GENESIS ENERGY LP
Form 10-K
February 26, 2010

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

Form 10-K

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

For the fiscal year ended December 31, 2009

OR

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

Commission file number 1-12295

GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware (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 Amex LLC

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 £ No R

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

Yes £ No R

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 R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes £   No £

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

R

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 £   Accelerated filer R   Non-accelerated filer £   Smaller reporting company £

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

Yes £   No R

The aggregate market value of the common units held by non-affiliates of the Registrant on June 30, 2009 (the last business day of Registrant’s most recently completed second fiscal quarter) was approximately $300,168,000 based on $12.72 per unit, the closing price of the common units as reported on the NYSE Amex LLC (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 19, 2010, the Registrant had 39,585,692 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; "Quintana" means Quintana Capital Group II, L.P. and its affiliates; "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 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, 2009.

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. We provide an integrated suite of services to refineries; oil, natural gas and CO2 producers; industrial and commercial enterprises that use NaHS and caustic soda; and businesses that use CO2 and other industrial gases. Substantially all of our revenues are derived from providing services to integrated oil companies, large independent oil and gas or refinery companies, and large industrial and commercial enterprises.

We conduct our operations 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. We manage our businesses through four divisions that constitute our reportable segments:

Pipeline Transportation—We transport crude oil and CO2 for others for a fee in the Gulf Coast region of the U.S. through approximately 550 miles of pipeline. Our Pipeline Transportation segment owns and operates three crude oil common carrier pipelines and two CO2 pipelines. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage terminals and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. Our 90-mile Texas System transports crude oil from West Columbia to several delivery points near Houston. Our crude oil pipeline systems include access to a total of approximately 0.7 million barrels of crude oil storage.

Our Free State Pipeline is an 86-mile, 20" CO2 pipeline that extends from CO2 source fields near Jackson, Mississippi, to oil fields in eastern Mississippi. We have a twenty-year transportation services agreement (through 2028) related to the transportation of CO2 on our Free State Pipeline.

In addition, Denbury Resources Inc. and its subsidiaries (Denbury) has leased from us (through 2028) the NEJD Pipeline System, a 183-mile, 20" CO2 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana. The NEJD System transports CO2 to tertiary oil recovery operations in southwest

Mississippi.

Refinery Services—We primarily (i) provide services to eight refining operations located predominantly in Texas, Louisiana and Arkansas; (ii) operate significant storage and transportation assets in relation to our business and (iii) sell NaHS (commonly pronounced as “nash”) and caustic soda to large industrial and commercial companies. Our refinery services primarily involve processing refiner’s high sulfur (or “sour”) gas streams to remove the sulfur. NaHS is a by-product derived from our refinery services process, and it constitutes the sole consideration we receive for these services. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including ConocoPhillips, CITGO and Ergon. Our refinery services footprint also includes terminals and we utilize railcars, ships, barges and trucks to transport product. Our refinery services contracts are typically long-term in nature and have an average remaining term of four years. We believe we are one of the largest marketers of NaHS in North and South America.

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Supply and Logistics—We provide services primarily to Gulf Coast oil and gas producers and refineries through a combination of purchasing , transporting, storing, blending and marketing of crude oil and refined products, primarily fuel oil. In connection with these services, we utilize our portfolio of logistical assets consisting of trucks, terminals, pipelines and barges. We have access to a suite of more than 270 trucks, 270 trailers and 1.6 million barrels of terminal storage capacity in multiple locations along the Gulf Coast as well as capacity associated with our three common carrier crude oil pipelines. In addition, our ownership interest in DG Marine provides us with access to twenty barges which, in the aggregate, include approximately 660,000 barrels of refined product transportation capacity. Usually, our supply and logistics segment experiences limited commodity price risk because it involves back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis. Unsold volumes are hedged with NYMEX derivatives to offset the remaining price risk.

Industrial Gases.

We provide CO2 and certain other industrial gases and related services to industrial and commercial enterprises.

We supply CO2 to industrial customers under long-term contracts. 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 volumetric production payments (also known as VPPs), minus transportation costs. In addition to supplying CO2, we own a 50% joint venture interest in T&P Syngas, from which we receive distributions earned from fees for manufacturing syngas (a combination of carbon monoxide and hydrogen), by Praxair, our 50% joint venture partner. Our other joint venture is a 50% interest in Sandhill Group, LLC, through which we process raw CO2 for sale to other customers for uses ranging from completing oil and natural gas producing wells to food processing.

Our General Partner and our Relationship with Quintana Capital Group and the Davison Family

On February 5, 2010, affiliates and co-investors of Quintana Capital Group II, L.P., along with members of the Davison family and members of our Senior Executive Management team (collectively the Quintana-Controlled Owner Group), acquired control of our general partner. Our general partner owns all of our general partner interest and all of our incentive distribution rights.

Quintana, an energy-focused private-equity firm headquartered in Houston, Texas, has stated that it intends to use us as one of its primary vehicles for investing in the midstream segment of the energy sector. Through its affiliated investment funds, Quintana, which has offices in Houston, Dallas and Midland, Texas and Beijing, China, currently manages approximately $900 million in capital for various U.S. and international investors. Quintana focuses on control-oriented investments across a wide range of sectors in the energy industry, developing a portfolio that is diversified across the energy value chain. Quintana is managed by highly experienced investors, including Corbin J. Robertson, Jr. and former Secretary of Commerce Donald L. Evans.

Members of the Davison family have invested in us since 2007. In addition to their investment in our general partner, members of the Davison family own approximately 30% of our common units and 51% of DG Marine, our inland marine transportation joint venture.

Prior to Quintana’s investment in us, Denbury Resources Inc. (NYSE:DNR) controlled our general partner. Denbury retained ownership of 10.2% of our outstanding common units after the sale to Quintana.

Although affiliates of our general partner are our investors, customers and transaction counterparties from time to time, neither our general partner nor any of its affiliates is obligated to enter into any additional transactions with (or to offer any opportunities to) us or to promote our interest, and neither our general partner or any of its affiliates 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, our general partner and each of its affiliates may, at any time, and without notice, alter its business strategy, including determining that it no longer desires to use us as an investment vehicle or a provider of any services. If our general partner or any of its affiliates were to make one or more offers to us, we cannot say that we would elect to pursue or consummate any such opportunity. Thus, though our relationship with our general partner is a strength, it also is a source of potential conflicts. For more information regarding our relationships with Quintana, members of the Davison family, and certain other affiliates, please read the section entitled "Certain Relationships and Related Transactions, and Director Independence."

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Business Strategy

Our primary business strategy is to provide an integrated suite of transportation, storage and marketing services to oil and gas producers, refineries and other customers. Successfully executing this strategy will enable us to generate sustainable cash flows to allow us to make quarterly cash distributions to our unitholders and to increase those distributions over time. We intend to develop our business by:

- Maintaining a balanced and diversified portfolio of assets to service our customers;
- Optimizing our existing assets and creating synergies through additional commercial and operating advancement;
- Enhancing and offering additional types of services to customers in our supply and logistics segment;
- Expanding the geographic reach of our refinery services and supply and logistics segments; and
- Broadening our asset base through strategic organic development projects as well as acquisitions.

Financial Strategy

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

- Maintain a prudent capital structure that will allow us to execute our growth strategy;
- Enhance our credit metrics and gain access to additional liquidity;
- Increase cash flows generated through fee-based services, emphasizing longer-term contractual arrangements and managing commodity price risks; and
- Create strategic arrangements and share capital costs and risks through joint ventures and strategic alliances.

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:

- Our businesses encompass a balanced, diversified portfolio of customers, operations and assets. We operate four business segments and own and operate assets which enable us to provide a number of services to refinery owners; oil, natural gas and CO_2 producers; industrial and commercial enterprises that use NaHS and caustic soda; and businesses which use CO_2 and other industrial gases. Our business lines complement each other as they allow us to offer an integrated suite of services to common customers across segments.
- Our pipeline transportation and related assets are strategically located. Our owned and operated crude oil pipelines are located in the Gulf Coast region and provide our customers access to multiple delivery points. In addition, a majority of our terminals are located in areas which can be accessed by either truck, rail or barge,
- The scale of our refinery services operations as well as our expertise and reputation for high performance standards and quality enable us to provide refiners with economic and proven services. We believe we are one of the largest marketers of NaHS in North and South America and we have a suite of assets which enables us to facilitate growth

in our business. In addition, our extensive understanding of the sulfur removal process and refinery services market provides us with an advantage when evaluating new opportunities and/or markets.

- Our supply and logistics business is operationally flexible. Our portfolio of trucks, barges and terminals affords us flexibility within our existing regional footprint and the capability to enter new markets and expand our customer relationships.

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- We are financially flexible and maintain significant liquidity. As of December 31, 2009, we had $320 million of loans and $5.2 million in letters of credit outstanding under our $500 million credit facility. Our borrowing base was $407 million at December 31, 2009.

- Experienced, Knowledgeable and Motivated Senior Executive Management Team with Proven Track Record. Our senior executive 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. Through their ownership in our limited partner and general partner, our senior executive management team is incentivized to create value for our equity holders.

2010 Developments

Association with Quintana Capital Group

In February 2010, the Quintana-Controlled Owner Group acquired control of our general partner. Our general partner owns all our general partner interest and all of our incentive distribution rights.

Eighteen Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for eighteen consecutive quarters. On February 12, 2010, we paid a cash distribution of $0.36 per unit to unitholders of record as of February 5, 2010, an increase per unit of $0.0075 (or 2.1%) from the distribution in the prior quarter, and an increase of 9.1% from the distribution in February 2009. 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.

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 13 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 sum of revenues from regulated published tariffs and pipeline loss allowance revenues and the fixed and variable costs of operating and maintaining our pipelines.

We own and operate three 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 which are in various phases of being produced through tertiary recovery strategy, including CO2 injection and flooding. Increased production from these fields could create increased demand for our crude oil transportation services because of the close proximity of our pipeline.

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

Jay System. Our Jay System 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.

We completed construction of an extension of our existing Florida oil pipeline system in 2009 extending the system to producers operating in southern Alabama. The new lateral 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. The project also included gathering connections to approximately 35 wells, additional oil storage capacity of 20,000 barrels in the field and a new delivery connection to a refinery in Alabama.

Texas System. The Texas System extends 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 CO2 source fields at Jackson Dome, near Jackson, Mississippi, to oil fields in east Mississippi. In addition, the NEJD Pipeline System, a 183-mile, 20" CO2 pipeline extends from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana and is currently being used to transport CO2 for tertiary recovery operations in southwest Mississippi.

Customers

Currently greater than 90% of the volume on the Mississippi System orignates from oil fields operated by Denbury. Denbury is the largest producer (based upon 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 fields. Our customers on our Mississippi, Jay and Texas Systems are primarily large, energy companies. 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. Currently Denbury has rights to exclusive use of our Free State Pipeline.

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

Our refinery services segment primarily (i) provides sulfur-extraction services to eight refining operations predominately located in Texas, Louisiana and Arkansas and (ii) transports and sells to commercial customers two products related to its refinery services activities – NaHS and caustic soda (or NaOH), each of which is discussed in more detail below. Our refinery services activities involve processing high sulfur (or “sour”) gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses large quantities of caustic soda (the primary raw material used in our process) to act as a scrubbing agent under prescribed temperature and pressure to remove sulfur. Sulfur removal in a refinery is a key factor in optimizing production of refined products such as gasoline, diesel, and aviation fuel. Our sulfur removal technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS (commonly pronounced “nash”). The resultant NaHS constitutes the sole consideration we receive for our refinery services activities.

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In conjunction with our supply and logistics segment, we sell and deliver NaHS and caustic soda to over 100 customers. We believe we are one of the largest marketers of NaHS in North America and South America. By minimizing our costs by utilizing our own logistical assets and leased storage sites, we believe we have a competitive advantage over other suppliers of NaHS.

NaHS is used in the specialty chemicals business (plastic additives, dyes and personal care products), in pulp and paper business, and in connection with mining operations (nickel, gold and separating copper from molybdenum) as well as bauxite refining (aluminum). NaHS has also gained acceptance in environmental applications, including waste treatment programs requiring stabilization and reduction of heavy and toxic metals and flue gas scrubbing. Additionally, NaHS can be used for removing hair from hides at the beginning of the tannery process.

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

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") and the residual level of sulfur allowed in lubricants and fuels is required to be reduced by regulatory agencies domestically and internationally. 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, providing us the capacity to meet any increases in NaHS demand.

Customers

At December 31, 2009, we provided onsite services utilizing NaHS units at eight refining locations, and we managed sulfur removal by exclusive rights to market NaHS produced at three third-party sites. While some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. These NaHS facilities are located primarily in the southeastern United States.

We sell our NaHS to customers in a variety of industries, with the largest customers involved in copper mining and the production of paper and pulp. We sell to customers in the copper mining industry in the western United States, Canada and Mexico. We also export the NaHS to South America for sale to customers for mining in Peru and Chile. No customer of the refinery services segment is responsible for more than ten percent of our consolidated revenues. Approximately 12% of the revenues of the refinery services segment in 2009 resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc. While the market price of copper and other ores where NaHS finds application declined in 2009 creating a reduction in mining operations and economic circumstances resulted in reduced demand for paper and pulp products from the paper mills that purchase NaHS, provisions in our service contracts with refiners allow us to adjust our sour gas processing rates (sulfur removal) to maintain a balance between NaHS supply and demand.

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

Competition for Refinery Services and Sales of NaHS and Caustic Soda

We believe that the U.S. refinery industry's demand for sulfur extraction services will increase because we believe sour oil will constitute an increasing portion of the total worldwide supply of crude oil and the phase in of stricter passenger vehicle emission standards will require refiners to produce additional quantities of low sulfur fuels. Both of these conditions can be met by refineries installing our sulfur removal technology under refinery service agreements. 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, our proven reliability and the regulatory permit processes required when changing methods of handling sulfur. NaHS technology is a reliable and cost effective manner to control refinery operating costs regardless of the crude slate being processed. 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 these refineries to continue to outsource their existing refinery services functions to us.

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

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

Supply and Logistics

Through our supply and logistics segment we provide a wide array of services to oil producers and refiners in the Gulf Coast region. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by truck to pipeline injection points and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via truck, railcar or barge, and sell refined products to customers in wholesale markets. Our barge transportation services are provided through DG Marine, in which we have a 49% interest. For our supply and logistics services, we generate fee-based income and profit from the difference between the price at which we re-sell the crude oil and petroleum products less the price at which we purchase the oil and products, minus the associated costs of aggregation and transportation.

Our crude oil supply and logistics operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations help to ensure (among other things) a base supply source for our oil pipeline systems and our refinery customers while providing our producer customers with a market outlet for their production. By utilizing our network of trucks, terminals and pipelines, we are able to provide transportation related services to crude oil producers and refiners as well as enter into back-to-back gathering and marketing arrangements with these same parties. Additionally, our crude oil gathering and marketing expertise and knowledge base, provides us with an ability to capitalize on opportunities which arise from time to time in our market areas. Given our network of terminals, we have the ability to store crude oil during periods of contango (oil prices for future deliveries are higher than for current deliveries) for delivery in future months. When we purchase and store crude oil during periods of contango, we limit commodity price risk by simultaneously entering into a contract to sell the inventory in 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 generally accepted accounting principles. See Note 17 of the Notes to the Consolidated Financial Statements. The most substantial component of the costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks.

Our refined products supply and logistics operations and DG Marine’s operations are also concentrated in the Gulf Coast region, principally Texas and Louisiana. Through our footprint of owned and leased trucks, leased railcars, terminals as well as our interest in DG Marine and its barges, we are able to provide Gulf Coast area refineries with transportation services as well as market outlets for their finished refined products. We primarily engage in the transportation and supply of fuel oil, asphalt, diesel and gasoline to our customers in wholesale markets as well as paper mills and utilities. By utilizing our broad network of relationships and logistics assets, including our terminal accessibility, we have the ability to gather, from refineries, various grades of refined products and blend them to meet the requirements of our other market customers. Our refinery customers may choose to manufacture various refined products depending on a number of economic and operating factors, and therefore we cannot predict the timing of contribution margins related to our blending services, However, when we are able to purchase and subsequently blend refined products, our contribution margin as a percentage of the revenues tends to be higher than the same percentage attributable to our recurring operations.

Within our supply and logistics business segment, in order to meet our customer needs, we employ many types of logistically flexible assets. These assets include 1.6 million barrels of leased and owned terminals, accessible by truck, rail or barge, 270 trucks and trailers, as well as barges with approximately 660,000 barrels of refined products capacity owned and operated by DG Marine. DG Marine's assets consist of ten pushboats and twenty double hulled, hot-oil asphalt-capable barges with capacities ranging from 30,000 to 38,000 barrels each.

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Customers and Competition

Our supply and logistics encompasses hundreds of producers and customers, for which we provide transportation related services, as well as gather from and market to crude oil and refined products. During 2009, 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.

In our crude oil supply and logistics operations, we compete with other midstream service providers and regional and local companies who may have significant market share in the areas in which they operate. In our supply and logistics refined products operations, we compete primarily with regional companies. Competitive factors in our supply and logistics business include price, relationships with our customers, range and quality of services, knowledge of products and markets, availability of trade credit and capabilities of risk management systems.

Industrial Gases

Overview

Our industrial gases segment is a natural outgrowth from our pipeline transportation business. 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.

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. 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, 2009, we have 127.0 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 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. These contracts expire between 2011 and 2023. Based on the current volumes being sold to our customers, we believe that we will need to acquire additional volumes from Denbury in 2014. When our VPPs expire, we will have to obtain additional CO2 supply should we choose to remain in the CO2 supply business.

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 CO_2 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.

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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. One of our sales contracts will expire on January 31, 2011. Sales under this contract accounted for $2.3 million, or 14%, of our industrial gases revenues in 2009. 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 30 customers, with sales to three of those customers representing approximately 66% of Sandhill's total revenues of approximately $10 million in 2009. In 2009, Sandhill sold approximately $1.5 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.

Competition

Currently, all of our CO2 supply is from our interest – our VPPs – in fields producing naturally occurring sources. In the future we may have to obtain our CO2 supply from manufactured processes. Naturally-occurring CO2, like that from the Jackson Dome area, occurs infrequently, and only in limited areas east of the Mississippi River. Our industrial CO2 customers have facilities that are connected to the NEJD CO2 pipeline, which makes delivery easy and efficient. Once our existing VPPs expire, we will have to obtain additional CO2 should we choose to remain in the CO2 supply business, and the competition and pricing issues we will face at that time are uncertain.

With regard to our CO2 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 CO2 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 CO2. As discussed above, the limited amounts of naturally-occurring CO2 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.

Geographic Segments

All of our operations are in the United States. Additionally, we transport and sell NaHS to customers in South America and Canada. Revenues from customers in foreign countries totaled approximately $9.5 million in 2009. The remainder of our revenues in 2009 and all of our revenues in 2008 and 2007 were generated from sales to customers in the United States.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies, independent refiners, and mining and other industrial companies that purchase NaHS. This energy industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and independent energy companies with stable payment experience. The credit risk related to contracts 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 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 2009 as a result of the tightening of the credit markets and the economic recession in the United States. 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, 2009 in the amount of $1.4 million. During 2009, we charged approximately $0.6 million to bad debt expense in our Consolidated Statements of Operations.

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Employees

To carry out our business activities, our general partner employed approximately 525 employees at December 31, 2009. Additionally, DG Marine employed 151 employees. None of these employees are represented by labor unions, and we believe that relationships with these employees are good.

Organizational Structure

Genesis Energy, LLC, a Delaware limited liability company, serves as our sole general partner and as the general partner of certain of our subsidiaries. Our general partner is controlled by Quintana Capital Group, L.P. Certain members of the Davison family and our Senior Management team own an interest in our general partner as described below. Below are charts depicting our ownership structure as of February 5, 2010 and December 31, 2009.

As of February 5, 2010:

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As of December 31, 2009:

(1)Through February 4, 2010, the incentive compensation arrangement between our general partner and our Senior Executive Management team (see Item 11. Executive Compensation.), represented by the Class B Membership Interests, provided them long-term incentive equity compensation that generally increased in value as the incentive distribution rights held by our general partner increased in value. The maximum amount of that interest was 20% (17.2% currently awarded) and would fluctuate in value with increases or decreases in our distributions to our partners and our success in generating available cash. As a result of the change in control transaction that occurred in February 2010, certain members of our Senior Executive Management team own Class A Membership Interests in our general partner.

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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—cost-of-service, 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

General

We are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of and compliance with permits for regulated activities, limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness areas or areas inhabited by endangered or threatened species, result in capital expenditures to limit or prevent emissions or discharges, and place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup, and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not materially affect us, there is no assurance that this trend will continue in the future.

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Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons. These persons include current owners and operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Such "responsible persons" may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

We also may incur liability under the Resource Conservation and Recovery Act, as amended, or RCRA, and analogous state laws which impose requirements and also liability relating to the management and disposal of solid and hazardous wastes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been in use for many years with the gathering and transportation of hydrocarbons including crude oil and other activities that could cause an environmental impact. 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 transported for treatment or disposal. Under these laws and regulations, we could be required to undertake investigations into suspected contamination, remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), remediate or clean up environmental contamination (including contaminated groundwater), restore affected properties, or undertake measures to prevent future contamination.

Water

The Federal Water Pollution Control Act, as amended, also known as the "Clean Water Act", and analogous state laws impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including oil, into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial civil and criminal penalties for non-compliance. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe we are in material compliance with these requirements.

The Oil Pollution Act, or OPA, is the primary federal law for oil spill liability. The OPA addresses three principal areas of oil pollution—prevention, containment and cleanup, and liability. The OPA subjects owners of certain facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill affects navigable waters, along shorelines or in the exclusive economic zone of the United States. Any unpermitted release of petroleum or other pollutants from our operations could also result in fines and penalties. The 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.

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Air Emissions

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

NEPA

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

DG Marine

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 CERCLA 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.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases”, including CO2, methane and certain other gases may be contributing to the warming of the Earth’s atmosphere. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate. Although these bills include several differences that require reconciliation before becoming law, both contain the basic feature of establishing a “cap and trade” system for restricting greenhouse gas emissions in the U.S. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse affect on demand for the refined products produced by our refining customers. In addition, at least 20 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate carbon dioxide, or CO2, emissions from automobiles as “air pollutants” under the Clean Air Act (the “CAA”). Although this decision did not address CO2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate “air pollutants” from those and other facilities. On April 17, 2009, the EPA released a “Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA’s proposed finding concludes that the atmospheric concentrations of several key greenhouse gases threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key greenhouse gases and hence to the threat of climate change. Although the EPA’s proposed finding, if finalized, does not establish emission requirements for motor vehicles, such requirements would be expected to occur through further rulemakings. Additionally, while the EPA’s proposed findings do not specifically address stationary sources, those findings, if finalized, would be expected to support the establishment of future emission requirements by the EPA for stationary sources. On September 23, 2009, the EPA finalized a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. On September 30, 2009, EPA proposed new thresholds for greenhouse gas emissions that define when Clean Air Act permits under the New Source Review, or NSR, and Title V operating permits programs would be required. Under the Title V operating permits program, EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide CO_2e (carbon dioxide equivalency) for existing industrial facilities. Facilities with greenhouse gas emissions below this threshold would not be required to obtain an operating permit. Under the Prevention of Significant Deterioration, or PSD, portion of NSR, EPA is proposing a major stationary source threshold of 25,000 tpy CO_2e. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO_2e. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas significance level. These proposals, along with new federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business.

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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 for 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.genesisenergy.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC. Additionally, these documents are available at the SEC's website (www.sec.gov). Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of them.

Item 1A. Risk Factors

Risks Related to Our Business

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

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business, and increase our market position and, ultimately, increase distributions to unitholders.

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

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

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

Continued uncertainty in the credit markets and concerns about local and global economic growth have had a significant adverse impact on global financial markets 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 2009, continue, they could negatively impact our profitability. Further tightening of the credit markets, lower levels of liquidity in many financial markets, and extreme volatility in fixed income, credit and equity markets could limit our access to capital. 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 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, 2009, 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. Interest rates in 2009 remained low, 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;

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- the volumes of sodium hydrosulfide, or NaHS, that we receive for our refinery services and the prices at which we sell NaHS;
- the demand for our trucking, barge and pipeline transportation services;
- the 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, 2009, we had approximately $320 million outstanding of senior secured indebtedness of Genesis and an additional $46.9 million of senior secured indebtedness of DG Marine.

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;

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- make guarantees;
- enter into any hedging agreement for speculative purposes;
- acquire or be acquired by other companies; and
- amend some of our contracts.

The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to unitholders. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to make distributions; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions, construction or development activities; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

We may incur additional indebtedness (public or private) in the future, under our existing credit facilities, by issuing debt instruments, under new credit agreements, under joint venture credit agreements, under capital leases or synthetic leases, on a project-finance or other basis, or a combination of any of these. If we incur additional indebtedness in the future, it likely would be under our existing credit facility or under arrangements which may have terms and conditions at least as restrictive as those contained in our existing credit facilities. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. 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, and, under our credit facility, any such event could limit our ability to fulfill our obligations under our debt instruments and to make cash distributions to unitholders which could adversely affect the market price of our securities.

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity - oil, refined products, NaHS, caustic soda 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, caustic soda 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.

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

The oil, refined products, and CO2 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.

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Finding and developing new reserves is very expensive, requiring large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital, and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all. Thus, oil production in our market area may not rise to sufficient levels to allow us to maintain or increase the commodity volumes we are experiencing.

Our ability to access NaHS depends primarily on the demand for our proprietary refinery services process. Demand for our services could be adversely affected by many factors, including lower refinery utilization rates, U.S. refineries accessing more “sweet” (instead of sour) crude, and the development of alternative sulfur removal processes that might be more economically beneficial to refiners.

We are dependent on third parties for NaOH for use in our refinery services process as well as volume to market to third parties. Should regulatory requirements or operational difficulties disrupt the manufacture of caustic soda by these producers, we could be affected.

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. 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 as some of our CO2 industrial sales contracts expire.

Fluctuations in demand for CO2 by our 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 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. As a large consumer of caustic soda, economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties. 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.

Additionally, if we misjudge demand for caustic soda, or the demand for NaHS, (as caustic soda is a key component in the provision of services for which we receive the by-product NaHS), we could own excess NaHS and NaOH for which there is no market, or that we are forced to sell at a loss. For example, in 2009, macroeconomic conditions negatively impacted the demand for NaHS, primarily in mining and industrial activities. If demand for NaHS remains low or declines further, our refinery services revenue will be negatively affected.

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

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

Even if reserves exist or refined products are produced in the areas accessed by our facilities, we may not be chosen by the producers or refiners to gather, refine, market, transport, store or otherwise handle any of these reserves, CO_2, NaHS, caustic soda or other refined products. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates;
- logistical efficiency in all of our operations;
- operational efficiency in our refinery services business;
- customer relationships; and
- access to markets.

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

Fluctuations in demand for crude oil or availability of refined products or NaHS, such as those caused by refinery downtime or shutdowns, can negatively affect our operating results. Reduced demand in areas we service with our pipelines and trucks can result in less demand for our transportation services. In addition, certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes transported by truck or transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

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Fluctuations in commodity prices could adversely affect our business.

Oil, natural gas, other petroleum products, NaHS, caustic soda and CO2 prices are volatile and could have an adverse effect on our profits and cash flow. Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Our operations can be affected by price reductions in those commodities depending on the extent to which we can pass on those costs to our customers. 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.

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 of the interest owners. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint.

We sell petroleum products to many wholesalers and end-users that are not large companies and are privately-owned operations. While those sales are not large volume sales, they tend to be frequent transactions such that a large balance can develop quickly. Additionally, we sell NaHS and caustic soda to customers in a variety of industries. Many of these customers are in industries that have been impacted by a decline in demand for their products and services. Even if our credit review and analytical procedures work properly, we have, and we could continue to experience losses in dealings with other parties.

Additionally, many of our customers 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 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 or any deterioration in its ability to satisfy its obligations, (including failing to purchase their required minimum take-or-pay volumes), our cash flows could be adversely affected.

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 one or 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 or any deterioration in its ability to satisfy its obligations to us (including failing to provide volumes to process), our cash flow from the syngas joint venture could be adversely affected.

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 2009, approximately 65% 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 sour gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if, for any reason, Conoco does not meet its obligations under that contract for an extended period of time, such non-performance could have a material adverse effect on our profitability and cash flow.

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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. 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 CO2-related operations.

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

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

The FERC regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state agencies. This regulation extends to such matters as:

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

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

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:

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- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and

- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

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.

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. 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.

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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.

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.

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.

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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
- 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

Our general partner and its affiliates have conflicts of interest with us and limited fiduciary responsibilities, which may permit them to favor their own interests to our unitholders’ detriment.

While Quintana has publicly announced that it intends to use as one of its primary vehicles for investing in the midstream segment of the energy sector, neither our general partner nor any of its affiliates is obligated to enter into any additional transactions with (or to offer any opportunities to) us or to promote our interest, and neither our general partner or any of its affiliates 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, our general partner and each of its affiliates may, at any time, and without notice, alter its business strategy. Additionally, if our general partner or any of its affiliates were to make one or more offers to us, we cannot say that we would elect to pursue or consummate any such opportunity.

If conflicts of interest arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand, 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 the owner of our general partner to pursue a business strategy that favors us or utilizes our assets. For example, our directors and officers who are also directors and/or officers of other entities (such as Quintana) have a fiduciary duty to make decisions based on the best interests of the equity holders of such other entities.
- affiliates of our general partner may compete with us. For example, affiliates of Quintana own other midstream interests.
- our general partner is allowed to take into account the interest of parties other than us, such as one or more of its affiliates, in resolving conflicts of interest;
-

our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings (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;

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- 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.

Affiliates of our general partner are not obligated to enter into any transactions with (or to offer any opportunities to) us. Further, 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, those entities could make the final determination regarding how any particular conflict of interest is resolved.

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, 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 direction of management.

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(s) 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.

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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. We obtained an amendment to the change in control provision in connection with the transfer of our general partner to Quintana by Denbury.

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

As of December 31, 2009, affiliates of Denbury owned 4,028,096 (approximately 10.2%) of our common units and members of the Davison family owned 11,785,979 (approximately 30%) of our common units. We also have other unitholders that may have large positions in our common units. In the future, any such parties may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, the sale could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow our general partner, members of the Davison family, Denbury and others to cause us to register for sale the partnership interests held by such persons, including common units. Those registration rights allow those unitholders 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 shelf registration statements for the units held by some holders of large blocks of our units, and those holders may sell their common units at any time, subject to certain restrictions under securities laws.

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

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

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 those equity securities on the same terms as they are issued to the other purchasers. 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 Quintana and Denbury, adverse developments concerning either of them could adversely affect us, even if we have not suffered any similar developments.

Prior to February 5, 2010, Denbury controlled our general partner. We continue to have some important relationships with Denbury. It is the operator of our largest CO_2 pipeline and the operator of the fields that produce our CO_2 reserves. We are also parties to agreements with Denbury, including the lease of the NEJD CO_2 pipeline and the transportation arrangements related to the Free State pipeline. Denbury is also a significant customer of our Mississippi System. On February 5, 2010, affiliates and co-investors of Quintana Capital Group II, L.P., along with members of the Davison family and members of our Senior Executive Management team acquired control of our general partner. We could be adversely affected if Denbury experiences any adverse developments or fails to pay us for our services on a timely basis or fails to meet its obligations to us. Additionally, if Quintana experiences any adverse developments (i) it could alter its business strategy, including determining that it no longer desires to use us as an investment vehicle, and (ii) the “market” could become concerned about our stability, each of which could negatively affect us.

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.

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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.

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 may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

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, 2009, our balance sheet reflected $325 million of goodwill and $136 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, 2009, such a write-off would need to exceed $329.2 million in order to result in an event of default.

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Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the "Qualifying Income Exception," exists with respect to publicly traded partnerships 90% or more of the gross income of which for every taxable year consists of "qualifying income." If less than 90% of our gross income for any taxable year is "qualifying income" from transportation or processing of natural resources including crude oil, natural gas or products thereof, interest, dividends or similar sources, we will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

Although we do not believe based upon our current operations that we are treated as a corporation for federal income tax purposes, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would pay state income tax at varying rates. Distributions to our unitholders would generally be taxable to them again as corporate distributions and no income, gains, losses, or deductions would flow through to them. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax on our gross income apportioned to Texas. Imposition of any such taxes on us by any other state would reduce the cash available for distribution to our unitholders.

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

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because these costs will reduce our cash available for distribution.

Unitholders maybe required to pay taxes on their share of income from us even if they do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, our unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or equal to the actual tax liability that results from that income.

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Tax gain or loss on the disposition of our common units could be more or less than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to unitholders in excess of the total net taxable income unitholders were allocated for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisors before investing in our common units.

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

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

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

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

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

We conduct a portion of our operations through subsidiaries that are, or are treated as, corporations for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. These corporate subsidiaries will be subject to corporate-level tax, which will reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS were to successfully assert that these corporate subsidiaries have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

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We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to successfully challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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 our 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, under our valuation methods, 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 valuation 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 our 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 our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and unitholders receiving two Schedule K-1's) for one fiscal year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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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 20 of the Notes to the 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 20 of the Notes to the 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 Amex LLC (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 Distributions
	High	Low	(1)
2010			
First Quarter (through February 19, 2010)	$ 21.00	$ 17.94	$ 0.3600
2009			
Fourth Quarter	$ 19.95	$ 15.10	$ 0.3525
Third Quarter	$ 16.89	$ 12.01	$ 0.3450
Second Quarter	$ 13.92	$ 9.82	$ 0.3375
First Quarter	$ 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

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

At February 19, 2010, we had 39,585,692 common units outstanding, including 4,028,096 common units held directly or indirectly by Denbury and 11,793,678 common units held by the Davison family. As of December 31, 2009, we had approximately 20,100 record holders of our common units, which include holders who own units through their brokers "in street name."

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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 are 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 11 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, 2009.

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)	123,857	(1)	832,928

(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. Due to the change in control of our general partner, the outstanding phantom units under our 2007 Long-term Incentive Plan vested on February 5, 2010. For additional discussion of our 2007 LTIP, see Note 16 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, 2009, 2008, 2007, 2006, and 2005 (in thousands, except per unit and volume data).

	Year Ended December 31,				
	2009	2008 (1)	2007 (1)	2006	2005
Income Statement Data:					
Revenues:					
Supply and logistics (2)	$1,226,838	$1,852,414	$1,094,189	$873,268	$1,038,549
Refinery services	141,365	225,374	62,095	-	-
Pipeline transportation, including natural gas sales	50,951	46,247	27,211	29,947	28,888
CO2 marketing	16,206	17,649	16,158	15,154	11,302
Total revenues	1,435,360	2,141,684	1,199,653	918,369	1,078,739
Costs and expenses:					
Supply and logistics costs (2)	1,198,071	1,815,090	1,078,859	865,902	1,034,888
Refinery services operating costs	88,910	166,096	40,197	-	-
Pipeline transportation, including natural gas purchases	13,024	15,224	14,176	17,521	19,084
CO2 marketing transportation costs	5,825	6,484	5,365	4,842	3,649
General and administrative expenses	40,413	29,500	25,920	13,573	9,656
Depreciation and amortization	62,581	71,370	38,747	7,963	6,721
Loss (gain) from sales of surplus assets	160	29	266	(16)	(479)
Impairment Expense (3)	5,005	-	1,498	-	-
Total costs and expenses	1,413,989	2,103,793	1,205,028	909,785	1,073,519
Operating income (loss) from continuing operations	21,371	37,891	(5,375)	8,584	5,220
Earnings from equity in joint ventures	1,547	509	1,270	1,131	501
Interest expense, net	(13,660)	(12,937)	(10,100)	(1,374)	(2,032)
Income (loss) from continuing operations before cumulative effect of change in accounting principle and income taxes	9,258	25,463	(14,205)	8,341	3,689
Income tax (expense) benefit	(3,080)	362	654	11	-
Income (loss) from continuing operations before cumulative effect of change in accounting principle	6,178	25,825	(13,551)	8,352	3,689
Income from discontinued operations	-	-	-	-	312
Cumulative effect of changes in accounting principle	-	-	-	30	(586)
Net income (loss)	6,178	25,825	(13,551)	8,382	3,415
Net loss (income) attributable to noncontrolling interests	1,885	264	1	(1)	-
Net income (loss) attributable to Genesis Energy, L.P.	$8,063	$26,089	$(13,550)	$8,381	$3,415
Net income (loss) attributable to Genesis Energy, L.P. per common unit basic:					
Continuing operations	$0.51	$0.59	$(0.66)	$0.59	$0.38
Discontinued operations	-	-	-	-	0.03

Cumulative effect of change in accounting principle	-	-	-	-	(0.06)
Net income (loss)	$0.51	$0.59	$(0.66)	$0.59	$0.35
Cash distributions per common unit	$1.3650	$1.2225	$0.93	$0.74	$0.61

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	Year Ended December 31,				
	2009	2008 (1)	2007 (1)	2006	2005
Balance Sheet Data (at end of period):					
Current assets	$189,244	$168,127	$214,240	$99,992	$90,449
Total assets	1,148,127	1,178,674	908,523	191,087	181,777
Long-term liabilities	387,766	394,940	101,351	8,991	955
Partners' capital:					
Genesis Energy, L.P.	595,877	632,658	631,804	85,662	87,689
Noncontrolling interests	23,056	24,804	570	522	522
Total partners' capital	618,933	657,462	632,374	86,184	88,211
Other Data:					
Maintenance capital expenditures (4)	4,426	4,454	3,840	967	1,543
Volumes - continuing operations:					
Crude oil pipeline (barrels per day)	60,262	64,111	59,335	61,585	61,296
CO2 pipeline (Mcf per day) (5)	154,271	160,220	-	-	-
CO2 sales (Mcf per day)	73,328	78,058	77,309	72,841	56,823
NaHS sales (DST) (6)	107,311	162,210	69,853	-	-
NaOH sales (DST) (6)	88,959	68,647	20,946	-	-

(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 the 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 2009, we recorded an impairment charge of $5.0 million related to an investment in the Faustina Project. For additional information related to this charge, see Note 9 of the Notes to the Consolidated Financial Statements included under Item 8 of this annual report. 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 2009
- Available Cash before Reserves
- 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 our revenues, expenses and net income, as well as two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves.

We define segment margin as revenues less 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 equity-based compensation plans and the unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Segment margin includes the non-income portion of payments received under direct financing leases. Segment margin includes all costs that are directly associated with a business segment including costs such as general and administrative expenses that are directly incurred by a business segment and 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 equity-based compensation plans which are impacted by changes in the market price for our common units. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant, and maintenance capital investment. A reconciliation of segment margin to income before income taxes is included in our segment disclosures in Note 13 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 unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, 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 2009

In 2009, we reported net income attributable to Genesis Energy, L.P. of $8.1 million, or $0.51 per common unit. Non-cash depreciation, amortization and impairment totaling $67.6 million and non-cash charges related to compensation to our senior executive team totaling $14.1 million reduced net income attributable to Genesis Energy, L.P. during the year. See additional discussion of our depreciation, amortization and impairment expense and the charge related to executive compensation in "Results of Operations – Other Costs and Interest" below.

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 2009, we generated $91 million of Available Cash before Reserves, and we distributed $60.1 million to holders of our common units and general partner. Cash provided by operating activities in 2009 was $90.1 million. Our total distributions attributable to 2009 increased 19% over the total distributions attributable to 2008.

Additionally, on January 14, 2010, we declared our eighteenth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2009. This distribution of $0.36 per unit (paid in February 2010) represents a 9% increase from our distribution of $0.33 per unit for the fourth quarter of 2008. During the fourth quarter of 2009, we paid a distribution of $0.3525 per unit related to the third quarter of 2009.

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The current economic recession continues to restrict the availability of credit and access to capital in our business environment. 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, $86 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, 2009 is as follows (in thousands):

	Year Ended December 31, 2009
Net (loss) income attributable to Genesis Energy, L.P.	$ 8,063
Depreciation, amortization and impairment	67,586
Cash received from direct financing leases not included in income	3,758
Cash effects of sales of certain assets	873
Effects of available cash generated by equity method investees not included in income	(495)
Cash effects of equity-based compensation plans	(121)
Non-cash tax expense	1,914
Earnings of DG Marine in excess of distributable cash	(4,475)
Non-cash equity-based compensation expense	18,512
Other non-cash items, net	(203)
Maintenance capital expenditures	(4,426)
Available Cash before Reserves	$ 90,986

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flows from operating activities (the most comparable GAAP measure) for the year ended December 31, 2009 in “Capital Resources and Liquidity – Non-GAAP Reconciliation” below. For the year ended December 31, 2009, net cash provided by operating activities was $90.1 million.

Results of Operations

Revenues, Costs and Expenses and Net Income

Our revenues for the year ended December 31, 2009 decreased $706 million, or 33% from 2008. Additionally, our costs and expenses decreased $690 million, or 33%, between the two periods. The majority of our revenues and our costs are derived from the purchase and sale of crude oil and petroleum products. The significant decline in our revenues and costs between 2008 and 2009 is primarily attributable to the fluctuations in the market prices for crude oil and petroleum products. In 2008, prices for West Texas Intermediate crude oil on the New York Mercantile

Exchange averaged $99.65, as compared to $61.80 in 2009 - a 38% decline. Net income (attributable to us) declined $18 million, or 69%, between 2009 and 2008. An increase in non-cash charges included in general and administrative expenses related to executive compensation and equity-based compensation totaling $16.6 million provided most of the decline in net income. See additional discussion of these charges in “Other Costs and Interest” below.

Revenues and costs and expenses in 2008 increased as compared to 2007 primarily as a result of a 38% increase in market prices for crude oil and the effects of a full-year of ownership of the Davison family businesses acquired in July 2007. Revenues increased $942 million, or 79%, while costs increased $899 million, or 75%, between the two periods. Net income attributable to us increased from a loss of $13.6 million in 2007 to income of $26.1 million in 2008. The majority of this improvement resulted from the effect of twelve months of activity from the Davison acquisition in 2008 as compared to five months in 2007.

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Included below is additional detailed discussion of the results of our operations focusing on segment margin and other costs including general and administrative expense, depreciation, amortization and impairment, interest and income taxes.

Segment Margin

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

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Pipeline transportation	$42,162	$33,149	$14,170
Refinery services	51,844	55,784	19,713
Supply and logistics	29,052	32,448	10,646
Industrial gases	11,432	13,504	13,038
Total segment margin	$134,490	$134,885	$57,567

Pipeline Transportation Segment

We operate three common carrier crude oil pipeline systems and a CO2 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 or Mcf per day):

Pipeline System	2009	2008	2007
Mississippi-Bbls/day	24,092	25,288	21,680
Jay - Bbls/day	10,523	13,428	13,309
Texas - Bbls/day	25,647	25,395	24,346
Free State - Mcf/day	154,271	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 with Capline, a pipeline system that moves crude oil from the Gulf Coast to refineries in the Midwest. In order to handle expected future increases in production volumes in the area surrounding the Mississippi System, we have made capital expenditures for tank, station and pipeline improvements over the last five years and we will continue to make further improvements.

Our Mississippi System is adjacent to several existing and prospective oil fields. Additional development of these fields using CO2 based tertiary recovery operations could create an opportunity for us to add to our existing pipeline infrastructure.

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. While crude oil price declines in late 2008 led a producer to shut-in production from some mature fields, the increase in prices at the end of 2009 resulted in a re-start of the production from those fields. As a result, volumes shipped on the Jay System in the fourth quarter of 2009 averaged 12,766 barrels per day, an increase of 2,243 barrels per day from the average for 2009.

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.

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.

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Volumes on our Texas System averaged 25,647 barrels per day during 2009. 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.

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 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 (through May 2028) to deliver CO2 on the Free State pipeline for use in in tertiary recovery operations in east Mississippi. Under the terms of the transportation services agreement, we are responsible for owning, operating, maintaining and making improvements to the pipeline. Denbury currently 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. Variations in Denbury's CO2 tertiary recovery activities create the fluctuations in the volumes transported on the Free State pipeline. 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 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.

We also have a twenty-year financing lease (through 2028) with Denbury initially valued at $175 million related to Denbury's North East Jackson Dome (NEJD) Pipeline System. Denbury 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 for our pipeline transportation segment were as follows.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Pipeline transportation revenues, excluding natural gas	$48,603	$41,097	$22,755
Natural gas tariffs and sales, net of gas purchases	278	232	334
Pipeline operating costs, excluding non-cash charges for equity-based compensation	(10,477)	(10,529)	(9,488)
Non-income payments under direct financing leases	3,758	2,349	569
Segment margin	$42,162	$33,149	$14,170

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Pipeline segment margin increased $9.0 million in 2009 as compared to 2008. This increase is primarily attributable to the following factors:

- An increase in revenues from CO2 financing leases and tariffs of $10.5 million and a related increase in payments from the same financing leases of $1.4 million not included as income (non-income payments under direct financing leases).

- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines that went into effect July 1, 2009. The rate increases increased segment margin between the two periods by approximately $1.9 million.

- Partially offsetting the increase in segment margin was a decrease in revenues from sales of pipeline loss allowance volumes of $4.1 million,

- A decline in volumes transported on our crude oil pipelines between the two periods decreased segment margin by $1.0 million.

Revenues for 2008 only included results from the NEJD and Free State CO2 pipelines for a seven-month period while 2009 included results for a twelve-month period. The average volume transported on the Free State pipeline for 2009 was 154 MMcf per day, with the transportation fees and the minimum payments totaling $7.3 million and $1.2 million, respectively. Transportation fees and the minimum payments for the seven months in 2008 were $4.4 million and $0.7 million, respectively, with an average transportation volume of 160 MMcf per day.

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. The decline in market prices for crude oil reduced the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices decreased approximately $38 per barrel between the two periods. In addition, pipeline loss allowance volumes decreased by approximately 10,000 barrels between the annual periods. Based on historic volumes, a change in crude oil market prices of $10 per barrel has the effect of decreasing or increasing our pipeline loss allowance revenues by approximately $0.1 million per month.

The decreased crude oil pipeline volumes were principally due to a producer connected to our Jay System shutting in production at the end of 2008 due to the decline in crude oil prices in the latter half of 2008, resulting in a decline on the Jay System in average daily volume of 2,905 barrels per day The tariff on the Mississippi System is an incentive tariff, such that the average tariff per barrel decreases as the volumes increase; therefore the effect of the decline in the volumes of 1,196 barrels per day on that system was mitigated by the relatively low incremental tariff rate.

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 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 CO2 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

- 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 overall impact of an annual tariff increase on July 1, 2008 combined with the volume increase on the Mississippi System 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.

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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.

Refinery Services Segment

Operating results from our refinery services segment were as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Five-months Ended December 31, 2007
Volumes sold:			
NaHS volumes (Dry short tons "DST")	107,311	162,210	69,853
NaOH volumes (DST)	88,959	68,647	20,946
Total	196,270	230,857	90,799
NaHS revenues	$97,962	$167,715	$ 43,326
NaOH revenues	38,773	53,673	9,173
Other revenues	10,505	12,483	13,082
Total external segment revenues	$147,240	$233,871	$ 65,581
Segment margin	$51,844	$55,784	$ 19,713
Average index price for NaOH per DST (1)	$424	$702	$ 390
Raw material and processing costs as % of segment revenues	44 %	41 %	49 %
Delivery costs as a % of segment revenues	12 %	8 %	17 %

(1) Source: Harriman Chemsult Ltd.

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Segment margin for our refinery services segment decreased $3.9 million between 2009 and 2008. The significant components of this change were as follows:

- NaHS volumes declined 34%. Macroeconomic conditions have negatively impacted the demand for NaHS, primarily in mining and industrial activities. Since the second quarter of 2009, market prices and demand for copper and molybdenum have improved and demand for NaHS has increased, with sales of NaHS in the fourth quarter of 2009 totaling 31,967 DST, an increase of more than 6,800 DST over the average of the prior three quarters sales volumes. Similarly, future improvements in industrial activities including the paper and pulp and tanning industries may improve NaHS demand.

- NaOH (or caustic soda) sales volumes increased 30%. NaOH is a key component in the provision of our services for which we receive the by-product NaHS. We are a very large consumer of caustic soda, and our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties. With the decline in NaHS production during 2009, we focused on expanding our activities as a NaOH supplier.

- Average index prices for caustic soda were somewhat volatile in 2008, ranging from an average index price of approximately $450 per dry short ton (DST) during the first quarter of 2008 to a high of $950 per DST in the fourth quarter of 2008. Since that time market prices of caustic soda have decreased to approximately $230 per DST. This volatility affects both the cost of caustic soda used to provide our services as well as the price at which we sell NaHS and caustic soda.

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- Raw material and processing costs related to providing our refinery services and supplying caustic soda as a percentage of our segment margin increased 3% between periods. The key component in the provision of our refinery services is caustic soda. In addition, as discussed above, we also market caustic soda. As the market price of caustic soda has fluctuated in 2008 and 2009, we have had to aggressively manage our acquisition costs to minimize purchasing caustic soda for use in our operations in a period of falling market prices. We have generally been successful in this management, as reflected by the relatively small percentage increase in costs despite the significant decline in caustic prices. We have also taken steps to reduce processing costs and to manage our logistics costs related to our caustic soda purchases.

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

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 five-month results from 2007 and comparing those results to the 2008 segment margin would indicate that segment margin increased by approximately $8.5 million between the periods. Improved management of production and operating costs, as a percentage of revenues, was a significant contributor to this indicated increase.

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, 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 feedstocks. Despite crude oil being considered a somewhat homogenous commodity, many refiners are very particular about the quality of crude oil feedstock they process. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources meeting their requirements, and to purchase the crude oil and transport it to the refineries for sale. The imbalances and inefficiencies relative to meeting the refiners' requirements can provide opportunities for us to utilize our purchasing and logistical skills to meet their demands 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 under the accounting guidance. See Note 18 of the Notes to the Consolidated Financial Statements.

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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 "heavier" petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tend to be higher than the same percentage attributable to our recurring operations. We utilize our fleet of 270 trucks and 270 trailers and DG Marine's twenty "hot-oil" barges in combination with our 1.6 million barrels of existing leased and owned storage to service our refining customers and to store and blend the intermediate and finished refined products.

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

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Supply and logistics revenue	$1,226,838	$1,852,414	$1,094,189
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(1,115,809)	(1,736,637)	(1,041,738)
Operating and segment general and administrative costs,excluding non-cash charges for stock-based compensation and other non-cash expenses	(81,977)	(83,329)	(41,805)
Segment margin	$29,052	$32,448	$10,646
Volumes of crude oil and petroleum products (mbbls)	17,563	17,410	14,246

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

As discussed above in "Revenues, Costs and Expenses and Net Income," the average market prices of crude oil declined by approximately $38 per barrel, or approximately 38% between the two periods. Similarly, market prices for petroleum products declined significantly between 2008 and 2009. Fluctuations in these prices, however, have a limited impact on our segment margin.

The key factors affecting the change in segment margin between 2009 and 2008 were as follows:

- Segment margin generated by DG Marine's inland marine barge operations, which increased segment margin by $5.6 million;
- Crude oil contango market conditions, which increased segment margin by $2.2 million; and
- Reduction in opportunities to purchase and blend crude oil and products, which reduced segment margin by $11.1 million.

The inland marine transportation operations of Grifco Transportation, acquired by DG Marine in mid-July of 2008, contributed $5.6 million more to segment margin in 2009 as compared to 2008, primarily as a result of owning these operations for twelve months in 2009 as compared to approximately six months in 2008. These operations provided us with an additional capability to provide transportation services of petroleum products by barge. As part of the acquisition, DG Marine acquired six tows (a tow consists of a push boat and two barges.) A total of four additional tows added in the fourth quarter of 2008 and first half of 2009 generated the segment margin increase despite declines in average charter rates for the tows over the same period.

During 2009, crude oil markets were in contango (oil prices for future deliveries are higher than for current deliveries), providing an opportunity for us to purchase and store crude oil as inventory for delivery in future months. The crude oil markets were not in contango during most of 2008. During 2009, we held an average of approximately 174,000 barrels of crude oil per month in our storage tanks and hedged this volume with futures contracts on the NYMEX. We are accounting for the effects of this inventory position and related derivative contracts as a fair value hedge under accounting guidance. The effect on segment margin for the amount excluded from effectiveness testing related to this fair value hedge was a $2.2 million gain in 2009.

Offsetting these improvements in segment margin was a decrease in the margins from our crude oil gathering and petroleum products marketing operations. In 2009, we experienced some reductions in volumes as a result of crude oil producers' choices to reduce operating expenses or postpone development expenditures that could have maintained or enhanced their existing production levels. As a consequence of the reductions in volumes, our segment margin from crude oil gathering declined between the annual periods by $2.7 million. Volatile price changes in the petroleum products markets and robust refinery utilization in 2008 created blending and sales opportunities with expanded margins in comparison to historical rates. Relatively flat petroleum prices and reduced refinery utilization in 2009 narrowed the economics of our blending opportunities and reduced sales margins to more historical rates. Somewhat offsetting these margin declines were the additional opportunities to handle volumes from the heavy end of the refined barrel due to our access to additional leased heavy products storage capacity and to barge transportation capabilities through DG Marine. However, the net result of these factors was a reduction of our segment margin of $8.5 million from petroleum products and related activities.

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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.

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.

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.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO2 sales to industrial customers and our share of the available cash generated by our 50% joint ventures, T&P Syngas and Sandhill.

Operating Results

Operating results for our industrial gases segment were as follows.

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	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Revenues from CO2 marketing	$16,206	$17,649	$16,158
CO2 transportation and other costs	(5,825)	(6,484)	(5,365)
Available cash generated by equity investees	1,051	2,339	2,245
Segment margin	$11,432	$13,504	$13,038
Volumes per day:			
CO2 marketing - Mcf	73,328	78,058	77,309

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, 2009, we have no liabilities to customers for gas paid for but not taken.

Our seven industrial contracts expire at various dates beginning in 2011 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 2009, 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 2009 and 2008 under these contracts were as follows:

Quarter	2009	2008
First	69,833	73,062
Second	70,621	79,968
Third	80,520	83,816
Fourth	72,233	75,164

Segment margin decreased between 2009 and 2008 due to a decline in volumes and a slight decrease in the average sales price of CO2 to our customer. Volumes declined 6% between the periods as customers reduced purchases. The average sales price of CO2 decreased $0.01 per Mcf, or 2%, due to variations in the volumes sold among contracts with different pricing terms. The increasing margins from the industrial gases segment between 2007 and 2008 were the result of an increase in volumes and an increase in the average revenue per Mcf sold of 8% from 2007 to 2008. 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 remained consistent as a percentage of revenues at approximately 36% to 37%. The transportation rate we pay Denbury is adjusted annually for inflation in a manner similar to the sales prices for the CO2. We also recorded a charge for approximately $0.3 million and $0.9 million in 2009 and 2008, respectively, 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 2009, 2008, and 2007 was $0.9 million, $2.2 million and $1.9 million, respectively. In the third quarter of 2009, T&P Syngas performed a scheduled turnaround at its facility that decreased its revenues and increased maintenance expenses. Additionally, T&P Syngas incurred expenses related to improving its treatment of waste water. These activities were completed during the third quarter and the expenses were paid from funds generated by T&P Syngas, reducing the amounts available to be distributed to the partners in T&P Syngas. In 2010, we do not expect to perform a turnaround, which should result in additional cash being distributed to the partners as compared to 2009.

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Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
General and administrative expenses not separately identified below	$20,277	$25,131	$16,760
Bonus plan expense	3,900	4,763	2,033
Equity-based compensation plans (credit) expense	2,132	(394)	1,593
Compensation expense related to management team	14,104	-	3,434
Management team transition costs	-	-	2,100
Total general and administrative expenses	$40,413	$29,500	$25,920

Our general and administrative costs increased substantially between 2007 and 2008 as a result of the acquisitions we made mid-year in 2008 and 2007. Additional personnel in our financial, human resources and other functions to support our operations added to these costs. As we grew, we incurred increased legal, audit, tax and other consulting and professional fees, and additional director fees and expenses. In 2009, we reduced expenses primarily in the areas of professional fees and services.

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. As a result of our performance in 2009, the pool available for bonuses was determined to be $0.9 million less than 2008. Between 2008 and 2007, our bonus pool increased by $2.7 million due to the tripling of our personnel count in mid 2007. The bonus plan for employees is described in Item 11, “Executive Compensation” below.

We record equity-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 16 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 exercises 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.

Our senior management team was hired in August 2006 and finalized a compensation package in December 2008. 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. Upon completion of the terms of the compensation arrangements including the requirements for vesting, we determined that no expense was required to be recorded in 2008. We recorded compensation expense of $14.1 million related to our senior management team in

2009. Although this compensation is to ultimately come from our general partner, we have recorded the expense in our Consolidated Statements of Operations in general and administrative expenses 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. See additional discussion of the compensation arrangements with our senior management team in Item 11, "Executive Compensation."

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Additionally, we recorded transition costs primarily in the form of severance costs when members of our management team changed in December 2007. 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,		
	2009	2008	2007
		(in thousands)	
Depreciation on Genesis assets	$17,945	$17,331	$8,909
Depreciation of acquired DG Marine property and equipment	7,263	3,084	-
Amortization on acquired Davison intangible assets	32,647	46,326	25,350
Amortization on acquired DG Marine intangible assets	452	92	-
Amortization of CO2 volumetric production payments	4,274	4,537	4,488
Impairment expense	5,005	-	1,498
Total depreciation, amortization and impairment expense	$67,586	$71,370	$40,245

Depreciation, amortization and impairment increased between 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. Depreciation of DG Marine property and equipment also increased in 2009 as a result of the addition of four barges and a push boat to the fleet.

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 through 2010 than in years subsequent to that time. See Note 10 of the Notes 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. Amortization of CO2 volumetric payments decreased in 2009 as a result of a slight decrease in the volume of CO2 sold.

In 2009, we recorded a $5.0 million impairment charge related to our investment in the Faustina Project. The Faustina Project is a petroleum coke to ammonia project in which we first made an investment in 2006. As a result of a review of the financing alternatives available for the project to use as construction financing and a determination not to continue making investments in the project beginning in 2010, we determined that the likelihood of a recovery of our investment was remote and the fair value of the investment was zero. For additional information related to this charge, see Note 9 of the Notes to the Consolidated Financial Statements.

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, 2009	2008	2007
		(in thousands)	
Interest expense, including commitment fees, excluding DG Marine	$8,148	$10,738	$10,103
Amortization of facility fees, excluding DG Marine facility	662	664	441
Interest expense and commitment fees - DG Marine	4,446	2,269	-
Capitalized interest	(112)	(276)	(59)
Write-off of DG Marine facility fees and other fees	586	-	-
Interest income	(70)	(458)	(385)
Net interest expense	$13,660	$12,937	$10,100

The average interest rate on our debt was 2.06% in 2009, approximately 2.2% lower than the average rate in 2008. Our average outstanding debt balance, excluding the DG Marine credit facility, increased $114.0 million to $339 million in 2009 over the average outstanding debt balance in 2008, primarily due to the CO2 pipeline dropdown transactions in May 2008 and the DG Marine acquisition in July 2008. The increase in outstanding debt during the year partially offset the effects of the lower interest rates, with the result of an overall decrease for the year for interest and commitment fees on our credit facility of $2.6 million.

DG Marine incurred interest expense in 2009 of $4.4 million under its credit facility. Additionally, DG Marine recorded accretion of the discount on the seller-financed portion of the acquisition cost of the Grifco assets. (See Note 3 of the Notes to the Consolidated Financial Statements.) 2009 included a full year of these charges, resulting in an increase in net interest expense between 2009 and 2008 of $2.2 million.

Excluding interest and commitment fees on the DG Marine credit facility, net interest expense increased $0.6 million from 2007 to 2008. This increase in interest resulted from the borrowings in July 2007 to fund the Davison acquisition and the CO2 pipeline dropdown transactions in May 2008. Our average outstanding balance of debt was $225 million during 2008, an increase of $107 million over 2007. Our average interest rate during 2008 was 4.26%, a decrease of 3.52% from 2007.

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 tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles. In 2009, we recorded income tax expense of $3.1 million. In 2008 and 2007, we recorded income tax benefits totaling $0.4 million and $0.7 million, respectively. The current income taxes we expect to pay for 2009 are approximately $1.2 million, and we provided a deferred tax benefit of $0.2 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

Although credit and access to capital continue to be negatively impacted by current economic conditions in our business environment, recent market trends have indicated improvements in bank lending capacity and long-term interest rates. We anticipate that our short-term working capital needs will be met through our current cash balances, future internally-generated funds and funds available under our credit facility. Existing capacity in our credit facility and $4.1 million of cash on hand, as well as the absence of any need to access the capital markets, may allow us to take advantage of attractive acquisition and/or growth opportunities that develop.

For the 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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We continue to monitor the credit markets and the economic outlook to determine the extent of the impact on our business environment. While some increase in commodity prices for copper occurred during 2009 increasing demand for NaHS from the levels in the first quarter of 2009, continuing weak demand in the United States for fuel has impacted refiners to whom we sell crude oil and has reduced the availability of petroleum products for our marketing activities due to reduced refining operating levels. Difficulties for companies in the mining, paper and pulp products and leather industries have reduced demand by producers of these goods for the NaHS used in their processes. We continue to adjust to the effects of these macro-economic factors in our operating levels and financial decisions.

Our Consolidated Balance Sheet at December 31, 2009 includes total long-term debt of $366.9 million, consisting of $46.9 million outstanding under the non-recourse DG Marine credit facility and $320 million outstanding under our credit facility. Outstanding letters of credit under our credit facility at December 31, 2009 were $5.2 million. Our borrowing base under our $500 million credit facility is a function of our EBITDA (earnings before interest, taxes, depreciation and amortization), as defined in our credit agreement for our most recent four calendar quarters.

Our credit facility has provisions that allow us to increase our borrowing base for material acquisitions. Upon the completion of four full quarters of operations including the acquired operations, the EBITDA multiple used to determine our borrowing base is reduced from 4.75 times to 4.25 times. In mid-August 2009, upon reporting to our lenders our fourth full quarter of operations including the pipeline transactions that occurred in May 2008, our borrowing base was calculated using our last four quarters of EBITDA with a 4.25 multiplier; therefore, our borrowing base at December 31, 2009 was $407 million. This borrowing base resulted in approximately $82 million of remaining credit as of December 31, 2009 in addition to cash on hand and cash that we have temporarily invested in crude oil and petroleum products inventories. We believe that this level of credit will provide us sufficient liquidity to operate our business. We have committed capital available under our credit facility up to $500 million that we can access for material acquisitions that meet criteria specified in our credit agreement with the calculation of our borrowing base using the higher multiple and an agreed-upon amount of pro forma EBITDA associated with the acquisition.

DG Marine had $46.9 million of loans outstanding under its $54 million credit facility. As of December 31, 2009, DG Marine had completed and paid for all amounts related to the capital expenditure projects related to the expansion of its fleet.

During 2009, as refineries have reduced production capacity, demand for transportation services of heavy-end fuel oils by inland barges has weakened, putting pressure on the rates DG Marine can charge for its services. In response, DG Marine amended its credit facility in November 2009 to (i) adjust the definition of interest expense for purposes of the interest coverage ratio to exclude non-cash interest expense and interest under the subordinated loan agreement between DG Marine and Genesis; (ii) permit Genesis to guaranty up to $7.5 million of the outstanding balance under the DG Marine credit facility; (iii) reduce the maximum amount of the DG Marine credit facility from $90 million to $54 million due to the completion of its fleet expansion projects; and (iv) to provide a debt structure that would allow for additional credit support in certain circumstances. At December 31, 2009, Genesis had loans outstanding to DG Marine for the total amount available under a $25 million subordinated loan agreement to DG Marine. The proceeds of the loan were used to reduce the amount outstanding under the DG Marine credit facility. Additionally, at December 31, 2009, Genesis had provided a $7.5 million guaranty to the lenders under the DG Marine credit facility.

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.

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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 repayments under our credit facility and the DG Marine credit facility totaled $8.4 million as we utilized excess cash generated from operations to temporarily reduce debt balances. We also paid the remaining $6.0 million of seller-financing related to the acquisition from Grifco of the DG Marine assets. We paid distributions totaling $60.1 million to our limited partners and our general partner during 2009. See the details of distributions paid in “Distributions” below.

Investing. We utilized cash flows for capital expenditures. The most significant investing activities in 2009 were expenditures by DG Marine of $15.7 million for additional barges and related costs. As of December 31, 2009, DG Marine had twenty barges and ten push boats. DG Marine’s capital expenditures were funded through cash that was generated from operations and by borrowings under its credit facility and the Subordinated Loan Agreement with Genesis.

We also completed an expansion of our Jay System that extends the pipeline to producers operating in southern Alabama. That expansion consisted of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and includes storage capacity of 20,000 barrels. Including the acquisition of linefill in our supply and logistics segment, we expended $2.7 million on this project in 2009.

Other improvements in our pipeline operations totaling $1.3 million included improvements to segments of our Mississippi System. Capital expenditures at our refinery services locations included upgrades to control equipment and other site improvements.

In our supply and logistics segment, we expended approximately $3.7 million to add tank capacity for fuel oil at owned and leased locations. We also added new field office infrastructure in Alabama and Mississippi at a cost of approximately $0.5 million. Our expenditures are summarized in the table 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, 2009, 2008, and 2007 is as follows:

	Years Ended December 31,		
	2009	2008	2007
		(in thousands)	
Capital expenditures for property, plant and equipment:			
Maintenance capital expenditures:			
Pipeline transportation assets	1,281	719	2,880
Supply and logistics assets	1,667	729	440
Refinery services assets	1,246	1,881	469
Administrative and other assets	232	1,125	51
Total maintenance capital expenditures	4,426	4,454	3,840
Growth capital expenditures:			
Pipeline transportation assets	1,762	7,589	3,712
Supply and logistics assets	19,099	22,659	650
Refinery services assets	1,326	3,609	979
Total growth capital expenditures	22,187	33,857	5,341
Total	26,613	38,311	9,181
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
Acquisition of intangible assets	2,500	-	-
Total	2,500	347,964	639,579
Capital expenditures attributable to unconsolidated affiliates:			
Faustina project	83	2,397	1,104
Total	83	2,397	1,104
Total capital expenditures	$29,196	$388,672	$649,864

During 2010, we expect to expend approximately $4.9 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $1.0 million of improvements in our refinery services business, $0.7million in our crude oil pipeline operations, $1.5 million related to improvements at our terminals and the remainder on projects related to our truck transportation operations, including $0.6 million for replacement vehicles. In future years we expect to spend $2 million to $3 million per year on vehicle replacements.

We will also upgrade and integrate our existing information technology systems during 2010 in order to be positioned for further growth. We anticipate that we will expend approximately $9.0 million on this project during the year.

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

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 eighteen quarters, including the distribution paid for the fourth quarter of 2009, 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.

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Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
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
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931
Fourth quarter 2009	February 2010 (1)	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579

(1) This distribution was paid on February 12, 2010 to our general partner and unitholders of record as of February 5, 2010.

Our credit facility also includes a restriction on the amount of distributions we can pay in any quarter. At December 31, 2009, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $492.1 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.

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.

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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, 2009, is as follows (in thousands):

	Year Ended December 31, 2009
Cash flows from operating activities	$ 90,079
Adjustments to reconcile operating cash flows to Available Cash:	
Maintenance capital expenditures	(4,426)
Proceeds from sales of certain assets	873
Amortization of credit facility issuance fees	(2,503)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	101
Earnings of DG Marine in excess of distributable cash	(4,475)
Other items affecting available cash	1,768
Net effect of changes in operating accounts not included in calculation of Available Cash	9,569
Available Cash before Reserves	$ 90,986

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, 2009.

	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)	$-	$366,900	$-	$-	$366,900
Estimated interest payable on long-term debt (2)	17,581	13,850	-	-	31,431
Operating lease obligations	9,555	14,239	5,417	26,600	55,811
Unconditional purchase obligations (3)	80,490	-	-	-	80,490
Other Cash Commitments:					
Asset retirement obligations (4)	-	-	-	13,777	13,777

Liabilities associated with unrecognized tax benefits and associated interest (5)	4,332	-	-	-	4,332
Total	$111,958	$394,989	$5,417	$40,377	$552,741

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(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, 2009 remained outstanding through the final maturity dates of July 18, 2011 and November 15, 2011 and interest rates remained at the December 31, 2009 market levels through the final maturity dates.
(3)Unconditional purchase obligations include agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at December 31, 2009, were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.
(4)Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $4.8 million and is further discussed in Note 6 to the Consolidated Financial Statements.
(5)The estimated liabilities associated with unrecognized tax benefits and related interest will be settled as a result of expiring statutes or audit activity. The timing of any particular settlement will depend on the length of the tax audit and related appeals process, if any, or an expiration of statute. If a liability is settled due to a statute expiring or a favorable audit result, the settlement of the FIN 48 tax liability would not result in a cash payment.

We have guaranteed 50% of the $2.65 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.)

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.

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

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, trade names, and non-compete agreements involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired, and to the extent available, third party assessments. 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. 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.

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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 on October 1 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 impairment test 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, 2009, the carrying value of our goodwill was $325.0 million. We have not recorded any goodwill impairment charges during any of the periods included in this annual report.

At December 31, 2009, we estimated that the fair value of our supply and logistics and refinery services reporting units exceeded the carrying value of each unit's net assets by approximately $50 million and $80 million, respectively.

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 10 of the Notes to the Consolidated Financial Statements.

Asset Retirement Obligations

With regards to some of our assets, primarily related to our pipeline operations segment, we 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 6 of the Notes 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 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 equity-based compensation expense on a straight-line basis over the requisite service period for the awards. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate at each balance sheet date based on prior experience. As of December 31, 2009, there was $0.9 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 approximately one year. We also record compensation cost for changes in the estimated liability for vested SARs. The liability recorded for vested SARs fluctuates with the market price of our common units. See Note 16 of the Notes to our Consolidated Financial Statements for further discussion regarding our SAR plan.

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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. As a result of the change in control of our general partner in February 2010 when Denbury sold its interest in our general partner to Quintana, the outstanding phantom units at December 31, 2009 vested. We will record $0.5 million of compensation expense in the first quarter of 2010 related to this accelerated vesting.

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 are accounted for as liability awards under accounting guidance related to equity-based compensation. As such, the fair value of the compensation cost we record for these awards is recomputed at each measurement date and the expense recorded is 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 is affected by the distribution yield of a group of publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. At December 31, 2009, management estimated that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date was approximately $30.5 million. 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. Compensation expense of $14.1 million was recorded in 2009 related to these awards. This expense related to the awards is recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions change the amount of compensation cost we record. Changes in these assumptions do not, however, affect our Available Cash before Reserves, as the cash cost of the Class B Membership Interests will be borne by Denbury.

As a result of the change in control of our general partner in February 2010 when Denbury sold its interest in our general partner to Quintana, our senior executives vested in the Class B Membership Awards. The ultimate settlement value of these awards was approximately $15.4 million. As a result we will record a reduction in the expense related to these awards in the first quarter of 2010 of approximately $2.1 million.

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, 2009, 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.

Implemented in 2009

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162," (The Codification). The Codification establishes the FASB Accounting Standards Codification (ASC) as the source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. The Codification reorganizes GAAP pronouncements by topic and modifies the GAAP hierarchy to include only two levels: authoritative and non-authoritative. All of the content in the Codification carries the same level of authority. This statement was effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the Codification on September 30, 2009. Thus, subsequent references to GAAP in our Consolidated Financial Statements will refer exclusively to the Codification.

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Recognized and Non-Recognized Subsequent Events

In May 2009, the FASB issued new guidance for accounting for subsequent events. The new guidance establishes the accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. See "Subsequent Events" included in "Note 1 – Organization" for the related disclosure. The new guidance was applied prospectively beginning in the second quarter of 2009 and did not have a material impact on our Consolidated Financial Statements.

Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued new guidance regarding interim disclosures about the fair value of financial instruments. The new guidance requires fair value disclosures on an interim basis for financial instruments that are not reflected in the Consolidated Balance Sheets at fair value. Previously, the fair values of those financial instruments were only disclosed on an annual basis. We adopted the new guidance for our quarter ended June 30, 2009, and there was no material impact on our Consolidated Financial Statements.

Business Combinations

In December 2007, the FASB issued revised guidance for the accounting of business combinations. The revised guidance retains the purchase method of accounting used in business combinations but replaces superseded guidance 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 revised guidance requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The revised guidance applies to acquisitions we make after December 31, 2008. The impact to us will be dependent on the nature of the business combination.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued guidance regarding noncontrolling interests in consolidated financial statements. The new guidance establishes accounting and reporting standards for noncontrolling interests, which were 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. The new guidance 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. The provisions of the new guidance were effective for fiscal years beginning after December 15, 2008. On January 1, 2009, we adopted the new guidance which changed the presentation of the interests in Genesis Crude Oil, L.P. held by our general partner and the interests in DG Marine held by our joint venture partner in our Consolidated Financial Statements. Amounts for prior periods have been changed to be consistent with the presentation required by the new guidance.

Derivative Instruments and Hedging Activities

In March 2008, the FASB issued new guidance regarding disclosures about derivative instruments and hedging activities. The new guidance requires enhanced disclosures about our derivative and hedging activities. This guidance was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008.

We adopted the guidance on January 1, 2009 and have included the enhanced disclosures in Note 18.

Application of the Two-Class Method to Master Limited Partnerships

In March 2008, the FASB issued new guidance regarding the application of the two-class method to Master Limited Partnerships. Under this guidance, the computation of earnings per unit will be affected by the incentive distribution rights ("IDRs") we are contractually obligated to distribute at the end of the each reporting period. In periods when earnings are in excess of cash distributions, we will reduce net income or loss for the current reporting period (for purposes of calculating earnings or loss per unit only) by the amount of available cash that will be distributed to our limited partners and general partner for its general partner interest and incentive distribution rights for the reporting period, and the remainder will be allocated to the limited partner and general partner in accordance with their ownership interests. When cash distributions exceed current-period earnings, net income or loss (for purposes of calculating earnings or loss per unit only) will be reduced (or increased) by cash distributions, and the resulting excess of distributions over earnings will be allocated to the general partner and limited partner based on their respective sharing of losses. The new guidance was effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted this guidance on January 1, 2009 and have reflected the calculation of earnings per unit for the year ended December 31, 2009, 2008 and 2007 in accordance with its provisions. See Note 12 of the Notes to the Consolidated Financial Statements.

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Measuring Liabilities and Fair Value

In August 2009, the FASB issued guidance that provides clarification to the valuation techniques required to measure the fair value of liabilities. The guidance also provides clarification around required inputs to the fair value measurement of a liability and definition of a Level 1 liability. The guidance was effective for interim and annual periods beginning after August 2009. We adopted this standard beginning with our financial statements for the year ended December 31, 2009. The adoption of this standard did not have a material effect on our financial statements.

Implemented January 1, 2010

Consolidation of Variable Interest Entities (“VIEs”)

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation, rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company’s involvement with a VIE affects its financial statements and exposure to risks. This guidance was effective for us beginning January 1, 2010. We are currently assessing the impact this guidance may 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.

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, 2009 were categorized as non-trading. On December 31, 2009, we had entered into NYMEX future contracts that will settle between February 2010 and August 2010 and NYMEX options contracts that will settle during February and March 2010. This accounting treatment is discussed further in Note 18 to our Consolidated Financial Statements.

The table below presents information about our open derivative contracts at December 31, 2009. 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, 2009 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)	451	111
Weighted average price per bbl	$ 78.18	$ 77.93
Contract value (in thousands)	$ 35,257	8,650
Mark-to-market change (in thousands)	735	202
Market settlement value (in thousands)	$ 35,992	$ 8,852
Heating Oil:		
Contract volumes (1,000 bbls)	94	43
Weighted average price per gal	$ 1.92	$ 2.04
Contract value (in thousands)	$ 7,591	3,688
Mark-to-market change (in thousands)	766	133
Market settlement value (in thousands)	$ 8,357	$ 3,821
RBOB Gasoline:		
Contract volumes (1,000 bbls)	14	
Weighted average price per gal	$ 1.91	
Contract value (in thousands)	$ 1,121	
Mark-to-market change (in thousands)	86	
Market settlement value (in thousands)	$ 1,207	$ -
#6 Fuel Oil:		
Contract volumes (1,000 bbls)	75	
Weighted average price per bbl	$ 68.06	
Contract value (in thousands)	$ 5,105	
Mark-to-market change (in thousands)	326	
Market settlement value (in thousands)	$ 5,431	$ -
NYMEX Option Contracts:		
Crude Oil- Written Calls		
Contract volumes (1,000 bbls)	73	
Weighted average premium received/paid	$ 2.79	
Contract value (in thousands)	$ 204	
Mark-to-market change (in thousands)	135	
Market settlement value (in thousands)	$ 339	$ -

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.

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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, 2009, we had $320.0 million of debt outstanding under our credit facility and $46.9 million outstanding under the DG Marine credit facility. DG Marine hedged a portion of its debt through July 2011.

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 99.

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, 2009. 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, 2009, 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, 2009. 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, 2009, 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, 2009, 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, 2009 of the Partnership and our report dated February 24, 2010 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2010

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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. 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 5, 2010 our general partner has eleven directors. Quintana has the right to designate and appoint six members to the board of directors of our general partner, at least two of which designees must be independent. On February 5, 2010, Quintana appointed four members to the board of directors. The Quintana appointees are Robert C. Sturdivant, Donald L. Evans, Corbin J. Robertson III and William K. Robertson. The members of the Davison family have the right to designate and appoint up to three directors, one of whom must be independent, as long as members of the Davison family hold at least 75% of the interest in our general partner that they acquired on February 5, 2010 (the “Effective Date”). If members of the Davison family hold less than 75% but more than 50% of the ownership interest in our general partner that they held on the Effective Date, they have the right to appoint two directors and if they hold less than 50%, they have the right appoint one director. The members of the Davison family designated and appointed James E. Davison and James E. Davison, Jr. to continue to serve as directors of our general partner. They waived their right to appoint a third director until a position on the board of directors is available. Another investor in our general partner, EIV Capital Fund LP, which has the right to designate one director of our general partner as long as it holds at least 75% of the ownership interest in our general partner that its held as of the Effective Date, also waived its right to appoint a director until a position on the board of directors is available. Mr. Sims will remain as one of our directors so long as he remains or chief executive officer. Susan O. Rheney, Martin G. White, J. Conley Stone and David C. Baggett continued as directors of our general partner after the change in control on February 5. 2010.

The independence standards established by the NYSE Amex LLC (formerly the American Stock Exchange) require us to have at least three independent directors on the Board. NYSE Amex LLC 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 Amex LLC, 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 Martin G. White 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 Amex LLC 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:

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- 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 Amex LLC 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.

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
Robert C. Sturdivant	64	Director and Chairman of the Board
Grant E. Sims	54	Director and Chief Executive Officer
David C. Baggett	48	Director
James E. Davison	72	Director
James E. Davison, Jr.	43	Director
Donald L. Evans	63	Director
Susan O. Rheney	50	Director
Corbin J. Robertson III	39	Director
William K. Robertson	34	Director
J. Conley Stone	78	Director
Martin G. White	64	Director

Robert V. Deere	55	Chief Financial Officer
Steven R. Nathanson	54	President, Refinery Services Division
Ross A. Benavides	56	Senior Vice President, General Counsel and Secretary
Karen N. Pape	51	Senior Vice President and Controller

Robert C. Sturdivant was named a director of our general partner by Quintana on February 5, 2010. Mr. Sturdivant currently serves as Vice President – Finance and Managing Director – Risk Management of certain Quintana affiliates, and has served in various roles with Quintana and its affiliates since 1974. Mr. Sturdivant represents Quintana's interests as a director on the boards of several private entities.

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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.

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. Mr. Davison is the son of James E. Davison.

Donald L. Evans was named a director of our general partner on February 5, 2010, by Quintana. Mr. Evans has served as President of The Don Evans Group, Ltd. since 2005 and served as the 34th Secretary of the U.S. Department of Commerce from 2001 to 2005. Since 2007, Mr. Evans has also served as the non-executive chairman of the board of directors of Energy Future Holdings Corp., a provider of electricity and related services.

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.

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

William K. Robertson was named a director our general partner by Quintana on February 5, 2010. Mr. Robertson has served as a Managing Director for Quintana since 2005, Managing Director, Midstream and Power since 2008 and is a principal in that organization. Prior to joining Quintana, Mr. Robertson worked in private investments with The CapStreet Group, LLC, and prior to that in the energy and power investment banking department of Merrill, Lynch, Pierce, Fenner & Smith Inc. Mr. Robertson is the brother of Corbin J. Robertson III.

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.

Robert V. Deere has served as Chief Financial Officer of our general partner since October 2008. Mr. Deere served as Vice President, Accounting and Reporting at Royal Dutch Shell (Shell) from 2003 through 2008, and in positions of increasing responsibility with Shell for five years prior to that appointment.

Steven R. Nathanson became an executive officer of our general partner in February 2010, and has served as President of our refinery services subsidiary, TDC, L.L.C. since 2002.

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.

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Karen N. Pape has served as Senior Vice President and Controller of our general partner since July 2007, and served as Vice President and Controller from May 2002 until July 2007. Ms. Pape served as Controller and as Director of Finance and Administration of our general partner from 1996 to 2002.

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 Amex LLC. Based solely on our review of the copies of such reports received by us, or written representations from certain reporting persons to us, we are aware of no filings that were not timely made.

Item 11. Executive Compensation

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 agreed that it would 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."

The Compensation Discussion and Analysis below discusses our compensation process, objectives and philosophy through December 31, 2009, as determined by the compensation committee of our Board. Among other things, it is designed to provide a fair understanding of the compensation to our named executive officers, or NEOs, for 2009. On February 5, 2010, Quintana acquired a controlling interest in our general partner from Denbury. At that time, three Denbury officers resigned from our Board and Quintana appointed four new directors. In connection with that change in control, the directors appointed by the Quintana-Controlled Owner Group authorized, as was their prerogative, certain actions, including issuing specified Series B unit awards to certain key employees, amending certain employment agreements and terminating our president. Those actions, each of which is described in more detail in the last paragraph of this Item 11 entitled “Compensation Changes Subsequent to December 31, 2009”, are not covered by the Compensation Discussion and Analysis report below. As of the date of this report, our general partner has not changed its compensation process, objectives or philosophies, although the reconstituted Board has the right to do so at any time, without notice.

Compensation Discussion and Analysis

Compensation Committee. During 2009, the compensation committee of our Board, or the Committee, consisted of the chairman of the board of directors and two independent directors. 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.

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 the first quarter. Depending on the magnitude of the anticipated changes, there may also be additional Committee meetings and discussions with management in advance of that meeting.

Committee and Board Approval. The Committee approves compensation and long-term awards for 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 the first quarter of each year, any applicable salary increases and/or long-term incentive are made or awarded. Bonuses are paid in March.

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Executive Officers. Our NEOs are Grant E. Sims, our chief executive officer, Robert V. Deere, our chief financial officer, Ross A. Benavides, our senior vice president and general counsel, Karen N. Pape, our senior vice president and controller, and our former president and chief operating officer, Joseph A. Blount, Jr. Messrs. Sims, Blount and Deere are referred to in this annual report as our Senior Executives and Mr. Benavides and Ms. Pape are referred to as our Other Executives.

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 were designed 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 provided 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 had 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 and a change in control of our general partner. The level of participation by our Senior Executives in the Class B Membership Interests was 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
- 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 additional awards to our Other Executives ceased 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. During 2009, each of our Senior Executives, Messrs. Sims, Blount and Deere, had 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. The employment agreements provide that 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.

For 2009, the Other Executives, Mr. Benavides and Ms. Pape, received 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 2009, all employees other than the Senior Executives and Other Executives received 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 compensated 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 did not provide any Senior Executive with a direct interest in any assets (including our IDRs) owned by our general partner.

These arrangements were 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.

In accordance with its terms, our Class B Membership Interest was redeemed in connection with the change in control of our general partner. The following discussion provides additional details regarding our Class B Membership

Interest, which remained outstanding until its redemption on February 5, 2010. See additional discussion below in "Compensation Changes Subsequent to December 31, 2009".

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

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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 %

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

The potential IDR percentage was 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, a Class B Membership Interest holder was entitled to receive from our general partner varied depending on the amount of cash we distributed 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 exceeded 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 increased 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 increased above specified thresholds such that our incentive distributions to our general partner increased, each Senior Executive would have been entitled to receive distributions from our general partner that constituted a larger share of our general partner's IDR distributions.

Each holder was 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 unit 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 quarterly periods in 2009, the percentages associated with our CABR per unit ranged from 10% to 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 were $0.925, and Mr. Deere's base level per unit was $1.975.

Our Senior Executives received the following distributions from our general partner during 2009 with respect to the quarters indicated:

Senior Executive	Fourth Quarter 2008 Distribution Amount	First Quarter 2009 Distribution Amount	Second Quarter 2009 Distribution Amount	Third Quarter 2009 Distribution Amount	Total 2009 Distribution Amount
Grant E. Sims	$ 44,595	$ 60,944	$ 55,241	$ 66,930	$ 227,710

Joseph A. Blount, Jr.	38,373	52,440	47,533	57,591	195,937
Robert V. Deere	-	-	-	-	-
Total	$ 82,968	$ 113,384	$ 102,774	$ 124,521	$ 423,647

As an example, the distributions in the table above with respect to the third quarter of 2009 were calculated as follows (in thousands, except per unit amounts):

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		Total	
Available Cash before Reserves generated for the four quarters	$	91,525	
Less: Adjustment to Available Cash before Reserves relating to specific transactions with our general partner and its affiliates		22,902	
CABR for the four quarters	$	68,623	
Weighted average units outstanding, including implied general partner units (1)		39,102	
Adjusted CABR at September 30, 2009 per adjusted unit (2)	$	1.755	
Base amount for Messrs. Sims and Blount		0.925	
Excess of CABR per Unit over base amount	$	0.830	
Applicable Percentage for Messrs. Sims and Blount for the quarter		10	%

(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.

The distribution that Mr. Sims received for the quarter was calculated as the product of (i) $1,729,474 (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 10%, and (iii) Mr. Sims Class B Membership Interest of 38.7%. The calculation of Mr. Blount's distribution amount was 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 CABR per adjusted unit did not exceed his base amount of $1.975.

In addition, our general partner 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 depended 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 occurred. In general, each Senior Executive was be entitled to receive a redemption amount if our general partner did not terminate his employment for cause, which redemption amount was subject to vesting as described below.

The redemption amount for each executive was 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 was 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 a group of specified publicly-traded entities which are general partners of publicly traded master limited partnerships. The vesting percentage of each executive was 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%

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(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, 2009, the redemption amount for each Class B Member was 25%.

Our general partner agreed that it would 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 was reimbursed 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.

Although our general partner will not seek reimbursement for the costs of the Class B Membership Interests and deferred compensation plan arrangements, we recorded non-cash expense during 2009. The Class B Membership Interests awarded to our senior executives were accounted for as liability awards under accounting guidance for equity-based compensation. As such, the fair value of the compensation cost we recorded for these awards was recomputed at each measurement date and the expense we recorded was adjusted based on that fair value. Management's estimates of the fair value of these awards were based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we would generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we would pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value was affected by the distribution yield of a group of publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. At December 31, 2009, management estimated that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date was approximately $30.5 million. During 2009, compensation expense of $14.1 million was recorded related to these awards.

As a result of the change in control of our general partner on February 5, 2010, the Class B Membership Interests were redeemed. See additional discussion below in "Executive Compensation – Change in Control and Other Termination Payments" and Note 23 to the Consolidated Financial Statements.

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

Bonuses and Deferred Compensation Awards.

Senior Executives. 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. These awards were paid on February 5, 2010 and the plan was terminated, in connection with the change in control of our general partner. See Note 23 of the Notes to the Consolidated Financial Statements.

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 2009. The Senior Executives were excluded from participation in the Bonus Plan in 2009. 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.

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 2009, 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.

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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 eligible earnings under the plan. 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 eligible earnings 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 2009, the Committee established a target of approximately $92 million for Available Cash before Reserves and before bonus expense and related employer tax burdens and subject to certain other adjustments, with a hurdle rate of 105%. We achieved 88% of the target for 2009. We achieved our safety incident rate goal for 2009. As a result, the

Bonus Pool for 2009 bonuses to be paid in March 2010 was calculated as 90% of 88% divided by 105%, or 79%. In accordance with the Bonus Plan, the total pool available for bonuses for 2009 was approximately $4.3 million. Management intends to recommend to the Committee that a total of $3.9 million be paid as bonuses for 2009, which represents approximately thirteen percent of total eligible compensation. The bonus recommendations for 2009 will be reviewed by the Committee in March 2010.

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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.

As a result of the change in control of our general partner, all outstanding phantom units vested on February 5, 2010. See Note 23 of the Notes to the Consolidated Financial Statements.

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, which determines, 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 were 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, do not receive awards under the Stock Appreciation Rights plan nor do our operations and administrative clerical personnel.

In February 2009, awards of rights were made totaling 500,983 units. Prior to 2009, the exercise price of the annual awards of rights had 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 trades 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 adjusted the exercise price to $13.00 (rather than $10.69 which was the result of the prior method of determining the exercise price) to reflect a more accurate representation of the unit value in the market environment existing at the award 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.

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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 $73,626 in 2009 for our Senior Executives and Other Executives. As a result of their status as Class B Members in our general partner, our Senior Executives were reimbursed for the additional benefit costs and taxes they paid or 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 self-employment taxes. These reimbursements in 2009 totaled $43,554, $45,224 and $44,366 for Messrs. Sims, Blount and Deere, respectively.

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.

Susan O. Rheney
Martin G. White

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2009 SUMMARY COMPENSATION TABLE

The following table summarizes certain information regarding the compensation paid or accrued by Genesis during 2009 to those persons who served as NEOs at the end of 2009.

2009 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	2009	340,000	-	7,267,894	-	-	50,904	7,658,798
Chief Executive Officer	2008	310,000	107,751	-	-	-	9,834	427,585
(Principal Executive Officer)	2007	310,000	-	-	-	-	1,838,476	2,148,476
Joseph A. Blount, Jr. (6)	2009	300,000	-	6,240,141	-	-	63,599	6,603,740
Former President & Chief	2008	270,000	97,599	-	-	-	19,936	387,535
Operating Officer	2007	270,000	-	-	-	-	1,618,984	1,888,984
Robert V. Deere (7)	2009	369,600	-	596,165	-	-	51,716	1,017,481
Chief Financial Officer	2008	89,557	-	-	-	-	621	90,178
(Principal Financial Officer)								
Ross A. Benavides	2009	234,000	-	102,120	186,611	-	20,313	543,044
Senior Vice President and	2008	227,500	170,000	65,638	(215,195)	-	19,584	267,527
General Counsel	2007	211,000	68,250	2,511	100,448	111,581	16,680	510,470
Karen N. Pape	2009	225,000	-	90,416	143,924	-	20,238	479,578
Senior Vice President &	2008	200,000	180,000	58,341	(164,728)	-	19,356	292,969
Controller	2007	184,000	52,500	2,232	77,139	94,577	16,680	427,128
(PrincipalAccounting Officer)								

(1) Amounts in this column 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 2009 and 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. Bonuses for 2009 will not be determined until March 2010.

(2) Amounts in this column for Messrs. Sims, Blount and Deere represent the expense related to the Class B Membership Interests and deferred compensation that are included in the determination of net income for the period under the accounting guidance for equity-based compensation. Amounts in this column for Mr. Benavides and Ms. Pape represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for the period under accounting guidance for awards of phantom units under our 2007 LTIP. The forfeiture rate that was applied to these awards at December 31, 2009, 2008 and 2007 was zero. See additional information on the assumptions utilized in the valuation of these awards under accounting guidance in Note 16 to the Consolidated Financial Statements.

(3) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for each period under accounting guidance 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. See additional information on the assumptions utilized in the valuation of these awards under accounting guidance in Note 16 to the Consolidated Financial Statements.

(4) Amounts in this column represent the amount paid to the Named Executive Officer as an award under the bonus plan that was effective in 2007. Messrs. Sims and Blount did participate in the bonus plan in 2007.

(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. Mr. Blount terminated effective February 10, 2010.

(7) Mr. Deere was employed by our general partner effective October 6, 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	2009	$ -	$ 7,350	$ -	$ 43,554	$ 50,904
	2008	$ -	$ 7,350	$ 2,484	$ -	$ 9,834
	2007	$ -	$ 6,600	$ 180	$ 1,831,696	$ 1,838,476
Joseph A. Blount, Jr.	2009	$ 11,025	$ 7,350	$ -	$ 45,224	$ 63,599
	2008	$ 10,350	$ 7,350	$ 2,236	$ -	$ 19,936
	2007	$ 9,900	$ 6,600	$ 180	$ 1,602,304	$ 1,618,984
Robert V. Deere	2009	$ -	$ 7,350	$ -	$ 44,366	$ 51,716
	2008	$ -	$ -	$ 621	$ -	$ 621
Ross A. Benavides	2009	$ 11,025	$ 7,350	$ 1,938	$ -	$ 20,313
	2008	$ 10,350	$ 7,350	$ 1,884	$ -	$ 19,584
	2007	$ 9,900	$ 6,600	$ 180	$ -	$ 16,680
Karen N. Pape	2009	$ 11,025	$ 7,350	$ 1,863	$ -	$ 20,238
	2008	$ 10,350	$ 7,350	$ 1,656	$ -	$ 19,356
	2007	$ 9,900	$ 6,600	$ 180	$ -	$ 16,680

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) For 2009, amount represents reimbursement for estimate of additional benefit costs and taxes of NEO related to his status as a Class B Membership in our general partner. For 2007, amount 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.

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 would receive an annual salary of $340,000, $300,000, and $369,600, respectively, subject to certain upward adjustments. The agreements provided that each senior executive's annual salary rate would 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 would be entitled to specified severance benefits under certain circumstances. No Senior Executive would be entitled to severance benefits if our general partner terminates him for cause. Each Senior Executive (or family) would be entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through December 31, 2012 if he dies, if he is terminated due to a disability or if he terminates his employment for good reason. If our general partner terminates a Senior Executive (other than for cause) within two years after a change of control, he would be entitled to continued health benefits for 18 months after his termination 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

Change in Control and Other Termination Payments.

Senior Executives. Based upon a hypothetical termination date of December 31, 2009, 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	17,434	20,416	20,495
Class B Membership Interest and deferred compensation (1)	6,587,831	5,668,599	2,383,195
Total	$ 7,625,265	$ 6,589,015	$ 3,512,490

(1) Upon termination due to a change in control, each Senior Executive was entitled to his deferred compensation amount, if any, and redemption of his Class B Membership Interest. Such 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 would have been based on the IDR payment for such quarter. Additionally each Senior Executive would have been 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 were computed assuming that each Senior Executive's CABR-related percentage was no less than 16%, utilizing the same management assumptions that were used to determine the fair value of the awards at December 31, 2009 . Additionally our estimate of the redemption of the Class B Membership Interests assumes that the distribution yield of a group of publicly-traded entities that are the general partners in publicly-traded master limited partnerships will be the same as the average at December 31, 2009.

Based upon a hypothetical termination date of December 31, 2009, 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, 2009, 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	17,434	20,416	20,495
Class B Membership Interest and deferred compensation (1)	5,718,314	4,920,410	-
Total	$ 6,755,748	$ 5,840,826	$ 1,129,295

(1) As with a termination for a change in control, termination without cause or for good reason would have entitled 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 would have been based on the IDR payment for such quarter. Additionally each Senior Executive would have been 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 would have been 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 10% for Messrs. Sims and Blount and zero for Mr. Deere at December 31, 2009.

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Our general partner was required to redeem the individual Class B Membership Interests under our general partner's existing limited liability company agreement as a result of the change of control effected by the sale of our general partner to the Quintana-Controlled Owner Group. Our senior executives and Denbury agreed to amend our general partner's existing limited liability company agreement to provide for the conversion of the Class B Membership Interests into Series A units in the general partner at the time of the change in control, rather than for the redemption of the Class B Membership Interests upon a change of control, and/or to confirm the amount each executive would receive upon redemption. Pursuant to a Class B Agreement dated February 5, 2010 among Mr. Sims, Denbury, and our general partner, a portion of Mr. Sims' individual Class B Membership Interest in our general partner was converted into Series A units in our general partner following the change in control and his remaining Class B Membership Interest was redeemed for $221,868 in cash. Mr. Deere also entered into a Class B Agreement dated February 5, 2010 pursuant to which a portion of his individual Class B Membership Interest was converted into Series A units in our general partner following the change in control and his remaining Class B Membership Interest was redeemed for $431,684 in cash. Mr. Blount received a payment for his Class B Membership Interest totaling $4.9 million.

Other Executives. Based upon a hypothetical termination date of December 31, 2009, the change in control termination benefits for our Other Executives would have been as follows (based on the closing price for our units of $18.90 at that time):

	Ross A. Benavides	Karen N. Pape
Severance plan payment	$ 1,059,375	$ 1,023,750
Healthcare and other insurance benefits	14,480	14,311
Fair market value of stock appreciation rights	177,418	135,702
Fair market value of phantom units	338,801	299,527
Total	$ 1,590,074	$ 1,473,290

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., material 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 sale by Denbury of our general partner was a change in control under the Severance Protection Plan.

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, which determines, 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.

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GRANTS OF PLAN BASED AWARDS IN FISCAL YEAR 2009

The following tables show the non-equity incentive plan awards granted to the Other Executives for 2009 and the outstanding SARs and phantom units awards at December 31, 2009 that were issued to our Other Executives. Information on rights granted to non-employee directors is included in the section entitled Director Compensation.

Grants of Plan-Based Awards in Fiscal Year 2009

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#) (1)	Exercise or Base Price of Option Awards ($/Sh)	Market Price of Common Units on Award Date (2)	Grant Date Fair Value of Stock and Option Awards (3)
Ross A. Benavides	2/26/2009	8,750	$ -	$ 7.59	$ 66,440
Karen N. Pape	2/26/2009	7,692	$ -	$ 7.59	$ 58,408

(1) Represents the number of phantom units awarded to the NEO on February 26, 2009.
(2) Represents the closing market price of our common units on the date of the phantom unit award.
(3) The amounts in this column represent the fair value of the award on the date of the grant, February 26, 2009, as calculated in accordance with accounting guidance for equity-based compensation.

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OUTSTANDING EQUITY AWARDS AT 2009 FISCAL YEAR-END

The following table presents information regarding the outstanding equity awards to our Other Executives at December 31, 2009.

Outstanding Equity Awards at 2009 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							$ 15,573,193
Joseph A. Blount, Jr.							$ 13,400,189
Robert V. Deere							$ 1,145,854
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	$ 173,426	
					8,750	$ 165,375	
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	$ 154,148	
					7,692	$ 145,379	

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

(2)

The first phantom unit award listed for each NEO vest on December 18, 2010. One third of the second award listed for each NEO vest annually on February 26 beginning in 2010. As a result of the change in control of our general partner, all outstanding phantom units vested on February 5, 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 accounting guidance for equity-based compensation.

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DIRECTOR COMPENSATION FOR FISCAL YEAR 2009

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 2009, 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 $140,000 for providing certain of its executives as directors of Genesis. Additionally, 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 $45,000 were paid to Denbury.

Director Compensation in Fiscal 2009

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($) (2)	Option Awards ($) (3)	Total
Mark C. Allen (4)	$ 51,000	$ 45,836	$ 11,557	$ 108,393
David C. Baggett, Jr.	$ 67,500	$ 45,836	$ -	$ 113,336
James E. Davison	$ 53,000	$ 45,836	$ 1,202	$ 100,038
James E. Davison, Jr.	$ 53,000	$ 45,836	$ 1,202	$ 100,038
Ronald T. Evans (4)	$ 53,000	$ 45,836	$ 30,144	$ 128,980
Susan O. Rheney	$ 77,000	$ 45,836	$ 39,134	$ 161,970
Gareth Roberts (4)	$ 29,000	$ 19,525	$ (4,660)	$ 43,865
Phil Rykhoek (4)	$ 52,000	$ 45,836	$ 26,767	$ 124,603
J. Conley Stone	$ 53,000	$ 45,836	$ 18,323	$ 117,159
Martin G. White	$ 68,500	$ 45,836	$ -	$ 114,336

(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 generally accepted accounting principles for awards of phantom units under our 2007 LTIP. The forfeiture rate that was applied to the phantom unit awards at December 31, 2009 was zero. Each director received an award of 3,500 phantom units on February 26, 2009. The grant date fair value of these awards was $8.88 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 generally accepted accounting principles for awards of stock appreciation rights. The forfeiture rate that was applied to these stock appreciation rights at December 31, 2009 was ten percent. Under our stock appreciation rights plan, the director will receive cash upon exercise of the

right.

(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. Mr. Roberts resigned as a director of our general partner in June 2009, and his stock appreciation rights were forfeited or expired unexercised.

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OUTSTANDING EQUITY AWARDS AT 2009 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 2009 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)	966	322	$ 15.77	9/29/2016		
		1,000	$ 19.57	12/29/2016		
		1,000	$ 20.92	2/14/2018		
					3,500	66,150
David C. Baggett					3,500	66,150
James E. Davison (4)		1,000	$ 20.92	2/14/2018		
					3,500	66,150
James E. Davison, Jr. (4)		1,000	$ 20.92	2/14/2018		
					3,500	66,150
Ronald T. Evans (3)	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		
					3,500	66,150
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		
					3,500	66,150
Phil Rykhoek (3)	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		
					3,500	66,150
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		
					3,500	66,150
Martin G. White					3,500	66,150

(1) These phantom units vest on February 26, 2010 or with a change in control of our general partner. A change in control occurred on February 5, 2010.

(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, 2009 of $18.90.

(3) Due to the resignation of this director on February 5, 2010, all unexercisable stock appreciation rights were forfeited on that date. The director has until May 5, 2010 to exercise his vested rights. After that date, the director forfeits any exercisable rights.

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(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, 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.

Compensation Changes Subsequent to December 31, 2009

On February 5, 2010, Mr. Sims, Mr. Deere and Ms. Pape, along with other members of our senior management team entered into restricted unit agreements with our general partner that provide for these individuals to receive Series B units in our general partner. The Series A units in our general partner were issued to the Quintana-Controlled Investor Group.

An aggregate of 767 Series B units were issued. The Series B units in our general partner vest in tranches, with one-fourth of the Series B units vesting each year until fully-vested. The restricted unit agreements contain provisions providing for unvested units becoming fully-vested under certain circumstances including a change in control of our general partner. Holders of Series B units, upon vesting, have the right to receive a share, of the quarterly incentive distributions paid to our general partner, subject to the rights of the holders of Series A units in our general partner to receive distributions up to certain threshold amounts first.

On February 5, 2010, Messrs. Sims and Deere each also entered into a waiver agreement which amended the terms of their respective employment agreements waiving certain change of control and severance payment rights and agreed to a form of employment agreement and related release that our general partner may require each to execute in the future.

The employment of Mr. Blount was terminated effective February 10, 2010. In connection with such termination, Mr. Blount will receive a severance package consisting of payment of his base salary for a period of 36 months, and health and welfare benefits for a period of 18 months.

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 February19, 2010, 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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		Beneficial Ownership of Common Units	
Title of Class	Name and Address of Beneficial Owner	Number of Units	Percent of Class
Genesis Energy, L.P.	David C. Baggett, Jr.	5,800	*
Common Units	James E. Davison (1) (2)	2,881,338	7.3
	James E. Davison, Jr. (3) (4)	3,160,567	8.0
	Susan O. Rheney	6,500	*
	Grant E. Sims (5)	6,000	*
	J. Conley Stone	7,800	*
	Martin G. White	7,900	*
	Steven R. Nathanson	129,907	0.3
	Ross A. Benavides	22,173	0.1
	Karen N. Pape	14,745	*
	All directors and executive officers as a group (15 in total)	6,242,730	15.7
	Todd A. Davison (6)	2,876,236	7.3
	Steven K. Davison (7)	2,875,537	7.3
	Terminal Service, Inc. (8)	1,010,835	2.6
	Denbury Gathering & Marketing Inc.and Denbury Onshore LLC (9)	4,028,096	10.2
	5100 Tennyson Parkway		
	Plano, Texas 75024		
	Swank Capital, LLC, Swank Energy Income Advisors,L.P. and Mr. Jerry V. Swank (10)	2,101,344	5.3
	3300 Oak Lawn Ave., Suite 650		
	Dallas, Texas 75219		
	Neuberger Berman, Inc. (11)	2,002,598	5.1
	605 Third Avenue		
	New York, NY 10158		

(1) James E. Davison is the sole stockholder of Davison Terminal Service, Inc., which directly owns 1,010,835 units. Additionally, Mr. Davison owns a six percent interest in our general partner.

(2) We have been granted a lien on 331,754 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(3) James E. Davison, Jr. owns a six percent interest in our general partner

(4) We have been granted a lien on 338,056 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses. Mr. Davison pledged 700,000 of these units as collateral for a loan from a bank.

(5) 1,000 of these common units are held by Mr. Sims' father. Mr. Sims disclaims beneficial ownership of these units. Effective February 5, 2010, Mr. Sims is also a 6.5 percent owner in our general partner.

(6) Todd A. Davison is the son of James E. Davison and the brother of James E. Davison, Jr., and a six percent owner in our general partner. Additionally, Mr. Davison provides services in our supply and logistics division. The mailing address for Mr. Davison is 2000 Farmerville Hwy., Ruston, LA 71270. We have been granted a lien on 338,056 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

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(7) Steven K. Davison is the son of James E. Davison and the brother of James E. Davison, Jr. and Todd A. Davison, and a six percent owner in our general partner. Mr. Davison also provides services to us in our supply and logistics division. The mailing address for Mr. Davison is 207 W. Alabama, Ruston, LA 71270. We have been granted a lien on 338,056 of these units to secure the Davison unitholders indemnification obligations to us under the terms of our acquisition of the Davison businesses.

(8) This entity is owned by James E. Davison. The mailing address of this entity is PO Box 607, Ruston, LA 71273.

(9) Denbury Gathering and Marketing Inc.is the former owner of our general partner. Denbury Gathering and Marketing Inc. and Denbury Onshore Inc. are wholly-owned subsidiaries of Denbury Resources Inc. Until January 29, 2010, 2,829,055 of these common units were held by our general partner. The units were transferred to Denbury Gathering & Marketing Inc. at that time.

(10) Information based on Schedule 13G filed with the SEC on February 16, 2010. 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.

(11) Information based on Schedule 13G filed with the SEC on February 17, 2010.

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. Genesis Energy, LLC is controlled by Quintana. Quintana 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

Genesis Energy, LLC, our general partner owns a 2% general partner interest in us and all incentive distribution rights. Our general partner also manages our operations and employs all of our employees.

Distributions and Payments to Our General Partner and its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our general partner and its affiliates in connection with our ongoing operations and in the event of a liquidation, including payments made for the year ended December 31, 2009.

Operational Stage

Distributions of available cash to our general partner and its affiliates	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.
	During 2009, our general partner received a total of $10.1 million from us as distributions, with $3.9 million attributable to its limited partner units, $1.1 million for its general partner interest, and $5.1 million related to its incentive distribution rights.
Payments to our general partner and its affiliates	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 2009, these reimbursements totaled $50.4 million. As of December 31, 2009, we owed our general partner $2.1 million related to these services.
Withdrawal or removal of our general partner	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 our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

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Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Review or Special Approval of Material Transactions with Related Persons

Before we consider entering into a material transaction with our general partner or any of its affiliates, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, (3) would comply with our partnership agreement, and (4) would be fair to us and our limited partners. 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 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.

Our Relationship with Quintana Capital Group, L.P.

On February 5, 2010, affiliates of Quintana Capital Group II, L.P., along with members of the Davison family and our Senior Executive Management team, acquired control of our general partner. Our general partner owns all of our general partner interest and all of our incentive distribution rights.

Quintana, an energy-focused private-equity firm headquartered in Houston, Texas, has stated that it intends to use us as one of its primary vehicles for investing in the midstream segment of the energy sector. Quintana, through its affiliated investment funds, currently manages approximately $900 million in capital for various U.S and international investors. With offices in Houston, Dallas and Midland, Texas and Beijing, China, Quintana focuses on control-oriented investments across a wide range of sectors in the energy industry, developing a portfolio that is diversified across the energy value chain. Formed in 2006, Quintana is managed by highly experienced investors, including Corbin J. Robertson, Jr. and former Secretary of Commerce Donald L. Evans.

Prior to Quintana's investment in us, Denbury Resources Inc. (NYSE:DNR) controlled our general partner. Denbury retained ownership of 10.2% of our outstanding common units after the sale of our general partner to Quintana.

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Our Relationship with the Davison Family

Certain Davison family members have been investors in us since 2007, when we issued 13,459,209 units to them as partial consideration for assets. At December 31, 2009, the Davison unitholders held approximately 30% of our outstanding common units.

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	%

In 2010, the members of the Davison family acquired an interest in our general partner. Pursuant to the agreements among the owners of our general partner executed on February 5, 2010, the Davison unitholders have the right to designate up to three directors to our board of directors, depending on their continued level of ownership in our general partner. The members of the Davison family have the right to designate and appoint up to three directors, one of whom must be independent, as long as members of the Davison family hold at least 75% of the interest in our general partner that they held as of February 5, 2010. If members of the Davison family hold less than 75% but more than 50% of the interest in our general partner that they held on February 5, 2010, they have the right to appoint two directors and if they hold less than 50%, they have the right appoint one director.

The members of the Davison family designated and appointed James E. Davison and James E Davison, Jr. to continue to serve as directors of our general partner. They waived their right to appoint a third director until a position on the board of directors is available.

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 were released, and the remaining 1,345,921 units will be released on July 26, 2010.

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, 2009 was approximately $16,000.

Our joint venture partner in DG Marine is TD Marine, LLC, an entity owned by James E. Davison and two of his sons. TD Marine owns 51% of the economic interest in DG Marine. Additionally, Community Trust Bank is a 17% participant in the DG Marine credit facility. Davison family members own approximately 12% of Community Trust Bank, and James E. Davison, Jr. serves on the board of the holding company that owns Community Trust Bank.

During 2009, we sold $0.8 million of petroleum products to businesses owned and operated by members of the Davison family in the ordinary course of our operations.

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Relationship with Denbury Resources, Inc.

Historically, we have entered into transactions with Denbury and its subsidiaries to acquire assets from time to time. We instituted specific procedures for evaluating and valuing our material transactions with Denbury and its subsidiaries.

We entered into transactions with Denbury in the ordinary course of our operations. During 2009, these transactions included:

- Provision of transportation services for crude oil by truck totaling $3.2 million.
- Provision of crude oil pipeline transportation services totaling $14.4 million.
- Provision of CO_2 and crude oil pipeline transportation services under lease arrangements for which we received payments totaling $21.9 million.
- Provision of CO_2 transportation services to our wholesale industrial customers by Denbury's pipeline. The fees for this service totaled $5.5 million in 2009.
- Provision of pipeline monitoring services to Denbury for its CO_2 pipelines totaling $120,000 in 2009.
- Provision of services by Denbury officers as directors of our general partner. We paid Denbury $185,000 for these services in 2009.

At December 31, 2009, we owed Denbury $1.0 million for provision of CO_2 transportation services. Denbury owed us $1.9 million for crude oil trucking and pipeline transportation services.

Denbury also owns 4,028,086 limited partner units and has the same rights and is entitled to receive distributions as the other limited partners with respect to those units. Denbury has registration rights with respect to such units, including the right to require us to file a shelf registration statement, which we filed in January 2010, and the right to demand three registrations of their units, in the form of an underwritten offering, up to two per calendar year and piggyback rights for other unit registrations.

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 Amex LLC, 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.

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, 2009 and 2008.

		2009		2008
		(in thousands)		
Audit Fees (1)	$	3,122	$	3,634
Audit-Related Fees (2)		80		296
Tax Fees (3)		479		368
All Other Fees (4)		4		3
Total	$	3,685	$	4,301

(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.

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(2) Includes fees for the audit of our employee benefit plan. In 2009, also includes fees for services related to third-party review of workpapers and review of correspondence with SEC. In 2008, amount includes fees for assistance in the documentation of internal controls over financial reporting.

(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 2009 and 2008 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 2009 and 2008, 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 99.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements and Financial Statement Schedules" set forth on page 99.

(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)

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3.9	Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated February 5, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated February 11, 2010)
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	Second Amendment to First Amended and Restated Credit Agreement dated as of February 5, 2010, 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 10.1 to Form 8-K dated February 11, 2010)
10.4	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)
10.5	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)
10.6	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)
10.7	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)
10.8	Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K dated July 31, 2007)
10.9	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)
10.10	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)
10.11	Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to Form 8-K dated July 31, 2007)
10.12	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)

10.13	Pledge and Security Agreement (incorporated by reference to Exhibit 10.5 to Form 8-K dated July 31, 2007)
10.14	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)
10.15	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)

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	10.16		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)
	10.17		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)
	10.18		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)
	10.19		Registration Rights Agreement among Denbury Resources, Inc., Denbury Gathering & Marketing, Inc., Denbury Onshore, LLC and Genesis Energy, L.P. dated February 5, 2010 (incorporated by reference to Exhibit 4.1 to Form 8-K dated February 11, 2010)
	10.20	+	Genesis Energy, LLC First Amended and Restated Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.24 to Form 10-K for the year ended December 31, 2008)
	10.21	+	Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.25 to Form 10-K for the year ended December 31, 2008)
	10.22	+	Genesis Energy, LLC Amended and Restated Severance Protection Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2006)
	10.23	+	Amendment to the Genesis Energy Severance Protection Plan (incorporated by reference to Exhibit 10.27 to Form 10-K for the year ended December 31, 2008)
	10.24	+	Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 21, 2007)
	10.25	+	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)
	10.26	+	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)
	10.27	+	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)
	10.28	+	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)
	10.29	+	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)
*	10.30	+	

		Employment Agreement by and between Genesis Energy, Inc. and Steve Nathanson dated July 25, 2007
10.31	+	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)
10.32	+	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)
10.33	+	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)

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	10.34	+	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)
	10.35	+	Deferred Compensation Grant – Genesis Energy, LLC – Grant E. Sims (incorporated by reference to Exhibit 10.8 to Form 8-K dated January 7, 2009)
	10.36	+	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)
	10.37	+	Class B Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K dated February 11, 2010)
	10.38	+	Class B Agreement (Blount), dated February 5, 2010 (incorporated by reference to Exhibit 10.3 to Form 8-K dated February 11, 2010)
	10.39	+	Class B Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K dated February 11, 2010)
	10.40	+	Waiver Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.41	+	Waiver Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.42	+	Restricted Unit Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.43	+	Restricted Unit Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.44	+	Restricted Unit Agreement (Pape), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
*	10.45	+	Restricted Unit Agreement (Nathanson) dated February 5, 2010
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 12 of the Notes 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

*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: February 26, 2010

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	February 26, 2010
/s/	Robert V. Deere Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	February 26, 2010
/s/	Karen N. Pape Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	February 26, 2010
/s/	Robert C. Sturdivant Robert C. Sturdivant	Chairman of the Board and Director	February 26, 2010
/s/	David C. Baggett, Jr. David C. Baggett, Jr.	Director	February 26, 2010
/s/	James E. Davison James E. Davison	Director	February 26, 2010
/s/	James E. Davison, Jr. James E. Davison, Jr.	Director	February 26, 2010
/s/	Donald L. Evans Donald L. Evans	Director	February 26, 2010
/s/	Susan O. Rheney Susan O. Rheney	Director	February 26, 2010
/s/	Corbin J. Robertson, III	Director	February 26, 2010

	Corbin J. Robertson, III		
/s/	William K. Robertson William K. Robertson	Director	February 26, 2010
/s/	J. Conley Stone J. Conley Stone	Director	February 26, 2010
/s/	Martin G. White Martin G. White	Director	February 26, 2010

*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, 2009 and 2008, 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, 2009. 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 consolidated 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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.

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, 2009, 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 February 24, 2010 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2010

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

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,148	$ 18,985
Accounts receivable - trade, net of allowance for doubtful accounts of $1,372 and $1,132 at December 31, 2009 and 2008, respectively	127,248	112,229
Accounts receivable - related party	2,617	2,875
Inventories	40,204	21,544
Net investment in direct financing leases, net of unearned income -current portion - related party	4,202	3,758
Other	10,825	8,736
Total current assets	189,244	168,127
FIXED ASSETS, at cost	373,927	349,212
Less: Accumulated depreciation	(89,040)	(67,107)
Net fixed assets	284,887	282,105
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	173,027	177,203
CO2 ASSETS, net of amortization	20,105	24,379
EQUITY INVESTEES AND OTHER INVESTMENTS	15,128	19,468
INTANGIBLE ASSETS, net of amortization	136,330	166,933
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	4,360	15,413
TOTAL ASSETS	$ 1,148,127	$ 1,178,674
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 114,428	$ 96,454
Accounts payable - related party	3,197	3,105
Accrued liabilities	23,803	26,713
Total current liabilities	141,428	126,272
LONG-TERM DEBT	366,900	375,300
DEFERRED TAX LIABILITIES	15,167	16,806
OTHER LONG-TERM LIABILITIES	5,699	2,834
COMMITMENTS AND CONTINGENCIES (Note 20)		
PARTNERS' CAPITAL:		
Common unitholders, 39,488 and 39,457 units issued and outstanding at December 31, 2009 and 2008, respectively	585,554	616,971
General partner	11,152	16,649

Accumulated other comprehensive loss	(829)	(962)
Total Genesis Energy, L.P. partners' capital	595,877	632,658
Noncontrolling interests	23,056	24,804
Total partners' capital	618,933	657,462
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,148,127	$ 1,178,674

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,		
	2009	2008	2007
REVENUES:			
Supply and logistics:			
Unrelated parties	$1,222,914	$1,847,575	$1,092,398
Related parties	3,924	4,839	1,791
Refinery services	141,365	225,374	62,095
Pipeline transportation, including natural gas sales:			
Transportation services - unrelated parties	16,097	19,469	17,153
Transportation services - related parties	32,590	21,730	5,754
Natural gas sales revenues	2,264	5,048	4,304
CO2 marketing:			
Unrelated parties	13,339	15,423	13,376
Related parties	2,867	2,226	2,782
Total revenues	1,435,360	2,141,684	1,199,653
COSTS AND EXPENSES:			
Supply and logistics costs:			
Product costs - unrelated parties	1,114,055	1,736,637	1,041,637
Product costs - related parties	1,754	-	101
Operating costs	82,262	78,453	37,121
Refinery services operating costs	88,910	166,096	40,197
Pipeline transportation costs:			
Pipeline transportation operating costs	10,954	10,306	10,054
Natural gas purchases	2,070	4,918	4,122
CO2 marketing costs:			
Transportation costs - related party	5,763	6,424	5,213
Other costs	62	60	152
General and administrative	40,413	29,500	25,920
Depreciation and amortization	62,581	71,370	38,747
Net loss on disposal of surplus assets	160	29	266
Impairment expense	5,005	-	1,498
Total costs and expenses	1,413,989	2,103,793	1,205,028
OPERATING INCOME (LOSS)	21,371	37,891	(5,375)
Equity in earnings of joint ventures	1,547	509	1,270
Interest income	70	458	385
Interest expense	(13,730)	(13,395)	(10,485)
Income (loss) before income taxes	9,258	25,463	(14,205)
Income tax (expense) benefit	(3,080)	362	654
NET INCOME (LOSS)	6,178	25,825	(13,551)
Net loss attributable to noncontrolling interests	1,885	264	1
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$8,063	$26,089	$(13,550)

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

	Year Ended December 31,		
	2009	2008	2007
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:			
BASIC	$0.51	$0.59	$(0.66)
DILUTED	$0.51	$0.59	$(0.66)
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
BASIC	39,471	38,961	20,754
DILUTED	39,603	39,025	20,754

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,		
	2009	2008	2007
Net income (loss)	$6,178	$25,825	$(13,551)
Change in fair value of derivatives:			
Current period reclassification to earnings	784	33	-
Changes in derivative financial instruments - interest rate swaps	(508)	(1,997)	-
Comprehensive income (loss)	6,454	23,861	(13,551)
Comprehensive loss attributable to noncontrolling interests	1,742	1,266	1
Comprehensive income (loss) attributable to Genesis Energy, L.P.	$8,196	$25,127	$(13,550)

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	Non-controlling Interests	Total
Partners' capital, January 1, 2007	13,784	$83,884	$1,778	$ -	$522	$86,184
Comprehensive income:						
Net loss	-	(13,279)	(271)	-	(1)	(13,551)
Cash contributions	-	-	1,412	-	-	1,412
Contribution for management compensation (Note 12)	-	-	3,434	-	-	3,434
Cash distributions	-	(16,743)	(432)	-	(2)	(17,177)
Issuance of units	24,469	561,403	10,618	-	51	572,072
Partners' capital, December 31, 2007	38,253	615,265	16,539	-	570	632,374
Comprehensive income:						
Net income	-	23,485	2,604	-	(264)	25,825
Interest rate swap losses reclassified to interest expense	-	-	-	16	17	33
Interest rate swap loss	-	-	-	(978)	(1,019)	(1,997)
Cash contributions	-	-	511	-	25,505	26,016
Cash distributions	-	(47,529)	(3,005)	-	(5)	(50,539)
Issuance of units	2,037	41,667	-	-	-	41,667
Unit based compensation expense	5	750	-	-	-	750
Redemption of units	(838)	(16,667)	-	-	-	(16,667)
Partners' capital, December 31, 2008	39,457	616,971	16,649	(962)	24,804	657,462
Comprehensive income:						
Net income		21,469	(13,406)	-	(1,885)	6,178
Interest rate swap losses reclassified to interest expense				383	401	784
Interest rate swap loss				(250)	(258)	(508)
Cash contributions			9			9
Contribution for management compensation (Note 12)			14,104			14,104
Cash distributions		(53,876)	(6,204)		(6)	(60,086)
Unit based compensation expense	31	990				990
Partners' capital, December 31, 2009	39,488	$585,554	$11,152	$ (829)	$23,056	$618,933

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,		
	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$6,178	$25,825	$(13,551)
Adjustments to reconcile net income (loss) to net cash provided by operating activities -			
Depreciation, amortization and impairment	67,586	71,370	40,245
Amortization and write-off of credit facility issuance costs	2,503	1,437	779
Amortization of unearned income and initial direct costs on direct financing leases	(18,095)	(10,892)	(620)
Payments received under direct financing leases	21,853	11,519	1,188
Equity in earnings of investments in joint ventures	(1,547)	(509)	(1,270)
Distributions from joint ventures - return on investment	950	1,272	1,845
Non-cash effect of unit-based compensation plans	4,248	(2,063)	910
Non-cash compensation charge	14,104	-	3,434
Deferred and other tax liabilities	1,914	(2,771)	(2,658)
Other non-cash items	(46)	882	347
Net changes in components of operating assets and liabilities, net of working capital acquired (See Note 15)	(9,569)	(1,262)	3,280
Net cash provided by operating activities	90,079	94,808	33,929
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(30,332)	(37,354)	(8,235)
CO2 pipeline transactions and related costs	-	(228,891)	-
Distributions from joint ventures - return of investment	-	886	395
Investments in joint ventures and other investments	(83)	(2,397)	(1,104)
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	1,182	718	(2,655)
Net cash used in investing activities	(29,233)	(333,724)	(321,342)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Bank borrowings	255,300	531,712	392,200
Bank repayments	(263,700)	(236,412)	(320,200)
Repayment to Grifco of seller-financing of asset acquisition	(6,000)	(6,000)	-
Credit facility issuance fees	(422)	(2,255)	(2,297)
Issuance of common units for cash	-	-	231,433
Redemption of common units for cash	-	(16,667)	-
General partner contributions	9	511	12,030
Noncontrolling interests contributions, net of distributions	(6)	25,500	49
Distributions to common unitholders	(53,876)	(47,529)	(16,743)
Distributions to general partner interest	(6,204)	(3,005)	(432)
Other, net	(784)	195	906
Net cash (used in) provided by financing activities	(75,683)	246,050	296,946

Net (decrease) increase in cash and cash equivalents	(14,837)	7,134	9,533
Cash and cash equivalents at beginning of period	18,985	11,851	2,318
Cash and cash equivalents at end of period	$4,148	$18,985	$11,851

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 and carbon dioxide (or CO2);
- Refinery services involving processing of high sulfur (or "sour") gas streams for refineries to remove the sulfur, and sale of the related by-product, sodium hydrosulfide (or NaHS, commonly pronounced nash) and supplying caustic soda (or NaOH);
- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting by trucks and barge of crude oil and petroleum products; and
- Industrial gas activities, including wholesale marketing of CO2 and processing of syngas through a joint venture.

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. In February 2010, Denbury sold our general partner interest to the Quintana-Controlled Owner Group. See Note 23.

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, 2009 and 2008 and our results of operations, cash flows and changes in partners' capital for the years ended December 31, 2009, 2008 and 2007. 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.

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.

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.

Subsequent Events

We have considered subsequent events through February 25, 2010, the date of issuance, in preparing the Consolidated Financial Statements and notes thereto.

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 Notes 3, 4 and 9.

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

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. The day-to-day operations are conducted by and managed by DG Marine employees.

T&P Syngas Supply Company

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. Reliant Processing Ltd. holds 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.

Noncontrolling 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 Consolidated Financial Statements as noncontrolling interests.

Use of Estimates

The preparation of our Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. We based these estimates and assumptions on historical experience and other information that we believed to be reasonable under the circumstances. Significant estimates that we make include: (1) 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.

Recent volatility in the financial markets 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.

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

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.

The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
Balance at beginning of period	$ 1,132	$ -
Charged to costs and expenses	558	1,152
Amounts written off	(320)	(20)
Recoveries	2	-
Balance at end of period	$ 1,372	$ 1,132

There was no allowance for doubtful accounts in 2007.

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 CO_2 pipelines, barge decommissioning, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. Accretion of the discount increases the liability and is recorded to expense. See Note 6.

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Direct Financing Leasing Arrangements

When a direct financing lease is consummated, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in pipeline revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets. See Note 7.

CO_2 Assets

Our CO_2 assets include three volumetric production payments and long-term contracts to sell the CO_2 volume. The contract values are being amortized on a units-of-production method. See Note 8.

Intangible Assets

Intangible assets with finite useful lives are amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are 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. No impairment has occurred of intangible assets in any of the periods presented.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We test goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. 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. No goodwill impairment has occurred in any of the periods presented. See Note 10.

Environmental Liabilities

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

Equity-Based Compensation

The compensation cost associated with our stock appreciation rights plan, which will result in the payment of cash to the employee upon exercise, is re-measured each reporting period. The liability and related compensation cost 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. The compensation cost related to phantom units issued under our 2007 Long-term Incentive Plan is recognized in our Consolidated Financial Statements based on estimated fair value at the date of the grant. See Note 16.

On December 31, 2008, our general partner awarded Class B Membership Interests in our general partner to our senior executives. The compensation cost related to these interests is re-measured at each reporting date based on the fair value of the interests, and changes in that fair value are recognized over the vesting period. Recorded expense will be subsequently adjusted to fair value until final settlement. See Note 16.

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Revenue Recognition

Product Sales - Revenues from the sale of crude oil and petroleum products by our supply and logistics segment, natural gas by our pipeline transportation segment, and caustic soda and NaHS by our refinery services segment are recognized when title to the inventory is transferred to the customer, collectability is reasonably assured and there are no further significant obligations for future performance by us. Most frequently, title transfers upon our delivery of the inventory to the customer at a location designated by the customer, although in certain situations, title transfers when the inventory is loaded for transportation to the customer. Our crude oil, 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 Consolidated Financial Statements at the lower of the recorded value or the market value at the balance sheet date. We value liabilities to replace crude oil at current market prices. The crude oil in inventory can then be sold, resulting in additional revenue if the sales price exceeds the inventory value.

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

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.

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.

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, 2009, 2008 and 2007, the fee averaged $0.2043, $0.1927, and $0.1848 per Mcf, respectively.

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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 Statements of Operations.

Income Taxes

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

Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative's fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income ("AOCI") and reclassified into earnings when the underlying position affects earnings. See Note 18.

Fair Value of Current Assets and Current Liabilities

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

Net Income Per Common Unit

Our net income is first allocated to our general partner based on the amount of incentive distributions to our general partner. We then allocate to our general partner the amount of equity-based compensation costs which our general partner has agreed to pay. 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 16 for discussion of our equity-based compensation.)

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 2009 and 2008, we reported net income; therefore incremental phantom units have been included in the calculation of diluted earnings per unit.

Effective January 1, 2009, we adopted new accounting guidance related to the consideration of distributions paid by a master limited partnership, like us, to its general and limited partners in the computation of earnings per unit.. See "Recent and Proposed Accounting Announcements – Implemented in 2009" below.

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Recent and Proposed Accounting Pronouncements

Implemented in 2009

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162," (The Codification). The Codification establishes the FASB Accounting Standards Codification (ASC) as the source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. The Codification reorganizes GAAP pronouncements by topic and modifies the GAAP hierarchy to include only two levels: authoritative and non-authoritative. All of the content in the Codification carries the same level of authority. This statement was effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the Codification on September 30, 2009. Thus, subsequent references to GAAP in our Consolidated Financial Statements will refer exclusively to the Codification.

Recognized and Non-Recognized Subsequent Events

In May 2009, the FASB issued new guidance for accounting for subsequent events. The new guidance establishes the accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. See "Subsequent Events" included in "Note 1 – Organization" for the related disclosure. The new guidance was applied prospectively beginning in the second quarter of 2009 and did not have a material impact on our Consolidated Financial Statements.

Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued new guidance regarding interim disclosures about the fair value of financial instruments. The new guidance requires fair value disclosures on an interim basis for financial instruments that are not reflected in the Consolidated Balance Sheets at fair value. Previously, the fair values of those financial instruments were only disclosed on an annual basis. We adopted the new guidance for our quarter ended June 30, 2009, and there was no material impact on our Consolidated Financial Statements.

Business Combinations

In December 2007, the FASB issued revised guidance for the accounting of business combinations. The revised guidance retains the purchase method of accounting used in business combinations but replaces superseded guidance 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 revised guidance requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The revised guidance applies to acquisitions we make after December 31, 2008. The impact to us will be dependent on the nature of the business combination.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued guidance regarding noncontrolling interests in consolidated financial statements. The new guidance establishes accounting and reporting standards for noncontrolling interests, which were 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. The new guidance 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. The provisions of the new guidance were effective for fiscal years beginning after December 15, 2008. On January 1, 2009, we adopted the new guidance which changed the presentation of the interests in Genesis Crude Oil, L.P. held by our general partner and the interests in DG Marine held by our joint venture partner in our Consolidated Financial Statements. Amounts for prior periods have been changed to be consistent with the presentation required by the new guidance.

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Derivative Instruments and Hedging Activities

In March 2008, the FASB issued new guidance regarding disclosures about derivative instruments and hedging activities. The new guidance requires enhanced disclosures about our derivative and hedging activities. This guidance was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the guidance on January 1, 2009 and have included the enhanced disclosures in Note 18. Adoption did not have any material impact on our financial position, results of operations or cash flows

Application of the Two-Class Method to Master Limited Partnerships

In March 2008, the FASB issued new guidance regarding the application of the two-class method of determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. Under this guidance, the computation of earnings per unit is affected by the incentive distribution rights ("IDRs") we are contractually obligated to distribute at the end of the each reporting period. In periods when earnings are in excess of cash distributions, we reduce net income or loss for the current reporting period (for purposes of calculating earnings or loss per unit only) by the amount of available cash that will be distributed to our limited partners and general partner for its general partner interest and incentive distribution rights for the reporting period, and the remainder is allocated to the limited partner and general partner in accordance with their ownership interests. When cash distributions exceed current-period earnings, net income or loss (for purposes of calculating earnings or loss per unit only) is reduced (or increased) by cash distributions, and the resulting excess of distributions over earnings is allocated to the general partner and limited partner based on their respective sharing of losses. The new guidance was effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted the new guidance on January 1, 2009 and have reflected the calculation of earnings per unit for the years ended December 31, 2009, 2008 and 2007 in accordance with its provisions. See Note 12.

Measuring Liabilities and Fair Value

In August 2009, the FASB issued guidance that provides clarification to the valuation techniques required to measure the fair value of liabilities. The guidance also provides clarification around required inputs to the fair value measurement of a liability and definition of a Level 1 liability. The guidance was effective for interim and annual periods beginning after August 2009. We adopted this standard beginning with our financial statements for the year ended December 31, 2009. The adoption of this standard did not have a material effect on our financial statements.

Implemented January 1, 2010

Consolidation of Variable Interest Entities ("VIEs")

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation, rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance was effective for us beginning January 1, 2010. We are currently assessing the impact this guidance may have on our consolidated financial statements.

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3. Acquisitions

2008 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). Grifco financed $12 million of additional purchase consideration that we agreed to pay after we placed the eight new barges in service. At December 31, 2009, all of the seller-financed additional purchase price consideration was paid.

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 11 and 12.

We entered into a subordinated loan agreement with DG Marine whereby we loaned $25 million to DG Marine. See Note 4.

Accounting provisions require the primary beneficiary to consolidate variable interest entities. 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.

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 noncontrolling interests in our Consolidated Financial Statements.

The acquisition cost allocated to the assets consisted 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 was owed to Grifco when the barges under construction were placed in service and $2.4 million of transaction costs. The acquisition cost was 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

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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 is 6 years.

See additional information on intangible assets in Note 10.

2008 Denbury Drop-Down Transactions

On May 30, 2008, we completed two transactions with Denbury Onshore LLC, (Denbury Onshore), a wholly-owned subsidiary of Denbury Resources Inc.

NEJD Pipeline System

In 2008, we entered into a twenty-year financing lease transaction with Denbury valued at $175 million and related to the 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 tertiary recovery 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.

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 7.

Free State Pipeline System

We purchased the Free State Pipeline for $75 million from Denbury, 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 CO_2 source fields at Jackson Dome, near Jackson, Mississippi, to oil fields in east Mississippi. We entered into a twenty-year transportation services agreement to deliver CO_2 on the Free State pipeline for use in 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 currently 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 of Denbury.

2007 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. 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.

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The Davison family is our largest unitholder, with approximately 30% 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

The purchase price was 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 10. 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 Statement 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 the 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.

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	Year Ended December 31, 2007
Pro Forma Earnings Data:	
Revenue	$ 1,574,730
Costs and expenses	1,572,809
Operating income	1,921
(Loss) Income before extraordinary items	(29,666)
Net (loss) income	(29,666)
Basic and diluted (loss) earnings per unit:	
As reported units outstanding	20,754
Pro forma units outstanding	28,319
As reported net (loss) income per unit	$ (0.64)
Pro forma net (loss) income per unit	$ (1.05)

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.

The purchase price was 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 10.

4. Consolidated Joint Venture - DG Marine

DG Marine is a joint venture we formed with TD Marine. TD Marine owns (indirectly) a 51% economic interest in DG Marine, and we own (directly and indirectly) a 49% economic interest. This joint venture gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

We 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 prime rate 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 also has a revolving credit facility with a syndicate of financial institutions that includes restrictions on DG Marine's ability to make specified payments under our subordinated loan agreement and distributions in respect of our equity interest. At December 31, 2009, $25 million was outstanding under the subordinated loan agreement; however this amount and the associated interest expense were eliminated in our Consolidated Financial Statements. No payments have been made to us from DG Marine under the subordinated loan agreement as of December 31, 2009. At December 31, 2008, there were no amounts outstanding under the subordinated loan agreement.

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At December 31, 2009 and 2008, our Consolidated Balance Sheets included the following amounts related to DG Marine:

	December 31, 2009	December 31, 2008
Cash	$ 585	$ 623
Accounts receivable - trade	3,216	2,812
Other current assets	2,421	859
Fixed assets, at cost	124,276	110,214
Accumulated depreciation	(9,139)	(3,084)
Intangible assets, net	1,758	2,208
Other assets	1,174	2,178
Total assets	$ 124,291	$ 115,810
Accounts payable	$ 1,788	$ 1,072
Accrued liabilities	3,601	9,258
Long-term debt	46,900	55,300
Other long-term liabilities	683	1,393
Total liabilities	$ 52,972	$ 67,023

5. Inventories

The major components of inventories were as follows:

	December 31, 2009	December 31, 2008
Crude oil	13,901	1,878
Petroleum products	22,150	5,589
Caustic soda	1,985	7,139
NaHS	2,154	6,923
Other	14	15
Total inventories	$ 40,204	$ 21,544

At December 31, 2009, market values of our inventory exceeded recorded costs. Our inventory at December 31, 2008 is reflected 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.

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6. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following.

	December 31, 2009	December 31, 2008
Land, buildings and improvements	$ 14,028	$ 13,549
Pipelines and related assets	156,274	139,184
Machinery and equipment	27,016	22,899
Transportation equipment	31,669	32,833
Barges and push boats	122,913	96,865
Office equipment, furniture and fixtures	4,412	4,401
Construction in progress	4,813	27,906
Other	12,802	11,575
Subtotal	373,927	349,212
Accumulated depreciation	(89,040)	(67,107)
Total	$ 284,887	$ 282,105

In 2009, 2008 and 2007, $112,000, $276,000 and $57,000 of interest cost, respectively, were capitalized related to the construction of pipelines and related assets.

Depreciation expense was $25.2 million, $20.4 million and $8.9 million for the years ended December 31, 2009, 2008, and 2007, 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 $1.5 million related to these assets.

Asset Retirement Obligations

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

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
Liabilities incurred and assumed in the current period	726
Liabilities settled in the current period	(117)
Accretion expense	152

Revisions in estimated cash flows	2,647
Asset retirement obligations as of December 31, 2009	$4,838

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 the year. Certain of our unconsolidated affiliates have asset retirement obligations recorded at December 31, 2009 and 2008 relating to contractual agreements. These amounts are immaterial to our Consolidated Financial Statements.

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7. Net Investment in 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 related to that lease that began in August 2008.

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

	December 31,			
		2009		2008
Total minimum lease payments to be received	$	385,565	$	407,392
Estimated residual values of leased property (unguaranteed)		1,287		1,287
Unamortized initial direct costs		2,380		2,580
Less unearned income		(212,003)		(230,298)
Net investment in direct financing leases	$	177,229	$	180,961

At December 31, 2009, minimum lease payments to be received for each of the five succeeding fiscal years are $21.9 million per year for 2010 through 2011, $21.8 million for 2012, $21.3 million for 2013 and $21.2 million for 2014.

8. CO2 Assets

CO2 assets consisted of the following.

	December 31,			
		2009		2008
CO2 volumetric production payments	$	43,570	$	43,570
Less - Accumulated amortization		(23,465)		(19,191)
Net CO2 assets	$	20,105	$	24,379

The volumetric production payments entitle us to a maximum daily quantity of CO2 of 91,875 million cubic feet, or 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, Denbury processes and delivers this CO2 to our industrial customers and receive a fee of $0.16 per Mcf, subject to inflationary adjustments from us. During 2009 this fee averaged $0.2043 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 2011 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 2009, 2008 and 2007, we recorded amortization of $4,274,000, $4,537,000 and $4,488,000, respectively. We have 127.0 Bcf of CO2 remaining under the volumetric production payments at December 31, 2009. 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 $4,274,000 for 2010, $3,920,000 for 2011 and 2012 and $3,258,000 for 2013 and 2014.

9. 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.

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	Year Ended December 31,		
	2009	2008	2007
Genesis' share of operating earnings	1,261	1,137	1,898
Amortization of excess purchase price	285	(628)	(628)
Net equity in earnings	$ 1,546	$ 509	$ 1,270
Distributions received	$ 950	$ 2,158	$ 2,240

Other Projects

In 2006, we invested in the Faustina Project, a petroleum coke to ammonia project that is in the development stage. As a result of a review of the financing alternatives for the project, requirements for continued funding for the project and the change in control of our general partner in February 2010, we decided not to fund our share of further development in the project. We further determined that the likelihood of a recovery of our investment was remote, and the fair value of the investment was zero. In 2009, we recorded a $5.0 million impairment charge related to our investment in the Faustina Project, reducing the value of that investment in our Consolidated Balance Sheets at December 31, 2009 to zero. At December 31, 2008, our Consolidated Balance Sheet included $4.9 million related to our investment in the Faustina Project.

10. 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, 2009:

		December 31, 2009			December 31, 2008		
	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	$ 41,450	$ 53,204	$ 94,654	$ 26,017	$ 68,637
Supply and logistics customer relationships	5	35,430	15,493	19,937	35,430	9,957	25,473
Refinery services supplier relationships	2	36,469	28,551	7,918	36,469	24,483	11,986
	6	38,678	11,681	26,997	38,678	7,176	31,502

Refinery services licensing agreements							
Supply and logistics trade names - Davison and Grifco	7	18,888	5,444	13,444	18,888	3,118	15,770
Supply and logistics favorable lease	15	13,260	1,144	12,116	13,260	671	12,589
Other	5	3,823	1,109	2,714	1,322	346	976
Total	5	$ 241,202	$ 104,872	$ 136,330	$ 238,701	$ 71,768	$ 166,933

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 $33.1 million, $46.4 million and $25.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

	2010	2011	2012	2013	2014
Refinery services customer relationships	$ 11,689	$ 8,972	$ 7,056	$ 7,116	$ 5,597
Supply and logistics customer relationships	4,488	3,603	2,819	2,165	1,660
Refinery services supplier relationships	2,925	2,629	2,364	-	-
Refinery services licensing agreements	4,105	3,690	3,416	3,163	2,928
Supply and logistics trade name	2,086	1,851	1,432	1,237	1,073
Supply and logistics favorable lease	474	474	474	474	474
Other	869	700	701	110	58
Total	$ 26,636	$ 21,919	$ 18,262	$ 14,265	$ 11,790

Goodwill

In connection with the Davison and Port Hudson acquisitions (See Note 3), we allocated the residual of the purchase price over the fair values of the net tangible and identifiable intangible assets acquired to goodwill. The carrying amount of goodwill by business segment at December 31, 2009 and 2008 was $301.9 million in refinery services and $23.1 million in supply and logistics. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Other Assets

Other assets consisted of the following.

	December 31,	
	2009	2008
Credit facility fees - Genesis	$ 5,022	$ 5,022
Credit facility fees - DG Marine	2,373	2,536
Initial direct costs related to Free State Pipeline lease	1,132	1,132
Deferred tax asset	-	1,543
Other deferred costs and deposits	131	7,502
	8,658	17,735
Less - Accumulated amortization	(4,298)	(2,322)
Net other assets	$ 4,360	$ 15,413

Amortization of the initial direct costs related to the Free State Pipeline lease for the years ended December 31, 2009 and 2008 was $60,000 and $35,000, respectively. Amortization expense of credit facility fees for the years ended December 31, 2009, 2008 and 2007 was $1,917,000, $1,437,000 and $779,000, respectively. In the fourth quarter of 2009, we charged to expense $586,000 of unamortized fees related to the DG Marine credit facility that we amended in November 2009. Additional fees of $423,000 related to the amendment of the DG Marine facility were deferred in

November 2009 and will be amortized over the remaining term of the facility. Total amortization of initial direct costs and credit facility fees for the next five years will be $1,898,000 for 2010, $1,413,000 for 2011 and $60,000 per year for 2012 through 2014.

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11. Debt

At December 31, 2009 our obligations under credit facilities consisted of the following:

	December 31, 2009	December 31, 2008
Genesis Credit Facility	$ 320,000	$ 320,000
DG Marine Credit Facility (non-recourse to Genesis)	46,900	55,300
Total Long-Term Debt	$ 366,900	$ 375,300

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, 2009 was $407 million.

At December 31, 2009, we had $320 million borrowed under our credit facility and $5.2 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, 2009 was $82 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, 2009, our borrowing rates were the prime rate plus 0.75% or the LIBOR rate plus 1.75%.

- 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, 2009, our letter of credit rate was 1.75%.

- 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 0.375%.

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. Our credit facility includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval.

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Financial Covenant	Requirement	Required Ratio through December 31, 2009	Actual Ratio as of December 31, 2009
Debt Service Coverage Ratio	Minimum	3.00 to 1.0	13.93 to 1.0
Leverage Ratio	Maximum	5.50 to 1.0	3.22 to 1.0
Funded Indebtedness Ratio	Maximum	0.65 to 1.0	0.40 to 1.0

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, 2009, the excess of distributable cash over distributions under this provision of the credit facility was $76.8 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. The facility amount was reduced to $54 million in November 2009. Genesis has provided a guaranty of $7.5 million to the lenders in the DG Marine credit facility.

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, 2009, our Consolidated Balance Sheet included $124.3 million of DG Marine's assets in our total assets.

At December 31, 2009, DG Marine had $46.9 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, 2009 was $7.1 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, 2009, 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, 2009, 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 $54 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, 2009, 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 3.88% in effect at December 31, 2009 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.

Financial Covenant	Requirement	Required Ratio through December 31, 2009	Actual Ratio as of December 31, 2009
Interest Coverage Ratio	Minimum	2.50 to 1.0	2.95 to 1.0
Leverage Ratio	Maximum	4.00 to 1.0	3.60 to 1.0
Asset Coverage Ratio	Minimum	1.0 to 1.0	1.75 to 1.0

Our long-term debt, including the DG Marine credit facility, totaling $366.9 million matures in 2011. We have estimated the fair value of our long-term debt to be approximately $359.9 million, or $7.0 million less than the carrying value of that debt based on consideration of our credit standing.

12. Partners' Capital and Distributions

Partner's capital at December 31, 2009 consists of 39,487,997 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 effect to the general partner interest), and a 2% general partner interest. Subsequent to December 31, 2009, our general partner transferred the common units it held to another affiliate of Denbury. See Note 23.

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 noncontrolling interest in the Consolidated Balance Sheet at December 31, 2009) 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 11, our credit facility limits the amount of distributions we may pay in any quarter. At December 31, 2009, our restricted net assets (as defined in Rule 4-03(e)(3) of Regulations S-X) were $492.1 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:

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	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	74.53	%	25.47	%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02	%	50.98	%

We paid distributions in 2008 and 2009 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 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
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579

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Net Income (Loss) per Common Unit

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

	Year Ended December 31, 2009	2008	2007
Numerators for basic and diluted net income (loss)per common unit:			
Income (loss) attributable to Genesis Energy, L.P.	$8,063	$26,089	$(13,550)
Less: General partner's incentive distribution paid or to be paid for the period	(6,318)	(2,613)	(335)
Add: Expense allocable to our general partner	18,853	-	-
Subtotal	20,598	23,476	(13,885)
Less: General partner 2% ownership	(412)	(470)	277
Income (loss) available for common unitholders	$20,186	$23,006	$(13,608)
Denominator for basic per common unit:			
Common Units	39,471	38,961	20,754
Denominator for diluted per common unit:			
Common Units	39,471	38,961	20,754
Phantom Units	132	64	-
	39,603	39,025	20,754
Basic net income per common unit	$0.51	$0.59	$(0.66)
Diluted net income per common unit	$0.51	$0.59	$(0.66)

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.

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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. In 2009, we recorded a additional non-cash contribution of $14.1 million from our general partner related to incentive compensation arrangements with our senior executives. 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.

13. 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. Substantially all of our revenues are derived from, and substantially all of our assets are located in the United States.

We define segment margin as revenues less 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 equity-based compensation plans and the unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Segment margin 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	Supply & Logistics	Industrial Gases (a)	Total
Year Ended December 31, 2009					
Segment margin (b)	$ 42,162	$51,844	$29,052	$11,432	$134,490
Capital expenditures (c)	$ 3,043	$2,572	$23,498	$83	$29,196
Maintenance capital expenditures	$ 1,281	$1,246	$1,899	$-	$4,426
Net fixed and other long-term assets (d)	$ 279,574	$409,556	$234,421	$35,332	$958,883
Revenues:					
External customers	$ 44,461	$147,240	$1,227,453	$16,206	$1,435,360
Intersegment (e)	6,490	(5,875)	(615)	-	-
Total revenues of reportable segments	$ 50,951	$141,365	$1,226,838	$16,206	$1,435,360
Year Ended December 31, 2008					
Segment margin (b)	$ 33,149	$55,784	$32,448	$13,504	$134,885
Capital expenditures (c)	$ 262,200	$5,490	$118,585	$2,397	$388,672
Maintenance capital expenditures	$ 719	$1,881	$1,854	$-	$4,454
Net fixed and other long-term assets (d)	$ 285,773	$434,956	$245,815	$44,003	$1,010,547
Revenues:					
External customers	$ 39,051	$233,871	$1,851,113	$17,649	$2,141,684
Intersegment (e)	7,196	(8,497)	1,301	-	-
Total revenues of reportable segments	$ 46,247	$225,374	$1,852,414	$17,649	$2,141,684
Year Ended December 31, 2007					
Segment margin (b)	$ 14,170	$19,713	$10,646	$13,038	$57,567
Capital expenditures (c)	$ 6,592	$503,765	$138,403	$1,104	$649,864
Maintenance capital expenditures	$ 2,880	$469	$491	$-	$3,840
Net fixed and other long-term assets (d)	$ 32,936	$468,068	$145,915	$47,364	$694,283
Revenues:					
External customers	$ 23,356	$65,581	$1,094,558	$16,158	$1,199,653
Intersegment (e)	3,855	(3,486)	(369)	-	-
Total revenues of reportable segments	$ 27,211	$62,095	$1,094,189	$16,158	$1,199,653

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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 for each year presented is as follows:

	Year Ended December 31, 2009	2008	2007
Segment margin	$ 134,490	$ 134,885	$ 57,567
Corporate general and administrative expenses	(36,475)	(22,113)	(17,573)
Depreciation, amortization and impairment	(67,586)	(71,370)	(40,245)
Net loss on disposal of surplus assets	(160)	(29)	(266)
Interest expense, net	(13,660)	(12,937)	(10,100)
Non-cash expenses not included in segment margin	(4,089)	1,355	(2,009)
Other non-cash items affecting segment margin	(3,262)	(4,328)	(1,579)
Income (loss) before income taxes	$ 9,258	$ 25,463	$ (14,205)

(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 $15.1 million, $14.5 million and $16.2 million at December 31, 2009, 2008 and 2007, respectively.

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

14. 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,		
	2009	2008	2007
Truck transportation services provided to Denbury	$3,167	$3,578	$1,791
Pipeline transportation services provided to Denbury	$14,375	$10,727	$5,290
Payments received under direct financing leases from Denbury	$21,853	$11,519	$1,188
Pipeline transportation income portion of direct financing lease fees	$18,295	$11,011	$641
Pipeline monitoring services provided to Denbury	$120	$120	$120
Directors' fees paid to Denbury	$185	$195	$150
CO2 transportation services provided by Denbury	$5,475	$6,424	$5,213
Crude oil purchases from Denbury	$1,754	$-	$101
Operations, general and administrative services provided by our general partner	$50,417	$51,872	$22,490
Distributions to our general partner on its limited partner units and general partner interest, including incentive distributions	$10,066	$6,463	$1,671
Sales of CO2 to Sandhill	$2,867	$2,941	$2,783
Petroleum products sales to Davison family businesses	$757	$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.

We earn tariffs on our Mississippi pipeline for transporting Denbury's 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 the Denbury's officers who served as directors of our general partner, at an annual rate and for attendance at meetings that was 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 2009, the inflation-adjusted transportation fee averaged $0.2043 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 16.

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Amounts due to and from Related Parties

At December 31, 2009 and 2008, we owed Denbury $1.0 million, respectively, for CO2 transportation charges. Denbury owed us $1.9 million and $2.0 million for transportation services at December 31, 2009 and 2008, respectively. We owed our general partner $2.1 million for administrative services at both December 31, 2009 and 2008. At December 31, 2009 and 2008, Sandhill owed us $0.7 million for purchases of CO2, respectively.

Drop-down transactions

On May 30, 2008, we entered into a $175 million financing lease arrangement with Denbury Onshore for the NEJD Pipeline System, and acquired the 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 12, we redeemed 837,690 of our common units owned by members of the Davison family in July 2008. 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 Community Trust Bank. At December 31, 2009, the total amount of Sandhill's obligation to the bank was $2.65 million; therefore, our guarantee was for $1.33 million.

Approximately 12% 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 12, our general partner made capital contributions in order to maintain its capital account totaling less than $0.1 million and $0.5 million in 2009 and 2008, 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 2009 and 2007, we recorded a capital contribution from our general partner of $14.1 million and $3.4 million, respectively, related to compensation recognized for our executive management team. See Note 16.

15. Supplemental Cash Flow Information

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

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	Year Ended December 31,		
	2009	2008	2007
Decrease (increase) in:			
Accounts receivable	$(7,979)	$61,126	$(35,362)
Inventories	(16,559)	(5,557)	(143)
Other current assets	(2,712)	(2,419)	(1,887)
Increase (decrease) in:			
Accounts payable	19,203	(58,224)	34,523
Accrued liabilities	(1,522)	3,812	6,149
Net changes in components of operating assets and liabilities,net of working capital acquired	$(9,569)	$(1,262)	$3,280

Cash received by us for interest during the years ended December 31, 2009, 2008 and 2007 was $0.1 million, $0.1 million and $0.3 million, respectively. Payments of interest and commitment fees were $13.3 million, $11.3 million and $8.4 million, during the years ended December 31, 2009, 2008 and 2007, respectively.

Cash paid for income taxes in during the years ended December 31, 2009, 2008 and 2007 was $0.2 million, $2.4 million and $1.6 million, respectively.

At December 31, 2009 and 2008, we had incurred liabilities for fixed asset additions totaling $0.5 million and $1.7 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 in our Consolidated Statements of Cash Flows. The seller-financed consideration payments made in December 2008 and December 2009 are 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.

16. 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, $2.2 million, and $0.8 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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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 $1.8 million, $1.7 million, and $1.5 million in 2009, 2008 and 2007, respectively. Effective January 1, 2008, the employees who operate the assets we acquired from the Davison family became participants in these plans.

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 accounting guidance, the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

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 expense we recognize 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, 2009	December 31, 2008	December 31, 2007
Expected life of rights (in years)	0.25 - 5.50	1.25 - 6.00	2.25 - 6.25
Risk-free interest rate	0.05% - 2.52%	0.57% - 1.71%	3.12% - 3.65%
Expected unit price volatility	43.8%	42.8%	34.2%
Expected future distribution yield	8.50%	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 and our employee population tripled in 2008, 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 lower distribution yield, we believe that the yield will be closer to 8.5% over the life of the outstanding rights.

- We estimated the expected forfeitures of non-vested rights and expirations of vested rights. We have 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, 2009, and changes during the year ended December 31, 2009:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2009	1,017,985	$ 18.09		
Granted during 2009	228,212	$ 13.00		
Exercised during 2009	(24,602)	$ 15.41		
Forfeited or expired during 2009	(101,597)	$ 18.34		
Outstanding at December 31, 2009	1,119,998	$ 17.14	7.4	$ 3,515
Exercisable at December 31, 2009	587,981	$ 16.13	6.2	$ 2,396

The weighted-average fair value at December 31, 2009 of rights granted during 2009 was $4.82 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights at Grant Date	Granted in 2009
Expected life of rights (in years)	5.50
Risk-free interest rate	2.52%

Expected unit price volatility	43.8%
Expected future distribution yield	8.50%

The total intrinsic value of rights exercised during 2009, 2008 and 2007 was $0.1 million, $0.4 million and $1.6 million, respectively, which was paid in cash to the participants.

At December 31, 2009, there was $0.9 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, 2009 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, 2009, 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, 2009 as follows:

Expense (Credits to Expense) Related to Stock Appreciation Rights

Statement of Operations	2009	2008	2007
Supply and logistics operating costs	$ 1,431	$ (997)	$ 528
Refinery services operating costs	325	23	-
Pipeline operating costs	360	(296)	420
General and administrative expenses	1,263	(1,141)	1,576
Total	$ 3,379	$ (2,411)	$ 2,524

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 832,928 remain authorized for issuance at December 31, 2009. 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 the expense we recognize is adjusted for 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, 2009. The grant date fair value of the awards is 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 2009, 2008 and 2007 was $0.7 million, $0.8 million and $0.9 million, respectively. The total fair value of Phantom Units that vested during the years ended December 31, 2009 and 2008 was $0.7 million and $0.1 million, respectively. Compensation expense recognized during 2009 and 2008 for Phantom Units was as follows:

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Expense Related to Phantom Unit Awards

Statement of Operations	2009	2008
Supply and logistics operating costs	$ 36	$ 114
Refinery services operating costs	120	-
Pipeline operating costs	4	139
General and administrative expenses	869	494
Total	$ 1,029	$ 747

Expense recorded during 2007 was less than $0.1 million. As of December 31, 2009, there was $0.5 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. Due to the provisions in the 2007 Plan providing for immediate vesting of outstanding Phantom Units upon the occurrence of a change in control of our general partner, the outstanding Phantom Units vested in February 2010. See Note 23.

The following table summarizes information regarding our non-vested Phantom Unit grants as of December 31, 2009:

Non-vested Phantom Unit Grants	Number of Units	Weighted Average Grant-Date Fair Value	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrisic Value
Non-vested at January 1, 2008	78,388	$ 19.32		
Granted during 2009	82,501	$ 8.14		
Vested during 2009	(33,532)	$ 19.79		
Forfeited during 2009	(3,500)	$ 8.88		
Non-vested at December 31, 2009	123,857	$ 12.04	0.9	$ 2,341

The weighted-average fair value of Phantom Units granted during 2009, 2008 and 2007 was determined using the following assumptions:

	Year Granted		
	2009	2008	2007
Expected distribution rate	$ 0.33	$ 0.285 - $0.315	$ 0.27
Risk-free rate	0.73% - 1.50 %	2.01% - 2.40 %	3.19% - 3.31 %
Weighted average grant date fair value	$ 8.14	$ 17.63	$ 21.92

Bonus Program

In January 2008, 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 2009 and 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 2009 and 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.

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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 2009 and 2008, we accrued $3.5 million and $4.0 million, respectively, for the general bonus pool and $0.4 million and $0.5 million, respectively, for the marketing bonus pool. 2009 bonuses will be paid to employees in March 2010.

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 our Senior Executives.) 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 material change in job status, a material reduction in pay, or a requirement to relocate more than 25 miles.

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 12) to the extent we increase the level of available cash we generate for each quarter through the vesting date.

Our general partner 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 . 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 are accounted for as liability awards under the guidance for equity-based compensation. As such, the fair value of the compensation cost we record for these awards is recomputed at each measurement date through final settlement and the expense to be recorded is adjusted based on that fair value. Therefore, changes in management's assumptions utilized in the determination of the fair value of the awards change the amount of compensation cost we record. Additionally the determination of fair value is affected by the distribution yield of a group of publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control.

As these awards were issued, among other reasons, in settlement of our obligation to these employees recorded as of December 2007, we treated the issuance as a modification in accordance with the accounting guidance for share-based payments. Therefore, we compared the value of the compensation arrangements before the modification ($3.4 million) to the fair value of the awards and reflected the incremental compensation cost over the requisite service period of the new grant.

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At December 31, 2009, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives is approximately $30.5 million. Management's estimates of fair value were made in order to record non-cash compensation expense over the vesting period. For the year ended December 31, 2009, we recorded expense of $14.1 million for these awards.

The fair value of the Class B Membership Awards and the related deferred compensation was calculated utilizing assumptions regarding the following factors:

- Estimates of the level of IDR distributions that would be paid to our general partner assuming our current quarterly increase in the distribution through the final vesting date of December 31, 2012.

- Estimates of the level of available cash we estimate we will generate for each quarter through the vesting date and available cash attributable to certain assets that are excluded in the computations.

- Estimates of an appropriate discount factor to utilize for computation of the fair value of the awards.

The Class B Membership Awards and related deferred compensation agreements contained provisions providing for accelerated vesting upon a change in control of our general partner. As a result of the sale of our general partner in February 2010, the Class B Membership Interests were redeemed or converted into other ownership interests in our general partner, and the deferred compensation was paid to the Senior Executives. See Note 23.

17. 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 12.5% and 14.6% of total revenues in 2009 and 2008, respectively. Shell Oil Company and Occidental Energy Marketing, Inc. accounted for 20.7% and 11.2% of total revenues in 2007, respectively. The revenues from these two customers in all three years relate primarily to our supply and logistics operations.

18. Derivatives

On January 1, 2009, we adopted new accounting guidance which require enhanced disclosures about (1) how and why we use derivative instruments, (2) how derivative instruments and related hedged items are accounted for by us and (3) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows.

Commodity Derivatives

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

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

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

At December 31, 2009, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

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	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	146	-
Weighted average contract price per bbl	$ 78.98	$ -
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	305	111
Weighted average contract price per bbl	$ 77.79	$ 77.93
Heating oil futures:		
Contract volumes (1,000 bbls)	94	43
Weighted average contract price per gal	$ 1.92	$ 2.04
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	14	-
Weighted average contract price per gal	$ 1.91	$ -
#6 Fuel Oil futures:		
Contract volumes (1,000 bbls)	75	-
Weighted average contract price per bbl	$ 68.06	$ -
Crude oil written calls:		
Contract volumes (1,000 bbls)	73	-
Weighted average premium received	$ 2.79	$ -

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.

Interest Rate Derivatives

DG Marine utilizes swap contracts with financial institutions to hedge interest payments for $32.9 million of its outstanding debt through July 2011. The weighted average interest rate of these swap contracts is 4.36%. DG Marine expects these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates, therefore, we have designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts is reported as a component of Accumulated Other Comprehensive Income (Loss) (AOCI) and reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility is recorded. To the extent that the change in the fair value of the interest rate swaps does not perfectly offset the change in the fair value of our exposure to interest rates, the ineffective portion of the hedge will be immediately recognized in interest expense in our Consolidated Statements of Operations.

Financial Statement Impacts

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

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

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

The following tables reflected the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at December 31, 2009:

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	Fair Value of Derivative Assets and Liabilities			
	Derivative Assets	Consolidated Balance Sheets Location	Derivative Liabilities	Consolidated Balance Sheets Location
Commodity derivatives - futures and call options:				
Hedges designated under accounting guidance as fair value hedges	$ 53	Other Current Assets	$ (159)(1)	Other Current Assets
Undesignated hedges	307	Other Current Assets	(2,118)(1)	Other Current Assets
Total commodity derivatives	360		(2,277)	
Interest rate swaps designated as cash flow hedges under accounting rules:				
Portion expected to be reclassified into earnings within one year			(1,176)	Accrued Liabilities
Portion expected to be reclassified into earnings after one year			(512)	Other Liabilities
Total derivatives	$ 360		$ (3,965)	

(1) These derivative liabilities have been funded with margin deposits recorded in our Consolidated Balance Sheets in Other Current Assets.

	Year Ended December 31, 2009 Effect on Consolidated Statements of Operations and Other Comprehensive Income (Loss) Amount of Loss Recognized in Income		
	Supply & Logistics - Product Costs	Interest Expense Reclassified from AOCI	Other Comprehensive Income (Loss) Effective Portion
Commodity derivatives - futures and call options:			
Contracts designated as hedges under accounting guidance:	$(5,321)(1)	$ -	$ -
Contracts not considered hedges under accounting guidance:	(2,446)		
Total commodity derivatives	(7,767)	-	-

Interest rate swaps designated as cash flow hedges under accounting guidance		(784)	(508)
Total derivatives	$(7,767)	$(784)	$ (508)

(1) Represents the amount of loss recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $7.5 million.

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During 2009, DG Marine's interest rate hedges fully offset the hedged risk; therefore, there was no ineffectiveness recorded for the hedges.

We expect to reclassify $1.2 million in unrealized losses from AOCI into interest expense during the next 12 months. Because a portion of these losses are 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 have no derivative contracts with credit contingent features.

19. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008. As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value at December 31, 2009			Fair Value at December 31, 2008		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives :						
Assets	$ 360	$ -	$ -	$ 482	$ -	$ -
Liabilities	$ (2,277)	$ -	$ -	$ (970)	$ -	$ -
Interest rate swaps	$ -	$ -	$ (1,688)	$ -	$ -	$ (1,964)

Level 1

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

Level 2

At December 31, 2009 and 2008, we had no Level 2 fair value measurements.

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, 2009	2008
Balance at beginning of period	$ (1,964)	$ -
Realized and unrealized gains (losses)-		
Reclassified into interest expense for settled contracts	784	33
Included in other comprehensive income	(508)	(1,997)
Balance at end of period	$ (1,688)	$ (1,964)
Total amount of losses for the year ended included in earnings attributable to the change in unrealized losses relating to liabilities still held at December 31, 2009 and 2008, respectively	$ (10)	$ (5)

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See Note 18 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 and (2) valuing potential impairment loss related to long-lived assets.

20. 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 2011 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, 2009, were as follows (in thousands).

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2010	$861	$ 3,438	$5,256	$9,555
2011	800	2,569	4,345	7,714
2012	768	1,453	4,304	6,525
2013	733	798	1,555	3,086
2014	731	596	1,004	2,331
2015 and thereafter	803	1,937	23,860	26,600
Total minimum lease obligations	$4,696	$ 10,791	$40,324	$55,811

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

Year ended December 31, 2009	$12,023
Year ended December 31, 2008	$8,757
Year ended December 31, 2007	$6,079

We have guaranteed the payments by our subsidiary 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, 2009 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. 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, 2009, Sandhill owed $2.65 million; therefore our guarantee was $1.33 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.

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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.

21. 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. 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.

Our income tax provision (benefit) is as follows:

	Year Ended December 31, 2009	2008	2007
Current:			
Federal	$ 1,458	$ 2,979	$ 1,665
State	1,442	872	339

Total current income tax expense	2,900	3,851	2,004
Deferred:			
Federal	168	(3,850)	(2,432)
State	12	(363)	(226)
Total deferred income tax benefit	180	(4,213)	(2,658)
Total income tax expense (benefit)	$ 3,080	$ (362)	$ (654)

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2009 balance sheet date. Deferred tax assets and liabilities consist of the following:

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	December 31, 2009	December 31, 2008
Deferred tax assets:		
Current:		
Other current assets	$ 279	$ 271
Other	8	97
Total current deferred tax asset	287	368
Net operating loss carryforwards - federal	-	1,415
Net operating loss carryforwards - state	-	128
Total long-term deferred tax asset	-	1,543
Total deferred tax assets	287	1,911
Deferred tax liabilities:		
Current:		
Other	(198)	(3)
Long-term:		
Fixed assets	(8,481)	(9,868)
Intangible assets	(6,686)	(6,937)
Total long-term liability	(15,167)	(16,805)
Total deferred tax liabilities	(15,365)	(16,808)
Total net deferred tax liability	$ (15,078)	$ (14,897)

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

	Year Ended December 31, 2009	2008	2007
Income (loss) before income taxes	$ 9,258	$ 25,463	$ (14,205)
Partnership (income) loss not subject to tax	(7,822)	(30,902)	8,894
Income (loss) subject to income taxes	1,436	(5,439)	(5,311)
Tax benefit at federal statutory rate	503	$ (1,904)	$ (1,859)
State income taxes, net of federal benefit	991	357	33
Effects of unrecognized tax benefits, federal and state	1,733	1,431	1,168
Return to provision, federal and state	(224)	(258)	-
Other	77	12	4
Income tax expense (benefit)	$ 3,080	$ (362)	$ (654)
Effective tax rate on income (loss) before income taxes	33 %	-1 %	5 %

The company adopted the provisions in accounting guidance related to uncertain tax positions on January 1, 2007. A reconciliation of the beginning and ending amount of unrecognized tax benefits was as follows:

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Balance at January 1, 2008	$864
Additions based on tax positions related to current year	1,735
Balance at December 31, 2008	2,599
Additions based on tax positions related to current year	1,733
Balance at December 31, 2009	$4,332

If the unrecognized tax benefits at December 31, 2009 were recognized, $4.3 million would affect our effective income tax rate. There are no uncertain tax positions as of December 31, 2009 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly decrease during 2010.

22. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2009 and 2008.

	2009 Quarters				Total
	First	Second	Third	Fourth	Year
Revenues	$253,493	$342,204	$403,389	$436,274	$1,435,360
Operating income (loss)	$7,021	$7,748	$8,356	$(1,754)	$21,371
Net income attributable to Genesis Energy, L.P.	$5,290	$4,456	$4,299	$(5,982)	$8,063
Net income per common unit - basic	$0.16	$0.13	$0.14	$0.08	$0.51
Net income per common unit - diluted	$0.16	$0.13	$0.14	$0.08	$0.51
Cash distributions per common unit (1)	$0.3300	$0.3375	$0.3450	$0.3525	$1.3650

	2008 Quarters				Total
	First	Second	Third	Fourth	Year
Revenues	$486,185	$640,540	$636,919	$378,040	$2,141,684
Operating income	$1,759	$11,032	$13,381	$11,719	$37,891
Net income attributable to Genesis Energy, L.P.	$1,645	$7,328	$10,763	$6,353	$26,089
Net income per common unit - basic	$0.03	$0.17	$0.25	$0.14	$0.59
Net income per common unit - diluted	$0.03	$0.17	$0.25	$0.14	$0.59
Cash distributions per common unit (1)	$0.2850	$0.3000	$0.3150	$0.3225	$1.2225

(1) Represents cash distributions declared and paid in the applicable period.

23. Subsequent Events

On February 5, 2010, affiliates of Quintana Capital Group, L.P., along with members of the Davison family and members of our senior executive management team, EIV Capital Fund LP, a Delaware limited partnership, and other investors (collectively, the New Owner Group) purchased all of the Class A membership interests in our general partner from Denbury. In connection with the amendment and restatement of our general partner's limited liability agreement, two forms of member interests in our general partner replaced the Class A Member and Class B Member Interests. These new member interests are identified as Series A and Series B units.

All of the Class B membership interests in our general partner held by the three existing Senior Executives (see Note 16) were either (i) converted into Series A units in our general partner or (ii) or redeemed by our general partner on February 5, 2010. The amounts owed under the deferred compensation plan with the Senior Executives was similarly converted or redeemed. In total, the value of the Series A units issued and cash payments made by our general partner to settle its obligations under the Class B membership interests and deferred compensation totaled $14.9 million. This value, when combined with amounts previously paid to the Senior Executives during 2009 related to the Class B Membership Interests, resulted in total non-cash compensation expense of $15.4 million. The difference between the recorded cumulative compensation expense related to these interests through December 31, 2009 of $17.5 million and the total non-cash compensation expense of $15.4 million will be recorded as a reduction of expense in the first quarter of 2010.

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As a result of the change in control of our general partner on February 5, 2010, all outstanding phantom units issued pursuant to our 2007 LTIP vested. As a result of this acceleration of the vesting period, we will record non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested. In connection with the departure of one of our Senior Executives in February 2010, we will also record approximately $1.0 million of compensation expense.

Pursuant to restricted unit agreements entered into with our general partner on February 5, 2010, certain members of the senior executive management team of the Company received an aggregate of 767 Series B units in our general partner that vest as follows: (i) 25% vest on the first anniversary of the issuance, (ii) 33 1/3% of the remaining unvested units vest on the second anniversary of the issuance, (iii) 50% of the remaining unvested units vest on the third anniversary of the issuance and (iv) 100% of the remaining unvested units vest on the fourth anniversary of the issuance. Under the terms of the restricted unit agreements, in the event of certain public offerings, a change of control or similar transaction by the Company, the executive's unvested units will become fully vested. In the event of death or disability, the executive's employment date will be deemed extended through to the next anniversary date for vesting purposes. If the executive is terminated for "cause" or he or she leaves without "good reason" (as such terms are defined in the restricted unit agreements), he or she will forfeit all of his or her units, whether vested or unvested. If the executive is terminated without "cause," by death or disability, or by the executive for "good reason," then he or she will forfeit all unvested units and our general partner will have the right to repurchase or redeem any vested units. Subject to the rights of the holders of Series A units to receive distributions up to certain threshold amounts, holders of Series B units, upon vesting, have the right to receive quarterly distributions and certain tax distributions in accordance with the Amended and Restated Limited Liability Company Agreement of the Company.

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Schedule I - Condensed Financial Information

Genesis Energy, L.P. (Parent Company Only)

Condensed Statements of Income and Comprehensive Income

	Years Ended December 31, 2009	2008	2007
	(in thousands)		
Equity in earnings (losses) of subsidiaries	$8,063	$26,089	$(13,550)
Net income (loss)	8,063	26,089	(13,550)
Other comprehensive gain (loss) of subsidiary	133	(962)	-
Total comprehensive income (loss)	$8,196	$25,127	$(13,550)

Condensed Balance Sheets

	December 31, 2009	2008
	(in thousands)	
Assets		
Cash	$2	$3
Investment in subsidiaries	628,553	665,334
Advances to subsidiaries	92	91
Total Assets	$628,647	$665,428
Partners' Capital		
Limited Partners	$617,629	$649,046
General Partner	11,847	17,344
Accumulated other comprehensive loss	(829)	(962)
Total Partners' Capital	$628,647	$665,428

See accompanying notes to condensed financial statements.

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Schedule I - Condensed Financial Information - Continued

Genesis Energy, L.P. (Parent Company Only)

Condensed Statements of Cash Flows

	Years Ended December 31, 2009	2008	2007
	(in thousands)		
Cash Flows from Operating Activities:			
Net income (loss)	$8,063	$26,089	$(13,550)
Equity in losses (earnings) of GCO	9,395	(15,773)	13,550
Equity in (earnings) losses of GNEJD	(17,458)	(10,316)	-
Change in advances to GCO	(1)	(7)	4
Net cash (used in) provided by operating activities	(1)	(7)	4
Cash Flows from Investing Activities:			
Investment in GCO	(9)	(511)	(216,172)
Distributions from GCO - return of investment	60,080	50,534	17,175
Net cash provided by (used in) investing activities	60,071	50,023	(198,997)
Cash Flows from Financing Activities:			
Issuance of limited and general partner interests, net	9	511	216,172
Distributions to limited and general partners	(60,080)	(50,534)	(17,175)
Net cash (used in) provided by financing activities	(60,071)	(50,023)	198,997
Net (decrease) increase in cash	(1)	(7)	4
Cash at beginning of period	3	10	6
Cash at end of period	$2	$3	$10

See accompanying notes to condensed financial statements.

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Schedule I – Condensed Financial Statements – Continued

Genesis Energy, L.P. (Parent Company Only)

Notes to Condensed Financial Statements

1. Basis of Presentation

Genesis Energy, L.P., or GEL, is the owner of 99.99% of Genesis Crude Oil, L.P., or GCO and 100% of Genesis NEJD Holdings, LLC, or GNEJD. These parent company only financial statements for GEL summarize the results of operations and cash flows for the years ended December 31, 2009, 2008 and 2007, and GEL's financial position at December 31, 2009 and 2008. In these statements, GEL's investments in GCO and GNEJD are stated on the equity method basis of accounting. The GEL statements should be read in conjunction with the Consolidated Financial Statements of Genesis Energy, L.P.

As discussed in Note 11 of the Notes to the Consolidated Financial Statements, the terms of the credit facility with GCO, limit the amount of distributions that GCO and its subsidiaries may pay to GEL. Such distributions may not exceed the sum of the distributable cash generated by GCO and its subsidiaries for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. This restriction results in the restricted net assets (as defined in Rule 4-08 (e)(3) of Regulation S-X) of GEL's subsidiary exceeding 25% of the consolidated net assets of GEL and its subsidiaries.

2. Contingencies

GEL guarantees the obligations of GCO under our credit facility. See Note 11 of the Notes to the Consolidated Financial Statements of Genesis Energy, L.P. for a description of GCO's credit facility.

GEL guarantees the obligations of GCO under our lease with Paccar Leasing Services. See Note 20 of the Notes to the Consolidated Financial Statements of Genesis Energy, L.P.

GEL has guaranteed crude oil and petroleum products purchases of GCO and its subsidiaries. These guarantees, totaling $43.0 million, were provided to counterparties. To the extent liabilities exist under the contracts subject to these guarantees, such liabilities are included in the Consolidated Financial Statements of Genesis Energy, L.P.

GEL has guaranteed $7.5 million of the outstanding debt of DG Marine under its credit facility.

3. Supplemental Cash Flow Information

In May 2008, additional limited partner interests in GCO with a value of $25 million were issued to GEL. GEL issued common units with an equal value as part of the consideration in acquisition of the Free State Pipeline from Denbury. In July 2008, additional limited partner interests in GCO with a value of $16.7 million were issued to GEL. GEL issued common units with an equal value as part of the consideration in the Grifco acquisition. These transactions are non-cash transactions and are not included in the Statements of Cash Flows in investing or financing activities.