment and nonperformance by customers is an important consideration in our business.

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 parties. 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. Even if our credit review and analysis mechanisms work properly, we have, and we could continue to experience losses in dealings with other parties.

Additionally, many of our customers are impacted by the weakening economic outlook and declining commodity prices in a manner that could influence the need for our products and services.

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

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FERC Regulation and a changing regulatory environment could affect our cash flow.

The FERC extensively 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.

Given the extent of this regulation, the extensive changes in FERC policy over the last several years, 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.

A substantial portion of our CO2 operations involves us supplying CO2 to industrial customers using reserves attributable to our volumetric production payment interests, which are a finite resource and projected to terminate around 2015.

The cash flow from our CO2 operations involves us supplying CO2 to industrial customers using reserves attributable to our volumetric production payments, which are projected to terminate around 2015. Unless we are able to obtain a replacement supply of CO2 and enter into sales arrangements that generate substantially similar economics, our cash flow could decline significantly around 2015.

Fluctuations in demand for CO2 by our industrial customers could have a material adverse impact on our profitability, results of operations and cash available for distribution.

Our customers are not obligated to purchase volumes in excess of specified minimum amounts in our contracts. As a result, fluctuations in our customers' demand due to market forces or operational problems could result in a reduction in our revenues from our sales of CO2.

Our wholesale CO2 industrial operations are dependent on five customers and our syngas operations are dependent on one customer.

If one or more of those customers experience financial difficulties such that they fail to purchase their required minimum take-or-pay volumes, our cash flows could be adversely affected, and we cannot assure unitholders that an unanticipated deterioration in those customers' ability to meet their obligations to us might not occur.

Our Syngas joint venture has dedicated 100% of its syngas processing capacity to one customer pursuant to a processing contract. The contract term expires in 2016, unless our customer elects to extend the contract for two additional five year terms. If our customer reduces or discontinues its business with us, or if we are not able to successfully negotiate a replacement contract with our sole customer after the expiration of such contract, or if the replacement contract is on less favorable terms, the effect on us will be adverse. In addition, if our sole customer for syngas processing were to experience financial difficulties such that it failed to provide volumes to process, our cash flow from the syngas joint venture could be adversely affected. We believe this customer is creditworthy, but we cannot assure unitholders that unanticipated deterioration of its ability to meet its obligations to the syngas joint venture might not occur.

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Our CO2 operations are exposed to risks related to Denbury's operation of its CO2 fields, equipment and pipeline as well as any of our facilities that Denbury operates.

Because Denbury produces the CO2 and transports the CO2 to our customers (including Denbury), any major failure of its operations could have an impact on our ability to meet our obligations to our CO2 customers (including Denbury). We have no other supply of CO2 or method to transport it to our customers. Sandhill relies on us for its supply of CO2 therefore our share of the earnings of Sandhill would also be impacted by any major failure of Denbury's operations.

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 2008, approximately 63% of our refinery services' division NaHS by-product was attributable to Conoco's refinery located in Westlake, Louisiana. That contract requires Conoco to make available minimum volumes of acid gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if Conoco is excused from performing, or refuses or is unable to perform, 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 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, depletion and amortization expenses. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our business, as discussed above.

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

Our forecast contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets, including some construction and development projects with technological challenges. We may not be able to complete our projects at the costs currently estimated. If we 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.

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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 adverse effects resulting from changes in commodity prices, although there are times when we do not have any hedging mechanisms in place. 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.

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 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, or in the case of DG Marine, only one of which is appointed by us. In addition, the other 50% owners in our T&P Syngas and Sandhill joint ventures operate those joint venture facilities and the other 51% owner of our DG Marine joint venture controls key operational decisions of the joint venture. Thus, without the concurrence of the other joint venture participant, 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.

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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 used in the provision of sour gas treatment services provided by us to refineries. NaHS, the resulting product from the refinery services we provide, 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 operating results from our trucking operations may fluctuate and may be materially adversely affected by economic conditions and business factors unique to the trucking industry.

Our trucking business is dependent upon factors, many of which are beyond our control. Those factors include excess capacity in the trucking industry, difficulty in attracting and retaining qualified drivers, significant increases or fluctuations in fuel prices, fuel taxes, license and registration fees and insurance and claims costs, to the extent not offset by increases in freight rates. Our results of operations from our trucking operations also are affected by recessionary economic cycles and downturns in customers’ business cycles. Economic and other conditions may adversely affect our trucking customers and their ability to pay for our services.

In the past, there have been shortages of drivers in the trucking industry and such shortages may occur in the future. Periodically, the trucking industry experiences substantial difficulty in attracting and retaining qualified drivers. If we are unable to continue to retain and attract drivers, we could be required to adjust our driver compensation package, let trucks sit idle or otherwise operate at a reduced level, which could adversely affect our operations and profitability.

Significant increases or rapid fluctuations in fuel prices are major issues for the transportation industry. Increases in fuel costs, to the extent not offset by rate per mile increases or fuel surcharges, have an adverse effect on our operations and profitability.

Denbury is the only shipper (other than us) on our Mississippi System.

Denbury is our only customer on the Mississippi System. This relationship may subject our operations to increased risks. Any adverse developments concerning Denbury could have a material adverse effect on our Mississippi System business. Neither our partnership agreement nor any other agreement requires Denbury to pursue a business strategy that favors us or utilizes our Mississippi System. Denbury may compete with us and may manage their assets in a manner that could adversely affect our Mississippi System business.

Our investment in DG Marine exposes us to certain risks that are inherent to the barge transportation industry as well certain risks applicable to our other operations.

DG Marine’s inland barge transportation business has exposure to certain risks which are significant to our other operations and certain risks inherent to the barge transportation industry. For example, unlike our other operations, DG Marine operates barges that transport products to and from numerous marine locations, which exposes us to new risks, including:

- being subject to the Jones Act and other federal laws that restrict U.S. maritime transportation to vessels built and registered in the U.S. and owned and manned by U.S. citizens, with any failure to comply with such laws potentially resulting in severe penalties, including permanent loss of U.S. coastwise trading rights, fines or forfeiture of vessels;

- relying on a limited number of customers;
- having primarily short-term charters which DG Marine may be unable to renew as they expire; and

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- competing against businesses with greater financial resources and larger operating crews than DG Marine.

In addition, like our other operations, DG Marine's refined products transportation business is an integral part of the energy industry infrastructure, which increases our exposure to declines in demand for refined petroleum products or decreases in U.S. refining activity.

Risks Related to Our Partnership Structure

Denbury and its affiliates have conflicts of interest with us and limited fiduciary responsibilities, which may permit them to favor their own interests to unitholder detriment.

Denbury indirectly owns the majority interest in, and controls, our general partner. Conflicts of interest may arise between Denbury and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interest and the interest of its affiliates or others over the interest of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Denbury to pursue a business strategy that favors us or utilizes our assets. Denbury's directors and officers have a fiduciary duty to make these decisions in the best interest of the stockholders of Denbury;

- Denbury may compete with us. Denbury owns the largest reserves of CO2 used for tertiary oil recovery east of the Mississippi River and may manage these reserves in a manner that could adversely affect our CO2 business;

- our general partner is allowed to take into account the interest of parties other than us, such as Denbury, 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 the limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, including for incentive distributions, 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;

- 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 general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and

- in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions even if the purpose or effect of the borrowing is to make incentive distributions.

Denbury is not obligated to enter into any transactions with (or to offer any opportunities to) us, although we expect to continue to enter into substantial transactions and other activities with Denbury and its subsidiaries because of the businesses and areas in which we and Denbury currently operate, as well as those in which we plan to operate in the future.

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Further, Denbury's beneficial ownership interest in our outstanding partnership interests could have a substantial effect on the outcome of some actions requiring partner approval. Accordingly, subject to legal requirements, Denbury makes the final determination regarding how any particular conflict of interest is resolved.

Some more recent transactions in which we, on the one hand, and Denbury and its subsidiaries, on the other hand, had a conflict of interest include:

- transportation services
- pipeline monitoring services; and
- CO2 volumetric production payment.

Even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business.

Unitholders did not elect our general partner or its board of directors and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by the stockholders of our general partner. In addition, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The vote of the holders of at least a majority of all outstanding units (excluding any units held by our general partner and its affiliates) is required to remove our general partner without cause. If our general partner is removed without cause, (i) Denbury will have the option to acquire a substantial portion of our Mississippi pipeline system at 110% of its then fair market value, and (ii) our general partner will have the option to convert its interest in us (other than its common units) into common units or to require our replacement general partner to purchase such interest for cash at its then fair market value. In addition, unitholders' voting rights are further restricted by our partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on matters relating to the succession, election, removal, withdrawal, replacement or substitution of our general partner. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner of direction of management.

As a result of these provisions, the price at which our common units trade may be lower because of the absence or reduction of a takeover premium.

The control of our general partner may be transferred to a third party without unitholder consent, which could affect our strategic direction and liquidity.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner from transferring its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and to control the decisions made by the board of directors and officers.

In addition, unless our creditors agreed otherwise, we would be required to repay the amounts outstanding under our credit facilities upon the occurrence of any change of control described therein. We may not have sufficient funds available or be permitted by our other debt instruments to fulfill these obligations upon such occurrence. A change of control could have other consequences to us depending on the agreements and other arrangements we have in place from time to time, including employment compensation arrangements.

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Our general partner and its affiliates or members of the Davison family 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, 2008 our general partner and its affiliates own 4,028,096 (approximately 10.2%) of our common units and members of the Davison family owned 11,781,379 (approximately 30%) of 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. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its subsidiaries to cause us to register for sale the partnership interests held by such persons, including common units. These registration rights allow our general partner and its subsidiaries to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us Additionally, we have filed a shelf registration statement for the units held by members of the Davison family, and the Davison family may sell their common units at any time, subject to certain restrictions under securities laws.

Our general partner has anti-dilution rights.

Whenever we issue equity securities to any person other than our general partner and its affiliates, our general partner and its affiliates have the right to purchase an additional amount of those equity securities on the same terms as they are issued to the other purchasers. This allows our general partner and its affiliates to maintain their percentage partnership interest in us. No other unitholder has a similar right. Therefore, only our general partner may protect itself against dilution caused by the issuance of additional equity securities.

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

Through its subsidiaries, Denbury controls our general partner, is a significant stakeholder in our limited partner interests and has historically, with its affiliates, employed the personnel who operate our businesses. In addition, we are parties to numerous agreements with Denbury, including the lease of the NEJD CO2 pipeline and the transportation arrangements related to the Free State pipeline. Denbury is also a significant customer of our Mississippi System. See "Our General Partner and Our Relationship with Denbury Resources Inc." under Item 1 – Business. We could be adversely affected if Denbury experiences any adverse developments or fails to pay us timely.

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 common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common 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 common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

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The interruption of distributions to us from our subsidiaries and joint ventures 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 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 will 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.

An impairment of goodwill and intangible assets could adversely affect some of our accounting and financial metrics and, possibly, result in an event of default under our revolving credit facility.

At December 31, 2008, our balance sheet reflected $325.0 million of goodwill and $166.9 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States ("GAAP") require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Financial and credit markets volatility directly impacts our fair value measurements for tests of impairment through our weighted average cost of capital that we use to determine our discount rate. If we determine that any of our goodwill or intangible assets were impaired, we would be required to record the impairment. Our assets, equity and earnings as recorded in our financial statements would be reduced, and it could adversely affect certain of our borrowing metrics. While such a write-off would not reduce our primary borrowing base metric of EBITDA, it would reduce our consolidated capitalization ratio, which, if significant enough, could result in an event of default under our credit agreement. At December 31, 2008, such a write-off would need to exceed $330 million in order to result in an event of default.

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 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 us 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.

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In addition, 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. Any change to current law could negatively impact the value of an investment in our common units. In addition, 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. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders.

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 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 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, and these costs will reduce our cash available for distribution.

Unitholders will be required to pay taxes on income 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 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 even the tax liability that results from that income.

Tax gain or loss on disposition of common units could be different 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 is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, 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 foreign persons face unique tax issues from owning 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), and non-U.S. persons raises issues unique to them. For example, a significant amount of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, may be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding tax at the highest effective tax rate applicable to individuals, and non-U.S. persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of 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 common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions 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 the common units or result in audit adjustments to the common unitholder’s tax returns.

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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 25 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 unitholders' responsibility to file all 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.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's tax returns.

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 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.

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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 of the Notes to Consolidated Financial Statements 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 of the Notes to Consolidated Financial Statements.)

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of the security holders during the fiscal year covered by this report.

PART II

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

Our common units are listed on the NYSE Alternext US (formerly the American Stock Exchange) under the symbol "GEL". The following table sets forth, for the periods indicated, the high and low sale prices per common unit and the amount of cash distributions paid per common unit.

	Price Range		Cash
	High	Low	Distributions (1)
2009			
First Quarter (through February 27, 2009)	$ 12.60	$ 7.57	$ 0.3300
2008			
Fourth Quarter	$ 16.00	$ 6.42	$ 0.3225
Third Quarter	$ 19.85	$ 11.75	$ 0.3150
Second Quarter	$ 22.09	$ 17.02	$ 0.3000
First Quarter	$ 25.00	$ 15.07	$ 0.2850
2007			
Fourth Quarter	$ 28.62	$ 20.01	$ 0.2700
Third Quarter	$ 37.50	$ 27.07	$ 0.2300
Second Quarter	$ 35.98	$ 20.01	$ 0.2200

First Quarter	$	22.01	$	18.76	$	0.2100

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

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At February 27, 2009, we had 39,456,774 common units outstanding, including 2,829,055 common units held by our general partner and 1,199,041 held by Denbury. As of December 31, 2008, we had approximately 10,100 record holders of our common units, which include holders who own units through their brokers "in street name."

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 and to our general partner. 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 is incorporated by reference as an exhibit to this Form 10-K.

In addition to its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Distributions" and Note 10 of the Notes to our Consolidated Financial Statements for further information regarding restrictions on our distributions.

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes information about our equity compensation plans as of December 31, 2008.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity Compensation plans approved by security holders:			
2007 Long-term Incentive Plan (2007 LTIP)	78,388	(1)	915,429

(1) Awards issued under our 2007 LTIP are phantom units for which the grantee will receive one common unit for each phantom unit upon vesting. There is no exercise price. For additional discussion of our 2007 LTIP, see Note 15 of the Notes to the Consolidated Financial Statements.

Recent Sales of Unregistered Securities

None.

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Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2008, 2007, 2006, 2005, and 2004 (in thousands, except per unit and volume data).

	Year Ended December 31,				
	2008 (1)	2007 (1)	2006	2005	2004
Income Statement Data:					
Revenues:					
Supply and logistics (2)	$ 1,852,414	$ 1,094,189	$ 873,268	$ 1,038,549	$ 901,902
Refinery services	225,374	62,095	-	-	-
Pipeline transportation, including natural gas sales	46,247	27,211	29,947	28,888	16,680
CO2 marketing	17,649	16,158	15,154	11,302	8,561
Total revenues	2,141,684	1,199,653	918,369	1,078,739	927,143
Costs and expenses:					
Supply and logistics costs (2)	1,815,090	1,078,859	865,902	1,034,888	897,868
Refinery services operating costs	166,096	40,197	-	-	-
Pipeline transportation, including natural gas purchases	15,224	14,176	17,521	19,084	8,137
CO2 marketing transportation costs	6,484	5,365	4,842	3,649	2,799
General and administrative expenses	29,500	25,920	13,573	9,656	11,031
Depreciation and amortization	71,370	38,747	7,963	6,721	7,298
(Gain) loss from sales of surplus assets	29	266	(16)	(479)	33
Impairment Expense (3)	-	1,498	-	-	-
Total costs and expenses	2,103,793	1,205,028	909,785	1,073,519	927,166
Operating income (loss) from continuing operations	37,891	(5,375)	8,584	5,220	(23)
Earnings from equity in joint ventures	509	1,270	1,131	501	-
Interest expense, net	(12,937)	(10,100)	(1,374)	(2,032)	(926)
Income (loss) from continuing operations before cumulative effect of change in accounting principle, income taxes and minority interest	25,463	(14,205)	8,341	3,689	(949)
Income tax benefit	362	654	11	-	-
Minority interest	264	1	(1)	-	-
Income (loss) from continuing operations before cumulative effect of change in accounting principle	26,089	(13,550)	8,351	3,689	(949)
Income (loss) from discontinued operations	-	-	-	312	(463)
Cumulative effect of changes in accounting principle	-	-	30	(586)	-
Net income (loss)	$ 26,089	$ (13,550)	$ 8,381	$ 3,415	$ (1,412)
Net income (loss) per common unit - basic					
Continuing operations	$ 0.61	$ (0.64)	$ 0.59	$ 0.38	$ (0.10)
Discontinued operations	-	-	-	0.03	(0.05)
Cumulative effect of change in accounting principle	-	-	-	(0.06)	-
Net income (loss)	$ 0.61	$ (0.64)	$ 0.59	$ 0.35	$ (0.15)

Cash distributions per common unit	$	1.2225	$	0.93	$	0.74	$	0.61	$	0.60

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	Year Ended December 31,				
	2008 (1)	2007 (1)	2006	2005	2004
Balance Sheet Data (at end of period):					
Current assets	$ 168,127	$ 214,240	$ 99,992	$ 90,449	$ 77,396
Total assets	1,178,674	908,523	191,087	181,777	143,154
Long-term liabilities	394,940	101,351	8,991	955	15,460
Minority interests	24,804	570	522	522	517
Partners' capital	632,658	631,804	85,662	87,689	45,239
Other Data:					
Maintenance capital expenditures (4)	4,454	3,840	967	1,543	939
Volumes - continuing operations:					
Crude oil pipeline (barrels per day)	64,111	59,335	61,585	61,296	63,441
CO2 pipeline (Mcf per day) (5)	160,220	-	-	-	-
CO2 sales (Mcf per day)	78,058	77,309	72,841	56,823	45,312
NaHS sales (DST) (6)	162,210	69,853	-	-	-

(1) Our operating results and financial position have been affected by acquisitions in 2008 and 2007, most notably the Grifco acquisition in July 2008 and the Davison acquisition, which was completed in July 2007. The results of these operations are included in our financial results prospectively from the acquisition date. For additional information regarding these acquisitions, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Supply and logistics revenues, costs and crude oil wellhead volumes are reflected net of buy/sell arrangements since April 1, 2006.

(3) In 2007, we recorded an impairment charge of $1.5 million related to our natural gas pipeline assets.

(4) 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.

(5) Volume per day for the period we owned the Free State CO2 pipeline in 2008.

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

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

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

- Overview of 2008
- Available Cash before Reserves
- Acquisitions in 2008
- Results of Operations
- Significant Events
- Capital Resources and Liquidity
- Commitments and Off-Balance Sheet Arrangements
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

In the discussions that follow, we will focus on 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. During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with a business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by a business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Previous periods have been restated to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. In addition, our segment margin definition excludes the non-cash effects of our stock-based compensation plans, 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 from before income taxes and minority interests is included in our segment disclosures in Note 12 to the consolidated financial statements.

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), the substitution of cash generated by our joint ventures in lieu of our equity income attributable to our joint ventures, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) 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. 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 Financial Measure" below.

Overview of 2008

In 2008, we reported net income of $26.1 million, or $0.61 per common unit. Non-cash depreciation and amortization totaling $71.4 million reduced net income during the year. See additional discussion of our depreciation and amortization expense in "Results of Operations – Other Costs and Interest" below.

Segment margin for all of our operating segments increased in 2008. The acquisitions of the Davison family business in July 2007, the two drop down transactions with Denbury in May 2008 and the acquisition in July 2008 of our interest in DG Marine which owns the inland marine transportation business of Grifco were the primary factors contributing to this improvement. During 2008, we continued to integrate these acquisitions with our existing operations.

Increases in cash flow generally result in increases in Available Cash before Reserves, from which we pay distributions quarterly to holders of our common units and our general partner. During 2008, we generated $89.8 million of Available Cash before Reserves, and we distributed $50.5 million to holders of our common units and general partner. Cash provided by operating activities in 2008 was $94.8 million. Our total distributions attributable to 2008 increased 109% over the total distributions attributable to 2007.

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Additionally, on January 8, 2009, we declared our fourteenth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2008. This distribution of $0.33 per unit (paid in February 2009) represents a 16% increase from our distribution of $0.285 per unit for the fourth quarter of 2007. During the fourth quarter of 2008, we paid a distribution of $0.3225 per unit related to the third quarter of 2008.

The current economic crisis has restricted the availability of credit and access to capital in our business environment. Despite efforts by treasury and banking regulators to provide liquidity to the financial sector, capital markets continue to remain constrained. While we anticipate that the challenging economic environment will continue for the foreseeable future, we believe that our current cash balances, future internally-generated funds and funds available under our credit facility will provide sufficient resources to meet our current working capital liquidity needs. The financial performance of our existing businesses, $195.5 million in cash and existing debt commitments and no need, other than opportunistically, to access the capital markets, may allow us to take advantage of acquisition and/or growth opportunities that may develop.

Our ability to fund large new projects or make large acquisitions in the near term may be limited by the current conditions in the credit and equity markets due to limitations in our ability to issue new debt or equity financing. We will consider other arrangements to fund large growth projects and acquisitions such as private equity and joint venture arrangements.

Available Cash before Reserves

Available Cash before Reserves for the year ended December 31, 2008 is as follows (in thousands):

	Year Ended December 31, 2008
Net income	$ 26,089
Depreciation and amortization	71,370
Cash received from direct financing leases not included in income	2,349
Cash effects of sales of certain assets	760
Effects of available cash generated by equity method investees not included in income	1,830
Cash effects of stock appreciation rights plan	(385)
Non-cash tax benefits	(2,782)
Earnings of DG Marine in excess of distributable cash	(2,821)
Other non-cash items, net	(2,172)
Maintenance capital expenditures	(4,454)
Available Cash before Reserves	$ 89,784

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the most comparable GAAP measure) for the year ended December 31, 2008 in “Capital Resources and Liquidity – Non-GAAP Reconciliation” below. For the year ended December 31, 2008, cash flows provided by operating activities were $94.8 million.

Acquisitions in 2008

Investment in DG Marine Transportation, LLC

On July 18, 2008, we completed the acquisition of an effective 49% economic interest in DG Marine, which acquired the inland marine transportation business of Grifco Transportation, Ltd. ("Grifco") and two of Grifco's affiliates. TD Marine, LLC, an entity formed by members of the Davison family (See discussion below on the acquisition of the Davison family businesses in 2007) owns (indirectly) a 51% economic interest in the joint venture. This acquisition gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

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Grifco received initial purchase consideration of approximately $80 million, comprised of $63.3 million in cash and $16.7 million, or 837,690 of our common units. DG Marine acquired substantially all of Grifco's assets, including twelve barges, seven push boats, certain commercial agreements, offices and the rights and obligations to acquire a total of eight new barges. Through December 31, 2008, DG Marine had taken delivery of four new barges and acquired two new push boats at a total cost of approximately $16 million. DG Marine expects to take delivery of the remaining new barges and one additional push boat in first half of 2009 (at a total cost of approximately $14.6 million). Upon delivery of the first four new barges and two new push boats in the latter half of 2008, DG Marine paid additional purchase consideration to Grifco of $6 million. After delivery of the remaining four barges and push boat, and after placing the barges and push boats into commercial operations, DG Marine will be obligated to pay additional purchase consideration of up to $6 million. The estimated discounted present value of that $6 million obligation is included in current liabilities in our consolidated balance sheets.

The Grifco acquisition and related closing costs were funded with $50 million of aggregate equity contributions from us and TD Marine, in proportion to our ownership percentages, and with borrowings of $32.4 million under a $90 million revolving credit facility which is non-recourse to us and TD Marine (other than with respect to our investments in DG Marine). Although DG Marine's debt is non-recourse to us, our ownership interest in DG Marine is pledged to secure its indebtedness and we have guaranteed $7.5 million of its indebtedness. The guarantee will expire on May 31, 2009 if DG marine's leverage ratio under its revolving credit agreement is less than 4.0 to 1.0. We funded our $24.5 million equity contribution with $7.8 million of cash and 837,690 of our common units, valued at $19.896 per unit, for a total value of $16.7 million. At closing, we also redeemed 837,690 of our common units from the Davison family. The total number of our outstanding common units did not change as a result of that investment.

We consolidate DG Marine's financial results even though we do not own a majority interest in it. We also do not control the key operational decisions of DG Marine. See Note 3 of the Notes to the Consolidated Financial Statements for more information on DG Marine.

Drop-down Transactions

We completed two "drop-down" transactions with Denbury in 2008 involving two of their existing CO2 pipelines - the NEJD and Free State CO2 pipelines. We paid for these pipeline assets with $225 million in cash and 1,199,041 common units valued at $25 million based on the average closing price of our units for the five trading days surrounding the closing date of the transaction. We expect to receive approximately $30 million per annum, in the aggregate, under the lease agreement for the NEJD pipeline and the Free State pipeline transportation services agreement. Future payments for the NEJD pipeline are fixed at $20.7 million per year during the term of the financing lease, and the payments related to the Free State pipeline are dependent on the volumes of CO2 transported therein, with a minimum monthly payment of $0.1 million.

The NEJD Pipeline System is a 183-mile, 20" pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldson, Louisiana, and is currently being used by Denbury for its Phase I area of tertiary operations in southwest Mississippi. Denbury has the rights to exclusive use of the NEJD Pipeline System and is responsible for all operations and maintenance on the system, and will bear and assume all obligations and liabilities with respect to the pipeline.

On August 5, 2008, Denbury announced that the economic impact of an approved tax accounting method change providing for an acceleration of tax deductions will likely affect certain types of future asset "drop-downs" to us. Transactions which are not sales for tax purposes for Denbury, such as the lease arrangement for the NEJD pipeline, would not be affected provided the transactions meet other tax structuring criteria for Denbury and us. There can be no assurances as to the amount, or timing, of any potential future asset "drop-downs" from Denbury to us.

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Results of Operations

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, 2008	2007	2006
	(in thousands)		
Pipeline transportation	$ 33,149	$ 14,170	$ 13,280
Refinery services	55,784	19,713	-
Industrial gases	13,504	13,038	12,844
Supply and logistics	32,448	10,646	5,017
Total segment margin	$ 134,885	$ 57,567	$ 31,141

Pipeline Transportation Segment

We operate three common carrier crude oil pipeline systems and a CO_2 pipeline in a four state area. We refer to these pipelines as our Mississippi System, Jay System, Texas System and Free State Pipeline. Volumes shipped on these systems for the last three years are as follows (barrels per day):

Pipeline System	2008	2007	2006
Mississippi-Bbls/day	25,288	21,680	16,931
Jay - Bbls/day	13,428	13,309	13,351
Texas - Bbls/day	25,395	24,346	31,303
Free State - Mcf/day	160,220(1)	-	-

(1) Daily average for the period we owned the pipeline in 2008.

The Mississippi System begins in Soso, Mississippi and extends to Liberty, Mississippi. At Liberty, shippers can transfer the crude oil to a connection to Capline, a pipeline system that moves crude oil from the Gulf Coast to refineries in the Midwest. The system has been improved to handle the increased volumes produced by Denbury and transported on the pipeline. In order to handle future increases in production volumes in the area that are expected, we have made capital expenditures for tank, station and pipeline improvements over the last three years and we will continue to make further improvements.

Denbury is the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury's existing and prospective oil fields. As Denbury continues to acquire and develop old oil fields using CO_2 based tertiary recovery operations, Denbury may need crude oil gathering and CO_2 supply infrastructure to those fields, which could create some opportunities for us.

Two segments of crude oil pipeline connect producing fields operated by Denbury to our Mississippi System. Denbury pays us a minimum payment each month for the right to use these pipeline segments. We account for these arrangements as direct financing leases.

The Jay Pipeline system in Florida and Alabama ships crude oil from mature producing fields in the area as well as production from new wells drilled in the area. The increase in crude oil prices in 2007 and 2008 led to interest in further development of the mature fields. We do not know what long-term impact the decline in crude oil prices in the fourth quarter of 2008 may have on the continued production from the mature fields, and the volumes transported on our pipeline.

The new production in the area produces greater tariff revenue for us due to the greater distance that the crude oil is transported on the pipeline. This increased revenue, increases in tariff rates each year on the remaining segments of the pipeline, sales of pipeline loss allowance volumes, and operating efficiencies that have decreased operating costs have contributed to increases in our cash flows from the Jay System. The recent decline in crude oil market prices will also impact our sales of pipeline loss allowance volumes.

As we have consistently been able to increase our pipeline tariffs as needed and due to the new production in the area surrounding our Jay System, we do not believe that a decline in volumes or revenues from sales of pipeline loss allowance volumes will affect the recoverability of the net investment that remains for the Jay System.

Volumes on our Texas System averaged 25,395 barrels per day during 2008. The crude oil that enters our system comes to us at West Columbia where we have a connection to TEPPCO's South Texas System and at Webster where we have connections to two other pipelines. One of these connections at Webster is with ExxonMobil Pipeline and is used to receive volumes that originate from TEPPCO's pipelines. We have a joint tariff with TEPPCO under which we earn $0.31 per barrel on the majority of the barrels we deliver to the shipper's facilities. Substantially all of the volume being shipped on our Texas System goes to two refineries on the Texas Gulf Coast.

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Our Texas System is dependent on the connecting carriers for supply, and on the two refineries for demand for our services. We lease tankage in Webster on the Texas System of approximately 165,000 barrels. We have a tank rental reimbursement agreement with the primary shipper on our Texas System to reimburse us for the expense of leasing of that storage capacity. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets connected to TEPPCO's pipeline systems.

We entered into a twenty-year transportation services agreement to deliver CO2 on the Free State pipeline for Denbury's use in its tertiary recovery operations. Under the terms of the transportation services agreement, we are responsible for owning, operating, maintaining and making improvements to the pipeline. Denbury has rights to exclusive use of the pipeline and is required to use the pipeline to supply CO2 to its current and certain of its other tertiary operations in east Mississippi. The transportation services agreement provides for a $0.1 million per month minimum payment plus a tariff based on throughput. Denbury has two renewal options, each for five years on similar terms.

We operate a CO2 pipeline in Mississippi to transport CO2 from Denbury's main CO2 pipeline to Brookhaven oil field. Denbury has the exclusive right to use this CO2 pipeline. This arrangement has been accounted for as a direct financing lease.

In May 2008, we entered into a twenty-year financing lease transaction with Denbury valued at $175 million related to Denbury's North East Jackson Dome (NEJD) Pipeline System. Denbury Onshore makes fixed quarterly base rent payments to us of $5.2 million per quarter or approximately $20.7 million per year.

Historically, the largest operating costs in our crude oil pipeline segment have consisted of personnel costs, power costs, maintenance costs and costs of compliance with regulations. Some of these costs are not predictable, such as failures of equipment, or are not within our control, like power cost increases. We perform regular maintenance on our assets to keep them in good operational condition and to minimize cost increases.

Operating results from operations for our pipeline transportation segment were as follows.

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Pipeline transportation revenues, excluding natural gas	$ 41,097	$ 22,755	$ 21,742
Natural gas tariffs and sales, net of gas purchases	232	334	612
Pipeline operating costs, excluding non-cash charges for stock-based compensation	(10,529)	(9,488)	(9,605)
Non-income payments under direct financing leases	2,349	569	531
Segment margin	$ 33,149	$ 14,170	$ 13,280

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Pipeline segment margin increased $19.0 million in 2008 as compared to 2007. This increase is primarily attributable to the following factors:

- An increase in revenues from the lease of the NEJD pipeline to Denbury beginning in May 2008 added $12.1 million to segment margin;
-

an increase in revenues from the Free State pipeline beginning in May 2008 added a total of $5.1 million to CO_2 tariff revenues, with the transportation fee related to 34.3 MMcf totaling $4.4 million and the minimum monthly payments totaling $0.7 million;

- an increase in revenues from crude oil tariffs and direct financing leases of $1.4 million; and

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- an increase in revenues from sales of pipeline loss allowance volumes of \$1.7 million, resulting from an increase in the average annual crude oil market prices of \$26.73 per barrel, offset by a decline in allowance volumes of approximately 15,000 barrels.

- Partially offsetting the increase in segment margin was an increase of \$1.0 million in pipeline operating costs.

Tariff and direct financing lease revenues from our crude oil pipelines increased primarily due to volume increases on all three pipeline systems totaling 4,776 barrels per day. These volume increases occurred despite the brief disruptions in operations caused by Hurricanes Gustav and Ike which affected power supplies on the Gulf Coast.

The tariff on the Mississippi System is an incentive tariff, such that the average tariff per barrel decreases as the volumes increase, however the overall impact of an annual tariff increase on July 1, 2008 with the volume increase still resulted in improved tariff revenues from this system of \$0.6 million. As a result of the annual tariff increase on July 1, 2008, average tariffs on the Jay System increased by approximately \$0.06 per barrel between the two periods. Combined with the 119 barrels per day increase in average daily volumes, the Jay System tariff revenues increased \$0.4 million. The impact of volume increases on the Texas System on revenues is not very significant due to the relatively low tariffs on that system. Approximately 75% of the 2008 volume on that system was shipped on a tariff of \$0.31 per barrel.

As is common in the industry, our 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. As compared to 2007, volumes from loss allowance were 15,000 barrels less, however the average price of crude oil was significantly higher during 2008 as compared to 2007. 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.

Pipeline operating costs increased \$1.0 million, with approximately \$0.4 million of that amount due to an increase in IMP testing and repairs, \$0.2 million related to the Free State pipeline acquired in May 2008 and \$0.1 million related to increased electricity costs. Fluctuations in the cost of our IMP program are a function of the length and age of the segments of the pipeline being tested each year and the type of test being performed. Electricity costs in 2008 were higher due to market increases in the cost of power. The remaining \$0.3 million of increased pipeline operating costs were related to various operational and maintenance items.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Pipeline segment margin increased \$0.9 million, or 7%, for 2007, as compared to 2006. Revenues from crude oil and CO2 tariffs and related sources were responsible for the increase for the period. Net profit from natural gas transportation and sales decreased slightly and pipeline operating costs increased, slightly offsetting the increase from tariffs and other sources.

Tariff revenues from transportation of crude oil and CO2 increased \$0.6 million in 2007 compared to the prior year period due primarily to increased volumes on the Mississippi System of 4,749 barrels per day and tariff increases on the Jay System. The volumes on the Jay System were almost identical to the prior year period. As a result of the annual tariff increase on July 1, 2007, average tariffs on the Jay System increased by approximately \$0.04 per barrel between the two periods. The effect on revenues of a decline in volumes on the Texas System was not significant due to the relatively low tariffs on that system.

Higher market prices for crude oil added $0.4 million to pipeline loss allowance revenues. During 2007, average crude oil market prices, as referenced by the prices posted by Shell Trading (US) Company for West Texas/New Mexico Intermediate grade crude oil, were $6.20 higher than in 2006.

Net profit from natural gas pipeline activities decreased in total $0.3 million from 2006 amounts. The natural gas pipeline activities were negatively impacted by production difficulties of a producer attached to the system. Due to the declines we have experienced in the results from our natural gas pipelines, we reviewed these assets to determine if the fair market value of the assets exceeded the net book value of the assets. As a result of this review, we recorded an impairment loss in 2007 related to these assets. See “Other Costs and Interest – Depreciation, Amortization and Impairment” below.

Operating costs decreased $0.1 million. The decrease in 2007 was due primarily to a decline in pipeline lease fees and insurance related to our pipeline operations.

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Refinery Services Segment

Segment margin from our refinery services for 2008 was $55.8 million. Segment margin from our refinery services for the five months we owned this business in 2007 was $19.7 million. Annualizing the 2007 results and comparing those results to the 2008 segment margin would indicate that segment margin increased by approximately $8.5 million between the periods.

We provide a service to refiners – processing the refiner's sour gas streams to reduce the sulfur content. The key cost components of the provision of this service are the purchase and transportation of caustic soda for use in the processing of the gas streams. Market prices for caustic soda were somewhat volatile in 2008, ranging from an average monthly low spot price of approximately $400 per dry short ton (DST) during the first quarter of 2008 as published by the Chemical Market Associates, Inc. (CMAI) to a high of $850 per DST in the fourth quarter of 2008. Our freight costs during 2008 fluctuated with freight demand and fuel prices. The price of diesel fuel ranged from a low of approximately $2.26 per gallon to a high of approximately $4.73 per gallon. In 2008, we believe that we were successful in mitigating some of the impact on segment margin of the volatility of these costs through our management of caustic acquisition and freight costs and by indexing our sales prices for NaHS to CMAI caustic market prices and adjusting sales prices for fluctuations in fuel surcharges. Additionally, we do, from time to time, engage in other activities such as selling caustic soda, buying NaHS from other producers for re-sale to our customers and buying and selling sulfur, the financial results of which are also reported in our refinery services segment.

We receive NaHS as consideration for provision of our services to the refiners. We sell the NaHS for use in applications including, but not limited to, agriculture, dyes and other chemical processing; waste treatment programs requiring stabilization and reduction of heavy and toxic metals; sulfidizing oxide ores (most commonly to separate copper from molybdenum; and certain applications in paper production and tannery processes. The table below reflects information about NaHS sales for 2008 and similar information for 2007 and 2006 volumes and sales prices on a pro forma basis based on historic data related to the refinery services operations.

	Year Ended December 31,	Pro Forma Year Ended December 31,	
	2008	2007	2006
NaHS Sales			
Dry Short Tons (DST)	162,210	164,059	159,952
Average sales price per DST, net of delivery costs	$ 888	$ 591	$ 561

NaHS sales prices per DST increased as we adjusted these prices throughout 2008 for fluctuations in the cost components of our services. As discussed above, market prices for caustic were volatile in 2008. Additionally, freight costs for delivering NaHS to our customers fluctuated in 2008 in a manner similar to the freight costs associated with our caustic supply as discussed above. We were generally successful in increasing our sales prices for NaHS to compensate for these cost fluctuations by indexing approximately 60% of our NaHS sales volumes to market prices for caustic soda and by adjusting sales prices for NaHS as fuel surcharges billed to us increased.

Our NaHS sales volumes declined slightly in 2008, with almost all of the decline occurring in the fourth quarter resulting primarily from the slowdown in worldwide economic activity.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO_2 sales to industrial customers and our share of the available cash generated by our 50% joint ventures, T&P Syngas and Sandhill.

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Operating Results

Operating results for our industrial gases segment were as follows.

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Revenues from CO2 marketing	$ 17,649	$ 16,158	$ 15,154
CO2 transportation and other costs	(6,484)	(5,365)	(4,842)
Available cash generated by equity investees	2,339	2,245	2,532
Segment margin	$ 13,504	$ 13,038	$ 12,844
Volumes per day:			
CO2 marketing - Mcf	78,058	77,309	72,841

CO2 – Industrial Customers

We supply CO2 to industrial customers under seven long-term CO2 sales contracts. The terms of our contracts with the industrial CO2 customers include minimum take-or-pay and maximum delivery volumes. The maximum daily contract quantity per year in the contracts totals 97,625 Mcf. Under the minimum take-or-pay volumes, the customers must purchase a total of 51,048 Mcf per day whether received or not. Any volume purchased under the take-or-pay provision in any year can then be recovered in a future year as long as the minimum requirement is met in that year. At December 31, 2008, we have no liabilities to customers for gas paid for but not taken.

Our seven industrial contracts expire at various dates beginning in 2010 and extending through 2023. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

Based on historical data for 2004 through 2008, we expect some seasonality in our sales of CO2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. The table below depicts these seasonal fluctuations. The average daily sales (in Mcfs) of CO2 for each quarter in 2008 and 2007 under these contracts were as follows:

Quarter	2008	2007
First	73,062	67,158
Second	79,968	75,039
Third	83,816	85,705
Fourth	75,164	80,667

The increasing margins from the industrial gases segment between the periods were the result of an increase in volumes and increases in the average revenue per Mcf sold of 8% from 2007 to 2008 and 1% from 2006 to 2007. Inflation adjustments in the contracts and variations in the volumes sold under each contract cause the changes in average revenue per Mcf.

Transportation costs for the CO2 on Denbury's pipeline have increased due to the increased volume and the effect of the annual inflation factor in the rate paid to Denbury. The average rate in 2008 increased 4% over the 2007 rate. The average rate per Mcf in 2007 increased 6% over the 2006 rate. In 2008, we also recorded a charge for approximately $0.9 million related to a commission on one of the industrial gas sales contracts. We expect this commission to continue in future years at a cost of approximately $0.3 million annually.

Equity Method Joint Ventures

Our share of the available cash before reserves generated by equity investments in each year primarily resulted from our investment in T&P Syngas. Our share of the available cash before reserves generated by T&P Syngas for 2008, 2007, and 2006 was $2.2 million, $1.9 million and $2.3 million, respectively.

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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, diesel and gasoline) to wholesale markets and some end-users such as paper mills and utilities;
- purchasing products from refiners that do not meet the specifications they desire, transporting the products to one of our terminals and blending the products to a quality that meets the requirements of our customers; and
- utilizing our fleet of trucks and trailers and barges to take advantage of logistical opportunities primarily in the Gulf Coast states and inland waterways.

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 choice of feedstock. Despite crude oil being considered a somewhat homogenous commodity, many refiners are very particular about the quality of crude oil feedstock they will 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 and take advantage of regional differences. The pricing in the majority of our purchase contracts contain a market price component, unfixed bonuses that are based on several other market factors 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.

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 in accordance with Statement of Financial Accounting Standards No. 133. See Note 17 of the Notes to the Consolidated Financial Statements.

In our petroleum products marketing operations, we supply primarily fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing their products that do not meet the specifications they desire, 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 280 trucks and 550 trailers and DG Marine's sixteen "hot-oil" barges in combination with our 1.1 million barrels of existing leased and owned storage to service our refining customers and store and blend the intermediate and finished refined products.

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

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Supply and logistics revenue	$ 1,852,414	$ 1,094,189	$ 873,268
Crude oil and products costs	(1,736,637)	(1,041,738)	(851,671)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based	(83,329)	(41,805)	(16,580)
Segment margin	$ 32,448	$ 10,646	$ 5,017
Volumes of crude oil and petroleum products (mbbls)	17,410	14,246	13,571

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

In 2008, our supply and logistics segment margin included a full year of contribution from the assets acquired in July 2007 from the Davison family, as compared to only five months in 2007. This additional seven months of activity in 2008 was the primary factor in the increase in segment margin.

The dramatic rise in commodity prices in the first nine months of 2008 provided significant opportunities to us to take advantage of purchasing and blending of "off-spec" products. The average NYMEX price for crude oil rose from \$95.98 per barrel at December 31, 2007 to a high of \$145.29 per barrel in July 2008, and then declined to \$44.60 per barrel at December 31, 2008. Grade differentials for crude oil widened significantly during this period as refiners sought to meet consumer demand for gasoline and diesel. This widening of grade differentials provided us with opportunities to acquire crude oil with a higher specific gravity and sulfur content (heavy or sour crude oil) at significant discounts to market prices for light sweet crude oil and sell it to refiners at prices providing significantly greater margin to us than sales of light sweet crude oil.

The absolute market price for crude oil also impacts the price at which we recognize volumetric gains and losses that are inherent in the handling and transportation of any liquid product. In 2008 our average monthly volumetric gains were approximately 2,000 barrels.

In the first half of 2007, crude oil markets were in contango, providing an opportunity for us to increase segment margin. This opportunity did not exist in most of 2008. Late in 2008, crude oil price markets were again in contango, so we anticipate that opportunities will exist to profit from this strategy in 2009.

The demand for gasoline by consumers during most of 2008 also led refiners to focus on producing the "light" end of the refined barrel. Some refiners were willing to sell the heavy end of the refined barrel, in the form of fuel oil or asphalt, as well as product not meeting their specifications for use in making gasoline, at discounts to market prices in order to free up capacity at their refineries to meet gasoline demand. Our ability to utilize our logistics equipment to transport product from the refiner's facilities to one of our terminals increased the opportunity to acquire the product at a discount.

As a result of the actions we took in light of the opportunities presented to us in the market, our average margin per barrel increased to \$6.65 in 2008 from \$3.68 per barrel in 2007. Before consideration of the costs of providing our services, we generated \$63.3 million of additional margin from our supply and logistics activities,

Our operating and segment general and administrative (G&A) costs increased by \$41.5 million in 2008 as compared to 2007. The costs of operating the logistical equipment and terminals acquired in the Davison acquisition for an additional seven months in 2008 accounted for approximately $30.2 million of this difference. Our inland marine transportation operations acquired in July 2008 added approximately $8.4 million to our costs in 2008. The remaining increase in costs of $2.9 million is attributable to the crude oil portion of our supply and logistics operations. The most significant components of our operating and segment G&A costs consist of fuel for our fleet of trucks, maintenance of our trucks, terminals and barges, and personnel costs to operate our equipment. In 2008, fuel costs for our trucks increased significantly as result of market prices for diesel fuel.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

The portions of our supply and logistics operations acquired in the Davison transaction added approximately $8.6 million to our supply and logistics segment margin for the five months we owned these operations in 2007. Our existing crude oil gathering and marketing operations contribution for 2007 was $0.6 million less than the contribution for 2006, however the contribution was actually the result of offsetting fluctuations as discussed below. Contribution by our crude oil operations is derived from sales of crude oil and from the transportation of crude oil volumes that we did not purchase by truck for a fee, with costs for this part of the operation relating to the purchase of the crude oil and the related aggregation and transportation costs.

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An increase in the operating and segment general and administrative costs related to our crude oil activities of $4.1 million was the largest contributor to the decrease in segment margin from crude oil operations. Compensation and related costs accounted for $1.8 million of the increased costs. In order to remain competitive in retaining drivers for our crude oil trucking, we increased compensation rates. We also had increased costs for fuel and repairs to our trucks and related equipment that combined to increase our operating costs in the crude oil area by $1.2 million. We increased the accrual for the remediation of a former trucking station by $0.3 million. Additionally we incurred costs of $0.7 million related to the operation of the Port Hudson facility which we acquired in 2007.

Partially offsetting these increased operating costs was an increase of 1,429 barrels per day in crude oil volumes that we transported for a fee. Most of this increase in volume was attributable to transportation of Denbury's production from its wellheads to our pipeline. The increase in the fees for these services was $2.7 million between 2006 and 2007. On a like-kind basis, volumes purchased and sold decreased by 2,531 barrels per day. We focused on volumes in 2007 that met our targets for profitability, and we were impacted by significant volatility between crude quality differentials between the periods, with the overall impact on margin of a decrease of $0.6 million. The margins generated from the storage of crude oil inventory in the contango market were $0.2 million greater in 2007 than 2006.

Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
General and administrative expenses not separately identified below	$ 25,131	$ 16,760	$ 9,007
Bonus plan expense	4,763	2,033	1,747
Stock-based compensation plans (credit) expense	(394)	1,593	1,279
Compensation expense related to management team	-	3,434	-
Management team transition costs	-	2,100	1,540
Total general and administrative expenses	$ 29,500	$ 25,920	$ 13,573

As a result of the substantial growth we have experienced beginning in 2006 and continuing through 2008, our general and administrative expenses have increased each year. We added a new senior management team in August 2006 and additional personnel in our financial, human resources and other functions to support the operations we acquired in 2008 and 2007 in the Davison and Grifco transactions. As we have grown, we have incurred increased legal, audit, tax and other consulting and professional fees, and additional director fees and expenses. Late in 2008, we moved to larger headquarters offices, incurring costs for moving as well as increased rent and related costs.

The expense we have recorded under our bonus plan increased substantially as a result of the improvement in our Available Cash before Reserves in each year and the tripling of our personnel count in mid 2007. The amounts paid under our bonus plan are a function of both the Available Cash before Reserves that we generate in a year and the improvement in our safety record, and are approved by our Compensation Committee of our Board of Directors. The bonus plan for employees is described in Item 11, "Executive Compensation" below.

We record stock-based compensation expense for phantom units issued under our long-term incentive plan and for our stock appreciation rights (SAR) plan. (See additional discussion in Item 11, "Executive Compensation" below and Note 15 to the Consolidated Financial Statements.) The fair value of phantom units issued under our long-term incentive plan is calculated at the grant date and charged to expense over the vesting period of the phantom units. Unlike the accounting for the SAR plan, the total expense to be recorded is determined at the time of the award and does not change except to the extent that phantom unit awards do not vest due to employee terminations. The SAR plan for employees and directors is a long-term incentive plan whereby rights are granted for the grantee to receive cash equal to the difference between the grant price and common unit price at date of exercise. The rights vest over several years. We determine the fair value of the SARs at the end of each reporting period and the fair value is charged to expense over the period during which the employee vests in the SARs. Changes in our common unit market price affect the computation of the fair value of the outstanding SARs. The change in fair value combined with the elapse of time and its effect on the vesting of SARs create the expense we record. Additionally any difference between the expected value for accounting purposes that an employee will receive upon exercise of his rights and the actual value received when the employee exercise the SARs creates additional expense. Due to fluctuations in the market price for our common units, expense for outstanding and exercised SARs has varied significantly between the periods.

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Our senior management team was hired in August 2006. Throughout 2006, 2007 and until December 2008, Denbury negotiated with that team to finalize a compensation package. Although the terms of these arrangements were not agreed to and completed at December 31, 2007, we recorded expense of $3.4 million in 2007, representing an estimated value of compensation attributable to our Chief Executive Officer and Chief Operating Officer for services performed during 2007. Although this compensation is to ultimately come from our general partner, we have recorded the expense in our Consolidated Statements of Operations in G&A expense due to the “push-down” rules for accounting for transactions where the beneficiary of a transaction is not the same as the parties to the transaction. On December 31, 2008, we finalized the arrangements with our senior management team. See additional discussion of the compensation arrangements with our senior management team in Item 11, “Executive Compensation.”

Additionally, we recorded transition costs primarily in the form of severance costs when members of our management team changed in December 2007 and August 2006. Our general partner made a cash contribution to us of $1.4 million in 2007 to partially offset the $2.1 million cash cost of the severance payment to a former member of our management team.

Depreciation, amortization and impairment expense was as follows:

	Year Ended December 31, 2008	2007	2006
Depreciation on Genesis assets	$ 17,331	$ 8,909	$ 3,719
Depreciation of acquired DG Marine property and equipment	3,084	-	-
Amortization on acquired Davison intangible assets	46,326	25,350	-
Amortization on acquired DG Marine intangible assets	92	-	-
Amortization of CO2 volumetric production payments	4,537	4,488	4,244
Impairment expense on natural gas pipeline assets	-	1,498	-
Total depreciation, amortization and impairment expense	$ 71,370	$ 40,245	$ 7,963

Depreciation, amortization and impairment increased in 2007 and 2008 due primarily to the depreciation and amortization expense recognized on the fixed assets and intangible assets acquired from the Davison family in July 2007 and the DG Marine acquisition in July 2008.

Our intangible assets are being amortized over the period during which the intangible asset is expected to contribute to our future cash flows. As intangible assets such as customer relationships and trade names are generally most valuable in the first years after an acquisition, the amortization we will record on these assets will be greater in the initial years after the acquisition. As a result, we expect to record significantly more amortization expense related to our intangible assets in 2008 through 2010 than in years subsequent to that time. See Note 9 to the Consolidated Financial Statements for information on the amount of amortization we expect to record in each of the next five years.

Amortization of our CO2 volumetric payments is based on the units-of-production method. We acquired three volumetric production payments totaling 280 Mcf of CO2 from Denbury between 2003 and 2005. Amortization is based on volumes sold in relation to the volumes acquired. In each annual period, the volume of CO2 sold has increased.

In 2007 and 2006, our natural gas pipeline activities were impacted by production difficulties of a producer attached to the system. Due to declines we experienced in the results from our natural gas pipelines, we reviewed these assets in 2007 to determine if the fair market value of the assets exceeded the net book value of the assets. As a result of this review, we recorded an impairment loss of $1.5 million related to these assets.

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Interest expense, net was as follows:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Interest expense, including commitment fees, excluding DG Marine	$ 10,738	$ 10,103	$ 781
Amortization of facility fees, excluding DG Marine facility	664	441	300
Interest expense and commitment fees - DG Marine	2,269	-	-
Capitalized interest	(276)	(59)	(9)
Write-off of facility fees and other fees	-	-	500
Interest income	(458)	(385)	(198)
Net interest expense	$ 12,937	$ 10,100	$ 1,374

Our average outstanding debt balance, excluding the DG Marine credit facility, increased $107.0 million to $225 million in 2008 over the average outstanding debt balance in 2007, primarily due to the Davison acquisition in July 2007 and the CO2 pipeline dropdown transactions in May 2008. The average interest rate on our debt, however, was 3.52% lower during 2008, partially offsetting the effects of the higher debt balance, resulting in an overall increase for the year for interest and commitment fees on our credit facility of $0.6 million, and an average interest rate of 4.26%.

DG Marine incurred interest expense in 2008 of $2.3 million under its credit facility. Additionally DG Marine recorded accretion of the discount on the payments to Grifco related upon successful launch of the barges under construction. (See Note 3 to the Consolidated Financial Statements.) The net effect of these changes was an increase in net interest expense between the 2008 and 2007 of $2.8 million.

Net interest expense increased $8.7 million from 2006 to 2007. This increase in interest resulted form the borrowings in July 2007 to fund the Davison acquisition, with a reduction in debt in December 2007 from the proceeds from an equity offering. Our average outstanding balance of debt was $118.5 million during 2007, an increase of $115.1 million over 2006. Our average interest rate during 2007 was 7.78%, a decrease of 0.64% from 2006. As a result of the termination of our prior credit facility to enter into the new facility we obtained in November 2006, we wrote-off $0.5 million of deferred facility fees related to the prior credit facility in 2006.

Income taxes. A portion of the operations we acquired in the Davison transaction 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 taxes expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles. In 2008 and 2007, we recorded an income tax benefit totaling $0.4 million and $0.7 million, respectively. The current income taxes we expect to pay for 2008 are approximately $2.4 million, and we provided a deferred tax benefit of $4.2 million related to temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

The current economic crisis has restricted the availability of credit and access to capital in our business environment. Despite efforts by treasury and banking regulators to provide liquidity to the financial sector, capital markets continue to remain constrained. While we anticipate that the challenging economic environment will continue for the foreseeable future, we believe that our current cash balances, future internally-generated funds and funds available under our credit facility will provide sufficient resources to meet our current working capital liquidity needs. The cash flow generated by our existing businesses, the $19.0 million in cash on hand, our existing debt commitments, and the absence of any need to access the capital markets, may allow us to take advantage of acquisition and/or growth opportunities that may develop.

Long-term, we continue to pursue a growth strategy that requires significant capital. We expect our long-term capital resources to include equity and debt offerings (public and private) and other financing transactions, in addition to cash generated from our operations. Accordingly, we expect to access the capital markets (equity and debt) from time to time to partially refinance our capital structure and to fund other needs including acquisitions and ongoing working capital needs. Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, to utilize our current credit facility 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. If we are unable to raise the necessary funds, we may be required to defer our growth plans until such time as funds become available.

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As of December 31, 2008, we had $320 million of loans and $3.5 million in letters of credit outstanding under our $500 million credit facility, resulting in $176.5 million of remaining credit, all of which was available under our borrowing base. Our borrowing base fluctuates each quarter based on our earnings before interest, taxes, depreciation and amortization, or EBITDA. Our borrowing base may be increased to the extent of EBITDA attributable to acquisitions, with approval of the lenders.

The terms of our credit facility also effectively limit the amount of distributions that we may pay to our general partner and holders of common units. Such distributions may not exceed the sum of the distributable cash generated for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. See Note 10 of the Notes to the Consolidated Financial Statements for additional information on our credit facility.

As of December 31, 2008, DG Marine had $55.3 million of loans outstanding under its $90 million credit facility. DG Marine will utilize this facility to fund its acquisition of additional barges and a push boat in the first half of 2009.

Uses of Cash

Our cash requirements include funding day-to-day operations, maintenance and expansion capital projects, debt service, and distributions on our common units and other equity interests. We expect to use cash flows from operating activities to fund cash distributions and maintenance capital expenditures needed to sustain existing operations. Future expansion capital – acquisitions or capital projects – will require funding through various financing arrangements, as more particularly described under “Liquidity and Capital Resources – Capital Resources/Sources of Cash” above.

Cash Flows from Operations. We 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.

Debt and Other Financing Activities. Our sources of cash are primarily from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $295.3 million. These borrowings related to the CO2 pipeline drop-down transactions in May 2008 and the acquisition by DG Marine of the Grifco assets in July 2008. Our joint venture partner in DG Marine (members of the Davison family) also contributed $25.5 million for its 51% interest and we redeemed $16.7 million of common units from those members of the Davison family at the time of the Grifco acquisition. In connection with our issuance of 1,199,041 common units to Denbury for a portion of the consideration in the drop-down transactions, our general partner contributed $0.5 million as required under our partnership agreement to maintain its two percent general partner capital account balance.

We paid distributions totaling $50.5 million to our limited partners and our general partner during 2008. See the details of distributions paid in “Distributions” below. DG Marine paid credit facility fees of $2.3 million in 2008.

Investing. We utilized cash flows to make acquisitions and for capital expenditures. The most significant investing activities in 2008 were the CO2 pipeline drop-down transactions in May 2008 for which we expended $225 million in cash as consideration (along with the issuance of $25 million of our common units) and the acquisition of the inland marine transportation assets of Grifco in July 2008. We paid Grifco $66.0 million in cash consideration at closing of the transaction (along with the issuance of $16.7 million of our common units and an agreement to pay an additional $12.0 million consideration, with one-half payable in December 2008 and the remainder in December 2009). On December 31, 2008 we expended $6.0 million for the first payment of the deferred consideration. We also expended approximately $16.0 million for additional barges and push boats. Additional information on our capital expenditures and business acquisitions is provided below.

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Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets, businesses and other asset acquisitions in the three years ended December 31, 2008, 2007, and 2006 is as follows:

	Years Ended December 31, 2008	2007 (in thousands)	2006
Capital expenditures for business combinations and asset purchases:			
DG Marine acquisition	$ 94,072	$ -	$ -
Free State Pipeline acquisition, including transaction costs	76,193	-	-
NEJD Pipeline transaction, including transaction costs	177,699	-	-
Davison acquisition	-	631,476	-
Port Hudson acquisition	-	8,103	-
Total	347,964	639,579	-
Capital expenditures for property, plant and equipment:			
Maintenance capital expenditures:			
Pipeline transportation assets	719	2,880	611
Supply and logistics assets	729	440	175
Refinery services assets	1,881	469	-
Administrative and other assets	1,125	51	181
Total maintenance capital expenditures	4,454	3,840	967
Growth capital expenditures:			
Pipeline transportation assets	7,589	3,712	360
Supply and logistics assets	22,659	650	-
Refinery services assets	3,609	979	-
Total growth capital expenditures	33,857	5,341	360
Total	38,311	9,181	1,327
Capital expenditures attributable to unconsolidated affiliates:			
Sandhill investment	-	-	5,042
Faustina project	2,397	1,104	1,016
Total	2,397	1,104	6,058
Total capital expenditures	$ 388,672	$ 649,864	$ 7,385

During 2009, we expect to expend approximately $12.7 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $1.9 million of improvements in our refinery services business, $2.6 million in our crude oil pipeline operations, including $2.0 million for rehabilitation of a segment of the Mississippi System as a result of IMP testing, $3.6 million related to integration and upgrades of our information technology systems, $2.7 related to improvements at our terminals and the remainder on projects related to our truck transportation operations, including $1.7 for replacement vehicles. In future years we expect to spend $4 million to $5 million per year on vehicle replacements.

We will also complete construction of an expansion of our existing Jay System that will extend the pipeline to producers operating in southern Alabama. That expansion will consist of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and will include storage capacity of 20,000 barrels. We expect to spend a total of approximately $4.1 million in 2009 to complete this project, including the acquisitions of crude oil linefill.

DG Marine is expected to expend approximately $14.6 million in 2009 for four new barges and one additional push boat. Upon receipt of these vessels, DG Marine will have twenty barges and ten push boats. DG Marine's capital expenditures are funded through its credit facility.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital discussed above in "Capital Resources -- Sources of Cash." We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows. The arrangement that Denbury has made with our new senior executive management team provide incentives to them to increase the available cash for our common unitholders. See "Item 11. Executive Compensation" for a description of these arrangements.

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Distributions

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 and to our general partner. 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 fourteen quarters, including the distribution paid for the fourth quarter of 2008, as shown in the table below (in thousands, except per unit amounts). Each quarter, the Board of Directors of our general partner determines the distribution amount per unit based upon various factors such as our operating performance, available cash, 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	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2006	February 2007	$ 0.2100	$ 2,895	$ 59	$ -	$ 2,954
First quarter 2007	May 2007	$ 0.2200	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.2300	$ 3,170(1)	$ 65	$ -	$ 3,235 (1)
Third quarter 2007	November 2007	$ 0.2700	$ 7,646	$ 156	$ 90	$ 7,892
Fourth quarter 2007	February 2008	$ 0.2850	$ 10,902	$ 222	$ 245	$ 11,369
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009 (2)	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110

(1) The distribution paid on August 14, 2007 to holders of our common units is net of the amounts payable with respect to the common units issued in connection with the Davison transaction. The Davison unitholders and our general partner waived their rights to receive such distributions, instead receiving purchase price adjustments with us.

(2) This distribution was paid on February 13, 2009 to our general partner and unitholders of record as of February 3, 2009.

Our credit facility also includes a restriction on the amount of distributions we can pay in any quarter. At December 31, 2008, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $573.6 million.

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to receive 13.3% of any distributions to our common unitholders in excess of $0.25 per unit, 23.5% of any distributions to our common unitholders in excess of $0.28 per unit, and 49% of any distributions to our common unitholders in excess of $0.33 per unit, without duplication. The likelihood and timing of the payment of any incentive distributions will depend on our ability to increase the cash flow from our existing operations and to make accretive acquisitions. In addition, our partnership agreement authorizes us to issue additional equity interests in our partnership with such rights, powers and preferences (which may be senior to our common units) as our general partner may determine in its sole discretion, including with respect to the right to share in distributions and profits and losses of the partnership.

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.

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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.

Available Cash before Reserves is a liquidity measure used by our management to compare cash flows generated by us to the cash distribution paid to our limited partners and general partner. 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 (also referred to as distributable cash flow) 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 liquidity measure) to cash flow from operating activities (the GAAP measure) for the year ended December 31, 2008, is as follows (in thousands):

	Year Ended December 31, 2008
Cash flows from operating activities	$ 94,808
Adjustments to reconcile operating cash flows to Available Cash:	
Maintenance capital expenditures	(4,454)
Proceeds from sales of certain assets	760
Amortization of credit facility issuance fees	(1,437)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	1,067
Available cash from NEJD pipeline not yet received and included in cash flows from operating activities	1,723
Earnings of DG Marine in excess of distributable cash	(2,821)
Other items affecting available cash	(1,124)
Net effect of changes in operating accounts not included in calculation of Available Cash	1,262
Available Cash before Reserves	$ 89,784

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Commitments and Off-Balance Sheet Arrangements

Contractual Obligation 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, 2008.

	Payments Due by Period				
Commercial Cash Obligations and Commitments	Less than one year	1 - 3 years	3 - 5 Years	More than 5 years	Total
Contractual Obligations:					
Long-term debt (1)	$ -	$ 375,300	$ -	$ -	$ 375,300
Estimated interest payable on long-term debt (2)	14,428	27,487	-	-	41,915
Operating lease obligations	5,324	7,961	4,417	11,067	28,769
Capital expansion projects (3)	14,713	-	-	-	14,713
Unconditional purchase obligations (4)	57,975	-	-	-	57,975
Remaining purchase obligation to Grifco (5)	6,000	-	-	-	6,000
Other Cash Commitments:					
Asset retirement obligations (6)	150	-	-	4,438	4,588
FIN 48 tax liabilities (7)	-	-	2,599	-	2,599
Total	$ 98,590	$ 410,748	$ 7,016	$ 15,505	$ 531,859

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of November 15, 2011. The DG Marine credit facility allows it to repay and re-borrow funds at any time through the maturity date of July 18, 2011.

(2) Interest on our long-term debt is at market-based rates. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2008 remained outstanding through the final maturity dates of July 18, 2011 and November 15, 2011 and interest rates remained at the December 31, 2008 market levels through the final maturity dates.

(3) We expect to complete the expansion of our Jay System in the first quarter of 2009. We also have signed commitments to purchase four newly-constructed barges. See “Capital Expenditures and Business Acquisitions” under “Liquidity and Capital Resources – Uses of Cash” above.

(4) 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, 2008, 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.

(5) DG Marine will pay Grifco $6 million after delivery of four new barges and boats. See Note 3 to the Consolidated Financial Statements.

(6) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $1.4 million, as determined under FIN 47 and SFAS 143, and is further discussed in Note 5 to the Consolidated Financial Statements.

(7)

The estimated FIN 48 tax liabilities 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 FIN 48 tax liability would not result in a cash payment.

We have guaranteed 50% of the $3.0 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

The preparation of 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 perceived 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 the consolidated financial statements (See Note 2 Summary of Significant Accounting Policies.)

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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, asset retirement obligations, 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-competes 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. 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. In connection with the Grifco acquisition in 2008 and the Davison and Port Hudson acquisitions in 2007, we performed allocations of the purchase price. See Note 3 of the Notes to the Consolidated Financial Statements.

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 may not be recoverable, we review our assets for impairment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. 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 and is primarily associated with the Davison acquisition in 2007. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the fourth quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which 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 is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2008, the carrying value of our goodwill was $325.0 million. We did not record any goodwill impairment charges during 2008.

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Due to the recent disruptions in the credit markets and macroeconomic conditions, we will continue to monitor the 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. If we determine that a triggering event has occurred, we will perform an interim goodwill impairment analysis.

For additional information regarding our goodwill, see Notes 3 and 9 of the Notes to Consolidated Financial Statements.

Asset Retirement Obligations

Some of our assets, primarily related to our pipeline operations segment, have obligations regarding removal and restoration activities when the asset is abandoned. Additionally, we generally have obligations to remove crude oil injection stations located on leased sites and to decommission barges when we take them out of service. We estimate the future costs of these obligations, discount those costs to their present values, and record a corresponding asset and liability in our Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including the ultimate expected cost of the obligation, the expected future date of the required cash payment, and interest and inflation rates. Revisions to these estimates may be required based on changes to cost estimates, the timing of settlement, and changes in legal requirements. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis and an adjustment in our depreciation expense in future periods. See Note 5 to our Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Equity Compensation Plan Accruals

We accrue for the fair value of our liability for the stock appreciation rights (“SAR”) awards we have issued to our employees and directors under the provisions of SFAS No. 123(R), Share-Based Payments, as amended and interpreted. 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. Our SAR plan was instituted December 31, 2003, so we have very limited experience from which to determine the expected term of the awards. As a result, we use the simplified method allowed by the Securities and Exchange Commission to determine the expected life, which results in an expected life of 6 to 7 years at the time an award it granted.

We recognize the stock-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, 2008, 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 less than 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. See Note 15 to our Consolidated Financial Statements for further discussion regarding our SAR plan.

For phantom unit awards granted under our 2007 Long-Term Incentive Plan, the total compensation expense recognized over the service period is determined by the grant date fair value of our common units that become earned. Uncertainties involved in the estimate of the compensation cost we record for our phantom units relate to the assumptions regarding the continued employment of personnel who have been awarded phantom units.

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On December 31, 2008, our general partner completed compensation arrangements with our senior executive team. See Item 11 – Executive Compensation - The Class B Membership Interest in our General Partner. The Class B Membership Interests awarded to our senior executives will be accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards will be recomputed at each measurement date and the expense to be recorded will be adjusted based on that fair value. Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value will be affected by the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. Included within the assumptions used to prepare these estimates are projections of available cash and distributions to our common unitholders and general partner, including an assumed level of growth and the effects of future new growth projects during the four-year vesting period. At December 31, 2008, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date is approximately \$12 million. The fair value of these incentive awards will be recomputed each quarter beginning with the quarter ending March 31, 2009 through the final settlement of the awards. Compensation expense of \$3.4 million was recorded in the fourth quarter of 2007 related to the previous arrangements between our general partner and our Senior Executives. The fair value to be recorded by us as compensation expense will be the excess of the recomputed estimated fair value over the previously recorded compensation expense of \$3.4 million. Due to the vesting conditions for the awards, the amount to which the Senior Executives were entitled on December 31, 2008 for the Class B Membership Awards and the related deferred compensation was zero. Management's estimates of fair value are made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at December 31, 2008. This expense will be recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions will change the amount of compensation cost we record. Changes in these assumptions would not, however, affect our Available Cash before Reserves, as the cash cost of the Class B Membership Interests will be borne by Denbury.

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, 2008, we are not aware of any contingencies or liabilities that will have a material effect on our financial position, results of operations, or cash flows.

Recent Accounting Pronouncements.

SFAS 141(R)

In December 2007, the FASB issued SFAS No. 141(R) “Business Combinations” (SFAS 141(R)). SFAS 141(R) replaces FASB Statement No. 141, “Business Combinations.” This statement retains the purchase method of accounting used in business combinations but replaces SFAS 141 by establishing principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction costs and restructuring costs be charged to expense as incurred. In addition, the statement requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted SFAS 141(R) on January 1, 2009. Adoption will impact our accounting for acquisitions we complete subsequent to that date.

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SFAS 160

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51” (SFAS 160). This statement establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary in an effort to improve the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We adopted SFAS 160 on January 1, 2009. We are assessing the impact of this statement on our financial statements, but expect it to impact the presentation of the non-controlling interest in our operating partnership.

SFAS 161

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133” (SFAS 161). This Statement requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS 133, and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS No. 161 on January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

EITF 07-4

In March 2008, the Emerging Issues Task Force (or EITF) of the FASB issued EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships” (EITF 07-4). EITF 07-4 addresses the application of the two-class method under SFAS No. 128 “Earnings Per Share” in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We adopted EITF 07-04 on January 1, 2009. Adoption will impact the net income available to limited partners used in our computation of earnings per unit, but will not impact our distributions to limited partners, financial position, results of operations, or cash flows. For additional information on our incentive distribution rights, see Note 11 to the Consolidated Financial Statements.

FASB Staff Position No. 142-3

In April 2008, the FASB issued FASB Staff Position No. 142-3, “Determination of the Useful Life of Intangible Assets” (FSP 142-3). This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset under Statement of Financial Accounting Standards No. 142, “Goodwill and other Intangible Assets.” The purpose of this FSP is to develop consistency between the useful life assigned to intangible assets and the cash flows from those assets. FSP 142-3 is effective for fiscal years beginning after December 31, 2008. We are currently evaluating the impact, if any, that the standard will have 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.

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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, 2008 were categorized as non-trading. On December 31, 2008, we had entered into NYMEX future contracts that will settle between February 2009 and August 2009 and NYMEX options contracts that will settle during February and March 2009. Although the intent of our risk-management activities is to hedge our margin, none of our derivative positions at December 31, 2008 qualified for hedge accounting. This accounting treatment is discussed further under Note 17 to our Consolidated Financial Statements.

The table below presents information about our open derivative contracts at December 31, 2008. Notional amounts in barrels, 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 multiplied by the December 31, 2008 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.

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	Sell (Short) Contracts	Buy (Long) Contracts
Futures Contracts:		
Crude Oil:		
Contract volumes (1,000 bbls)	146	107
Weighted average price per bbl	$ 53.25	$ 47.94
Contract value (in thousands)	$ 7,774	5,129
Mark-to-market change (in thousands)	(169)	(357)
Market settlement value (in thousands)	$ 7,605	$ 4,772
Heating Oil:		
Contract volumes (1,000 bbls)	35	-
Weighted average price per gal	$ 1.43	$ -
Contract value (in thousands)	$ 2,099	-
Mark-to-market change (in thousands)	21	-
Market settlement value (in thousands)	$ 2,120	$ -
Natural Gas:		
Contract volumes (10,000 mmBtus)		5
Weighted average price per mmBtu	$ -	$ 6.09
Contract value (in thousands)	$ -	304
Mark-to-market change (in thousands)	-	(23)
Market settlement value (in thousands)	$ -	$ 281
NYMEX Option Contracts:		
Crude Oil- Written/Purchased Calls		
Contract volumes (1,000 bbls)	90	6
Weighted average premium received/paid	$ 2.23	$ 0.10
Contract value (in thousands)	$ 200	$ 1
Mark-to-market change (in thousands)	11	1
Market settlement value (in thousands)	$ 211	$ 2
Natural Gas-Written Calls		
Contract volumes (10,000 mmBtus)	10	
Weighted average premium received	$ 0.33	
Contract value (in thousands)	$ 33	
Mark-to-market change (in thousands)	(10)	

Market settlement value (in thousands)	$ 23

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 and the DG Marine credit facility. Our debt bears interest at the LIBOR Rate or Prime Rate, at our option, plus the applicable margin. We have not, historically hedged our interest rates. On December 31, 2008, we had $320.0 million of debt outstanding under our credit facility and $55.3 million outstanding under the DG Marine credit facility. DG Marine hedged a portion of its debt through July 2011.

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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.

Item 9A. 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.

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, 2008. 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, 2008, 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, 2008. 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 below.

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Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

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 internal control over financial reporting of Genesis Energy, L.P. and subsidiaries (the "Partnership") as of December 31, 2008, 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 maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company'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 Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2008 of the Partnership and our report dated March 11, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Partnership's adoption of new accounting standards.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2009

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Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

Our general partner manages our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. However, in connection with the Davison acquisition, our general partner has agreed to let the Davison family designate two directors through July 27, 2010 and, subsequent to that date, one director so long as it holds at least 10% of our common units. Our general partner owes a fiduciary duty to our unitholders, but our partnership agreement contains various provisions modifying and restricting the fiduciary duty. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. As of February 28, 2009 our general partner has eleven directors. Denbury, indirectly, elects all members to the board of directors of our general partner other than the Davison appointee. Currently nine members of the board of directors, which we refer to as our Board, were selected by Denbury and two were selected by the Davisons. The independence standards established by the NYSE Alternext US (formerly the American Stock Exchange) require us to have at least three independent directors on the Board. NYSE Alternext US does not require a listed limited partnership like us to have a majority of independent directors on the Board of our general partner or to establish a compensation committee or a nominating committee. Although we currently have a compensation committee, it does not satisfy the independence standards established by NYSE Alternext US, and we are not required to maintain a compensation committee in the future.

The compensation committee of our general partner oversees compensation decisions for the employees of our general partner, as well as the compensation plans of our general partner. The members of the Compensation Committee are Gareth Roberts and Susan O. Rheney, both of whom are non-employee directors of our general partner. The Compensation Committee adopted a written Compensation Committee charter that is available on our website.

In addition, our general partner has an audit committee composed of directors who meet the independence and experience standards established by NYSE Alternext US and the Securities Exchange Act of 1934, as amended. Susan O. Rheney, David C. Baggett and Martin G. White serve as the members of the audit committee. The audit committee assists the board in its oversight of the quality and integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the following responsibilities:

- has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm;
- is responsible for confirming the independence and objectivity of our independent registered public accounting firm;

- can help us resolve conflicts of interest; and
- oversees our anonymous complaint procedure established for our employees.

Our independent registered public accounting firm is given unrestricted access to the audit committee. The Board believes that Susan O. Rheney qualifies as an audit committee financial expert as such term is used in the rules and regulations of the SEC. The audit committee adopted a written Audit Committee Charter in August 2003. The full text of the Audit Committee Charter is available on our website.

In addition, the members of our Audit Committee may review specific matters that the board believes may involve conflicts of interest. When requested to by our general partner, the audit committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the audit committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE Alternext US and the Securities Exchange Act of 1934, as amended, to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the audit committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

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As is common with MLPs, we do not have any employees. All of our executive management personnel are employees of our general partner. Such personnel devote all of their time to conduct our business and affairs. The officers of our general partner manage the day-to-day affairs of our business, operate our business, and provide us with general and administrative services. We reimburse our general partner for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses.

Directors and Executive Officers of our general partner

Set forth below is certain information concerning the directors and executive officers of our general partner. All executive officers serve at the discretion of our general partner.

Name	Age	Position
Gareth Roberts	56	Director and Chairman of the Board
Grant E. Sims	53	Director and Chief Executive Officer
Mark C. Allen	40	Director
David C. Baggett	47	Director
James E. Davison	71	Director
James E. Davison, Jr.	42	Director
Ronald T. Evans	46	Director
Susan O. Rheney	49	Director
Phil Rykhoek	52	Director
J. Conley Stone	77	Director
Martin G. White	63	Director
Joseph A. Blount, Jr.	48	President and Chief Operating Officer
Robert V. Deere	54	Chief Financial Officer
Ross A. Benavides	55	Senior Vice President, General Counsel and Secretary
Karen N. Pape	50	Senior Vice President and Controller

Gareth Roberts has served as a director and chairman of the Board since May 2002. Mr. Roberts is President, Chief Executive Officer and a director of Denbury Resources Inc. and has been employed by Denbury since 1992.

Grant E. Sims has served as 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.

Mark C. Allen has served as a director of our general partner since June 2006. Mr. Allen is Vice President and Chief Accounting Officer of Denbury, and has been employed by Denbury since April 1999.

David C. Baggett has served as a director of our general partner since March 2008. Mr. Baggett is the founder and managing partner of Opportune LLP, a financial consulting firm formed in June 2005. From April 2003 until June 2005 he was a private investor. From October 1998 until April 2003, he held various positions at American Plumbing and Mechanical, including President, Chief Operating Officer, Chief Financial Officer and board member.

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.

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.

Ronald T. Evans has served as a director of our general partner since May 2002. Mr. Evans is Senior Vice President of Reservoir Engineering of Denbury and has been employed by Denbury since September 1999.

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Susan O. Rheney has served as a director of our general partner since March 2002. Ms. Rheney is a private investor and formerly was a principal of The Sterling Group, L.P., a private financial and investment organization, from 1992 to 2000. Ms. Rheney serves on the board of directors, audit committee and finance committee of CenterPoint Energy, Inc., an energy delivery company headquartered in Texas.

Phil Rykhoek has served as a director of our general partner since May 2002. Mr. Rykhoek is Chief Financial Officer, Senior Vice President, Secretary and Treasurer of Denbury, and has been employed by Denbury since 1995.

J. Conley Stone has served as a director of our general partner since January 1997. From 1987 to his retirement in 1995, he served as President, Chief Executive Officer, Chief Operating Officer and Director of Plantation Pipe Line Company, a common carrier liquid petroleum products pipeline transporter.

Martin G. White has served as a director of our general partner since March 2008. Mr. White retired in 2006 from Occidental Chemical Corporation (OxyChem) after most recently serving as Vice President of OxyChem's joint venture, OxyVinyls, a position he held since the formation of OxyVinyls in May 1999.

Joseph A. Blount, Jr. has served as President and Chief Operating Officer of our general partner since August 2006. Mr. Blount served as President and Chief Operating Officer of Unocal Midstream & Trade from March of 2000 to September of 2005. Upon the acquisition of Unocal by Chevron in September of 2005, Mr. Blount left to pursue personal interests, including investments.

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) for the last five years, and in positions of increasing responsibility with Shell for five years prior to that appointment.

Ross A. Benavides has served as General Counsel and Secretary of our general partner since December 1999. He previously also held the position of Chief Financial Officer from October 1998 until October 2008.

Karen N. Pape served as Vice President and Controller of our general partner since March 2002, and was named Senior Vice President in 2007. Ms. Pape served as Controller and as Director of Finance and Administration of our general partner since December 1996.

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, 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 the 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 Alternext US. 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 one filing that was not timely made by Mr. Martin G. White, Director, who failed to timely file a Form 4 reporting the purchase of 100 common units in September 2008. Such transaction was subsequently included on a Form 5.

Item 11. Executive Compensation

We are managed by our general partner, who employs our executive officers and employees. 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 and for the costs of health and life insurance. Our general partner has agreed that it will not seek reimbursement for compensation pursuant to the Class B Membership Interest Awards and deferred compensation awards discussed below. See "Certain Relationships and Related Transactions."

Compensation Discussion and Analysis

Compensation Committee. The compensation committee of our Board, or the Committee, consists of the chairman of the board of directors and one independent director. The Committee is responsible for making recommendations to the Board regarding compensation policies, incentive compensation policies and employee benefit plans, and recommends awards thereunder. The Committee recommends specific compensation levels for our named executive officers, or NEOs. The Committee also administers our Stock Appreciation Rights Plan, 2007 Long-Term Incentive Plan, Bonus Plan, and Severance Protection Plan. Our Board has adopted a Compensation Committee Charter setting forth the Committee’s purpose and responsibilities.

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Board Process. Following the end of the year, management reviews the compensation of all employees of our general partner, and, based on their review, the results of the Partnership as a whole, and the internal recommendations of supervisory personnel, makes a proposal to the Committee. Final review of this recommendation is made by the Committee and the Board in February. Depending on the magnitude of the anticipated changes, there may also be additional Committee meetings and discussions with management in advance of the February meeting.

Committee and Board Approval. The Committee approves all compensation and long-term awards for all executive officers, taking into consideration the recommendation of the Senior Executives (defined below) with regard to compensation for the Other Executives (defined below). The Committee also reviews and approves our overall compensation programs for all employees, taking into consideration the recommendation of management described above, and any significant changes to these programs. The Committee administers all of our compensation plans (other than our 401(k) plan, health and other fringe benefit plans), including our Bonus Plan, 2007 Long-Term Incentive Compensation Plan, and Stock Appreciation Rights Plan, under which all of our long-term equity awards are granted. The Board considers, reviews and ratifies the compensation package based on a recommendation from the Committee. Following approval of the entire compensation program in February, any applicable salary increases and/or long-term incentive are made or awarded in the first quarter of the year. Bonuses are paid in March.

Executive Officers. Our NEOs consist of our Senior Executives: Grant E. Sims, our chief executive officer, Joseph A. Blount, Jr., our president and chief operating officer and Robert V. Deere, our chief financial officer. Our Other Executives: consist of Ross A. Benavides, our senior vice president and general counsel, and Karen N. Pape, our senior vice president and controller.

Compensation Objectives and Philosophy. Our compensation programs are designed by the Committee to attract, retain, and motivate key personnel who possess the skills and qualities necessary to perform effectively in an MLP in the industries in which we operate. We pay base salaries at a level that we feel are appropriate for the skills and qualities of the individual employees based on their past performance and current responsibilities with the Partnership. The other components of employees’ compensation are consistent among employee groups and generally are proportional to base salary. We reward employees primarily for the effort and results of the Partnership as a whole, the results of the business segment, and for individual performance.

On December 31, 2008, we finalized the compensation arrangements (including underlying documentation) for our Senior Executives. These arrangements are intended to incentivize our Senior Executives to create value for our common unitholders by maintaining and increasing (over time) the distribution rate we pay on our common units.

As described in more detail below, we believe that the combination of base salaries, cash bonuses, Long-Term Incentive Plans and the Class B Membership Interests provides 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 and employees with the interests of our common unitholders and Denbury, the owner of the majority of our general partner. Our Bonus Plan is driven by the generation of available cash, which is an important metric of value for our unitholders, before reserves and bonuses, and our safety record. Our Stock Appreciation Rights Plan and 2007 Long Term Incentive Plan are linked primarily to the appreciation in our common unit price. The Class B Membership Interests have the potential to provide participation in our incentive distribution rights to our Senior Executives, as well as redemption of those rights in specified circumstances, including most events involving their termination of employment. The level of participation by our Senior Executives in the Class B Membership Interests is largely driven by the generation of available cash as well as the level of distributions we pay to our common unitholders and general partner.

Components of our Compensation Program. Two distinct compensation programs apply to our employees. The first applies to our Senior Executives, the second applies to our Other Executives and to certain other employees. The elements of the compensation program for our Senior Executives consist of:

- base salaries,
- an ability to earn a increasing share of the cash distributions attributable to the incentive distribution rights (IDRs) held by our general partner, referred to as the Class B Membership Interests below, and

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- other compensation (including reimbursement for certain self-employment taxes and other costs borne by the executive as a result of their status as members of our general partner).

The elements of our Company-wide compensation program that applies to the Other Executives and to certain other employees (excluding the Senior Executives) consist of:

- base salaries,
- annual cash bonuses (performance-based cash incentive compensation),
- a Stock Appreciation Rights Plan (however participation will cease in 2009),
- our 2007 Long Term Incentive Plans (phantom units and distribution equivalent rights),
- a Severance Protection Plan, and
- other compensation (including contributions to the 401(k) plan and annual term life insurance premiums).

The Other Executives' compensation programs are generally available to other members of our management team.

Base Salaries.

Senior Executives. On December 31, 2008, each of our Senior Executives, Messrs. Sims, Blount and Deere, entered into an employment agreement with our general partner under which he will receive an annual salary of $340,000, $300,000, and $369,600, respectively, subject to certain upward adjustments. Each senior executive's annual salary rate will be increased by (i) $30,000 if our market capitalization is at least $1.0 billion for any 90-consecutive-day period, and (ii) an additional amount equal to 10% of his then effective base salary each time our market capitalization increases by an additional $300 million. See additional disclosure in the Employment Agreements section below.

Other Executives. The Committee seeks to establish and maintain base salaries for our Other Executives at a competitive level based on several factors. These factors include our objectives, the nature and responsibility of the position (considering our size and complexity), the expertise of the individual executive, and the recommendation of the Senior Executives. In making recommendations, the Committee exercises subjective judgment using no specific weights for these factors. Base salaries are the primary part of the compensation package whereby a distinction is made for individual performance of the Other Executives.

The Other Executives received salary increases mid-year in 2007 and did not receive salary increases for 2008. For 2009, the Other Executives, Mr. Benavides and Ms. Pape, will receive a salary increase of three percent to a base salary of $234,300, and a salary increase of thirteen percent to a base salary of $225,000, respectively. For 2008, all employees other than the Senior Executives and Other Executives received average salary increases of approximately four percent. For 2009, other employees will average salary increases of approximately three percent.

The Class B Membership Interest in Our General Partner.

Senior Executives. As part of finalizing the compensation arrangements for our Senior Executives in December 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. These Class B Membership Interests compensate the holders thereof by providing rewards based on increased shares of the cash distributions attributable to our incentive distribution rights (or IDRs) to the extent we increase Cash Available Before Reserves, or CABR (defined below) (from which we pay distributions on our common units) above specified targets. CABR generally means Available Cash before Reserves, as defined in Item 7 – "Management's Discussion and Analysis" above, less Available Cash before Reserves generated from specific transactions with our general partner and its affiliates (including Denbury Resources Inc.) The Class B Membership Interests do not provide any Senior Executive with a direct interest in any assets (including our IDRs) owned by our general partner.

These arrangements are intended to incentivize our Senior Executives to create value for our common unitholders and general partner by maintaining and increasing (over time) the distribution rate to them. Each holder of a Class B Membership Interest is entitled (a) to receive from our general partner quarterly cash distributions in an amount equal to a varying percentage of the incentive distributions we make to our general partner, and (b) upon the occurrence of specified events and circumstances, to receive from our general partner a payment of cash (or, in certain circumstances, common units owned by our general partner) in redemption of such Class B Membership Interests.

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Our Board has made the following awards of Class B Membership Interests:

Senior Executive	Class B Membership Interest Percentage	Potential IDR Percentage
Grant E. Sims	38.7%	7.74%
Joseph A. Blount, Jr.	33.3	6.66
Robert V. Deere	14.0	2.80
Total Awarded	86.0	17.20
Available for Future Awards	14.0	2.80
Total	100.0%	20.00%

Our general partner is not obligated to award the remaining 14.0% of the unissued Class B Membership Interests.

The potential IDR percentage will be subject to the effects of vesting and future levels of available cash and distributions to our common unitholders and general partner, as discussed below, in determining the portion of the general partner's IDRs distributable to them.

The amount of the quarterly cash distribution, if any, a Class B Membership Interest holder is entitled to receive from our general partner will vary depending on the amount of cash we distribute in respect of our IDRs and the amount by which the growth in Cash Available before Reserves, or CABR, per common unit for an annual period ending with the current quarter exceeds specified base levels. CABR generally means Available Cash before Reserves, as defined in Item 7 – "Management's Discussion and Analysis" above, less Available Cash before Reserves generated from specific transactions with our general partner and related Denbury affiliates In other words, all other things being equal, if our Available Cash before Reserves increases on a per unit basis (other than from specific transactions with our general partner and its affiliates) above specified base levels and our distribution rate on our common units increases above specified thresholds such that our incentive distributions to our general partner increase, each Senior Executive would be entitled to receive distributions from our general partner that constitute a larger share of our general partner's IDR distributions.

Each holder will be entitled to receive a quarterly distribution in an amount equal to the product of (i) the IDR distributions made by us to our general partner and attributable to the applicable quarter, (ii) that Senior Executive's Class B Membership Interest percentage and (iii) the percentage associated with the growth in CABR per common unitt actually achieved for an annual period ending with the current quarter over specified base levels. The CABR per unit base levels, as well as the related target percentages, are set forth below. Based on the CABR per unit for the annual period ending at December 31, 2008, the percentages associated with our CABR per unit were 14% for Messrs. Sims and Blount and zero for Mr. Deere. For purposes of determining the applicable base percentage for a relevant quarter, Messrs. Sims' and Blount's base levels per unit are $0.925, and Mr. Deere's base level per unit is $1.975.

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Excess of our CABR per Unit for the relevant quarter over each Senior Executive's Base Amount per Unit:(1)	Applicable Percentage (for the relevant quarter)
Excess of $0.14 or less of CABR per Unit over Senior Executive's Base Amount per Unit	0%
Excess of $0.14 through $0.29 of CABR per Unit over Senior Executive's Base Amount per Unit	2%
Excess of $0.30 through $0.44 of CABR per Unit over Senior Executive's Base Amount per Unit	4%
Excess of $0.45 through $0.59 of CABR per Unit over Senior Executive's Base Amount per Unit	6%
Excess of $0.60 through $0.74 of CABR per Unit over Senior Executive's Base Amount per Unit	8%
Excess of $0.75 through $0.89 of CABR per Unit over Senior Executive's Base Amount per Unit	10%
Excess of $0.90 through $1.04 of CABR per Unit over Senior Executive's Base Amount per Unit	12%
Excess of $1.05 through $1.19 of CABR per Unit over Senior Executive's Base Amount per Unit	14%
Excess of $1.20 through $1.34 of CABR per Unit over Senior Executive's Base Amount per Unit	16%
Excess of $1.35 through $1.49 of CABR per Unit over Senior Executive's Base Amount per Unit	18%
Excess of $1.50 or greater of CABR per Unit over Senior Executive's Base Amount per Unit	20%

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(1) Senior Executive’s Base Amount per Unit is specified in his Class B Membership Interest Award Agreement. The base amount for Messrs. Sims and Blount is $0.925. The base amount for Mr. Deere is $1.975.

For example, our Senior Executives received the following distributions from our general partner in the first quarter of 2009 with respect to the quarter ended December 31, 2008:

Senior Executive		Distribution Amount
Grant E. Sims	$	44,595
Joseph A. Blount, Jr.		38,373
Robert V. Deere		-
Total	$	82,968

The above distributions were calculated as follows (in thousands, except per unit amounts):

		Total
Available Cash before Reserves generated for the four quarters	$	89,784
Less: Adjustment to Available Cash before Reserves relating to specific Transaction with our general partner and its affiliates		11,628
CABR for the four quarters	$	78,156
Weighted average units outstanding, including implied general partner units (1)		39,089
Adjusted annual CABR at December 31, 2008 per adjusted unit (2)	$	2.00

Base amount for Messrs. Sims and Blount		0.925
Excess of CABR per Unit over base amount	$	1.075
Applicable Percentage for Messrs. Sims and Blount for the quarter		14%

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(1) Adjusted units outstanding is calculated separately for each quarter in the annual period and applied to the CABR for the respective quarter. The calculation excludes common units issued to our general partner and its affiliates resulting from any transaction between us and our general partner and its affiliates after March 31, 2008.

(2) This amount represents the sum of the individual quarterly calculations in the annual period.

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The distribution that Mr. Sims received for the quarter is calculated as the product of (i) $823,093 (which is the amount of IDR distributions attributable to that quarter that we actually paid to our general partner) (ii) the CABR-related percentage of 14%, and (iii) Mr. Sims Class B Membership Interest of 38.7%. The calculation of Mr. Blount's distribution amount is similar to that of Mr. Sims utilizing his Class B Membership Interest of 33.3%. Mr. Deere was not entitled to a distribution for the quarter because the adjusted annual CABR per adjusted unit only exceeded his base amount of $1.975 by $0.025.

In addition, our general partner has agreed to redeem each Senior Executive's equity interest for cash (or, in specified circumstances, for common units owned by our general partner) in certain circumstances including most events involving termination of that Senior Executive's employment with our general partner or when a change of control occurs. The amount of the redemption payment will depend on the nature of the triggering event (i.e. termination with or without cause or good reason or due to death, disability or a change of control) and/or the time at which the triggering event occurs. In general, each Senior Executive will be entitled to receive a redemption amount if our general partner did not terminate his employment for cause, which redemption amount is subject to vesting as described below.

The redemption amount for each executive will be an amount equal to the vested portion of the excess, if any, of (a) the then current value of the general partner's future IDRs multiplied by the product of (i) the relevant member's Class B Membership Interest percentage and (ii) his then effective CABR-related percentage over (b) $1,007,229 for Mr. Sims, $866,685 for Mr. Blount, and zero for Mr. Deere. The determined value of our IDRs will be the present value of the annualized cash flows attributable to the IDRs at the time of the triggering event discounted at an annual interest rate equal to the average of the annualized yield of ten specified publicly-traded entities which are general partners of publicly traded master limited partnerships. The vesting percentage of each executive will be the percentage, in general, determined as of the relevant valuation date, indicated below:

(i)	termination for cause:		0%
(ii)	after a change of control; upon such Class B Member's termination for good reason; or upon a termination during the period beginning six months prior to and ending on a change of control other than termination by our general partner for cause or termination by the Class B Member without good reason:		100%
(iii)	if the Class B Member voluntarily terminates his employment other than for good reason, if termination occurs:		
	(a)	prior to the 1st anniversary of the Class B Member's award:	0%
	(b)	on or after the 1st anniversary, and prior to the 2nd anniversary, of the Class B Member's award:	25%
	(c)	on or after the 2nd anniversary, and prior to the 3rd anniversary, of the Class B Member's award:	50%
	(d)	on or after the 3rd anniversary, and prior to the 4th anniversary, of the Class B Member's award:	75%
	(e)	after the 4th anniversary of the Class B Member's award:	100%

On December 31, 2008, the redemption amount for each Class B Member was zero ($0).To the extent our general partner or any of its affiliates own any of our common units, a Class B Member may elect to receive any portion of his redemption payment in the form of such common units (in lieu of cash), the number of which would be based on the average closing price of our common units during a specified five trading day period.

In general, the holders of the Class B Membership Interests will not have any contractual rights limiting the manner in which our general partner may operate its business. For example, without obtaining the consent of any holder of the Class B Membership Interest, our general partner could sell all or any portion of our IDRs or merge, consolidate or otherwise reorganize. If our general partner sells all or any portion of our IDRs, the distribution and redemption payments due to the holders of its Class B Membership Interest will be determined based on the assets our general partner receives in exchange for such IDRs.

Our general partner has agreed that it will not seek reimbursement (on behalf of itself or its affiliates) under our partnership agreement for the costs of these Senior Executive compensation arrangements to the extent relating to their ownership of Class B Membership Interests (including current cash distributions and redemption payments made by our general partner in respect thereof) and the deferred compensation amounts. Our general partner has retained its right to (and intends to) seek reimbursement for the costs of these Senior Executive compensation arrangements to the extent relating to the employment agreements (including base salary and fringe benefits) and cash bonuses, if any, which costs will be borne by us.

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Although our general partner will not seek reimbursement for the costs of the Class B Membership Interests and deferred compensation plan arrangements, we will record non-cash expense during the four-year vesting period. The Class B Membership Interests awarded to our senior executives will be accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards will be recomputed at each measurement date and the expense to be recorded will be adjusted based on that fair value. Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value will be affected by the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. Included within the assumptions used to prepare these estimates are projections of available cash and distributions to our common unitholders and general partner, including an assumed level of growth and the effects of future new growth projects during the four-year vesting period. At December 31, 2008, Management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date is approximately $12 million. The fair value of these incentive awards will be recomputed each quarter beginning with the quarter ending March 31, 2009 through the final settlement of the awards. Compensation expense of $3.4 million was recorded in the fourth quarter of 2007 related to the previous arrangements between our general partner and our Senior Executives. The fair value to be recorded by us as compensation expense will be the excess of the recomputed estimated fair value over the previously recorded $3.4 million. Due to the vesting conditions for the awards, the amount to which the Senior Executives were entitled on December 31, 2008 for the Class B Membership Awards and the related deferred compensation was zero. Management's estimates of fair value are made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at December 31, 2008.

Other Executives. Only our Senior Executives may hold Class B Membership Interests.

Bonuses and Deferred Compensation Awards.

Senior Executives. In connection with the Senior Executives' compensation agreements, we paid a bonus to each of Messrs. Sims and Blount of $107,751 and $97,599, respectively, in December 2008.

Additionally, our general partner adopted an unfunded, nonqualified deferred compensation plan and made awards under that plan to Messrs. Sims and Blount in a maximum amount of $1,007,229 and $866,685, respectively.

Our deferred compensation plan provides Messrs. Sims and Blount with incentive compensation that is deferred until after such participant's separation from service with our general partner. Under that plan, Messrs. Sims and Blount were awarded a maximum deferred compensation amount equal to the lesser of $1,007,229 for Mr. Sims and $866,685 for Mr. Blount, or the value of such participant's Class B Membership Interest on the date such interest is valued for purposes of determining the redemption amount. In general, each participant will be entitled to receive his deferred compensation award to the same extent he will be entitled to receive a payment in respect of the redemption of his Class B Membership Interest, subject to the same general vesting requirements summarized above regarding each executive's redemption amount.

Like the redemption payment, a participant may elect to receive his deferred compensation payment in the form of our common units (in lieu of cash) to the extent our general partner or any of its affiliates own any of our common units.

Bonus Plan for Other Executives and other employees. In January 2009, the Committee of the Board of our general partner approved a bonus program, referred to below as the "Bonus Plan," for all employees of our general partner that is applicable to 2008. The Senior Executives are excluded from participation in the Bonus Plan. The Bonus Plan is paid at the discretion of our Board based on the recommendation of the Committee, and can be amended or changed at any time. Since the determination of whether bonuses will be paid each year and in what amounts is determined by the Committee on a company-wide basis, the Other Executives only receive bonuses if other employees receive bonuses.

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The Bonus Plan is based primarily on the amount of money we generate for distributions to our unitholders, and is measured on a calendar-year basis. For 2008, two metrics are 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 generate and our company-wide safety record improvement. The level of Available Cash before Reserves generated for the year as a percentage of a target set by our Committee is weighted ninety percent and the achieved level of the targeted improvement in our safety record is weighted ten percent. The sum of the weighted percentage achievement of these targets is multiplied by the eligible compensation and the target percentages established by our Committee for the various levels of our employees to determine the maximum general bonus pool.

The general bonus pool will be distributed as follows:

- Each eligible employee will be eligible to receive a bonus after the end of the year up to a specified percentage of their year-to-date gross wages. Certain compensation, such as awards under our Stock Appreciation Rights Plan, car allowances and relocation expenses, will be excluded from the calculation. Each employee must be a regular, full-time active employee, not on probation, at the time the bonus is paid in order to be eligible to receive a bonus. The date of payment of the bonuses is at the discretion of management, but is expected to be before March 15 each year.

- There are five levels of participation in the Bonus Plan. Employees in each level will be eligible for a bonus each year in accordance with the following table. The determination of what level applies to each employee will be made by the Committee based on the recommendation of the Senior Executives.

- The percentage of adjusted year-to-date gross wages paid as a bonus will be a function of the general bonus pool available and the employee's Participation Level in the Bonus Plan. The bonus amount each employee will be eligible to receive will be determined in accordance with the table shown below. The bonus may be adjusted up or down to reflect business unit contribution and individual performance. These adjustments are discretionary and will be determined by the Senior Executives with approval by the Committee.

Bonus Targets	Job Classifications
0 - 10%	Operations and administrative clerical personnel
0 - 20%	Professional/supervisory personnel
0 - 25%	Senior professionals/management personnel
0 - 50%	Senior management/executive personnel
0 - 100%	Key executive personnel, including the Other Executives

A separate marketing bonus pool is available for compensating certain marketing personnel that is based on the contribution of that group to Available Cash before Reserves. A minimum level of contribution to Available Cash before Reserves is required before any amounts are allocated to the marketing bonus pool. Our Other Executives do not participate in this pool.

The Bonus Plan is designed to enhance our financial performance by rewarding employees for achieving financial performance and safety objectives. Since 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, we believe the Bonus Plan is designed to reward employees on a basis that is aligned with the interests of the unitholders. We believe that this generates a bonus that represents a meaningful level of compensation for the employee population and that encourages employees to operate as a unified team to generate results that are aligned with the interests of the unitholders. By including safety improvement in the calculation of the Bonus Pool, we encourage our employees to focus on the impact their job performance has on the environment in which we operate.

For 2008, the Committee established a target of approximately $81 million for Available Cash before Reserves and before bonus expense and related employer tax burdens, with a hurdle rate of 105%. We achieved 117% of the target which exceeded the target level set at the beginning of the 2008 for Available Cash before Reserves. We did not achieve our safety incident rate goal for 2008. As a result, the Bonus Pool for 2008 bonuses to be paid in March 2009 was calculated as 90% of 117% divided by 105%, or 100%. In accordance with the Bonus Plan, the total pool available for bonuses for 2008 was $5.1 million. Our Committee approved bonuses totaling $4.5 million, which represents approximately 15.5 percent of total eligible compensation. These bonuses were paid in March 2009.

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Long-Term Incentive Compensation and Stock Appreciation Rights.

The 2007 Long-Term Incentive Compensation Plan (2007 LTIP).

Senior Executives. Our Senior Executives are not eligible and do not participate in our 2007 LTIP.

Non-Employee Directors, Other Executives and other Employees. Our unitholders approved a Long-Term Incentive Plan on December 18, 2007 which provides for awards of Phantom Units and Distribution Equivalent Rights to our non-employee directors and employees. Phantom units are notional units representing unfunded and unsecured promises to deliver a common unit to the participant should specified vesting requirements be met. Distribution Equivalent Rights are rights to receive an amount of cash equal to all or a portion of the cash distributions made by us during a specified period. The 2007 LTIP is administered by the Committee. Subject to adjustment as provided in the 2007 LTIP, awards with respect to up to an aggregate of 1,000,000 units may be granted under the 2007 LTIP.

The 2007 LTIP is intended to provide a means whereby employees and directors providing services to us may develop a sense of proprietorship and personal involvement in our development and financial success through the award of phantom units, and/or distribution equivalent rights; and the 2007 LTIP allows for various forms of equity or equity-based awards, providing flexible incentives to employees and directors.

The Committee (at its discretion) will designate participants in the 2007 LTIP, determine the types of awards to grant to participants, determine the number of units to be covered by any award, and determine the conditions and terms of any award including vesting, settlement and forfeiture conditions. The 2007 LTIP may be amended or terminated at any time by the Board or the Committee; however, any material amendment, such as a material increase in the number of units available under the 2007 LTIP or a change in the types of awards available under the 2007 LTIP, will also require the approval of our unitholders. The Committee is also authorized to make adjustments to the terms and conditions of and the criteria included in awards under the plan in specified circumstances. The 2007 LTIP is effective until December 18, 2017 or, if earlier, the time which all available units under the 2007 LTIP have been delivered to participants or the time of termination of the plan by the Board or the Committee.

In February 2009, the Committee approved awards granting phantom units with a total value (assuming a market price of $13 per common unit) as of February 26, 2009 of $0.6 million (47,601 phantom units) to 17 employees of our general partner. Grants were made to Mr. Benavides and Ms. Pape with values in amounts of $113,800 (8,750 phantom units) and $100,000 (7,692 phantom units) respectively, or approximately 50 percent of their base salaries. The amounts awarded were entirely discretionary and were based on the recommendation of the Senior Executives to the Committee.

Additionally, the Committee awarded each non-employee director an award of 3,500 phantom units on February 26, 2009.

Stock Appreciation Rights Plan.

Other Executives and employees. In December 2003, the Board approved a Stock Appreciation Rights plan or SAR plan. Under the terms of this plan, regular, full-time active employees and the members of the Board, excluding the Senior Executives, are eligible to participate in the plan. The plan is administered by the Committee, who shall determine, in its full discretion, the number of rights to award, the grant date of the rights and the formula for allocating rights to the participants and the strike price of the rights awarded.

Beginning in 2009, rights will be awarded to our professional/supervisory personnel, senior professional/managerial personnel and senior management/executive personnel. Our Senior Executives and key executive personnel, including our Other Executives, as well as our directors, will no longer receive awards under the Stock Appreciation Rights plan. Our operations and administrative clerical personnel will also no longer participate in this plan.

In February 2008, awards of rights were made to all personnel including our Other Executives. Grants of SARs were made to all personnel in February 2008 totaling 500,983 units. This grant included the personnel of the Davison entities, who received initial grants in 2008 totaling 387,512 SARs in individual allocations similar to what they would have received had they been employed in 2003, and 113,471 SARs to the personnel employed in the operations we owned prior to the Davison acquisition. The total SARs allocated to the employees of the legacy operations was approximately the same number of SARs awarded at the end of 2006. Mr. Benavides and Ms. Pape received grants at February 14, 2008 of 5,448 and 4,790 rights, respectively. The number of SARs allocated to these individuals was a product of the total 113,471 and the ratio of the maximum bonus for Mr. Benavides and Ms. Pape under the Bonus Plan in effect in 2007 to the total of the maximum bonuses for all employees who participated in the Bonus Plan in 2007.

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The exercise price of the annual awards of rights has been the average of the closing market price of our units for the ten days prior to the date of the grant. This methodology has been used by the Committee for annual grants so that the exercise price is not unduly influenced by trading of our units on one particular date. The volume of units that trade each day is frequently small, such that one or a few small trade can have a significant influence on the price. Additionally, we may see unusual trading occur in the late months of the year at prices that do not necessarily correspond to the latest market prices. For 2009, we will adjust the exercise price to reflect a more accurate representation of the unit value in the current market environment, but not below the closing price of our common units on the grant date. This methodology is subject to change for any grant in the future. Additional details describing the operation of the SAR plan are included below.

Other Compensation and Benefits.

Severance Benefits. We believe that companies should provide reasonable severance benefits to employees. With respect to our Other Executives, these severance benefits should reflect the fact that it may be difficult for employees to find comparable employment within a short period of time. Although we typically pay severance when we terminate any employee unless such termination is for “cause”, we do not have any pre-defined severance benefits for our Other Executives, except in the case of a change in control, a plan adopted in June 2005. This plan is described under “Change of Control” below.

Other Benefits. Each Senior Executive is entitled to vacation, medical and health coverage, and similar fringe benefits received by the Other Executives; provided; however, that none of our Senior Executives will be eligible to participate in our general partner’s Stock Appreciation Rights Plan, Severance Protection Plan, or 2007 Long-Term Incentive Plan. Our Senior Executives and Other Executives participate in our benefit plans on the same terms as our other employees. These plans include medical, dental, disability and life insurance, and matching and profit-sharing contributions to our 401(k) plan. We match up to 100 percent of the first three percent that the participant contributes to the 401(k) plan and 50 percent of the next three percent contributed. Additionally, we make a contribution to our 401(k) plan in the amount of three percent as a profit-sharing contribution to our 401(k) for each eligible employee. As reflected in the Summary Compensation Table, the cost to Genesis of the 401(k) matching contributions and profit-sharing contributions and term life premiums aggregated $69,331 in 2008 for our Senior Executives and Other Executives. As a result of their status as Class B Members in our general partner, our Senior Executives will be reimbursed for the additional taxes they will owe individually related to certain benefits they receive from us including medical, dental, disability and life insurance, and matching and profit-sharing contributions to our 401(k) plan, as well as the self-employment taxes they will owe. These reimbursements will begin in 2009.

Our only retirement benefits are our 401(k) plan and a retirement vesting provision included in our Stock Appreciation Rights Plan. We do not have any pension plans or post-retirement medical benefits.

Compensation Committee Report

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 of the Exchange Act.

The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis included above. Based on the review and discussions, the Compensation Committee approved that the Compensation Discussion and Analysis be included in this Form 10-K.

This report is submitted by the Compensation Committee.

Gareth Roberts (Chairman)
Susan O. Rheney

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Executive Compensation

2008 SUMMARY COMPENSATION TABLE

The following table summarizes certain information regarding the compensation paid or accrued by Genesis during 2008 to those persons who served as NEOs at the end of 2008.

2008 Summary Compensation Table

Name & Principal Position	Year	Salary ($)	Bonus (1) ($)	Stock Awards (2) ($)	Option Awards (3) ($)	Non-Equity Incentive Plan Compen- sation (4) ($)	All Other Compen- sation (5) ($)	Total ($)
Grant E. Sims (6)	2008	310,000	107,751	-	-	-	9,834	427,585
Chief Executive Officer	2007	310,000	-	-	-	-	1,838,476	2,148,476
(Principal Executive Officer)	2006	112,077	-	-	-	-	56	112,133
Joseph A. Blount, Jr. (6)	2008	270,000	97,599	-	-	-	19,936	387,535
President & Chief Operating	2007	270,000	-	-	-	-	1,618,984	1,888,984
Officer	2006	97,615	-	-	-	-	4,449	102,064
Robert V. Deere (7) (8)	2008	89,557	-	-	-	-	621	90,178
Chief Financial Officer (Principal Financial Officer)								
Ross A. Benavides (8)	2008	227,500	170,000	65,638	(215,195)	-	19,584	267,527
Senior Vice President and	2007	211,000	68,250	2,511	100,448	111,581	16,680	510,470
General Counsel	2006	195,000	-	-	101,231	78,000	16,668	390,899
Karen N. Pape	2008	200,000	180,000	58,341	(164,728)	-	19,356	292,969
Senior Vice President &	2007	184,000	52,500	2,232	77,139	94,577	16,680	427,128
Controller	2006	150,000	-	-	77,430	60,000	15,032	302,462
(Principal								

Accounting Officer)

(1) Amounts in this column represent for Mr. Sims and Mr. Blount represent the amount that was paid as a bonus at the time of execution of their employment agreements. Amounts in this column for Mr. Benavides and Ms. Pape for 2008 represent bonuses paid in March 2009 relative to 2008 under our bonus program that was effective for 2008. Amounts in this column for Mr. Benavides and Ms. Pape in 2007 represent the amount that was paid as a retention bonus in September 2007.

(2) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for the period under the provisions of SFAS 123(R) for awards of phantom units under our 2007 LTIP. The forfeiture rate that was applied to these awards at December 31, 2008 and 2007 was zero.

(3) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for in each period under the provisions of SFAS 123(R) for awards under our Stock Appreciation Rights plan. The forfeiture rate that was applied to these amounts in each year was 10%. Because of the decline in our common unit market price and the effects of that decline on the fair value of outstanding stock appreciation rights, we recorded a reduction in the liability for these awards in 2008. These reductions are reflected as negative amounts in the table above.

(4) Amounts in this column represent the amount that will be paid to the Named Executive Officer as an award under our Bonus Plan. Messrs. Sims, Blount and Deere do not participate in the Bonus Plan.

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

(6) Mr. Sims and Mr. Blount were employed by our general partner effective August 6, 2006.

(7) Mr. Deere was employed by our general partner effective October 6, 2008.

(8) Mr. Deere served as Chief Financial Officer from October 2008 to the present. Mr. Benavides served as Chief Financial Officer from January to October 2008.

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Name	Year	401(k) Matching Contributions (a)	401(k) Profit-Sharing Contributions (b)	Insurance Premiums (c)	Other Compensation (d)	Totals
Grant E. Sims	2008	$ -	$ 7,350	$ 2,484	$ -	$ 9,834
	2007	$ -	$ 6,600	$ 180	$ 1,831,696	$ 1,838,476
	2006	$ -	$ -	$ 56	$ -	$ 56
Joseph A. Blount, Jr.	2008	$ 10,350	$ 7,350	$ 2,236	$ -	$ 19,936
	2007	$ 9,900	$ 6,600	$ 180	$ 1,602,304	$ 1,618,984
	2006	$ 4,393	$ -	$ 56	$ -	$ 4,449
Robert V. Deere	2008	$ -	$ -	$ 621	$ -	$ 621
Ross A. Benavides	2008	$ 10,350	$ 7,350	$ 1,884	$ -	$ 19,584
	2007	$ 9,900	$ 6,600	$ 180	$ -	$ 16,680
	2006	$ 9,900	$ 6,600	$ 168	$ -	$ 16,668
Karen N. Pape	2008	$ 10,350	$ 7,350	$ 1,656	$ -	$ 19,356
	2007	$ 9,900	$ 6,600	$ 180	$ -	$ 16,680
	2006	$ 8,264	$ 6,600	$ 168	$ -	$ 15,032

Amounts in this table represent:

(a) Matching contributions by Genesis to our 401(k) plan on each NEO's behalf.

(b) Profit-sharing contributions by Genesis to our 401(k) plan on each NEO's behalf.

(c) Term life insurance premiums paid by Genesis on each NEO's behalf.

(d) Represents an amount for the estimated value of the compensation earned in 2007 under the proposed arrangements between the Senior Executive and our general partner that existed at that time. Beginning in 2009, the fair value of the awards of the Class B Membership Interests and the deferred compensation awards, less these previously recorded amounts, will be recorded as non-cash compensation expense over their four-year vesting period, and adjusted quarterly until final settlement. The expense recorded for this arrangement in 2007 was an amount agreed to by the parties as a fair representation of the value provided and earned in 2007. While our general partner will bear the cash cost of the Class B Membership Interests and the deferred compensation awards to our Senior Executives, the expense will be recognized as compensation by us and as a capital contribution by our general partner, as the purpose of the Senior Executive compensation arrangements is to incentivize these individuals to grow the partnership.

Employment Agreements.

On December 31, 2008, each of our Senior Executives, Messrs. Sims, Blount and Deere, entered into an employment agreement with our general partner under which he will receive an annual salary of $340,000, $300,000, and $369,600, respectively, subject to certain upward adjustments. Each senior executive's annual salary rate will be increased by (i) $30,000 if our market capitalization is at least $1.0 billion for any 90-consecutive-day period, and (ii) an additional amount equal to 10% of his then effective base salary each time our market capitalization increases by an additional $300 million.

Under his employment agreement, each Senior Executive will be entitled to specified severance benefits under certain circumstances. No Senior Executive will be entitled to severance benefits if our general partner terminates him for cause. Each Senior Executive (or family) will 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 a Senior Executive (other than for cause) within two years after a change of control, he will be entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through the later of December 31, 2012 or three years from his date of termination.

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Each employment agreement contains customary non-solicitation and non-competition provisions that prohibit our Senior Executives from competing with us after termination, including working for, supervising, assisting, or participating in any competing business (as defined in the employment agreements) 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 for cause or without good reason, and for a period of one year after termination if the employment agreement is terminated other than by our general partner for cause or by the Senior Executive without good reason.

Either our general partner or a Senior Executive may terminate his agreement at any time subject to the economic consequences resulting from such termination. For example, if a Senior Executive terminates his employment agreement prior to December 31, 2012 other than for good reason, he will not receive any severance payments or continuing fringe benefits under his employment agreement, and he will effectively forfeit his Class B Membership Interest and his deferred compensation award. On the other hand, if our general partner terminates a Senior Executive's employment prior to that date without cause or due to a disability, or if that Senior Executive terminates his employment for good reason, of if our general partner terminates a Senior Executive's employment without cause within two years after a change of control, that Senior Executive will be entitled to receive a severance payment and continuing fringe benefits under his employment agreement, as well as a payment of the redemption amount (if any) in redemption of his Class B Membership Interest.

Change in Control and Other Termination Payments.

Senior Executives. Based upon a hypothetical termination date of December 31, 2008, the change in control termination benefits for our Senior Executives would have been as follows:

	Grant E. Sims	Joseph A. Blount, Jr.	Robert V. Deere
Severance payment pursuant to employment agreement	$ 1,020,000	$ 900,000	$ 1,108,800
Healthcare and other insurance benefits	23,238	23,238	23,238
Class B Membership Interest and deferred compensation (1)	4,609,185	3,966,043	1,667,405
Total	$ 5,652,423	$ 4,889,281	$ 2,799,443

(1) Upon termination due to a change in control, each Senior Executive will be entitled to his deferred compensation amount, if any, and redemption of his Class B Membership Interest. Such payment will be paid no later than sixty days after our general partner receives its distribution payment from us for the quarter ended September 30, 2010, and will be based on the IDR payment for such quarter. Additionally each Senior Executive will be entitled to continue to receive a share of the quarterly IDR payment our general partner receives from us through the quarter ended September 30, 2010. These amounts will be computed assuming that each Senior Executive's CABR-related percentage is no less than 16%. The amounts in this table represent management's estimates of the amount each Senior Executive would receive using assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the September 30, 2010 and estimates of the future amount of incentive distributions we will pay to our general partner related to quarters through September 30, 2010. Additionally our estimate of the redemption of the Class B Membership Interests assumes that the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships will be the same as the average at December 31, 2008.

Based upon a hypothetical termination date of December 31, 2008, the termination benefits for our Senior Executives for voluntary termination or termination for cause would be zero. Based upon a hypothetical termination date of December 31, 2008, the termination benefits for our Senior Executives for termination without cause or for good reason, including death or disability would have been:

	Grant E. Sims	Joseph A. Blount, Jr.	Robert V. Deere
Severance payment pursuant to employment agreement	$ 1,020,000	$ 900,000	$ 1,108,800
Healthcare and other insurance benefits	23,238	23,238	23,238
Class B Membership Interest and deferred compensation (1)	3,456,888	2,974,532	-
Total	$ 4,500,126	$ 3,897,770	$ 1,132,038

(1) As with a termination for a change in control, termination without cause or for good reason would entitle each Senior Executive to his deferred compensation amount, if any, and redemption of his Class B Membership Interest. The termination payment would be paid no later than sixty days after our general partner receives its distribution payment from us for the quarter ended September 30, 2010, and will be based on the IDR payment for such quarter. Additionally each Senior Executive will be entitled to continue to receive a share of the quarterly IDR payment our general partner receives from us through the quarter ended September 30, 2010. The difference from a termination for a change in control is that these amounts will be computed utilizing each Senior Executive's CABR-related percentage at the date of termination. The amounts in this table were calculated similarly to the amounts for a change in control, except the CABR-related percentages were 12% for Messrs. Sims and Blount and zero for Mr. Deere at December 31, 2008.

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Other Executives. Based upon a hypothetical termination date of December 31, 2008, the change in control termination benefits for our Other Executives would have been as follows (based on the closing price for our units of $8.69 at that time):

	Ross A. Benavides	Karen N. Pape
Severance plan payment	$ 1,069,247	$ 910,616
Healthcare and other insurance benefits	12,751	12,322
Fair market value of stock appreciation rights	-	-
Fair market value of phantom units	79,739	70,876
Total	$ 1,161,737	$ 993,814

It is our belief that the interests of unitholders will best be served if the interests of our Other Executives are aligned with theirs. Providing change of control benefits should eliminate, or at least reduce, the reluctance of management to pursue potential change of control transactions that may be in the best interests of our unitholders.

We have two benefits for our employees and Other Executives in the event of a change of control: (i) our cash Severance Protection Plan, and (ii) vesting of SARs. Under the terms of our Severance Protection Plan, an employee is entitled to receive a severance payment if a change of control occurs and the employee is terminated within two years of that change (i.e. a "double trigger" award). The Severance Protection Plan will not apply to any employee who is terminated for cause or by an employee's own decision for other than good reason (e.g., change of job status or a required move of more than 25 miles). If entitled to severance payments under the terms of the Severance Protection Plan, Mr. Benavides and Ms. Pape will receive three times the sum of their annual salary and the average of their bonus amounts in the last twenty-four months, certain other members of management will receive two times the sum of their annual salary and the average of their bonus amounts in the last twenty-four months, and all other employees will receive between one-third to one and one-half times the sum of their annual salary and the average of their bonus amounts in the last twenty-four months depending upon their salary level and length of service with us. All employees will also receive medical and dental reimbursement benefits for one-half the number of months for which they receive severance benefits.

A change in control is defined in the Severance Protection Plan. Generally, a change in control is a change in the control of Denbury, a disposition by Denbury of more than 50% of our general partner, or a transaction involving the disposition of substantially all of our assets.

The Severance Protection Plan also provides that if our Other Executives are subject to the "parachute payment" excise tax under IRC Section 4999, then we will pay the employee under the severance plan an additional amount to "gross up" the severance payment so that the employee will receive the full amount due under the terms of the severance plan after payment of the excise tax.

If a participant in our SAR Plan is terminated within one year of a change in control, all SARs would immediately vest.

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Other Compensation

Long Term Incentive Plan

As discussed in the Compensation Discussion and Analysis, our unitholders approved the Genesis Energy, Inc. 2007 Long Term Incentive Plan, or 2007 LTIP, on December 18, 2007 which provides for awards of Phantom Units and Distribution Equivalent Rights to non-employee directors and employees of Genesis Energy, LLC, our general partner. Phantom Units are notional units representing unfunded and unsecured promises to deliver a common unit to the participant should specified vesting requirements be met. Distribution Equivalent Rights are rights to receive an amount of cash equal to all or a portion of the cash distributions made by us during a specified period. The 2007 LTIP will be administered by the Committee. Subject to adjustment as provided in the 2007 LTIP, awards with respect to up to an aggregate of 1,000,000 units may be granted under the 2007 LTIP.

The Committee (at its discretion) will designate participants in the 2007 LTIP, determine the types of awards to grant to participants, determine the number of units to be covered by any award, and determine the conditions and terms of any award including vesting, settlement and forfeiture conditions. The 2007 LTIP may be amended or terminated at any time by the Board or the Committee; however, any material amendment, such as a material increase in the number of units available under the 2007 LTIP or a change in the types of awards available under the 2007 LTIP, will also require the approval of our unitholders. The Committee is also authorized to make adjustments in the terms and conditions of and the criteria included in awards under the plan in specified circumstances. The 2007 LTIP is effective until December 18, 2017 or, if earlier, the time which all available units under the 2007 LTIP have been delivered to participants or the time of termination of the plan by the Board or the Committee.

Stock Appreciation Rights Plan

As discussed in the Compensation Discussion and Analysis, we have a Stock Appreciation Rights plan, or SAR, for our employees. Our Senior Executives do not participate in this plan and, beginning in 2009, our Other Executives, certain key employees and the Board will no longer receive awards under this plan. Under the terms of this plan, certain employees are eligible to participate in the plan. The plan is administered by the Committee, who shall determine, in its full discretion, the number of rights to award, the grant date of the rights, the vesting period of the rights awarded 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. 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 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 to receive a cash payment equal to 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. The cash payment to the participant will be net of any applicable withholding taxes required by law. If the Committee determines, in its full discretion, that it would cause significant financial harm to us to make cash payments to participants who have exercised rights under the plan, then the 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 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.

Bonus Program

As discussed in the Compensation Disclosure and Analysis, we have a bonus program for all eligible employees of our general partner, with the exception of our Senior Executives. This program provides for our Other Executives to receive bonuses annually at the discretion of our Board based on the recommendation of the Committee. A bonus pool is determined based on our achieving certain levels of Available Cash before Reserves and bonus expense and the improvement in our safety record. Each eligible employee will be eligible to receive a bonus; however, the actual amounts paid will be determined by the Senior Executives with the approval of the Committee. The total paid for 2008 bonuses was $4.5 million.

GRANTS OF PLAN BASED AWARDS IN FISCAL YEAR 2008

The following tables show the non-equity incentive plan awards granted to the Other Executives for 2008 and the outstanding SARs and phantom units awards at December 31, 2008 that were issued to our Other Executives. Information on rights granted to non-employee directors is included in the section entitled Director Compensation. These tables do not include the phantom unit awards made to Mr. Benavides and Ms. Pape in February 2009 of 8,750 and 7,692, respectively.

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Grants of Plan-Based Awards in Fiscal Year 2008

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#) (1)	Exercise or Base Price of Option Awards ($/Sh) (2)	Market Price of Common Units on Award Date (3)	Grant Date Fair Value of Stock and Option Awards
Grant E. Sims	12/31/2008				$ 6,225,068(4)
Joseph A. Blount, Jr.	12/31/2008				$ 5,356,454(4)
Robert V. Deere	12/31/2008				$ 429,222(4)
Ross A. Benavides	2/14/2008	5,448	$ 20.92	$ 21.19	$ 22,031(5)
Karen N. Pape	2/14/2008	4,790	$ 20.92	$ 21.19	$ 19,370(5)

(1) The amounts in this column represent stock appreciation rights granted to the named Executive Officer during 2008.

(2) We accrue for the fair value of our liability for the SARs we have issued to our employees and directors under the provisions of SFAS No. 123(R), Share-Based Payments, as amended and interpreted. These provisions require us to make estimates that affect the determination of the fair value of the outstanding stock appreciation rights, including estimates of the expected life of the rights, expected forfeiture rates of the rights, expected future volatility of our unit price and expected future distribution yield on our units. We base our estimates of these factors on historical experience and internal data. A summary of the assumptions used for the valuation at December 31, 2008 is included in Note 15 of the Notes to our Consolidated Financial Statements. The actual timing and amounts of payments to employees that will ultimately be made under the SAR plan will most likely differ from the estimates that are used in determining fair value. Since the value of our common units is affected more by actual cash distributions and Available Cash and expectations for growth of our business, which factors are not fully contemplated under the methodology of SFAS 123(R), our Committee does not consider the accounting method for the SAR plan in determining the amount of SARs to grant our employees.

(3) For the awards granted on February 14, 2008, the exercise price represents the average of the closing market price of our units for the ten days preceding February 14, 2008. The closing market price for our units on February 14, 2008 was $21.19.

(4) Amount represents management’s estimate of the fair value of the Class B Membership award and deferred compensation award granted on December 31, 2008 to the NEO. See a description of these awards at “The Class B Membership Interest in Our General Partner” above in “Compensation Discussion and Analysis.” This fair value was estimated under the methodology of SFAS 123(R) and will be recorded as non-cash compensation expense during the four-year vesting period that begins in 2009. Subsequent to the vesting period, the previously recorded

compensation expense will be adjusted to fair value at each reporting date.

(5) The amounts in this column represent the fair value of the award on the date of the grant, February 14, 2008, as calculated in accordance with the provisions of SFAS 123(R).

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The compensation described in the table above for our Senior Executives is a result of finalizing their compensation arrangements (including the underlying documentation) in December 2008. These arrangements are intended to incentivize our Senior Executives to create value for our common unitholders and general partnerby maintaining and increasing (over time) the distribution rate we pay to them. Our Senior Executives, including Mr. Deere, will be rewarded based on whether the shares of the cash distributions attributable to our incentive distribution rights (or IDRs) increase, which is based upon the extent to which we increase Cash Available Before Reserves, or CABR (defined below) per unit and cash distributions. CABR generally means Available Cash before Reserves, as defined in Item 7 – "Management's Discussion and Analysis" above, less Available Cash before Reserves generated from specific transactions with our general partner and other Denbury affiliates. These specific transactions include the Free State Pipeline, the NEJD Pipeline, and any future transactions.

In summary, each of our Senior Executives has received an equity interest in our general partner (Class B Membership Interest) and is entitled to receive a base salary and to participation in our customary fringe benefits, such as health, medical and severance benefits, with reimbursement of taxes for the effects of the receipt of the base salary and fringe benefits as a member in the general partner rather than as an employee. Messrs. Sims and Blount also received awards under a deferred compensation plan. The Class B Membership Interests awarded to our senior executives will be accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards will be recomputed at each measurement date and the expense to be recorded will be adjusted based on that fair value. Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value will be affected by the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. Included within the assumptions used to prepare these estimates are projections of available cash and distributions to our common unitholders and general partner, including an assumed level of growth and the effects of future new growth projects during the four-year vesting period. At December 31, 2008, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date is approximately $12 million. The fair value of these incentive awards will be recomputed each quarter beginning with the quarter ending March 31, 2009 through the final settlement of the awards. Compensation expense of $3.4 million was recorded in the fourth quarter of 2007 related to the previous arrangements between our general partner and our Senior Executives. The fair value to be recorded by us as compensation expense will be the excess of the recomputed estimated fair value over the previously recorded $3.4 million. Due to the vesting conditions for the awards, the amount to which the Senior Executives were entitled on December 31, 2008 for the Class B Membership Awards and the related deferred compensation was zero. Management's estimates of fair value are made in order to record non-cash compensation expense over the vesting period, and do not represent necessarily contractual amounts payable under these awards at December 31, 2008. This expense will be recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions will change the amount of compensation cost we record. Changes in these assumptions would not, however, affect our Available Cash before Reserves, as the cash cost of the Class B Membership Interests will be borne by Denbury.

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OUTSTANDING EQUITY AWARDS AT 2008 FISCAL YEAR-END

The following table presents information regarding the outstanding equity awards to our Other Executives at December 31, 2008.

Outstanding Equity Awards at 2008 Fiscal Year-End

	Stock Appreciation Rights				Stock Awards		
Name	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable (1)	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date	Number of Phantom Units That Have Not Vested (#) (2)	Market Value of Phantom Units That Have Not Vested ($)	Fair Value of Class B Membership Interests That Have Not Vested (3)
Grant E. Sims							$ 6,225,068
Joseph A. Blount, Jr.							$ 5,356,454
Robert V. Deere							$ 429,222
Ross A. Benavides	15,889		$ 9.26	12/31/2013			
		3,777	$ 12.48	12/31/2014			
		4,015	$ 11.17	12/31/2015			
		1,003	$ 16.95	8/29/2016			
		5,270	$ 19.57	12/29/2016			
		5,448	$ 20.92	2/14/2018			
					9,176	$ 79,739	
Karen N. Pape	12,153		$ 9.26	12/31/2013			
		2,889	$ 12.48	12/31/2014			
		3,071	$ 11.17	12/31/2015			
		767	$ 16.95	8/29/2016			
		4,254	$ 19.57	12/29/2016			
		4,790	$ 20.92	2/14/2018			
					8,156	$ 70,876	

(1) The unexercisable rights of each named executive officer vest on the following dates in the order they are listed: January 1, 2009, January 1, 2010, January 1, 2010, December 31, 2010 and February 14, 2012.

(2) These phantom units vest on December 18, 2010.

(3) Amount represents management's estimate of the fair value of the Class B Membership award and deferred compensation award granted on December 31, 2008 to the NEO. See a description of these awards at "The Class B Membership Interest in Our General Partner" above in "Compensation Discussion and Analysis." This fair value was estimated under the methodology of SFAS 123(R) and will be recorded as non-cash compensation expense during the four-year vesting period that begins in 2009. Subsequent to the vesting period, the previously recorded compensation expense will be adjusted to fair value at each reporting date.

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DIRECTOR COMPENSATION FOR FISCAL YEAR 2008

The table below reflects compensation for the directors. Directors who are employees of our general partner, like Mr. Sims, do not receive compensation for service as a director. During 2008, compensation for the independent and Davison directors consisted of an annual fee of $40,000. The Audit Committee Chairman received an additional annual fee of $10,000. Audit Committee members received an additional annual fee of $2,500. We paid Denbury fees totaling $160,000 for providing four of its executives as directors of Genesis. Additionally, non-employee directors received a fee for attendance at meetings of $2,000 for each meeting attended in person and $1,000 for meetings attended telephonically. This fee was applicable to meetings of the Board and committee meetings, however only one meeting fee could be earned per day. Meeting fees for the four executives provided by Denbury as directors totaling $35,000 were paid to Denbury.

Director Compensation in Fiscal 2008

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($) (2)	Option Awards ($) (3)	Total
Mark C. Allen (4)	$ 50,000	$ 26,805	$ (9,692)	$ 67,113
David C. Baggett, Jr.	$ 49,250	$ 26,805	$ -	$ 76,055
James E. Davison	$ 50,000	$ 26,805	$ 165	$ 76,970
James E. Davison, Jr.	$ 51,000	$ 26,805	$ 165	$ 77,970
Ronald T. Evans (4)	$ 50,000	$ 26,805	$ (34,691)	$ 42,114
Susan O. Rheney	$ 73,000	$ 26,805	$ (45,964)	$ 53,841
Gareth Roberts (4)	$ 45,000	$ 26,805	$ (34,691)	$ 37,114
Phil Rykhoek (4)	$ 50,000	$ 26,805	$ (30,926)	$ 45,879
J. Conley Stone	$ 60,250	$ 26,805	$ (24,354)	$ 62,701
Martin G. White	$ 49,875	$ 26,805	$ -	$ 76,680

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

(2) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for the period under the provisions of SFAS 123(R) for awards of phantom units under our 2007 LTIP. The forfeiture rate that was applied to the phantom unit awards at December 31, 2008 was zero. Each director received an award of 2,300 phantom units. The grant date fair value of these awards was $20.12 per phantom unit.

(3) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for the period under the provisions of SFAS123(R) for awards of stock

appreciation rights. The forfeiture rate that was applied to these stock appreciation rights at December 31, 2008 was ten percent. Under our stock appreciation rights plan, the director will receive cash upon exercise of the right. Because of the decline in our common unit market price and the effects of that decline on the fair value of outstanding stock appreciation rights, we recorded a reduction in the liability for most of these awards in 2008. These reductions are reflected as negative amounts in the table above.

(4) Fees were paid in cash for these directors to Denbury. The phantom unit and stock appreciation rights awards are individual awards of the named director.

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OUTSTANDING EQUITY AWARDS AT 2008 FISCAL YEAR END

The outstanding awards of stock appreciation rights to the directors of our general partner are shown in the table below.

Oustanding Equity Awards at 2008 Fiscal Year-End to Directors

	Stock Appreciation Rights				Stock Awards	
Name	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date	Number of Phantom Units That Have Not Vested (#) (1)	Market Value of Phantom Units That Have Not Vested ($)(2)
Mark C. Allen (3)	1,288		$ 15.77	9/29/2016		
		1,000	$ 19.57	12/29/2016		
		1,000	$ 20.92	2/14/2018		
					2,300	19,987
David C. Baggett					2,300	19,987
James E. Davison (4)		1,000	$ 20.92	2/14/2018		
					2,300	19,987
James E. Davison, Jr. (4)		1,000	$ 20.92	2/14/2018		
					2,300	19,987
Ronald T. Evans (5)	2,576		$ 9.26	12/31/2013		
		612	$ 12.48	12/31/2014		
		651	$ 11.17	12/31/2015		
		1,000	$ 19.57	12/29/2016		
		1,000	$ 20.92	2/14/2018		
					2,300	19,987
Susan O. Rheney (5)	3,435		$ 9.26	12/31/2013		
		816	$ 12.48	12/31/2014		
		868	$ 11.17	12/31/2015		
		1,000	$ 19.57	12/29/2016		
		1,000	$ 20.92	2/14/2018		
					2,300	19,987
Gareth Roberts (5)	2,576		$ 9.26	12/31/2013		
		612	$ 12.48	12/31/2014		
		651	$ 11.17	12/31/2015		
		1,000	$ 19.57	12/29/2016		

		1,000	$	20.92	2/14/2018		
						2,300	19,987
Phil Rykhoek (5)	2,576		$	11.00	8/25/2014		
		612	$	12.48	12/31/2014		
		651	$	11.17	12/31/2015		
		1,000	$	19.57	12/29/2016		
		1,000	$	20.92	2/14/2018		
						2,300	19,987
J. Conley Stone (5)	773		$	9.26	12/31/2013		
		735	$	12.48	12/31/2014		
		781	$	11.17	12/31/2015		
		1,000	$	19.57	12/29/2016		
		1,000	$	20.92	2/14/2018		
						2,300	19,987
Martin G. White						2,300	19,987

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(1) These phantom units vest on June 3, 2009.
(2) The market value of the phantom units that have not vested was determined by multiplying the number of phantom units by the closing price of our common units on December 31, 2008 of $8.69.
(3) Mr. Allen's first stock appreciation rights award will vest one-fourth annually beginning September 29, 2007 through September 29, 2010. Mr. Allen's remaining unexercisable stock appreciation rights will vest on January 1, 2011 and February 14, 2012.
(4) The unexercisable stock appreciation rights of this director vest on February 14, 2012.
(5) The unexercisable stock appreciation rights of this director vest on the following dates in the order they are listed: January 1, 2009, January 1, 2010, January 1, 2011 and February 14, 2012.

Compensation Committee Interlocks and Insider Participation

None of the members of the Compensation 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 Compensation Committee.

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

Securities Authorized for Issuance Under Equity Compensation Plans

See Item 5 – Equity Compensation Plans.

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 28, 2009, regarding the beneficial ownership of our units by beneficial owners of 5% or more of the 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.

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Title of Class	Name and Address of Beneficial Owner	Beneficial Ownership of Common Units Number of Units	Percent of Class
Genesis Energy, L.P. Common Units	Genesis Energy, LLC	2,829,055	7.2
	Gareth Roberts (1)	12,300	*
	Grant E. Sims (2)	6,000	*
	Mark C. Allen (1)	7,300	*
	David C. Baggett, Jr.(1)	2,300	*
	James E. Davison (1) (3) (4)	2,877,838	7.3
	James E. Davison, Jr. (1) (5)	3,157,067	8.0
	Ronald T. Evans (1)	15,300	*
	Susan O. Rheney (1)	3,000	*
	Phil Rykhoek (1)	12,300	*
	J. Conley Stone (1)	4,300	*
	Martin G. White (1)	4,400	*
	Ross A. Benavides (6)	18,459	*
	Karen N. Pape (7)	11,542	*
	All directors and executive officers as a group (13 in total)	6,132,106	15.5
	Denbury Onshore LLC (8) 5100 Tennyson Parkway Plano, Texas 75024	1,199,041	3.0
	Todd A. Davison (9)	2,875,537	7.3
	Steven K. Davison (10)	2,875,537	7.3
	Terminal Service, Inc. (11)	1,010,835	2.6
	Swank Capital, LLC, Swank Energy Income Advisors, L.P. and Mr. Jerry V. Swank (12) 3300 Oak Lawn Ave., Suite 650 Dallas, Texas 75219	2,871,087	7.3
	Neuberger Berman, Inc. (13) 605 Third Avenue New York, NY 10158	2,181,894	5.5

(1) Number of units includes phantom units for which the holder has the right to receive 2,300 common units upon vesting on June 3, 2009.

(2) 1,000 of these common units are held by Mr. Sims' father. Mr. Sims disclaims beneficial ownership of these units.

(3) James E. Davison is the sole stockholder of Davison Terminal Service, Inc., which directly owns 1,010,835 units.

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(4) We have been granted a lien on 1,327,007 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(5) We have been granted a lien on 1,352,226 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(6) Includes 9,176 phantom units which will vest on December 18, 2010.

(7) Includes 8,156 phantom units which will vest on December 18, 2010.

(8) Denbury Onshore, LLC is an affiliate of our general partner and a wholly-owned subsidiary of Denbury.

(9) Todd A. Davison is the son of James E. Davison and the brother of James E. Davison, Jr., and an employee of our general partner. The mailing address for Mr. Davison is 2000 Farmerville Hwy., Ruston, LA 71270. We have been granted a lien on 1,352,226 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(10) Steven K. Davison is the son of James E. Davison and the brother of James E. Davison, Jr. and Todd A. Davison, and an employee of our general partner. The mailing address for Mr. Davison is 207 W. Alabama, Ruston, LA 71270. We have been granted a lien on 1,352,226 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(11) This entity is owned by James E. Davison. It was formerly known as Davison Terminal Service, Inc. The mailing address of this entity is PO Box 607, Ruston, LA 71273.

(12) Information based on Schedule 13G filed with the SEC on February 17, 2009. Swank Capital, LLC and Mr. Jerry V. Swank claim sole voting and dispositive powers over these units. Swank Energy Income Advisors, L.P. claims shared voting and dispositive powers over these units.

(13) Information based on Schedule 13G filed with the SEC on February 12, 2009.

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 all of our 2% general partner interest and all of our incentive distribution rights, in addition to 7.2% of our units. Genesis Energy, LLC is a majority-owned subsidiary of Denbury. Denbury has advised us that it has not pledged any of its interest in our general partner under any agreements or arrangements.

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

Our General Partner

Our operations are managed by, and our employees are employed by, Genesis Energy, LLC, our general partner. Our general partner does not receive any management fee or other compensation in connection with the management of our business, but is reimbursed for all direct and indirect expenses incurred on our behalf. During 2008, these reimbursements totaled $51.9 million. As of December 31, 2008, we owed our general partner $2.1 million related to these services.

Our general partner owns the 2% general partner interest and all incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13.3% of amounts we distribute to our common unitholders in excess of $0.25 per unit, 23.5% of the amounts we distribute to our common unitholders in excess of $0.28 per unit, and 49% of the amounts we distribute to our common unitholders in excess of $0.33 per unit. See Item 11. Executive Compensation for information regarding our Senior Executives interest in the incentive distribution rights owned by our general partner.

Our general partner also owns 2,829,055 limited partner units and has the same rights and is entitled to receive distributions as the other limited partners with respect to those units.

During 2008, our general partner received a total of $6.5 million from us as distributions, with $3.5 million attributable to its limited partner units, $1.0 million for its general partner interest, and $2.0 million related to its incentive distribution rights.

Relationship with Denbury Resources, Inc.

Historically, we have entered into transactions with Denbury and its subsidiaries to acquire assets from time to time. We have instituted specific procedures for evaluating and valuing our material transactions with Denbury and its subsidiaries. Before we consider entering into a material transaction with Denbury or any of its subsidiaries, 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. In addition, our general partner's board of directors may seek "Special Approval" (as defined in our partnership agreement) from our Audit Committee, which is comprised solely of independent directors. That committee:

- evaluates and, where appropriate, negotiates 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.

Traditionally, we have consummated proposed material acquisitions or dispositions with Denbury only when we have evaluated the transaction, our Audit Committee has approved and recommended the transaction and our general partner's full board has approved the transaction, however, such approvals are not required under our partnership agreement.

During 2005, 2004 and 2003, we acquired CO_2 volumetric production payments and related wholesale marketing contracts from Denbury for $14.4 million, $4.7 million and $24.4 million, respectively. In May 2008, we completed two transactions with Denbury involving CO_2 pipelines. We acquired the Free State CO_2 pipeline for $75 million, comprised of $50 million of cash and $25 million of our common units. These common units are owned by Denbury Onshore LLC, a wholly-owned subsidiary of Denbury and an affiliate of our general partner. Additionally, we entered into a twenty-year financing lease transaction with Denbury valued at $175 million related to Denbury's NEJD Pipeline System.

Additionally we enter into transactions with Denbury in the ordinary course of our operations. During 2008, these transactions included:

- Provision of transportation services for crude oil by truck totaling $3.6 million.
- Provision of crude oil pipeline transportation services totaling $10.7 million.
- Provision of CO_2 and crude oil pipeline transportation services under lease arrangements for which we received payments totaling $11.5 million.
- Provision of CO_2 transportation services to our wholesale industrial customers by Denbury's pipeline. The fees for this service totaled $6.4 million in 2008.
- Provision of pipeline monitoring services to Denbury for its CO_2 pipelines totaling $120,000 in 2008.
- Provision of services by Denbury officers as directors of our general partner. We paid Denbury $195,000 for these services in 2007.

At December 31, 2008, we owed Denbury $1.0 million for provision of CO_2 transportation services. Denbury owed us $2.0 million for crude oil trucking and pipeline transportation services.

Our partnership agreement provides that, with the approval of at least a majority of our limited partners, our general partner also may be removed without cause. Any limited partner interests held by our general partner and its affiliates would be excluded from such a vote. If it is proposed that the removal is without cause and an affiliate of Denbury is not proposed as a successor, then any action for removal must also provide for Denbury to be granted an option effective upon its removal to purchase our Mississippi pipeline system at a price that is 110 percent of its fair market value at that time. Denbury also has the right to purchase the Mississippi CO_2 pipeline to Brookhaven field at its fair market value at that time. Fair value is to be determined by agreement of two independent appraisers, one chosen by the successor general partner and the other by Denbury or if they are unable to agree, the mid-point of the values determined by them. Additionally, in the event our general partner is removed by our common unitholders without the approval of Denbury, Denbury has the option to prepay its obligation under the NEJD Pipeline lease.

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Relationship with Davison family

We have entered into an aircraft interchange agreement with the Davison family where each party will make available to the other party its aircraft on an as-available basis, in exchange for equal flight-time on the other party's aircraft any appropriate difference between the cost of owning, operating, and maintaining the aircraft. The estimated value of the equal flight-time owed to the Davison family at December 31, 2008 was approximately $16,000.

In connection with the terms of our acquisition of the Davison businesses, the Davison unitholders have registration rights with respect to their units.

These rights include the following provisions:

- the right to require us to file a shelf registration statement, which we filed in 2008;
- the right to demand five registrations of their units, one per calendar year, and piggyback rights for other unit registrations; and
- the Davison unitholders have agreed to specified restrictions on the sale and transfer of the units they received in consideration of this acquisition. The Davison unitholders cannot sell any of the units issued as consideration except that portion provided below (subject to certain exceptions):

At closing (July 25, 2007)	20%
At July 25, 2008	20%
At January 25, 2009	20%
At July 25, 2009	30%
At July 25, 2010	10%
	100%

Pursuant to a unitholder agreement between the Davison unitholders and us, executed on July 25, 2007, the Davison unitholders have the right to designate up to two directors to our board of directors, depending on their continued level of ownership in us. Until July 25, 2010, the Davison unitholders have the right to designate two directors to our board of directors. Thereafter, the Davison unitholders will have the right to designate (i) one director if they beneficially own at least 10% but less than 35% of our outstanding common units, or (ii) two directors if they beneficially own 35% or more of our outstanding common units. If their percentage ownership in our common units drops below 10% after July 25, 2010, the Davison unitholders would have no rights to designate directors. At December 31, 2008, the Davison unitholders held approximately 30% of our outstanding common units.

On July 25, 2007, the Davison unitholders designated James E. Davison and James E. Davison, Jr. as directors to the Board of Directors of our general partner.

To secure their indemnification obligations under the agreement with us for the acquisition of their businesses, the Davison unitholders have granted to us a lien on 5,383,684 units, or 40% of the units they received as consideration. On July 24, 2009, 4,037,763 of these units will be released, with the remaining 1,345,921 units released on July 26, 2010.

Our joint venture partner in DG Marine is TD Marine, LLC, an entity owned by James E. Davison and two of his sons. Additionally, Community Trust Bank is a 17% participant in the DG Marine credit facility. Davison family members own approximately 14% of Community Trust Bank, and James E. Davison, Jr. serves on the board of the holding company that owns Community Trust Bank.

During 2008, we sold $1.3 million of petroleum products to businesses owned and operated by members of the Davison family in the ordinary course of our operations.

Director Independence

Susan O. Rheney, David C. Baggett and Martin G. White, all members of our Audit Committee, meet the listing standard requirements of NYSE Alternext US, and the SEC rules to be considered independent directors of Genesis. Additionally, J. Conley Stone also meets the requirements to be considered an independent director. The term "independent director" means a person other than an officer or employee of our general partner, the Partnership or its subsidiaries, or Denbury or its subsidiaries, or any other individual having a relationship that, in the opinion of the Board of Directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. To be considered independent, neither the director nor an immediate family member of the director has had any direct or indirect material relationship with Genesis.

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The independent directors meet regularly in executive sessions outside of the presence of the non-independent directors or members of our management after each of the regularly scheduled quarterly Audit Committee meetings. See additional discussion of director independence at Item 10. Directors, Executive Officers and Corporate Governance – Management of Genesis Energy, L.P.

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, 2008 and 2007.

	2008	2007
	(in thousands)	
Audit Fees (1)	$ 3,634	$ 3,107
Audit-Related Fees (2)	296	1,945
Tax Fees (3)	368	165
All Other Fees (4)	3	2
Total	$ 4,301	$ 5,219

(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 audits of our general partner and separate audits of certain of our consolidated subsidiaries and joint ventures.
(2) Includes fees for the audit of our employee benefit plan and assistance in the documentation of internal controls over financial reporting. Also includes fees for audits of acquired businesses.
(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 2008 and 2007 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 (collectively, the “Disclosure Categories”) that the independent auditor may perform. The policy requires that each fiscal year, a description of the services (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 2008 and 2007, 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.

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(a)(3) Exhibits

	3.1	Certificate of Limited Partnership of Genesis Energy, L.P. ("Genesis") (incorporated by reference to Exhibit 3.1 to Registration Statement, File No. 333-11545)
	3.2	Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 4.1 to Form 8-K dated June 15, 2005)
	3.3	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 3.3 to Form 10-K dated December 31, 2007)
	3.4	Certificate of Limited Partnership of Genesis Crude Oil, L.P. ("the Operating Partnership") (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 1996)
	3.5	Fourth Amended and Restated Agreement of Limited Partnership of the Operating Partnership (incorporated by reference to Exhibit 4.2 to Form 8-K dated June 15, 2005)
	3.6	Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)
	3.7	Certificate of Formation of Genesis Energy, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)
	3.8	Limited Liability Company Agreement of Genesis Energy, LLC dated December 29, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)
	3.9	First Amendment to Limited Liability Company Agreement of Genesis Energy, LLC dated December 31, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)
	4.1	Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K dated December 31, 2007)
	10.1	First Amended and Restated Credit Agreement dated as of May 30, 2008 among Genesis Crude Oil, L.P., Genesis Energy, L.P., the Lenders Party Hereto, Fortis Capital Corp., and Deutsche Bank Securities Inc. (incorporated by reference to Exhibit 10.4 to Form 8-K dated June 5, 2008)
	10.2	First Amendment to First Amended and Restated Credit Agreement, dated as of July 18, 2008, among Genesis Crude Oil, L.P., Genesis Energy, L.P., the lenders party thereto, Fortis Capital Corp. and Deutsche Bank Securities Inc. (incorporated by reference to Exhibit 10.3 to Form 8-K dated July 22, 2008)
*	10.3	Production Payment Purchase and Sale Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P.
*	10.4	Carbon Dioxide Transportation Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P.
	10.5	

	Second Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed August 26, 2004 (incorporated by reference to Exhibit 99.1 to Form 8-K dated August 26, 2004)
10.6	Second Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.2 to Form 8-K dated August 24, 2004)
10.7	Third Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed October 11, 2005 (incorporated by reference to Exhibit 99.2 to Form 8-K dated October 11, 2005)

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10.8	Third Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.3 to Form 8-K dated October 11, 2005)
10.9	Contribution and Sale Agreement by and among Davison Petroleum Products, L.L.C., Davison Transport, Inc., Transport Company, Davison Terminal Service, Inc., Sunshine Oil & Storage, Inc., T&T Chemical, Inc. Fuel Masters, LLC, TDC, L.L.C. and Red River Terminals, L.L.C. dated April 25, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 31, 2007)
10.10	Amendment No. 1 to the Contribution and Sale Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.2 to Form 8-K dated July 31, 2007)
10.11	Amendment No. 2 to the Contribution and Sale Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated October 19, 2007)
10.12	Amendment No. 3 to the Contribution and Sale Agreement dated March 3, 2008 (incorporated by reference to Exhibit 10.21 to Form 10-K dated December 31, 2007)
10.13	Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K dated July 31, 2007)
10.14	Amendment No. 1 to the Registration Rights Agreement dated November 16, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated November 16, 2007)
10.15	Amendment No. 2 to the Registration Rights Agreement dated December 6, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2007)
10.16	Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to Form 8-K dated July 31, 2007)
10.17	Amendment No. 1 to the Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.2 to Form 8-K dated October 19, 2007)
10.18	Pledge and Security Agreement (incorporated by reference to Exhibit 10.5 to Form 8-K dated July 31, 2007)
10.19	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)
10.20	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 Form 8-K dated June 5, 2008)
10.21	Transportation Services Agreement between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 5, 2008)
10.22	Contribution and Sale Agreement by and Among Grifco Transportation, Ltd., Grifco Transportation Two, Ltd., and Shore Thing, Ltd. and Genesis Marine Investments, LLC and Genesis Energy, L.P.

			and TD Marine, LLC (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 22, 2008)
	10.23		Omnibus Agreement dated as of June 11, 2008 by and among TD Marine, LLC, James E. Davison, Steven K. Davison, Todd A Davison and Genesis Energy, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 22, 2008)
*	10.24	+	Genesis Energy, LLC First Amended and Restated Stock Appreciation Rights Plan
*	10.25	+	Form of Stock Appreciation Rights Plan Grant Notice
	10.26	+	Genesis Energy, LLC Amended and Restated Severance Protection Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2006)
*	10.27	+	Amendment to the Genesis Energy Severance Protection Plan

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	10.28	+	Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 21, 2007)
	10.29	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Graded) (incorporated by reference to Exhibit 10.2 to Form 8-K dated December 21, 2007)
	10.30	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Cliff) (incorporated by reference to Exhibit 10.3 to Form 8-K dated December 21, 2007)
	10.31	+	Employment Agreement by and between Genesis Energy, LLC and Grant E. Sims, dated December 31, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated January 7, 2009)
	10.32	+	Employment Agreement by and between Genesis Energy, LLC and Joseph A. Blount, Jr., dated December 31, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K dated January 7, 2009)
	10.33	+	Employment Agreement by and between Genesis Energy, LLC and Robert V. Deere, dated December 31, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated January 7, 2009)
	10.34	+	Genesis Energy, LLC Deferred Compensation Plan, effective December 31, 2008 (incorporated by reference to Exhibit 10.4 to Form 8-K dated January 7, 2009)
	10.35	+	Genesis Energy, LLC Award – Individual Class B Interest for Grant E. Sims dated December 31, 2009 (incorporated by reference to Exhibit 10.5 to Form 8-K dated January 7, 2009)
	10.36	+	Genesis Energy, LLC Award – Individual Class B Interest for Joseph A. Blount, Jr. dated December 31, 2009 (incorporated by reference to Exhibit 10.6 to Form 8-K dated January 7, 2009)
	10.37	+	Genesis Energy, LLC Award – Individual Class B Interest for Robert V. Deere dated December 31, 2009 (incorporated by reference to Exhibit 10.7 to Form 8-K dated January 7, 2009)
	10.38	+	Deferred Compensation Grant – Genesis Energy, LLC – Grant E. Sims (incorporated by reference to Exhibit 10.8 to Form 8-K dated January 7, 2009)
	10.39	+	Deferred Compensation Grant – Genesis Energy, LLC – Joseph A. Blount, Jr. (incorporated by reference to Exhibit 10.9 to Form 8-K dated January 7, 2009)
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 11 to the Consolidated Financial Statements
*	21.1		Subsidiaries of the Registrant
*	23.1		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

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* Filed herewith

\+ A management contract or compensation plan or arrangement.

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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: March 16, 2009	By: /s/ Grant E. Sims Grant E. Sims Chief Executive Officer

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

NAME	TITLE (OF GENESIS ENERGY, LLC)*	DATE
/s/ Grant E. Sims Grant E. Sims	Director and Chief Executive Officer (Principal Executive Officer	March 16, 2009
/s/ Robert V. Deere Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	March 16, 2009
/s/ Karen N. Pape Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	March 16, 2009
/s/ Gareth Roberts Gareth Roberts	Chairman of the Board and Director	March 16, 2009
/s/ Mark C. Allen Mark C. Allen	Director	March 16, 2009
/s/ David C. Baggett, Jr. David C. Baggett, Jr.	Director	March 16, 2009
/s/ James E. Davison James E. Davison	Director	March 16, 2009
/s/ James E. Davison, Jr. James E. Davison, Jr.	Director	March 16, 2009
/s/ Ronald T. Evans Ronald T. Evans	Director	March 16, 2009
/s/ Susan O. Rheney Susan O. Rheney	Director	March 16, 2009

/s/	Phil Rykhoek Phil Rykhoek	Director	March 16, 2009
/s/	J. Conley Stone J. Conley Stone	Director	March 16, 2009
/s/	Martin G. White Martin G. White	Director	March 16, 2009

*Genesis Energy, LLC is our general partner.

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GENESIS ENERGY, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
AND FINANCIAL STATEMENT SCHEDULES

All other 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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. and subsidiaries (the "Partnership") as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), partners' capital, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Genesis Energy, L.P. and subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As described in Note 2 to the consolidated financial statements and effective as of January 1, 2008, the Partnership adopted Statement of Financial Accounting Standards ("SFAS") No. 157, which established new accounting and reporting standards for fair value measurements of certain financial assets and liabilities.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2009 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP
DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2009

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GENESIS ENERGY, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,985	$ 11,851
Accounts receivable - trade, net of allowance for doubtful accounts of $1,132 at December 31, 2008	112,229	178,658
Accounts receivable - related party	2,875	1,441
Inventories	21,544	15,988
Net investment in direct financing leases, net of unearned income -current portion - related party	3,758	609
Other	8,736	5,693
Total current assets	168,127	214,240
FIXED ASSETS, at cost	349,212	150,413
Less: Accumulated depreciation	(67,107)	(48,413)
Net fixed assets	282,105	102,000
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	177,203	4,764
CO2 ASSETS, net of amortization	24,379	28,916
EQUITY INVESTEES AND OTHER INVESTMENTS	19,468	18,448
INTANGIBLE ASSETS, net of amortization	166,933	211,050
GOODWILL	325,046	320,708
OTHER ASSETS, net of amortization	15,413	8,397
TOTAL ASSETS	$ 1,178,674	$ 908,523
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 96,454	$ 154,614
Accounts payable - related party	3,105	2,647
Accrued liabilities	26,713	17,537
Total current liabilities	126,272	174,798
LONG-TERM DEBT	375,300	80,000
DEFERRED TAX LIABILITIES	16,806	20,087
OTHER LONG-TERM LIABILITIES	2,834	1,264
MINORITY INTERESTS	24,804	570
COMMITMENTS AND CONTINGENCIES (Note 19)		
PARTNERS' CAPITAL:		
	616,971	615,265

Common unitholders, 39,457 and 38,253 units issued and outstanding at December 31, 2008 and 2007, respectively		
General partner	16,649	16,539
Accumulated other comprehensive loss	(962)	-
Total partners' capital	632,658	631,804
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,178,674	$ 908,523

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

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

	Year Ended December 31, 2008	2007	2006
REVENUES:			
Supply and logistics:			
Unrelated parties (including revenues from buy/sell arrangements of $69,772 in 2006)	$ 1,847,575	$ 1,092,398	$ 872,443
Related parties	4,839	1,791	825
Refinery services	225,374	62,095	-
Pipeline transportation, including natural gas sales:			
Transportation services - unrelated parties	19,469	17,153	17,119
Transportation services - related parties	21,730	5,754	4,948
Natural gas sales revenues	5,048	4,304	7,880
CO2 marketing:			
Unrelated parties	15,423	13,376	13,098
Related parties	2,226	2,782	2,056
Total revenues	2,141,684	1,199,653	918,369
COSTS AND EXPENSES:			
Supply and logistics costs:			
Product costs - unrelated parties (including costs from buy/sell arrangements of $68,899 in 2006)	1,736,637	1,041,637	850,106
Product costs - related parties	-	101	1,565
Operating costs	78,453	37,121	14,231
Refinery services operating costs	166,096	40,197	-
Pipeline transportation costs:			
Pipeline transportation operating costs	10,306	10,054	9,928
Natural gas purchases	4,918	4,122	7,593
CO2 marketing costs:			
Transportation costs - related party	6,424	5,213	4,640
Other costs	60	152	202
General and administrative	29,500	25,920	13,573
Depreciation and amortization	71,370	38,747	7,963
Net loss (gain) on disposal of surplus assets	29	266	(16)
Impairment expense	-	1,498	-
Total costs and expenses	2,103,793	1,205,028	909,785
OPERATING INCOME (LOSS)	37,891	(5,375)	8,584
Equity in earnings of joint ventures	509	1,270	1,131
Interest income	458	385	198
Interest expense	(13,395)	(10,485)	(1,572)
Income (loss) before income taxes and minority interest	25,463	(14,205)	8,341
Income tax benefit	362	654	11
Minority interest	264	1	(1)
Income (loss) before cumulative effect adjustment	26,089	(13,550)	8,351
Cumulative effect adjustment of adoption of new accounting principle	-	-	30
NET INCOME (LOSS)	$ 26,089	$ (13,550)	$ 8,381

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS - CONTINUED
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2008	2007	2006
NET INCOME (LOSS) PER COMMON UNIT:			
BASIC	$ 0.61	$ (0.64)	$ 0.59
DILUTED	$ 0.60	$ (0.64)	$ 0.59
OUTSTANDING COMMON UNITS:			
BASIC	38,961	20,754	13,784
DILUTED	39,025	20,754	13,784

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

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$ 26,089	$ (13,550)	$ 8,381
Interest rate swap loss	(962)	-	-
Comprehensive income (loss)	$ 25,127	$ (13,550)	$ 8,381

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

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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	Total
Partners' capital, January 1, 2006	13,784	$ 85,870	$ 1,819	$ -	$ 87,689
Net income	-	8,214	167	-	8,381
Cash distributions	-	(10,200)	(208)	-	(10,408)
Partners' capital, December 31, 2006	13,784	83,884	1,778	-	85,662
Net loss	-	(13,279)	(271)	-	(13,550)
Cash contributions	-	-	1,412	-	1,412
Contribution for management compensation (Note 11)	-	-	3,434	-	3,434
Cash distributions	-	(16,743)	(432)	-	(17,175)
Issuance of units	24,469	561,403	10,618	-	572,021
Partners' capital, December 31, 2007	38,253	615,265	16,539	-	631,804
Net income	-	23,485	2,604	-	26,089
Cash contributions	-	-	511	-	511
Cash distributions	-	(47,529)	(3,005)	-	(50,534)
Issuance of units	2,037	41,667	-	-	41,667
Unit based compensation expense	5	750	-	-	750
Redemption of units	(838)	(16,667)	-	-	(16,667)
Interest rate swap loss	-	-	-	(962)	(962)
Partners' capital, December 31, 2008	39,457	616,971	16,649	(962)	632,658

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

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 26,089	$ (13,550)	$ 8,381
Adjustments to reconcile net income (loss) to net cash provided by operating activities -			
Depreciation and amortization	71,370	40,245	7,963
Amortization and write-off of credit facility issuance costs	1,437	779	969
Amortization of unearned income and initial direct costs on direct financing leases	(10,892)	(620)	(655)
Payments received under direct financing leases	11,519	1,188	1,186
Equity in earnings of investments in joint ventures	(509)	(1,270)	(1,131)
Distributions from joint ventures - return on investment	1,272	1,845	1,565
Non-cash effect of unit-based compensation plans	(2,063)	910	1,929
Non-cash compensation charge	-	3,434	-
Deferred and other tax liabilities	(2,771)	(2,658)	(11)
Other non-cash items	618	346	(61)
Net changes in components of operating assets and liabilities, net of working capital acquired (See Note 14)	(1,262)	3,280	(8,873)
Net cash provided by operating activities	94,808	33,929	11,262
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed assets	(37,354)	(8,235)	(1,260)
CO2 pipeline transactions and related costs	(228,891)	-	-
Distributions from joint ventures - return of investment	886	395	528
Investments in joint ventures and other investments	(2,397)	(1,104)	(6,042)
Acquisition of Grifco assets	(65,693)	-	-
Acquisition of Davison assets, net of cash acquired	(993)	(301,640)	-
Acquisition of Port Hudson assets	-	(8,103)	-
Other, net	718	(2,655)	(68)
Net cash used in investing activities	(333,724)	(321,342)	(6,842)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Bank borrowings	531,712	392,200	8,000
Bank repayments	(236,412)	(320,200)	-
Additional purchase price consideration paid to Grifco	(6,000)	-	-
Credit facility issuance fees	(2,255)	(2,297)	(2,726)
Issuance of common units for cash	-	231,433	-
Redemption of common units for cash	(16,667)	-	-
General partner contributions	511	12,030	-
Minority interest contributions, net of distributions	25,500	49	(1)
Distributions to common unitholders	(47,529)	(16,743)	(10,200)
Distributions to general partner interest	(3,005)	(432)	(208)
Other, net	195	906	(66)
Net cash provided by (used in) financing activities	246,050	296,946	(5,201)

Net increase (decrease) in cash and cash equivalents	7,134	9,533	(781)
Cash and cash equivalents at beginning of period	11,851	2,318	3,099
Cash and cash equivalents at end of period	$ 18,985	$ 11,851	$ 2,318

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

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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 area of the United States. We conduct our operations through our operating subsidiaries and joint ventures. We manage our businesses through four divisions:

- Pipeline transportation of crude oil, carbon dioxide (or CO2) and, to a lesser degree, natural gas;
- 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);
- Industrial gas activities, including wholesale marketing of CO2 and processing of syngas through a joint venture; and
- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting by trucks and barge of crude oil and petroleum products.

Our 2% general partner interest is held by Genesis Energy, LLC, a Delaware limited liability company and an indirect, majority-owned subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner and its affiliates also own 10.2% of our outstanding common units.

Our general partner manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to our management.

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, 2008 and 2007 and our results of operations, cash flows and changes in partners' capital for the years ended December 31, 2008, 2007 and 2006. All intercompany 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.

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 three joint ventures: DG Marine Transportation, LLC (DG Marine), T&P Syngas Supply Company (T&P Syngas) and Sandhill Group, LLC (Sandhill). As of the acquisition date in July 2008, DG Marine is consolidated in our financial statements. We account for our 50% investments in T&P Syngas and Sandhill by the equity method of accounting. See Note 8.

DG Marine Transportation, LLC

In July 2008, we acquired an interest in DG Marine which acquired the inland marine transportation business of Grifco Transportation, Ltd and two of its affiliates. DG Marine is a joint venture with TD Marine, LLC, an entity owned by members of the Davison family. We own an effective 49% economic interest and TD Marine, LLC owns a 51% economic interest in DG Marine. TD Marine, LLC controls the DG Marine joint venture and the day-to-day operations are conducted by and managed by DG Marine employees. The provisions of Financial Interpretation No. 46(R) “Consolidation of Variable Interest Entities” (FIN 46R), require us to consolidate DG Marine in our consolidated financial statements. See Note 3. The results of the operations of DG Marine have been included in our consolidated financial statements since the date of the acquisition.

T&P Syngas Supply Company

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We own a 50% interest in T&P Syngas, a Delaware general partnership. Praxair Hydrogen Supply Inc. ("Praxair") owns the remaining 50% partnership interest in T&P Syngas. T&P Syngas is a partnership that owns a syngas manufacturing facility located in Texas City, Texas. That facility processes natural gas to produce syngas (a combination of carbon monoxide and hydrogen) and high pressure steam. Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility under a long-term processing agreement. T&P Syngas receives a processing fee for its services. Praxair operates the facility.

Sandhill Group, LLC

We own a 50% interest in Sandhill. At December 31, 2008, Reliant Processing Ltd. held the other 50% interest in Sandhill. Sandhill owns a CO2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemical and oil industries. The facility acquires CO2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

Minority Interests

Our general partner owns a 0.01% general partner interest in Genesis Crude Oil, L.P. and TD Marine, LLC, a related party, owns the remaining 51% economic interest in DG Marine. The net interest of those parties in our results of operations and financial position are reflected in our financial statements as minority interests.

In July 2007, we acquired the energy-related businesses of the Davison family. See Note 3. The results of the operations of these businesses have been included in our consolidated financial statements since August 1, 2007.

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) estimated useful lives of assets, which impacts depreciation and amortization, (2) liability and contingency accruals, (3) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (4) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, and (5) 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.

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. The Partnership has 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

Our accounts receivable are primarily from purchasers of crude oil and petroleum products, and, to a lesser extent, purchasers of NaHS and CO2. These purchasers include refineries, marketing and trading companies. The majority of our accounts receivable relate to our supply and logistics activities that can be described as high volume and low margin activities.

Volatility in the financial markets in the latter half of 2008 combined with significant energy price volatility has caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business. We utilize our credit review process to monitor these conditions and to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require.

We review our outstanding accounts receivable balances on a regular basis and record a reserve 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.

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the activity of our allowance for doubtful accounts for the year ended December 31, 2008:

	Year Ended December 31, 2008
Balance at beginning of period	$ -
Charged to costs and expenses	1,152
Amounts written off	(20)
Balance at end of period	$ 1,132

Inventories

Crude oil and petroleum products inventories held for sale are valued at the lower of average cost or market. Fuel inventories are carried at the lower of cost or market. Caustic soda and NaHS inventories are stated 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, 25 years for push boats and barges, 10 to 20 years for machinery and equipment, 40 years for tanks, 3 to 7 years for vehicles and transportation equipment, and 3 to 10 years for buildings, office equipment, furniture and fixtures and other equipment.

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

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

Certain volumes of crude oil 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, natural gas and CO2 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 5.

Direct Financing Leasing Arrangements

We lease four pipelines to Denbury under direct financing leases. Three of these leases of pipeline segments to Denbury will expire in 2013 to 2015. The NEJD Pipeline System lease to Denbury will expire in 2028, subject to certain extension options.

GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets. See Note 6.

CO2 Assets

Our CO2 assets include three volumetric production payments and long-term contracts to sell the CO2 volume. The contract values are being amortized on a units-of-production method. See Note 7.

Intangible Assets

Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," (SFAS 142) requires that intangible assets with finite useful lives 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 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. As of December 31, 2008, no impairment has occurred of intangible assets.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We account for goodwill under SFAS 142, which prohibits amortization of goodwill, but instead requires testing for impairment at least annually. We test goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. If the 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 is recorded 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. See Note 9.

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.

Unit-Based Compensation

On January 1, 2006, we adopted the provisions of SFAS No. 123(R), “Share-Based Payments”. This statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, “Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans” which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), 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.

Our 2007 Long-term Incentive Plan provides for awards of phantom units to our non-employee directors and to the employees of our general partner. SFAS No. 123(R) requires that compensation cost related to phantom units issued under our 2007 Long-term Incentive Plan be recognized in our consolidated financial statements based on estimated fair value at the date of the grant. See Note 15.

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On December 31, 2008, our general partner awarded Class B Membership Interests in our general partner to our senior executives. SFAS 123(R) requires that the compensation cost related to these interests be re-measured at each reporting date based on the fair value of the interests, and changes in that fair value be recognized over the vesting period. Recorded expense will be subsequently adjusted to fair value until final settlement. See Note 15.

Revenue Recognition

Product Sales - Revenues from the sale of crude oil, petroleum products, natural gas, caustic soda and NaHS are recognized when title to the inventory is transferred to the customer, collectibility 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, natural gas 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 or natural gas 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 expense, 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 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.

CO2 Sales - Revenues from CO2 marketing activities are recorded when title transfers to the customer at the inlet meter of the customer's facility.

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 as a net amount in our consolidated statements of operations beginning with April 2006. Transactions for periods prior to April 2006 are not reflected as a net amount; however the amounts are disclosed parenthetically on the consolidated statements of operations, in accordance with the provision of Emerging Issues Task Force Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty.” Had this provision been in effect in the first quarter of 2006, our reported supply and logistics revenues from unrelated parties for the year ended December 31, 2006 would have been reduced by $69 million to $803 million. Our reported supply and logistics product costs from unrelated parties for the year ended December 31, 2006 would have been reduced by $69 million to $781 million. This change had no effect on operating income, net income or cash flows.

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.

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Cost of sales for the CO2 marketing activities consists of a transportation fee charged by Denbury to transport the CO2 to the customer through Denbury's pipeline and insurance costs. The transportation fee charged by Denbury is adjusted annually for inflation. For the years ended December 31, 2008, 2007 and 2006, the fee averaged $0.1927, $0.1848 and $0.1740 per Mcf, respectively.

Excise and Sales Taxes

The Company collects and remits 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 income statements.

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 statement of operations, is includable 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

We minimize our exposure to price risk by limiting our inventory positions. However when we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. DG Marine uses interest rate swap contracts to manage its exposure to interest rate risk.

We account for those derivative transactions in accordance with Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended and interpreted. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded on the balance sheet 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 cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable, other current liabilities and derivatives approximates their fair value due to their short-term nature. The fair values of these instruments are represented in our consolidated balance sheets.

Net Income Per Common Unit

Our net income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated 98% to the limited partners and 2% to the general partner. Basic net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period. Diluted net income per common unit is calculated in the same manner, but also considers the impact to common units for the potential dilution from phantom units outstanding. (See Note 15 for discussion of phantom units.)

In a period of net operating losses, incremental phantom units are excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. During 2008, we have reported net income; therefore incremental phantom units have been included in the calculation of diluted earnings per unit.

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EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock (or partnership distributions to unitholders). EITF 03-06 applies to any accounting period where our aggregate net income exceeds our aggregate distribution. In such periods, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results; however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it would have the impact of reducing the earnings per limited partner units. This result occurs as a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions (as defined in our partnership agreement), not earnings, in any given period. Our aggregate net earnings have not exceeded our aggregate distributions; therefore EITF 03-06 has not had an impact on our calculation of earnings per unit.

Effective January 1, 2009, we adopted EITF 07-04 and EITF 03-06 will no longer be applied. See “Recent and Proposed Accounting Announcements – Implemented January 1, 2009” below.

Recent and Proposed Accounting Pronouncements

Implemented in 2008

FASB Staff Position FIN 46(R)-8

In December 2008, the FASB issued FASB Staff Position FIN 46(R)-8, “Disclosures about Variable Interest Entities” (FSP FIN 46(R)-8). FSP FIN 46(R)-8 requires enhanced disclosures about a company’s involvement in variable interest entities (VIEs). The enhanced disclosures required by this FSP are intended to provide users of financial statements with an greater understanding of: (1) the significant judgments and assumptions made by a company in determining whether it must consolidate a VIE and/or disclose information about its involvement with a VIE; (2) the nature of restrictions on the assets of a VIE that are consolidated and reported by a company in its statement of financial position, including the carrying amounts of such assets; (3) the nature of, and changes in, the risks associated with a company’s involvement with a VIE; (4) how a company’s involvement with a VIE affects the company’s financial position, financial performance, and cash flows. This FSP was effective for us on December 31, 2008. See Note 3 for disclosures regarding our involvement with VIEs.

SFAS 157

We adopted Statement of Financial Accounting Standards (SFAS) No. 157, “Fair Value Measurements” (SFAS 157), with respect to financial assets and financial liabilities that are regularly adjusted to fair value, as of January 1, 2008. SFAS 157 provides a common fair value hierarchy to follow in determining fair value measurements in the preparation of financial statements and expands disclosure requirements relating to how such measurements were developed. SFAS 157 does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements. On February 12, 2008 the Financial Accounting Standards Board (FASB) issued Staff Position No. 157-2, “Effective Date of FASB Statement No. 157” (FSP 157-2) which amends SFAS 157 to delay the effective date for all non-financial assets and non-financial liabilities, except for those that are recognized at fair value in the financial statements on a recurring basis. The partial adoption of SFAS 157 as described above had no material impact on us. We have not yet determined the impact, if any, that the second phase of the adoption of SFAS 157 in 2009 will have relating to its fair value measurements of non-financial assets and non-financial liabilities. See Note 18 for further information regarding fair-value measurements.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159). This statement was effective for us as of January 1, 2008. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. We did not elect to utilize voluntary fair value measurements as permitted by the standard.

Implemented January 1, 2009

SFAS 141(R)

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" (SFAS 141(R)). SFAS 141(R) replaces FASB Statement No. 141, "Business Combinations." This statement retains the purchase method of accounting used in business combinations but replaces SFAS 141 by establishing principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction costs and restructuring costs be charged to expense as incurred. In addition, the statement requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted SFAS 141(R) on January 1, 2009. Adoption will impact our accounting for acquisitions we complete subsequent to that date.

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SFAS 160

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51” (SFAS 160). This statement establishes accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine “minority interest” category); (ii) elimination of minority interest expense as a line item on the statement of operations and, as a result, that net income be allocated between the parent and the noncontrolling interests on the face of the statement of operations; and (iii) enhanced disclosures regarding noncontrolling interests. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We adopted SFAS 160 on January 1, 2009. Such adoption will impact the presentation of the minority interests in Genesis Crude Oil, L.P. held by our general partner and DG Marine held by our joint venture partner.

SFAS 161

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133” (SFAS 161). This Statement requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS 133, and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS No. 161 on January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

EITF 07-4

In March 2008, the Emerging Issues Task Force (or EITF) of the FASB issued EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships” (EITF 07-4). EITF 07-4 addresses the application of the two-class method under SFAS No. 128 “Earnings Per Share” in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We adopted EITF 07-04 on January 1, 2009. Adoption will impact the net income available to limited partners used in our computation of earnings per unit, but will not impact our distributions to limited partners, financial position, results of operations, or cash flows. For additional information on our incentive distribution rights, see Note 10.

FASB Staff Position No. 142-3

In April 2008, the FASB issued FASB Staff Position No. 142-3, “Determination of the Useful Life of Intangible Assets” (FSP 142-3). This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset under Statement of Financial Accounting Standards No. 142, “Goodwill and other Intangible Assets.” The purpose of this FSP is to develop consistency between the useful life assigned to intangible assets and the cash flows from those assets. FSP 142-3 is effective for fiscal years beginning after December 31, 2008. We are currently evaluating the impact, if any, that the standard will have on our consolidated financial statements.

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3. Acquisitions

DG Marine Transportation Investment

On July 18, 2008, DG Marine completed the acquisition of the inland marine transportation business of Grifco Transportation, Ltd. ("Grifco") and two of Grifco's affiliates. DG Marine is a joint venture we formed with TD Marine, LLC, an entity owned by members of the Davison family. (See discussion below on the acquisition of the Davison family businesses in 2007.). TD Marine owns (indirectly) a 51% economic interest in the joint venture, DG Marine, and we own (directly and indirectly) a 49% economic interest. This acquisition gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

Grifco received initial purchase consideration of approximately $80 million, comprised of $63.3 million in cash and $16.7 million, or 837,690 of our common units. A portion of the units are subject to certain lock-up restrictions. DG Marine acquired substantially all of Grifco's assets, including twelve barges, seven push boats, certain commercial agreements, and offices. Additionally, DG Marine and/or its subsidiaries acquired the rights, and assumed the obligations, to take delivery of four new barges in late third quarter of 2008 and four additional new barges late in first quarter of 2009 (at a total price of approximately $27 million). Upon delivery of the eight new barges, the acquisition of three additional push boats (at an estimated cost of approximately $6 million), and after placing the barges and push boats into commercial operations, DG Marine will be obligated to pay additional purchase consideration of up to $12 million. At December 31, 2008, DG Marine had taken delivery of four of the new barges and $6 million of the additional purchase price consideration was paid. At December 31, 2008, the $5.9 million estimated present value of the remaining $6 million obligation is included in "Accrued Liabilities" in our consolidated balance sheet. The effective interest rate of the obligation was 4.7%

The Grifco acquisition and related closing costs were funded with $50 million of aggregate equity contributions from us and TD Marine, in proportion to our ownership percentages, and with borrowings of $32.4 million under a revolving credit facility which is non-recourse to us and TD Marine (other than with respect to our investments in DG Marine). Although DG Marine's debt is non-recourse to us, our ownership interest in DG Marine is pledged to secure its indebtedness. We funded our $24.5 million equity contribution with $7.8 million of cash and 837,690 of our common units, valued at $19.896 per unit, for a total value of $16.7 million. At closing, we also redeemed 837,690 of our common units from the Davison family. See Notes 10 and 11.

We have entered into a subordinated loan agreement with DG Marine whereby we may (at our sole discretion) lend up to $25 million to DG Marine. The loan agreement provides for DG Marine to pay us interest on any loans at the rate at which we borrowed funds under our credit facility plus 4%. Those loans will mature on January 31, 2012. Under that subordinated loan agreement, DG Marine is required to make monthly payments to us of principal and interest to the extent DG Marine has any available cash that otherwise would have been distributed to the owners of DG Marine in respect of their equity interest. DG Marine's revolving credit facility includes restrictions on DG Marine's ability to make specified payments under the subordinated loan agreement and distributions in respect of our equity interest. At December 31, 2008, there were no amounts outstanding under the subordinated loan agreement. We have, however, provided a $7.5 million guaranty to the lenders under DG Marine's credit facility. This guaranty will expire on May 31, 2009, if DG Marine's leverage ratio under its credit facility is less than 4.00 to 1.00 at May 31, 2009.

The provisions of Financial Interpretation No. 46(R) "Consolidation of Variable Interest Entities" (FIN 46R), require the primary beneficiary to consolidate variable interest entities. As stated in FIN 46R, in determining the primary beneficiary of a variable interest entity ("VIE") that is held between two or more related parties the primary beneficiary is considered to be the party that is "most closely associated" with the VIE. We are considered to be the primary beneficiary due to (i) our involvement in the design of DG Marine, (ii) the ongoing involvement with regards to financial and operating decision making of DG Marine, excluding matters related to new contracts and vessel disposal which are decided solely by TD Marine, and (iii) the financial support we provide to DG Marine. TD Marine has no requirements to make any additional contributions to DG Marine.

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As we are considered the primary beneficiary, DG Marine is consolidated in our consolidated financial statements and the 51% ownership interest of TD Marine in the net assets and net income of DG Marine is included in minority interests in our consolidated financial statements.

The acquisition cost allocated to the assets consists of $63.3 million of cash, $16.7 million of value from the issuance of our limited partnership units to Grifco, $11.7 million related to the discounted value of the additional consideration that will be owed to Grifco when the barges under construction are placed in service and $2.4 million of transaction costs. The acquisition cost has been allocated to the assets acquired based on estimated fair values. Such fair values were developed by management.

The allocation of the acquisition cost is summarized as follows:

Property and equipment	$ 91,772
Amortizable intangible assets:	
Customer relationships	800
Trade name	900
Non-compete agreements	600
Total allocated cost	$ 94,072

The weighted average amortization period for the intangible assets at the date of acquisition is 10 years for customer relationships, 3 years for the trade name and 7 years for the non-compete agreements. The weighted average amortization period for all intangible assets acquired in the Grifco transaction was 6 years.

See additional information on intangible assets and goodwill in Note 9.

At December 31, 2008, our Consolidated Balance Sheets included the following amounts related to DG Marine:

Cash	$ 623
Accounts receivable - trade	2,812
Other current assets	859
Fixed assets, at cost	110,214
Accumulated depreciation	(3,084)
Intangible assets, net	2,208
Other assets	2,178
Total assets	$ 115,810
Accounts payable	$ 1,072
Accrued liabilities	9,258
Long-term debt	55,300
Other long-term liabilities	1,393
Minority interests	24,233
Total liabilities	$ 91,256

2008 Denbury Drop-Down Transactions

On May 30, 2008, we completed two "drop-down" transactions with Denbury Onshore LLC, (Denbury Onshore), a wholly-owned subsidiary of Denbury Resources Inc., the indirect owner of our general partner.

NEJD Pipeline System

In 2008, we entered into a twenty-year financing lease transaction with Denbury valued at $175 million and related to Denbury's North East Jackson Dome (NEJD) Pipeline System. The NEJD Pipeline System is a 183-mile, 20" pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana, and is currently being leased and used by Denbury for its Phase I area of tertiary operations in southwest Mississippi. We recorded this lease arrangement in our consolidated financial statements as a direct financing lease. Under the terms of the agreement, Denbury Onshore began making quarterly rent payments beginning August 30, 2008. These quarterly rent payments are fixed at $5,166,943 per quarter or approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term, we will convey all of our interests in the NEJD Pipeline to Denbury Onshore for a nominal payment.

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The NEJD Pipeline System is a 183-mile, 20" CO_2 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldson, Louisiana, currently being used by Denbury for its tertiary operations in southwest Mississippi. Denbury has the rights to exclusive use of the NEJD Pipeline System, will be responsible for all operations and maintenance on that system, and will bear and assume all obligations and liabilities with respect to that system. The NEJD transaction was funded with borrowings under our credit facility.

See additional discussion of this direct financing lease in Note 6.

Free State Pipeline System

We purchased Denbury's Free State Pipeline for $75 million, consisting of $50 million in cash which we borrowed under our credit facility, and $25 million in the form of 1,199,041 of our common units. The number of common units issued was based on the average closing price of our common units from May 28, 2008 through June 3, 2008.

The Free State Pipeline is an 86-mile, 20" pipeline that extends from Denbury's CO_2 source fields at Jackson Dome, near Jackson, Mississippi, to Denbury's oil fields in east Mississippi. We entered into a twenty-year transportation services agreement to deliver CO_2 on the Free State pipeline for Denbury's use in its tertiary recovery operations. Under the terms of the transportation services agreement, we are responsible for owning, operating, maintaining and making improvements to that pipeline. Denbury has rights to exclusive use of that pipeline and is required to use that pipeline to supply CO_2 to its current and certain of its other tertiary operations in east Mississippi. The transportation services agreement provides for a $100,000 per month minimum payment, which is accounted for as an operating lease, plus a tariff based on throughput. Denbury has two renewal options, each for five years on similar terms. Any sale by us of the Free State Pipeline and related assets or of an ownership interest in our subsidiary that holds such assets would be subject to a right of first refusal purchase option in favor of Denbury.

Davison Businesses Acquisition

On July 25, 2007, we acquired five energy-related businesses from several entities owned and controlled by the Davison family of Ruston, Louisiana (the "Davison Acquisition"). The businesses include the operations that comprise our refinery services division, and other operations included in our supply and logistics division, which transport, store, procure and market petroleum products and other bulk commodities. The assets acquired in this transaction provide us with opportunities to expand our services to energy companies in the areas in which we operate.

For financial reporting purposes, the consideration for this acquisition consisted of $623 million of value, net of cash acquired. The consideration is comprised of $293 million in cash, (which is net of $21.7 million of cash acquired), and 13,459,209 common units of Genesis valued at $330 million. In accordance with EITF, No. 99-12, "Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination," the fair value of Genesis common units issued was determined using an average price of $24.52, which was the average closing price of Genesis common units for the two days before and after the date on which the terms of the acquisition were agreed to and announced. The direct transaction costs totaled $8.9 million and consist primarily of legal and accounting fees and other external costs related directly to the acquisition.

The Davison family is our largest unitholder, with approximately 33% of our outstanding common units. It has designated two of the family members to the board of directors of our general partner, and as long as it maintains a specified minimum percentage of our common units, it will have the continuing right to designate up to two directors. The Davison family has agreed to restrictions that limit its ability to sell specified percentages of its common units through July 26, 2010. Pursuant to an agreement between us and the Davison unitholders, the Davison unitholders have registration rights with respect to their common units. These rights include the right to require us to file a Form S-3 shelf registration statement, if we are eligible.

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The purchase price has been allocated to the assets acquired and liabilities assumed based on estimated fair values. Such fair values were developed by management. The allocation of the purchase price is summarized as follows:

Cash and cash equivalents	$ 21,686
Accounts receivable	55,631
Inventories	10,825
Other current assets	982
Other assets	294
Property and equipment	67,655
Goodwill	316,739
Amortizable intangible assets:	
Customer relationships	129,284
Supplier agreements	36,469
Licensing agreements	38,678
Trade name	17,988
Covenants not-to-compete	695
Favorable lease agreement	13,260
Accounts payable and accrued expenses	(35,230)
Deferred tax liabilties assumed	(21,794)
Total allocation	$ 653,162

See additional information on intangible assets and goodwill in Note 9. Goodwill represents the residual of the purchase price over the fair value of net tangible and identifiable intangible assets acquired.

The following table presents selected unaudited pro forma financial information incorporating the historical operating results of the Davison businesses. The effective closing date of our purchase of the Davison businesses was July 25, 2007. As a result, our Consolidated Statements of Operations for the year ended December 31, 2007 includes five months of results of operations of these acquired businesses. 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.

	Year Ended December 31, 2007	Year Ended December 31, 2006
Pro Forma Earnings Data:		
Revenue	$ 1,574,730	$ 1,479,174
Costs and expenses	1,572,809	1,477,275
Operating income	1,921	1,899
(Loss) Income before extraordinary items	(29,666)	(19,664)
Net (loss) income	(29,666)	(19,664)
Basic and diluted (loss) earnings per unit:		
As reported units outstanding	20,754	13,784
Pro forma units outstanding	28,319	28,319
As reported net (loss) income per unit	$ (0.64)	$ 0.59

Pro forma net (loss) income per unit	$	(1.05)	$	(0.69)

Port Hudson Assets Acquisition

Effective July 1, 2007, we paid $8.1 million for BP Pipelines (North America) Inc.'s Port Hudson crude oil truck terminal, marine terminal, and marine dock on the Mississippi River, which includes 215,000 barrels of tankage, a pipeline and other related assets in East Baton Rouge Parish, Louisiana. The acquisition was funded with borrowings under our credit facility.

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The purchase price has been allocated to the assets acquired based on estimated fair values. The allocation of the purchase price is summarized as follows:

Property and equipment	$ 4,134
Goodwill	3,969
Total	$ 8,103

See additional information on goodwill in Note 9.

4. Inventories

The major components of inventories were as follows:

	December 31, 2008	December 31, 2007
Crude oil	1,878	3,710
Petroleum products	5,589	6,527
Caustic soda	7,139	1,998
NaHS	6,923	3,557
Other	15	196
Total inventories	$ 21,544	$ 15,988

Our inventory at December 31, 2008 is net of charges totaling $1.2 million that we recorded to reduce the cost basis of our crude oil and petroleum products inventory to reflect market value. The lower of cost or market adjustment is included in "Product Costs" of our Supply & Logistics segment on our consolidated statements of operations. The costs of inventories did not exceed market values at December 31, 2007.

5. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following.

	December 31, 2008	December 31, 2007
Land, buildings and improvements	$ 13,549	$ 11,978
Pipelines and related assets	139,184	63,169
Machinery and equipment	22,899	25,097
Transportation equipment	32,833	32,906
Barges and push boats	96,865	-
Office equipment, furniture and fixtures	4,401	2,759
Construction in progress	27,906	7,102

Other		11,575		7,402
Subtotal		349,212		150,413
Accumulated depreciation and impairment		(67,107)		(48,413)
Total	$	282,105	$	102,000

In 2008, 2007 and 2006, $276,000, $57,000 and $9,000 of interest cost, respectively, were capitalized related to the construction of pipelines and related assets.

Depreciation expense was $20,415,000, $8,909,000 and $3,719,000 for the years ended December 31, 2008, 2007, and 2006, respectively.

Asset Impairment Charge

During the fourth quarter of 2007, changes in the source of the supply of natural gas to our natural gas gathering pipelines (which are included in our pipeline transportation segment) indicated to us that the carrying amount of our natural gas gathering pipelines might not be recoverable. We made certain assumptions when estimating future cash flows to be generated from the assets including declines in future sales volumes and costs of testing required for integrity purposes. As a result, we tested the carrying value of these assets for recoverability, and determined that we should record an impairment charge of $1,498,000 related to these assets.

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Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with the removal of certain segments of our oil, natural gas 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.

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

Asset retirement obligations as of December 31, 2006	$	708
Liabilities incurred and assumed in the current period		468
Revisions in estimated retirement obligations		(81)
Accretion expense		78
Asset retirement obligations as of December 31, 2007		1,173
Liabilities incurred and assumed in the current period		121
Accretion expense		136
Asset retirement obligations as of December 31, 2008	$	1,430

At December 31, 2008, $0.2 million of our asset retirement obligation was classified in "Accrued liabilities" under current liabilities in our Consolidated Balance Sheets. Liabilities incurred and assumed during the period are for properties acquired during each year. Certain of our unconsolidated affiliates have asset retirement obligations recorded at December 31, 2008 and 2007 relating to contractual agreements. These amounts are immaterial to our consolidated financial statements.

6. Net Investment in Direct Financing Leases

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline and a CO_2 pipeline segment to transport crude oil from and CO_2 to producing fields operated by Denbury. Denbury pays us a minimum payment each month for the right to use these pipeline segments. Those arrangements have been accounted for as direct financing leases. As discussed in Note 3, we entered into a lease arrangement with Denbury related to the NEJD Pipeline in May 2008 that is being accounted for as a direct financing lease. Denbury pays us fixed payments of $5.2 million per quarter that began in August 2008.

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

	December 31,			
	2008		2007	
Total minimum lease payments to be received	$	407,392	$	7,039
Estimated residual values of leased property (unguaranteed)		1,287		1,287
Unamortized initial direct costs		2,580		-
Less unearned income		(230,298)		(2,953)

Net investment in direct financing leases	$	180,961	$	5,373

At December 31, 2008, minimum lease payments to be received for each of the five succeeding fiscal years are $21.9 million per year for 2009 through 2011, $21.8 million for 2012 and $21.3 million for 2013.

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7. CO2 Assets

CO2 assets consisted of the following.

	December 31,	
	2008	2007
CO2 volumetric production payments	$ 43,570	$ 43,570
Less - Accumulated amortization	(19,191)	(14,654)
Net CO2 assets	$ 24,379	$ 28,916

The volumetric production payments entitle us to a maximum daily quantity of CO2 of 101,375 million cubic feet, or Mcf, per day through December 31, 2009, 91,875 Mcf per day for the calendar years 2010 through 2012 and 73,875 Mcf per day beginning in 2013 until we have received all volumes under the production payments. Under the terms of transportation agreements with Denbury, Denbury will process and deliver this CO2 to our industrial customers and receive a fee of $0.16 per Mcf, subject to inflationary adjustments. During 2008 this fee averaged $0.1927 per Mcf.

The terms of the contracts with the industrial customers include minimum take-or-pay and maximum delivery volumes. The seven industrial contracts expire at various dates between 2010 and 2016, with one small contract extending until 2023.

The CO2 assets are being amortized on a units-of-production method. After purchase price adjustments, we had 276.7 Bcf of CO2 at acquisition, and the total $43.6 million cost is being amortized based on the volume of CO2 sold each month. For 2008, 2007 and 2006, we recorded amortization of $4,537,000, $4,488,000 and $4,244,000, respectively. We have 153.8 Bcf of CO2 remaining under the volumetric production payments at December 31, 2008. Based on the historical deliveries of CO2 to the customers (which have exceeded minimum take-or-pay volumes), we expect amortization for the next five years to be approximately $4,537,000 from 2009 to 2010, $4,157,000 for 2011 and 2012 and $3,431,000 for 2013.

8. Equity Investees and Other Investments

Equity Investees

We are accounting for our 50% ownership in each of two joint ventures, T&P Syngas and Sandhill under the equity method of accounting. We paid $7.8 million more for our interest in these joint ventures than our share of capital on their balance sheets at the date of the acquisition. This excess amount of the purchase price over the equity in the joint ventures has been allocated to the tangible and intangible assets of the joint ventures based on the fair value of those assets, with the remainder of the excess purchase price of $0.7 million allocated to goodwill. The table below reflects information included in our consolidated financial statements related to our equity investees.

	Year Ended December 31,		
	2008	2007	2006
Genesis' share of operating earnings	1,137	1,898	1,690
Amortization of excess purchase price	(628)	(628)	(559)

Net equity in earnings	$	509	$	1,270	$	1,131
Distributions received	$	2,158	$	2,240	$	2,093

Other Projects

We have also invested $4.6 million in the Faustina Project, a petroleum coke to ammonia project that is in the development stage. All of our investment may later be redeemed, with a return, or converted to equity after the project has obtained construction financing. The funds we have invested are being used for project development activities, which include the negotiation of off-take agreements for the products and by-products of the plant to be constructed, securing permits and securing financing for the construction phase of the plant. We have recorded our investment in this debt security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed.

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No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair value of our investment at December 31, 2008, therefore the investment is included in our consolidated balance sheet at cost.

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

In connection with the Davison and DG Marine acquisitions (See Note 3), we allocated a portion of the purchase price to intangible assets based on their fair values. The following table reflects the components of intangible assets being amortized at December 31, 2008:

		December 31, 2008			December 31, 2007		
	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	$ 26,017	$ 68,637	$ 94,654	$ 9,380	$ 85,274
Supply and logistics customer relationships	5	35,430	9,957	25,473	34,630	3,287	31,343
Refinery services supplier relationships	2	36,469	24,483	11,986	36,469	9,241	27,228
Refinery services licensing agreements	6	38,678	7,176	31,502	38,678	2,218	36,460
Supply and logistics trade names - Davison and Grifco	7	18,888	3,118	15,770	17,988	930	17,058
Supply and logistics favorable lease	15	13,260	671	12,589	13,260	197	13,063
Other	5	1,322	346	976	721	97	624
Total	5	$ 238,701	$ 71,768	$ 166,933	$ 236,400	$ 25,350	$ 211,050

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The trade names are the Davison and Grifco names, which we retained the right to use in our operations. The favorable lease relates to a lease of 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 favorable lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $46.4 million and $25.4 million for the years ended December 31, 2008 and 2007, respectively.

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

	2009	2010	2011	2012	2013
Refinery services customer relationships	$ 15,433	$ 11,689	$ 8,972	$ 7,056	$ 7,116
Supply and logistics customer relationships	5,536	4,488	3,603	2,819	2,165
Refinery services supplier relationships	4,068	2,925	2,629	2,364	-
Refinery services licensing agreements	4,505	4,105	3,690	3,416	3,163
Supply and logistics trade name	2,326	2,086	1,851	1,432	1,237
Supply and logistics favorable lease	474	474	474	474	474
Other	285	187	53	54	56
Total	$ 32,627	$ 25,954	$ 21,272	$ 17,615	$ 14,211

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Goodwill

The carrying amount of goodwill by business segment at December 31, 2008 and 2007 was as follows:

	Refinery Services	Supply & Logistics	Total
2007 Additions:			
Davison acquisition	$ 297,621	$ 19,118	$ 316,739
Port Hudson Assets Acquisition	-	3,969	3,969
Balance, December 31, 2007	297,621	23,087	320,708
Davison acquisition, due to purchase price adjustments	4,338	-	4,338
December 31, 2008	$ 301,959	$ 23,087	$ 325,046

We performed our annual goodwill impairment test pursuant to SFAS 142 on October 1, 2008. The fair value of our supply and logistics and refinery services reporting units were estimated using a combined income (discounted cash flow) and market approach (guideline public company and comparable merged and acquired transactions) valuation method which indicated that the fair value of our net assets in each reporting unit exceeded the carrying value of that reporting unit, and an impairment charge was not required. The estimated fair value of our reporting units is dependent on several significant assumptions and estimates, including our growth rates for revenues and costs, changes in operating margins, future capital expenditures related to our existing operations, our cost of capital (discount rate) and cash flow market multiples. Our business plans and recent operating results also impact our estimate of the fair value of our reporting units.

SFAS 142 requires the performance of an interim goodwill impairment test if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Due to the ongoing deterioration of the credit markets and the overall macroeconomic conditions existing at December 31, 2008, we evaluated our fourth quarter performance and the outlook for our business segments, also considering the decline in our market capitalization, and concluded that we did not have a triggering event in the fourth quarter that would require the performance of an interim goodwill impairment test.

We will continue to monitor the general economic conditions, our operational and financial performance measures and our market capitalization to determine if a triggering event occurs and will perform an interim goodwill impairment analysis, if necessary. 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, 2008	December 31, 2007
Credit facility fees - Genesis	$ 5,022	$ 5,022
Credit facility fees - DG Marine	2,536	-
Initial direct costs related to Free State Pipeline lease	1,132	-
Deferred tax asset	1,543	941
Other deferred costs and deposits	7,502	3,284

		17,735		9,247
Less - Accumulated amortization		(2,322)		(850)
Net other assets	$	15,413	$	8,397

Amortization of the initial direct costs related to the Free State Pipeline lease for the year ended December 31, 2008 was $35,000. Amortization expense of credit facility fees for the years ended December 31, 2008, 2007 and 2006 was $1,437,000, $779,000 and $394,000, respectively. In the fourth quarter of 2006, we also charged to expense $575,000 of unamortized fees related to the facility that we replaced in November 2006. Total amortization of initial direct costs and credit facility fees for the next five years will be $1,993,000 for 2009 and 2010, $1,465,000 in 2011 and $60,000 in 2012 and 2013.

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10. Debt

At December 31, 2008 our obligations under credit facilities consisted of the following:

	December 31, 2008	December 31, 2007
Genesis Credit Facility	$ 320,000	$ 80,000
DG Marine Credit Facility (non-recourse to Genesis)	55,300	-
Total Long-Term Debt	$ 375,300	$ 80,000

Genesis Credit Facility

We have a $500 million credit facility $100 million of which can be used for letters of credit, with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The borrowing base is recalculated quarterly and at the time of material acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA (earnings before interest, taxes, depreciation and amortization), computed in accordance with the provisions of our credit facility.

The borrowing base may be increased to the extent of pro forma additional EBITDA, as defined in the credit agreement, attributable to acquisitions or internal growth projects with approval of the lenders. Our borrowing base as of December 31, 2008 exceeds $500 million.

At December 31, 2008, we had $320 million borrowed under our credit facility and we had $3.5 million in letters of credit outstanding. 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 November 15, 2011. The total amount available for borrowings at December 31, 2008 was $176.5 million under our credit facility.

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

- The interest rate on borrowings may be based on the prime rate or the LIBOR rate, at our option. The interest rate on prime rate loans can range from the prime rate plus 0.50% to the prime rate plus 1.875%. The interest rate for LIBOR-based loans can range from the LIBOR rate plus 1.50% to the LIBOR rate plus 2.875%. The rate is based on our leverage ratio as computed under the credit facility. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2008, our borrowing rates were the prime rate plus 0.50% or the LIBOR rate plus 1.50%.

- Letter of credit fees will range from 1.50% to 2.875% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2008, our letter of credit rate was 1.50%.

- We pay a commitment fee on the unused portion of the $500 million maximum facility amount. The commitment fee will range from 0.30% to 0.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2008, the commitment fee rate was 0.30%.

Collateral under the credit facility consists of substantially all our assets, excluding our interest in the NEJD pipeline, our ownership interest in the Free State pipeline, and the assets of and our equity interest in, DG Marine. All of the equity interest of DG Marine is pledged to secure its credit facility, which is described below. While our general partner is jointly and severally liable for all of our obligations unless and except to the extent those obligations provide that they are non-recourse to our general partner, our credit facility expressly provides that it is non-recourse to our general partner (except to the extent of its pledge of its general partner interest in certain of our subsidiaries), as well as to Denbury and its other subsidiaries.

Our credit facility contains customary covenants (affirmative, negative and financial) that limit the manner in which we may conduct our business. Our credit facility contains three primary financial covenants - a debt service coverage ratio, leverage ratio and funded indebtedness to capitalization ratio – that require us to achieve specific minimum financial metrics. In general, our debt service coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense. Our leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with our credit facility) to EBITDA (as adjusted). Our funded indebtedness ratio compares outstanding debt to the sum of our consolidated total funded debt plus our consolidated net worth.

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Financial Covenant	Requirement	Required Ratio through December 31, 2008	Actual Ratio as of December 31, 2008
Debt Service Coverage Ratio	Minimum	2.75 to 1.0	8.53 to 1.0
Leverage Ratio	Maximum	6.0 to 1.0	2.82 to 1.0
Funded Indebtedness Ratio	Maximum	0.80 to 1.0	0.39 to 1.0

Our credit facility includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. The ratios in the table above are the required ratios for the period following a material acquisition. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however, the amount of such distributions may not exceed the sum of the distributable cash (as defined in the credit facility) generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At December 31, 2008, the excess of distributable cash over distributions under this provision of the credit facility was $49.7 million.

DG Marine Credit Facility

In connection with its acquisition of the Grifco assets on July 18, 2008, DG Marine entered into a $90 million revolving credit facility with a syndicate of banks led by SunTrust Bank and BMO Capital Markets Financing, Inc. In addition to partially financing the Grifco acquisition, DG Marine may borrow under that facility for general corporate purposes, such as paying for its newly constructed barges and funding working capital requirements, including up to $5 million in letters of credit. That facility, which matures on July 18, 2011, is secured by all of the equity interests issued by DG Marine and substantially all of DG Marine's assets. Other than the pledge of our equity interest in DG Marine and our guaranty of $7.5 million, that facility is non-recourse to us and TD Marine. At December 31, 2008, our consolidated balance sheet included $115.8 million of DG Marine's assets in our total assets.

At December 31, 2008, DG Marine had $55.3 million outstanding under its credit facility. Due to the revolving nature of loans under the DG Marine credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date. The total amount available for borrowings at December 31, 2008 was $34.7 million under this credit facility.

The key terms for rates under the DG Marine credit facility are as follows:

- The interest rate on borrowings may be based on the prime rate or the LIBOR rate, at our option. The interest rate on prime rate loans can range from the prime rate plus 1.50% to the prime rate plus 4.00%. The interest rate for LIBOR-based loans can range from the LIBOR rate plus 2.50% to the LIBOR rate plus 5.00%. The rate is based on DG Marine's leverage ratio as computed under the credit facility. Under the terms of DG Marine's credit facility, the rates will fluctuate quarterly based on the leverage ratio. At December 31, 2008, DG Marine's borrowing rates were the prime rate plus 4.00% or the LIBOR rate plus 5.00%.
-

Letter of credit fees will range from 2.50% to 5.00% based on DG Marine's leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2008, there were no letters of credit outstanding under the DG Marine credit facility.

- DG Marine pays a commitment fee on the unused portion of the $90 million facility amount. The commitment fee will range from 0.25% to 0.50% based on its leverage ratio as computed under the credit facility. The rate will fluctuate quarterly based on the leverage ratio. At December 31, 2008, the commitment fee rate was 0.50%.

In August 2008, DG Marine entered into a series of interest rate swap agreements to effectively fix the underlying LIBOR rate on $32.9 million of its borrowings under its credit facility through July 18, 2011. The fixed interest rates in the swap agreements range from the three-month interest rate of 3.20% in effect at December 31, 2008 to 4.68% at July 18, 2011.

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DG Marine's credit facility contains customary covenants (affirmative, negative and financial) that limit the manner in which it may conduct its business. DG Marine's credit facility contains three primary financial covenants – an interest coverage ratio, leverage ratio and asset coverage ratio – that require DG Marine to achieve specific minimum financial metrics. In general, the interest coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense. The leverage ratio calculation compares DG Marine's funded debt (as calculated in accordance with the credit facility) to EBITDA (as adjusted). The asset coverage ratio compares an estimated liquidation value of DG Marine's boats and barges to DG Marine's outstanding debt.

Maturities of long-term debt in the next five years, including the DG Marine credit facility, are $375.3 million in 2011. We have estimated the fair value of our long-term debt to be approximately $358.4 million, or $16.9 million less than the carrying value of that debt based on consideration of our credit standing.

11. Partners' Capital and Distributions

Partner's capital at December 31, 2008 consists of 39,456,774 common units, including 4,028,096 units owned by our general partner and its affiliates, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest), and a 2% general partner interest.

Our general partner owns all of our general partner interest, including incentive distribution rights (IDRs), all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which is reflected as a minority interest in the Consolidated Balance Sheet at December 31, 2008) and operates our business.

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.

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 and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. As discussed in Note 10, our credit facility limits the amount of distributions we may pay in any quarter. At December 31, 2008, our restricted net assets (as defined in Rule 4-03(e)(3) of Regulations S-X) were $573.6 million.

Pursuant to our partnership agreement, our general partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds, in addition to its 2% general partner interest. The allocations of distributions between our common unitholders and our general partner, including the incentive distribution rights is as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Common Unit:		
Up to and including $0.25 per Unit	98.00%	2.00%
First Target - $0.251 per Unit up to and including $0.28 per Unit	84.74%	15.26%
Second Target - $0.281 per Unit up to and including $0.33 per Unit	74.26%	25.47%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02%	50.98%

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We paid distributions in 2007 and 2008 as follows:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2006	February 2007	$ 0.2100	$ 2,895	$ 59	$ -	$ 2,954
First quarter 2007	May 2007	$ 0.2200	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.2300	$ 3,170(1)	$ 65	$ -	$ 3,235(1)
Third quarter 2007	November 2007	$ 0.2700	$ 7,646	$ 156	$ 90	$ 7,892
Fourth quarter 2007	February 2008	$ 0.2850	$ 10,902	$ 222	$ 245	$ 11,369
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110

(1) The distribution paid on August 14, 2007 to holders of our common units is net of the amounts payable with respect to the common units issued in connection with the Davison transaction. The Davison unitholders and our general partner waived their rights to receive such distributions, instead receiving purchase price adjustments with us.

Net Income (Loss) per Common Unit

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

	Year Ended December 31, 2008	2007	2006
Numerators for basic and diluted net income (loss)per common unit:			
Income (loss) before cumulative effect adjustment	$ 26,089	$ (13,550)	$ 8,351
Less: General partner's incentive distribution paid	(2,035)	-	-
Subtotal	24,054	(13,550)	8,351
Less: General partner 2% ownership	(481)	271	(167)
Income (loss) before cumulative effect adjustment available for common unitholders	$ 23,573	$ (13,279)	$ 8,184
Income from cumulative effect adjustment	$ -	$ -	$ 30
Less: General partner 2% ownership	-	-	-

Income from cumulative effect adjustment available for common unitholders	$ -	$ -	$ 30
Denominator for basic per common unit:			
Common Units	38,961	20,754	13,784
Denominator for diluted per common unit:			
Common Units	38,961	20,754	13,784
Phantom Units	64	-	-
	39,025	20,754	13,784
Basic net income per common unit	$ 0.61	$ (0.64)	$ 0.59
Diluted net income per common unit	$ 0.60	$ (0.64)	$ 0.59

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Equity Issuances and Contributions

During the last three years we have issued a total of 15,495,940 common units in the acquisition of assets. A summary of these unit issuances is as follows:

Period	Acquisition Transaction	Units		Value Attributed to Assets
July 2008	Grifco	838	$	16,667
May 2008	Free State Pipeline	1,199	$	25,000
July 2007	Davison	13,459	$	330,000

We issued new common units to the public and our general partner for cash as follows:

Period	Purchaser of Common Units	Units		Gross Unit Price		Issuance Value		GP Contributions		Costs		Net Proceeds
December 2007	Public	9,200	$	22.000	$	202,400	$	-	$	8,846	$	193,554
December 2007	General Partner	735	$	21.120	$	15,518	$	4,447	$	-	$	19,965
July 2007	General Partner	1,075	$	20.836	$	22,361	$	6,171	$	-	$	28,532

On July 18, 2008, we issued 837,690 of our common units to Grifco. The units were issued at a value of $19.896 per unit, for a total value of $16.7 million, as a portion of the consideration for the acquisition of the inland marine transportation business of Grifco.

Additionally, on July 18, 2008, we redeemed 837,690 of our common units owned by members of the Davison family. Those units had been issued as a portion of the consideration for the acquisition of the energy-related business of the Davison family in July 2007. The redemption was at a value of $19.896 per unit, for a total value of $16.7 million. After giving effect to the issuance and redemption described above, we did not experience a change in the number of common units outstanding

On May 30, 2008, we issued 1,199,041 common units to Denbury in connection with the acquisition of the Free State pipeline. Our general partner also contributed $0.5 million to maintain its capital account balance.

On December 10, 2007 we issued 9,200,000 common units is a public offering, providing cash of $193.6 million after underwriters discount and offering costs. Our general partner exercised its right to maintain its proportionate share of our outstanding units and purchased 734,732 common units from us for $15.5 million, or $21.12 per common unit. Our general partner also contributed approximately $4.4 million to maintain its capital account balance.

In July 2007, we issued 13,459,209 common units to the entities owned and controlled by the Davison family as a portion of the purchase price. Additionally at that time, our general partner exercised its right to maintain its proportionate share of our outstanding common units by purchasing 1,074,882 common units from us for $22.4 million cash, or $20.8036 per common unit. As required under our partnership agreement, our general partner also contributed approximately $6.2 million to maintain its capital account balance.

Our general partner made a capital contribution of $1.4 million in December 2007 to offset a portion of the severance payment to a former executive. We also recorded a non-cash capital contribution of $3.4 million from our general partner for the estimated value of the compensation earned in 2007 under the proposed arrangements with our senior management team related to an incentive interest in our general partner. As the purpose of incentive interest is to incentivize these individuals to grow the partnership, the expense is recognized as compensation by us and a capital contribution by the general partner.

12. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate and intrastate crude oil, and to a lesser extent, natural gas and 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; (3) Industrial Gases – the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility, and (4) Supply and Logistics – terminaling, blending, storing, marketing, gathering and transporting by truck and barge crude oil and petroleum products. All of our revenues are derived from, and all of our assets are located in the United States.

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During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with the business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by the business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Previous periods have been restated to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. Our segment margin definition also excludes the non-cash effects of our stock-based compensation plans, 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.

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	Pipeline Transportation	Refinery Services	Industrial Gases (a)	Supply & Logistics	Total
Year Ended December 31, 2008					
Segment margin excluding depreciation and amortization (b)	$ 33,149	$ 55,784	$ 13,504	$ 32,448	$ 134,885
Capital expenditures (c)	$ 262,200	$ 5,490	$ 2,397	$ 118,585	$ 388,672
Maintenance capital expenditures	$ 719	$ 1,881	$ -	$ 1,854	$ 4,454
Net fixed and other long-term assets (d)	$ 285,773	$ 434,956	$ 44,003	$ 245,815	$ 1,010,547
Revenues:					
External customers	$ 39,051	$ 233,871	$ 17,649	$ 1,851,113	$ 2,141,684
Intersegment (e)	7,196	(8,497)	-	1,301	-
Total revenues of reportable segments	$ 46,247	$ 225,374	$ 17,649	$ 1,852,414	$ 2,141,684
Year Ended December 31, 2007					
Segment margin excluding depreciation and amortization (b)	$ 14,170	$ 19,713	$ 13,038	$ 10,646	$ 57,567
Capital expenditures (c)	$ 6,592	$ 503,765	$ 1,104	$ 138,403	$ 649,864
Maintenance capital expenditures	$ 2,880	$ 469	$ -	$ 491	$ 3,840
Net fixed and other long-term assets (d)	$ 32,936	$ 468,068	$ 47,364	$ 145,915	$ 694,283
Revenues:					
External customers	$ 23,226	$ 62,095	$ 16,158	$ 1,098,174	$ 1,199,653
Intersegment (e)	3,985	-	-	(3,985)	-
Total revenues of reportable segments	$ 27,211	$ 62,095	$ 16,158	$ 1,094,189	$ 1,199,653
Year Ended December 31, 2006					
Segment margin excluding depreciation and amortization (b)	$ 13,280	$ -	$ 12,844	$ 5,017	$ 31,141
Capital expenditures (c)	$ 971	$ -	$ 6,058	$ 356	$ 7,385
Maintenance capital expenditures	$ 611	$ -	$ -	$ 356	$ 967
Net fixed and other long-term assets (d)	$ 31,863	$ -	$ 51,630	$ 7,602	$ 91,095
Revenues:					
External customers	$ 25,479	$ -	$ 15,154	$ 877,736	$ 918,369
Intersegment (e)	4,468	-	-	(4,468)	-
Total revenues of reportable segments	$ 29,947	$ -	$ 15,154	$ 873,268	$ 918,369

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(a) The industrial gases segment includes our CO2 marketing operations and the income from our investments in T&P Syngas and Sandhill.

(b) A reconciliation of segment margin to income before income taxes and minority interest for each year presented is as follows:

	Year Ended December 31,		
	2008	2007	2006
Segment margin excluding depreciation and amortization	$ 134,885	$ 57,567	$ 31,141
Corporate general and administrative expenses	(22,113)	(17,573)	(10,238)
Depreciation and amortization	(71,370)	(40,245)	(7,963)
Net (loss) gain on disposal of surplus assets	(29)	(266)	16
Interest expense, net	(12,937)	(10,100)	(1,374)
Non-cash expenses not included in segment margin	1,206	(1,855)	(1,343)
Other non-cash items affecting segment margin	(4,179)	(1,733)	(1,898)
Income (loss) before income taxes and minority interest	$ 25,463	$ (14,205)	$ 8,341

(c) Capital expenditures includes fixed asset additions and acquisitions of businesses.

(d) 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 Industrial Gases segment include investments in equity investees totaling $14.5 million, $16.2 million and $17.2 million at December 31, 2008, 2007 and 2006, respectively.

(e) 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.

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	Year Ended December 31, 2008	2007	2006
Truck transportation services provided to Denbury	$ 3,578	$ 1,791	$ 825
Pipeline transportation services provided to Denbury	$ 10,727	$ 5,290	$ 4,228
Payments received under direct financing leases from Denbury	$ 11,519	$ 1,188	$ 1,186
Pipeline transportation income portion of direct financing lease fees	$ 11,011	$ 641	$ 655
Pipeline monitoring services provided to Denbury	$ 120	$ 120	$ 65
Directors' fees paid to Denbury	$ 195	$ 150	$ 120
CO2 transportation services provided by Denbury	$ 6,424	$ 5,213	$ 4,640
Crude oil purchases from Denbury	$ -	$ 101	$ 1,565
Operations, general and administrative services provided by our general partner	$ 51,872	$ 22,490	$ 16,777
Distributions to our general partner on its limited partner units and general partner interest, including incentive distributions	$ 6,463	$ 1,671	$ 963
Sales of CO2 to Sandhill (for the period since Sandhill became a related party)	$ 2,941	$ 2,783	$ 2,056
Petroleum products sales to Davison family businesses	$ 1,261	$ -	$ -
Transition services costs to Davison family	$ -	$ 9,880	$ -

Transportation Services

We provide truck transportation services to Denbury to move their crude oil from the wellhead to our Mississippi pipeline. Denbury pays us a fee for this trucking service that varies with the distance the crude oil is trucked. These fees are reflected in the statement of operations as supply and logistics revenues.

Denbury is the only shipper on our Mississippi pipeline other than us, and we earn tariffs for transporting their oil. We earned fees from Denbury for the transportation of their CO2 on our Free State pipeline. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven and NEJD CO2 pipelines and recorded pipeline transportation income from these arrangements.

We also provide pipeline monitoring services to Denbury. This revenue is included in pipeline revenues in the statements of operations.

Directors’ Fees

We paid Denbury for the services of each of four of Denbury’s officers who serve as directors of our general partner, at an annual rate and for attendance at meetings that are the same as the rates at which our independent directors were paid.

CO2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO2 for us to our customers.   In 2008, the inflation-adjusted transportation fee averaged $0.1927 per Mcf.

Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions are provided by our general partner. We reimburse the general partner for all direct and indirect costs of these services, excluding any payments to our management team pursuant to their Class B Membership Interests. See Note 15.

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Amounts due to and from Related Parties

At December 31, 2008 and 2007, we owed Denbury $1.0 million, respectively, for CO2 transportation charges. Denbury owed us $2.0 million and $0.9 million for transportation services at December 31, 2008 and 2007, respectively. We owed our general partner $2.1 million and $0.7 million for administrative services at December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007, Sandhill owed us $0.7 and $0.5 million for purchases of CO2, respectively. At December 31, 2007, we owed the Davison family entities $0.8 million for reimbursement of costs paid primarily related to employee transition services.

Drop-down transactions

On May 30, 2008, we entered into a $175 million financing lease arrangement with Denbury Onshore for its NEJD Pipeline System, and acquired its Free State CO2 pipeline system for $75 million, consisting of $50 million cash and $25 million of our common units. See Note 3.

Unit redemption

As discussed in Note 11, we redeemed 837,690 of our common units owned by members of the Davison family. The total value of the units redeemed was $16.7 million.

DG Marine joint venture

Our partner in the DG Marine joint venture is TD Marine, LLC, a joint venture consisting of three members of the Davison family. See Note 3.

Financing

Our credit facility is non-recourse to our general partner, except to the extent of its pledge of its 0.01% general partner interest in Genesis Crude Oil, L.P. Our general partner's principal assets are its general and limited partnership interests in us. Our credit agreement obligations are not guaranteed by Denbury or any of its other subsidiaries.

We guarantee 50% of the obligation of Sandhill to a bank. At December 31, 2008, the total amount of Sandhill's obligation to the bank was $3.0 million; therefore, our guarantee was for $1.5 million.

Approximately 14% of the outstanding common shares of Community Trust Bank are held by Davison family members. Community Trust Bank is a 17% participant in the DG Marine credit facility. James E. Davison, Jr., a member of our board of directors, also serves on the board of the holding company that owns Community Trust Bank.

As discussed in Note 11, our general partner made capital contributions in order to maintain its capital account totaling $0.5 million and $10.6 million in 2008 and 2007, respectively. Our general partner also purchased common units totaling $37.9 million in 2007. In addition, our general partner made a capital contribution of $1.4 million in December 2007 to offset a portion of the severance payment to a former executive. In 2007, we recorded a capital contribution from our general partner of $3.4 million related to compensation recognized for our executive management team. See Note 15.

In December 2008, our general partner established Class B Membership Interests in our general partner to be used as long-term incentive compensation for our senior executives. See Note 15.

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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, 2008	2007	2006
Decrease (increase) in:			
Accounts receivable	$ 61,126	$ (35,362)	$ (6,472)
Inventories	(5,557)	(143)	(4,664)
Other current assets	(2,419)	(1,887)	870
Increase (decrease) in:			
Accounts payable	(58,224)	34,523	1,359
Accrued liabilities	3,812	6,149	34
Net changes in components of operating assets and liabilities, net of working capital acquired	$ (1,262)	$ 3,280	$ (8,873)

Cash received by us for interest during the years ended December 31, 2008, 2007 and 2006 was $0.1 million, $0.3 million and $0.2 million, respectively. Payments of interest and commitment fees were $11.3 million, $8.4 million and $1.0 million, during the years ended December 31, 2008, 2007 and 2006, respectively.

Cash paid for income taxes in during the years ended December 31, 2008 and 2007 was $2.4 million and $1.6 million, respectively.

At December 31, 2008 and 2007, we had incurred liabilities for fixed asset additions totaling $1.7 million and $0.9 million, respectively, that had not been paid at the end of the year and, therefore, are not included in the caption “Additions to property and equipment” on the Consolidated Statements of Cash Flows. We had incurred liabilities for other assets totaling $0.3 million at December 31, 2007 that had not been paid at the end of the year and, therefore, are not included in the caption “Other, net” under investing activities on the Consolidated Statements of Cash Flows.

In May 2008, we issued common units with a value of $25 million as part of the consideration for the acquisition of the Free State Pipeline from Denbury. In July 2008, we issued common units with a value of $16.7 million as part of the consideration for the acquisition of the inland marine transportation assets of Grifco. These common unit issuances are non-cash transactions and the value of the assets acquired is not included in investing activities and the issuance of the common units is not reflected under financing activities in our Consolidated Statements of Cash Flows. Additionally, we deferred payment of $12 million ($11.7 million discounted) of the consideration in the acquisition from Grifco to December 2008 and 2009. This deferral of the payment of consideration was a non-cash transaction and the value of the assets acquired is not included in investing activities and the payments due in December 2009 is not reflected under financing activities in our Consolidated Statements of Cash Flows. The subsequent payment in December 2008 of one-half of the consideration is included in financing cash flows.

In July 2007, we issued common units with a value of $330 million as part of the consideration in the Davison acquisition. This common unit issuance is a non-cash transaction and the value of the assets acquired is not included under investing activities and the issuance of the common units are not reflected under financing activities in our Consolidated Statements of Cash Flows.

In 2007, our general partner made a non-cash contribution to us in the amount of $3.4 million that is not included in financing activities in the Consolidated Statements of Cash Flows. This contribution related to the estimated compensation earned by our management team for its services in 2007 under the proposed compensation arrangement with these individuals that existed at December 31, 2007.

15. Employee Benefit Plans and Equity-Based Compensation Plans

We do not directly employ any of the persons responsible for managing or operating our activities. Employees of our general partner provide those services and are covered by various retirement and other benefit plans.

In order to encourage long-term savings and to provide additional funds for retirement to its employees, our general partner sponsors a profit-sharing and retirement savings plan. Under this plan, our general partner's matching contribution is calculated as an equal match of the first 3% of each employee's annual pretax contribution and 50% of the next 3% of each employee's annual pretax contribution. Our general partner also made a profit-sharing contribution of 3% 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 $2.2 million, $0.8 million, and $0.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our general partner also provided certain health care and survivor benefits for its active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. Our general partner plans to continue self-insuring these plans in the future. The expenses included in the consolidated statements of operations for these benefits were $1.7 million, $1.5 million, and $1.3 million in 2008, 2007 and 2006, respectively. Effective January 1, 2008, the employees who operate the assets we acquired from the Davison family became participants in these plans.

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Stock Appreciation Rights Plan

Under the terms of our stock appreciation rights plan, regular, full-time active employees (with the exception of our chief executive officer, chief operating officer and chief financial officer) and the members of the Board are eligible to participate in the plan. The plan is administered by the Compensation Committee of the Board, who shall determine, 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.

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 averages 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. The cash payment to the participant will be net of any applicable withholding taxes required by law. If the 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 plan, then the 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 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 SFAS No. 123 (revised December 2004), "Share-Based Payments.", 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.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we include the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount at each balance sheet date with the adjustment reflected in the statement of operations.

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, 2008	December 31, 2007	December 31, 2006
Expected life of rights (in years)	1.25 - 6.00	2.25 - 6.25	3.25 - 7.00

Risk-free interest rate	0.57% - 1.71%	3.12% - 3.65%	4.53% - 4.57%
Expected unit price volatility	42.8%	34.2%	32.1%
Expected future distribution yield	6.00%	6.00%	6.00%

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- In determining the expected life of the rights, we use the simplified method allowed by the Securities and Exchange Commission. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee exercise patterns.

- The expected volatility of our units is computed using the historical period we believe is representative of future expectations. We determined the period to use as the historical period by considering our distribution history and distribution yield.

- The risk-free interest rate was determined from the current yield for U.S. Treasury zero-coupon bonds with a term similar to the remaining expected life of the rights.

- In determining our expected future distribution yield, we considered our history of distribution payments, our expectations for future payments, and the distribution yields of entities similar to us. While current market conditions result in a higher distribution yield, we believe that the yield will be closer to 6% over the life of the outstanding rights.

- We estimated the expected forfeitures of non-vested rights and expirations of vested rights. We have very limited experience with employee forfeiture and expiration patterns, as our plan was not initiated until December 31, 2003. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also used different estimates for different groups of employees.

The following table reflects rights activity under our plan as of January 1, 2008, and changes during the year ended December 31, 2008:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2008	593,458	$ 15.45		
Granted during 2008	536,308	$ 20.83		
Exercised during 2008	(38,995)	$ 19.52		
Forfeited or expired during 2008	(72,786)	$ 21.23		
Outstanding at December 31, 2008	1,017,985	$ 18.09	7.9	$ -
Exercisable at December 31, 2008	381,016	$ 14.82	6.2	$ -

The weighted-average fair value at December 31, 2008 of rights granted during 2008 was $0.67 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights Granted in 2008	
Expected life of rights (in years)	5.25 - 6.00
Risk-free interest rate	1.57% - 1.71%

Expected unit price volatility	42.8%
Expected future distribution yield	6.00%

The total intrinsic value of rights exercised during 2008, 2007 and 2006 was $0.4 million, $1.6 million and $0.4 million, respectively, which was paid in cash to the participants.

At December 31, 2008, there was $0.2 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. This amount was calculated as the fair value at December 31, 2008 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, 2008, the remaining cost will be recognized over a weighted average period of approximately one year.

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We recorded charges and credits related to our stock appreciation rights for three years ended December 31, 2008 as follows:

Expense (Credits to Expense) Related to Stock Appreciation Rights

Statement of Operations	2008	2007	2006
Supply and logistics operating costs	$ (997)	$ 528	$ 362
Refinery services operating costs	23	-	-
Pipeline operating costs	(296)	420	289
General and administrative expenses	(1,141)	1,576	1,279
Total	$ (2,411)	$ 2,524	$ 1,930

2007 Long Term Incentive Plan

Our Genesis Energy, Inc. 2007 Long Term Incentive Plan (the "2007 LTIP") provides for awards of Phantom Units and Distribution Equivalent Rights to non-employee directors and employees of Genesis Energy, LLC, our general partner. Phantom Units are notional units representing unfunded and unsecured promises to deliver a Partnership common unit to the participant should specified vesting requirements be met. Distribution Equivalent Rights are rights to receive an amount of cash equal to all or a portion of the cash distributions made by the Partnership during a specified period. The 2007 LTIP is administered by the Compensation Committee of the board of directors of our general partner (the "Board").

The Compensation Committee (at its discretion) will designate participants in the 2007 LTIP, determine the types of awards to grant to participants, determine the number of units to be covered by any award, and determine the conditions and terms of any award including vesting, settlement and forfeiture conditions. The 2007 LTIP may be amended or terminated at any time by the Board or the Compensation Committee; however, any material amendment, such as a material increase in the number of units available under the 2007 LTIP or a change in the types of awards available under the 2007 LTIP, will also require the approval of our unitholders. The Compensation Committee is also authorized to make adjustments in the terms and conditions of and the criteria included in awards under the plan in specified circumstances.

The common units to be awarded under the 2007 Plan will be obtained by our general partner through purchases made on the open market, from us, from any affiliates of our general partner or from any other person; however, it is generally intended that units are to be acquired from us as newly-issued common units.

Subject to adjustment as provided in the 2007 LTIP, awards with respect to up to an aggregate of 1,000,000 units may be granted under the 2007 LTIP, of which 915,429 remain authorized for issuance at December 31, 2008. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of the units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures. Due to the positions of the small group of employees and non-employee directors who received these grants, we have assumed that there will be no forfeitures of these Phantom Units in our fair value calculation as of December 31, 2008. The grant date fair value of the awards are measured by reducing the grant date market price by the present value of the distributions expected to be paid on the shares during the requisite service period, discounted at an appropriate risk-free interest rate.

The aggregate grant date fair value of Phantom Unit awards granted during 2008 and 2007 was $0.8 million and $0.9 million, respectively. The total fair value of Phantom Units that vested during the year ended December 31, 2008 was $0.1 million. Compensation expense recognized during 2008 for Phantom Units was $0.7 million. Expense recorded during 2007 was less than $0.1 million. As of December 31, 2008, there was $0.9 million of unrecognized compensation expense related to these units. This unrecognized compensation cost is expected to be recognized over a weighted-average period of one year.

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The following table summarizes information regarding our non-vested Phantom Unit grants as of December 31, 2008:

Non-vested Phantom Unit Grants	Number of Units	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2007	-	
Granted during 2007	39,362	$ 21.92
Non-vested at December 31, 2007	39,362	$ 21.92
Granted during 2008	45,209	$ 17.63
Vested during 2008	(6,183)	$ 23.46
Non-vested at December 31, 2008	78,388	$ 19.32

The weighted-average fair value of Phantom Units granted during 2007 and 2008 was determined using the following assumptions:

Year Granted	Grant Date Price	Expected Distribution Rate	Risk Free Rate
2007	$ 24.52	$ 0.27	3.19% - 3.31%
2008	$ 15.50 - $21.30	$ 0.285 - $0.315	2.01% - 2.40%

Bonus Program

In January 2009, the Committee of the Board of our general partner approved a bonus program (referred to below as the Bonus Plan) for all employees of our general partner (with the exception of our Chief Executive Officer, Chief Operating Officer and Chief Financial Officer (collectively our “Senior Executives”)) that was applicable to 2008. The Bonus Plan is paid at the discretion of our Board based on the recommendation of the Compensation Committee, and can be amended or changed at any time. The Bonus Plan is designed to enhance the financial performance of the Partnership by rewarding employees for achieving financial performance and safety objectives. While the maximum amount that will be paid each year as bonuses is calculated based on two metrics, the actual amounts paid individually are discretionary and may total to less than the maximum that might otherwise be available.

The Bonus Plan is based primarily on the amount of money we generate for distributions to our unitholders, and is measured on a calendar-year basis. For 2008, two metrics were used to determine the bonus pool – the level of Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) that we generate and our company-wide safety record improvement. The level of Available Cash before Reserves generated for the year as a percentage of a target set by our Committee is weighted ninety percent and the achieved level of the targeted improvement in our safety record is weighted ten percent. The sum of the weighted percentage achievement of these targets is multiplied by the eligible compensation and the target percentages established by our Compensation Committee for the various levels of our employees to determine the maximum bonus pool from which the majority of our employees are paid bonuses.

A separate marketing bonus pool is available for compensating certain marketing personnel that is based on the contribution of that marketing group to Available Cash before Reserves. A minimum level of contribution to Available Cash before Reserves is required before any amounts are allocated to the marketing bonus pool.

For 2008, we accrued $4.0 million for the general bonus pool and $0.5 million for the marketing bonus pool in 2008. These bonuses were paid to employees in March 2009. In 2007 and 2006, we accrued $2.0 million and $1.8 million for bonuses under previous bonus arrangements.

Severance Protection Plan

In June 2005, the Compensation Committee of the Board of Directors of our general partner approved the Genesis Energy Severance Protection Plan, or Severance Plan, for employees of our general partner (with the exception of the new senior management team.) The Severance Plan provides that a participant in the Plan is entitled to receive a severance benefit if his employment is terminated during the period beginning six months prior to a change in control and ending two years after a change in control, for any reason other than (x) termination by our general partner for cause or (y) termination by the participant for other than good reason. Termination by the participant for other than good reason would be triggered by a change in job status, a reduction in pay, or a requirement to relocate more than 25 miles.

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A change in control is defined in the Severance Plan. Generally, a change in control is a change in the control of Denbury, a disposition by Denbury of more than 50% of our general partner, or a transaction involving the disposition of substantially all of the assets of Genesis.

The amount of severance is determined separately for three classes of participants. The first class, which includes two Executive Officers of Genesis, would receive a severance benefit equal to three times that participant's annual salary and bonus amounts. The second class, which includes certain other members of management, would receive a severance benefit equal to two times that participant's salary and bonus amounts. The third class of participant would receive a severance benefit based on the participant's salary and bonus amounts and length of service. Participants would also receive certain medical and dental benefits.

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. These Class B Membership Interests compensate the holders thereof by providing rewards based on increased shares of the cash distributions attributable to our incentive distribution rights (or IDRs)(See Note 11) to the extent we increase Cash Available Before Reserves, or CABR (defined below) (from which we pay distributions on our common units) above specified targets. CABR generally means Available Cash before Reserves, less Available Cash before Reserves generated from specific transactions with our general partner and its affiliates (including Denbury Resources Inc.) The Class B Membership Interests do not provide any Senior Executive with a direct interest in any assets (including our IDRs) owned by our general partner. During his employment with our general partner, each Senior Executive will be entitled to receive quarterly distributions in respect of his Class B Membership Interest from our general partner in amounts equal to a percentage of the distributions we pay in respect of our IDRs. Each Senior Executive's quarterly distribution percentage of our IDRs may vary from quarter-to-quarter based on a formula included in the agreements. In addition, upon the occurrence of specified events and circumstances, our general partner will redeem a Senior Executive's Class B Membership Interest when that executive's employment with our general partner is terminated or when a change of control occurs. Additionally our chief executive officer and chief operating officer participate in a deferred compensation plan, whereby they may be entitled to receive a cash payment upon termination of employment.

Our general partner has agreed that it will not seek reimbursement (on behalf of itself or its affiliates) under our partnership agreement for the costs of these Senior Executive compensation arrangements to the extent relating to their ownership of Class B Membership Interests (including current cash distributions made by the general partner out of its IDRs and payment of redemption amounts for those IDRs) and the deferred compensation amounts.

Although our general partner will not seek reimbursement for the costs of the Class B Membership Interests and deferred compensation plan arrangements, we will record non-cash expense. The Class B Membership Interests awarded to our senior executives will be accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards will be recomputed at each measurement date and the expense to be recorded will be adjusted based on that fair value. Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value will be affected by the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. Included within the assumptions used to prepare these estimates are projections of available cash and distributions to our common unitholders and general partner, including an assumed level of growth and the effects of future new growth projects during the four-year vesting period. These assumptions were used to estimate the total amount that would be paid under the Class B Membership awards through the final vesting date and are do not represent the contractual amounts payable under these awards at the reporting date. The estimated total amount was discounted to December 31, 2008 using a discount rate of 16%, representing the risks inherent in the assumptions we used and the time until final vesting. Due to the limited number of participants in the Class B Membership awards, we assumed a forfeiture rate of zero. At December 31, 2008, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date is approximately $12 million. The fair value of these incentive awards will be recomputed each quarter beginning with the quarter ending March 31, 2009 through the final settlement of the awards. Compensation expense of $3.4 million was recorded in the fourth quarter of 2007 related to the previous arrangements between our general partner and our Senior Executives. The fair value to be recorded by us as compensation expense will be the excess of the recomputed estimated fair value over the previously recorded $3.4 million. Due to the vesting conditions for the awards, the amount to which the Senior Executives were entitled on December 31, 2008 for the Class B Membership Awards and the related deferred compensation was zero. Management's estimates of fair value are made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at December 31, 2008. This expense will be recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions will change the amount of compensation cost we record.

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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.

Shell Oil Company accounted for 14.6% of total revenues in 2008. Shell Oil Company and Occidental Energy Marketing, Inc. accounted for 20.7% and 11.2% of total revenues in 2007, respectively. Occidental Energy Marketing, Inc., Shell Oil Company and Calumet Specialty Products Partners, L.P. accounted for 20.3%, 19.1% and 10.9% of total revenues in 2006, respectively. The revenues from these five customers in all three years relate primarily to our supply and logistics operations.

17. Derivatives

Our market risk in the purchase and sale of crude oil and petroleum products contracts is the potential loss that can be caused by a change in the market value of the asset or commitment. In order to hedge our exposure to such market fluctuations, we may enter into various financial contracts, including futures, options and swaps. Historically, any contracts we have used to hedge market risk were less than one year in duration, although we have the flexibility to enter into arrangements with a longer term. The derivative instruments that we use consist primarily of futures and options contracts traded on the NYMEX which we use to hedge our exposure to commodity prices, primarily crude oil, fuel oil and petroleum products.

Additionally, DG Marine entered into a series of interest rate swap contracts with two financial institutions related to $32.9 million of the outstanding debt under the DG Marine credit facility. These swaps effectively convert this portion of DG Marine’s debt from floating LIBOR rate to a series of fixed rates through July 2011. We have determined that these swaps are effective cash flow hedges of DG Marine’s interest rate exposure.

At December 31, 2008 and 2007, we had no commodity price risk derivatives that were designated as hedges for financial reporting purposes. Therefore, the derivative contracts were marked to fair value based on the closing price for the contracts at the end of each period and an asset or liability was recorded for the fair value and the change in fair value was recorded in our consolidated statements of operations.

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The following table summarizes the liabilities on our consolidated balance sheet that are related to the fair value of our open derivative positions:

	December 31, 2008	December 31, 2007
Decrease in other current assets	$ (488)	$ (744)
Increase in accrued liabilities	(698)	-
Increase in other long-term liabilities	(1,266)	-
Total liabilities	$ (2,452)	$ (744)

The liabilities related to the fair value of our open positions consists of unrealized gains/losses recognized in earnings and unrealized losses deferred to other comprehensive income ("OCI") as follows, by category (losses designated in parentheses):

	December 31, 2008				December 31, 2007	
	Total Liabilities	Losses	Minority Interests	OCI	Total Liabilities	Losses
Commodity price risk derivatives	$ (488)	$ (488)	$ -	$ -	$ (744)	$ (744)
Interest rate risk hedging by DG Marine	(1,964)	-	(1,002)	(962)	-	-
Total	$ (2,452)	$ (488)	$ (1,002)	$ (962)	$ (744)	$ (744)

In each year, the impact on earnings of our unrealized losses from commodity price risk derivatives in the table above is included in the Consolidated Statements of Operations under the caption "Supply and logistics costs."

The net loss recorded in AOCI and minority interests is expected to be reclassified to future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility is recorded. We expect the total net loss to be reclassified into earnings during the period the swaps are outstanding, with $0.7 million of net loss expected to be reclassified in 2009 and a total of $1.3 million reclassified to earnings during 2011 and 2012. Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified to earnings will differ and could vary materially as a result of changes in market conditions.

We determined that the remainder of our derivative contracts qualified for the normal purchase and sale exemption and were designated and documented as such at December 31, 2008 and December 31, 2007.

18. Fair-Value Measurements

As discussed in Note 2, effective January 1, 2008 we partially adopted SFAS 157. As defined in SFAS 157, fair value as the price that would be received from selling an asset, or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Whenever possible, we use market data that market participants would use when pricing an asset or liability. These inputs can be either readily observable or market corroborated. We apply the market approach for recurring fair value measurements related to our derivatives. SFAS 157 establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement)

The 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, 2008. As required by SFAS 157, 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.

	Fair Value at December 31, 2008		
Recurring Fair Value Measures	Level 1	Level 2	Level 3
Commodity derivatives (based on quoted market prices on NYMEX)	$ (488)	$ -	$ -
Interest rate swaps	$ -	$ -	$ (1,964)

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Level 1

Included in Level 1 of the fair value hierarchy are 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 3

Included within Level 3 of the fair value hierarchy are our interest rate swaps. The fair value of our interest rate swaps is based on indicative broker price quotations. These derivatives are included in Level 3 of the fair value hierarchy because broker price quotations used to measure fair value are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these Level 3 derivatives is not based upon significant management assumptions or subjective inputs.

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as level 3 in the fair value hierarchy:

	Year Ended December 31, 2008
Balance as of January 1, 2008	$ -
Realized and unrealized gains (losses)-	
Included in other comprehensive income	(962)
Included in minority interests	(1,002)
Balance as of December 31, 2008	$ (1,964)

See Note 17 for additional information on our derivative instruments.

We generally apply fair value techniques on a non-recurring basis associated with (1) valuing the potential impairment loss related to goodwill pursuant to SFAS 142, and (2) valuing potential impairment loss related to long-lived assets accounted for pursuant to SFAS 144.

19. Commitments and Contingencies

Commitments and Guarantees

In 2008, we entered into a new office lease for our corporate headquarters that extends until January 31, 2016. We lease office space for field offices under leases that expire between 2008 and 2013. To transport products, we lease tractors and trailers for our crude oil gathering and marketing activities and lease barges and railcars for our refinery services segment. 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, 2008, were as follows (in thousands).

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2009	$ 745	$ 3,322	$ 1,257	$ 5,324
2010	813	3,071	322	4,206
2011	794	2,639	322	3,755
2012	762	1,552	322	2,636
2013	733	726	322	1,781
2014 and thereafter	1,534	2,583	6,950	11,067
Total minimum lease obligations	$ 5,381	$ 13,893	$ 9,495	$ 28,769

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

Year ended December 31, 2008	$ 8,757
Year ended December 31, 2007	$ 6,079
Year ended December 31, 2006	$ 3,258

We have guaranteed the payments by our operating partnership to the banks under the terms of our credit facility related to borrowings and letters of credit. To the extent liabilities exist under the letters of credit, such liabilities are included in the consolidated balance sheet. Borrowings at December 31, 2008 were $320.0 million and are reflected in the consolidated balance sheet. We have also guaranteed the payments by our operating partnership under the terms of our operating leases of tractors and trailers. Such obligations are included in future minimum rental payments in the table above.

We guarantee $7.5 million of the outstanding debt of DG Marine under its credit facility. This guarantee will expire on May 31, 2009, if DG Marine's leverage ratio under its credit facility is less than 4.00 to 1.00. The outstanding debt of DG Marine in included in our Consolidated Balance Sheets. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

We guaranteed $1.2 million of residual value related to the leases of trailers. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

We guaranty 50% of the obligations of Sandhill under a credit facility with a bank. At December 31, 2008, Sandhill owed $3.0 million; therefore our guarantee was $1.5 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot be accurately estimated at this time, we expect that our annual expenditures for integrity testing, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines to average from $1.0 million to $1.5 million.

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 adverse 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 portion of the operations we acquired in the Davison transactions are owned by wholly-owned corporate subsidiaries that are taxable as corporations. We pay federal and state income taxes on these operations. The income taxes associated with these operations are accounted for in accordance with SFAS 109 “Accounting for Income Taxes.”

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In May 2006, the State of Texas enacted a law which will require us to pay a tax of 0.5% on our "margin," as defined in the law, beginning in 2008 based on our 2007 results. The "margin" to which the tax rate is applied generally will be 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.

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have any impact on our consolidated financial statements.

As of December 31, 2007 we had unrecognized tax benefits of $1.0 million. At December 31, 2008 we have unrecognized tax benefits of $2.6 million. The change in the unrecognized tax benefits are a result of additions related to current year tax positions. If the unrecognized tax benefits at December 31, 2008 were recognized, $2.6 million would affect our effective income tax rate. There are no uncertain tax positions as of December 31, 2008 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly decrease during 2009.

Our income tax provision (benefit) is as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007
Current:		
Federal	$ 2,979	$ 1,665
State	872	339
Total current income tax expense	3,851	2,004
Deferred:		
Federal	(3,850)	(2,432