GENESIS ENERGY LP
Form 10-K
March 17, 2008

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

Form 10-K

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

For the fiscal year ended December 31, 2007

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.)
500 Dallas, Suite 2500, 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	American Stock Exchange

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 x

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

Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x   No ¨

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

x

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

Large accelerated filer¨   Accelerated filer x   Non-accelerated filer ¨   Smaller reporting company¨

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

Yes ¨   No x

The aggregate market value of the common units held by non-affiliates of the Registrant on June 29, 2007 (the last business day of Registrant’s most recently completed second fiscal quarter) was approximately $444,166,000 based on $34.88 per unit, the closing price of the common units as reported on the American Stock Exchange. On February 29, 2008, the Registrant had 38,253,264 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 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; “Denbury” means Denbury Resources Inc. and its subsidiaries; “CO2” means carbon dioxide; and “NaHS”, which is commonly pronounced as “nash”, means sodium hydrosulfide. Except to the extent otherwise provided, the information contained in this form is as of December 31, 2007.

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, and trucks and truck terminals. We provide services to refinery owners; oil, natural gas and CO2 producers; industrial and commercial enterprises that use CO2 and other industrial gases; and individuals and companies that use our dry-goods trucking services. Substantially all of our revenues are derived from providing services to integrated oil companies, large independent oil and gas or refinery companies, and large industrial and commercial enterprises.

We manage our businesses through four divisions which constitute our reportable segments:

Pipeline Transportation—We transport crude oil and, to a lesser extent, natural gas and CO2 for others for a fee in the Gulf Coast region of the U.S. through approximately 500 miles of pipeline. We own and operate three crude oil common carrier pipelines, a small CO2 pipeline and several small natural gas pipelines. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminaling and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and can deliver crude oil to a terminal near Mobile, Alabama. Our 90-mile Texas System transports crude oil from West Columbia to Webster, Webster to Texas City and Webster to Houston. Our crude oil pipeline systems include a total of approximately 0.7 million barrels of leased and owned tankage.

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

Supply and Logistics—We provide terminaling, blending, storing, marketing, gathering and transporting (by trucks), and other supply and logistics services to third parties, as well as to support our other businesses. Our terminaling, blending, marketing and gathering activities are focused on crude oil and petroleum products, primarily fuel oil. We own or lease approximately 300 trucks, 600 trailers and almost 1.5 million barrels of liquid storage capacity at eleven different locations. We also conduct certain crude oil aggregating operations, including purchasing, gathering and transporting (by trucks and pipelines operated by us and trucks, pipelines and barges operated by others), and reselling that crude oil to help ensure (among other things) a base supply source for our crude oil pipeline systems. Usually, our supply and logistics segment experiences limited commodity price risk because it generally involves back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

Industrial Gases.

- CO_2 — We supply CO_2 to industrial customers under seven long-term contracts, with an average remaining contract life of 8 years. We acquired those contracts, as well as the CO_2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with affiliates of our general partner. Our compensation for supplying CO_2 to our industrial customers is the effective difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our volumetric production payments (also known as VPPs), minus transportation costs.

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

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

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

Our General Partner and Our Relationship with Denbury Resources Inc.

We continue to benefit from our strategic affiliation with Denbury Resources Inc. (NYSE:DNR), which indirectly owns 100% of our general partner interest, all of our incentive distribution rights and 7.4% of our outstanding common units. Denbury, which had an equity market capitalization of approximately \$7.7 billion as of February 29, 2008, operates primarily in Mississippi, Louisiana and Texas, emphasizing the tertiary recovery of oil using CO_2 flooding. Denbury is the largest producer (based on average barrels produced per day) of oil in Mississippi, and it is one of only a handful of producers in the U.S. that possesses CO_2 tertiary recovery expertise along with large deposits of CO_2 reserves, approximately 5.6 trillion cubic feet of estimated proved CO_2 reserves as of December 31, 2007. Other than the CO_2 reserves owned by Denbury, we are not aware of any significant natural sources of CO_2 from East Texas to Florida. Denbury is conducting its CO_2 tertiary recovery operations in the Eastern Gulf Coast of the U.S., an area with many mature oil reservoirs that potentially contain substantial volumes of recoverable oil. In addition to the amounts it has already expended on the Free State and North East Jackson Dome, or NEJD, CO_2 pipelines, Denbury has announced that it expects to spend approximately \$775 million between December 31, 2007 and the end of 2009 to build CO_2 pipelines to support its tertiary oil recovery expansions.

We believe Denbury's equity ownership interests in us provide Denbury with economic and strategic incentives to furnish business opportunities to us in the form of acquisitions, leases, transportation agreements and other transactions. In fact, Denbury has indicated that it may use us as a vehicle to provide its midstream infrastructure needs, particularly with respect to CO_2 pipelines. We believe Denbury may provide us with future growth opportunities due to the following additional factors, among others:

- Denbury's continued need to construct pipelines and gathering systems necessary to support its operations, which we may have an opportunity to provide for them;
- Denbury's significant economic and strategic interests in us;
- the close proximity of certain of Denbury's assets and operations to certain of our assets and operations; and
- the extent of Denbury's growth capital requirements.

Denbury has announced its intention, which it may change at any time, to drop down certain midstream assets. We expect to complete a drop down transaction involving the Free State and NEJD CO_2 pipelines in the first quarter of 2008.
Although our relationship with Denbury may provide us with a source of acquisition and other growth opportunities, Denbury is not obligated to enter into any transactions with (or to offer any opportunities to) us or to promote our interest, and none of Denbury or any of its affiliates (including our general partner) has any obligation or commitment to contribute or sell any assets to us or enter into any type of transaction with us, and each of them, other than our general partner, has the right to act in a manner that could be beneficial to its interests and detrimental to ours. Further, Denbury may, at any time, and without notice, alter its business strategy, including determining that it no longer desires to use us as a provider of its midstream infrastructure. Additionally, if Denbury were to make one or more offers to us, we cannot say that we would elect to pursue or consummate any such opportunity. In addition, though our relationship with Denbury is a significant strength, it also is a source of potential conflicts.

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Our Objective and Strategies

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

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

- Expanding our asset base through strategic construction and development projects with third parties and Denbury. We intend to expand our asset base through strategic and accretive construction and developments projects, or joint ventures, in new and existing markets.

- Optimizing our CO2 and other industrial gases expertise and infrastructure. We intend to optimize our expertise regarding CO2 and other industrial gases to create growth opportunities.

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

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

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

- Increasing stable cash flows generated through fee based services, longer-term contractual arrangements and managing commodity price risks. We intend to generate more stable cash flows, when practical, by (i) emphasizing fee-based compensation under longer term contracts, and (ii) using contractual arrangements, including back-to-back contracts and derivatives. We charge fee-based arrangements for substantially all of our services. We are able to enter into longer term contracts with most of our customers in our refinery services and industrial gases divisions. Our marketing activities do not include speculative transactions. While our refinery services division has some exposure to monthly changes in the prices of caustic soda and sodium hydrosulfide, also referred to as NaHS (pronounced "nash"), a natural by-product of those operations, prices for those commodities are not as volatile as prices for oil, natural gas and their derivatives.

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

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

- Maintaining, on average, a conservative capital structure that will allow us to execute our growth strategy while, over the longer term, enhancing our credit ratings. We intend to maintain, on average, a conservative capital structure that will allow us to execute our growth strategy while, over the longer term, enhancing our credit ratings.

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Our Key Strengths

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

Ø Experienced, Knowledgeable and Motivated Senior Management Team with Proven Track Record. Our senior management team has over 40 years of combined experience in the midstream sector. They have worked together and separately in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. To help ensure that our senior management team is incentivized to execute our growth strategy in a manner that is accretive on a "distribution per unit" basis, our general partner has undertaken to negotiate agreements relating to an equity-based incentive compensation arrangement to provide the members of our senior management team with the opportunity to earn an interest in our general partner if performance criteria are met. Those performance criteria are expected to include a correlation between earning the general partner interest with the successful completion of non-Denbury acquisitions and/or other organic growth that earn a reasonable rate of return.

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

- sulfur handling and removal is typically not a core business of our refinery customers, especially when employing our proprietary processes and expertise that result in the by-product of NaHS;

- over a long period of time, we have developed and maintained strong relationships with our refinery services customers, which relationships are based on our reputation for high standards of performance, reliability and safety;

- the sulfur removal process we use, -- the NaHS sulfur removal process, -- is generally more reliable and less capital and labor intensive than the conventional "Claus" process employed at most refineries;

- we have the scale of operations and supply and logistics capabilities to make the NaHS sulfur removal process extremely reliable as a means to remove sulfur efficiently while working in concert with the refineries to ensure uninterrupted refinery operations;

- other than the possibility of each individual refinery employing its own sulfur removal operations, we do not have many competitors in the sulfur removal business; and

- we believe that the demand for sulfur removal at U.S. refineries will increase in the years ahead as the quality of the oil supply used by refineries in the U.S. continues to drop (or become more "sour"). As that occurs, we believe more refineries will seek economic and proven sulfur removal processes from reputable service providers that have the scale and logistical capabilities to efficiently perform such services. In addition, we have an increasing array of services we can offer to our refinery customers.

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

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

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

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

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

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

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

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

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

Ø Financial Flexibility. We have the financial flexibility to pursue additional growth projects. As of December 31, 2007, we had $80 million of loans and $5.3 million in letters of credit outstanding under our $500 million credit facility, resulting in $271 million of remaining credit availability under our borrowing base. Our borrowing base as of December 31, 2007 was approximately $356 million, and fluctuates each quarter based on our earnings before interest, taxes, depreciation and amortization, or EBITDA. Our borrowing base may be increased to the extent of EBITDA attributable to acquisitions, with approval of the lenders.

Ø Relationship with Denbury. We have a strong relationship with Denbury, the indirect owner of our general partner. Denbury has indicated that it may use us as a vehicle to provide its midstream infrastructure needs, particularly with respect to CO2 pipelines. We believe Denbury has an economic and strategic incentive to provide business opportunities to us. We also believe that, if we can become an instrumental component of Denbury's future development projects, we can leverage those operations (and our relationship with Denbury) into oil transportation and storage opportunities with third parties, such as other producers and refinery operators, in the areas into which Denbury expands its operations.

Recent Developments

Acquisition of Refinery Services Division and Other Businesses

On July 25, 2007, we acquired five energy-related businesses, including the operations that comprise our refinery services division, from several entities owned and controlled by the Davison family of Ruston, Louisiana. The other acquired businesses, which transport, store, procure and market petroleum products and other bulk commodities, are included in our supply and logistics segment.

Our acquisition agreement with the Davisons provided that we would deliver to them $563 million of consideration, half in common units (13,459,209 common units at an agreed-to value of $20.8036 per unit) and half in cash, subject to specified purchase price adjustments. Our financial statements at December 31, 2007 reflect a total acquisition price of $631.5 million, which includes purchase price adjustments, our transaction costs of $8.9 million, working capital acquired, net of cash acquired, and a valuation of the units at $24.52 per unit, which was the average closing price of our units during the five trading day period ending two days after we signed the acquisition agreement.

The Davison family was our largest unitholder at December 31, 2007, with a 33.0% interest in us (represented by 12,619,069 of our common units). It has designated two of the members of the board of directors of our general partner, and as long as it maintains a specified minimum ownership 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. For example, prior to July 25, 2008, the Davison family may not sell more than 20% of its common units.

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Denbury Drop Down Transactions

We have reached substantial agreement and are in the process of finalizing the business issues with Denbury and the lenders in our credit facility as to the terms of the drop-down by Denbury to us of Denbury's NEJD and Free State CO_2 pipelines and the terms of a long-term transportation service arrangement for the Free State line and a 20-year financing lease for the NEJD system. We expect to pay for these pipeline assets with $225 million in cash and $25 million of our common units based on the average closing price of our units on the thirty days prior to the closing of the transaction. We expect to receive approximately $30 million per annum, in the aggregate, under the lease and the transportation services agreement (and a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State pipeline dependant on the volumes of CO_2 transported therein. While the business terms of the transactions and associated documentation have been substantially completed, closing remains subject to completion of closing documentation, receipt of a fairness opinion and approval by the audit committee and the board of directors of our general partner.

Nine Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for nine consecutive quarters. On February 14, 2008, we paid a cash distribution of $0.285 per unit to unitholders of record as of February 7, 2008, an increase per unit of $0.015 (or 5.6%) from the distribution in the prior quarter. In the immediately preceding quarter, we increased our quarterly distribution rate by $0.04 (or 17.4%), and in each preceding quarter, we increased our distribution rate by $0.01. 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.

Acquired Terminal and Dock Facilities

Effective July 1, 2007, we paid $8.1 million for BP Pipelines (North America) Inc.'s Port Hudson 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. That acquisition was funded with borrowings under our credit facility.

Florida Oil Pipeline System Expansion

We committed to construct an extension of our existing Florida oil pipeline system that would extend to producers operating in southern Alabama. That new lateral will consist of approximately 33 miles of 8" pipeline originating in the Little Cedar Creek Field in Conecuh County, Alabama to a connection to our Florida Pipeline System in Escambia County, Alabama. That project also will include gathering connections to approximately 30 wells and oil storage capacity of 20,000 barrels in the field. We expect to place those facilities in service in the fourth quarter of 2008.

Description of Segments and Related Assets

We conduct our business through four primary segments: Pipeline Transportation, Refinery Services, Industrial Gases and Supply and Logistics. Our Supply and Logistics segment was previously known as Crude Oil Gathering and Marketing. With the Davison acquisition, we expanded our operations into petroleum products and other transportation services, and combined these operations due to their similarities and our approach to managing these operations. These segments are strategic business units that provide a variety of energy related services. Financial information with respect to each of our segments can be found in Note 12 to our Consolidated Financial Statements.

Pipeline Transportation

Crude Oil Pipelines

Overview. Our core pipeline transportation business is the transportation of crude oil for others for a fee. Through the pipeline systems we own and operate, we transport crude oil for our gathering and marketing operations and for other shippers pursuant to tariff rates regulated by the Federal Energy Regulatory Commission, or FERC, or the Railroad Commission of Texas. Accordingly, we offer transportation services to any shipper of crude oil, if the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Pipeline revenues are a function of the level of throughput and the particular point where the crude oil was injected into the pipeline and the delivery point. We also can earn revenue from pipeline loss allowance volumes. In exchange for bearing the risk of pipeline volumetric losses, we deduct volumetric pipeline loss allowances and crude 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.

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

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

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

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

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

We recently committed to construct an extension of our existing Florida oil pipeline system that would extend to producers operating in southern Alabama. The new lateral will consist of approximately 33 miles of 8” pipeline originating in the Little Cedar Creek Field in Conecuh County, Alabama to a connection to our Florida Pipeline System in Escambia County, Alabama. The project will also include gathering connections to approximately 30 wells and additional oil storage capacity of 20,000 barrels in the field. The project is expected to be placed in service in the second half of 2008.

Texas System. The active segments of the Texas System extend from West Columbia to Webster, Webster to Texas City and Webster to Houston. Those segments include approximately 90 miles of pipe. 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.

On a much smaller scale, we also transport CO_2 and gather natural gas for a fee. However, with the acquisition of the CO_2 pipelines from Denbury expected in the first quarter of 2008, our CO_2 pipelines (including leased lines) will extend approximately 280 miles. See additional discussion in ‘Denbury Drop Down Transactions” above.

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Customers

Denbury, a large independent energy company, is the sole shipper (other than us) on our Mississippi System. The customers on our Jay and Texas Systems are primarily large, energy companies. Revenues from customers of our pipeline transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to production, refineries and connecting pipelines. We believe that high capital costs, tariff regulation and the cost of acquiring rights-of-way make it unlikely that other competing crude oil pipeline systems, comparable in size and scope to our pipelines, will be built in the same geographic areas in the near future.

Refinery Services

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

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

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

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

Our sulfur removal facilities consist of NaHS units that are located at sites leased at five refineries, primarily in the southeastern United States. We expect to complete an additional NaHS facility at a refinery in Utah in 2008.

Customers

Refinery Services: At December 31, 2007, we provided services to eight refining operations.

NaHS Marketing: We sell our NaHS to customers in a variety of industries, with the largest customers involved in copper mining and the production of paper. We sell to customers in the copper mining industry in the western United States as well as customers who export the NaHS to South America for mining in Peru and Chile. Many of the paper mills that purchase NaHS from us are located in the southeastern United States. No customer of the refinery services segment is responsible for more than ten percent of our consolidated revenues. Approximately 11% of the revenues of the refinery services segment for the five month period of our ownership resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc.

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Competition for Refinery Services Business

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

Industrial Gases

Overview

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

CO2 – Industrial Customers

We supply CO2 to industrial customers under seven long-term CO2 sales contracts. We acquired those contracts, as well as the CO2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with Denbury. Since 2003, we have purchased those contracts, along with three VPPs representing 280.0 Bcf of CO2 (in the aggregate), from Denbury for a total of $43.1 million in cash. 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, 2007, we have 182.3 Bcf of CO2 remaining under the VPPs.

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

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

CO2 - Processing

On April 1, 2006, we acquired a 50% partnership interest in Sandhill for $5.0 million in cash, which we funded with cash on hand. Reliant Processing Ltd. owns the remaining 50% of Sandhill. Sandhill is a limited liability company that owns a CO_2 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 that we acquired in 2005 from Denbury. 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

On April 1, 2005, we acquired from TCHI, Inc., a wholly-owned subsidiary of ChevronTexaco Global Energy, Inc., a 50% partnership interest in T&P Syngas for $13.4 million in cash, which we funded with proceeds from our credit facility. 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 also is our partner in the joint venture and owns the remaining 50% interest.

Customers

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

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

Sandhill sells to approximately 20 customers, with sales to two of those customers representing approximately 40% of Sandhill's total revenues of approximately $11 million in 2007. In addition, in 2007, Sandhill sold approximately $1.9 million of CO2 to affiliates of Reliant Processing, Ltd., a 50% owner of 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. We believe we have an adequate access to supply to service existing contracts through their terms. 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, including the fields controlled by Denbury. Our industrial CO2 customers have facilities that are connected to Denbury's CO2 pipeline, which makes delivery easy and efficient. Once our existing VPPs expire, we will have to obtain CO2 from Denbury or other suppliers 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 a competing facility, 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.

Supply and Logistics

Our supply and logistics segment was previously known as our crude oil gathering and marketing segment. With the acquisition of the Davison businesses, we renamed the segment and we included the petroleum products, fuel logistics, terminaling and truck transportation activities we acquired from the Davisons.

Our crude oil gathering and marketing operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. Those operations, which involve purchasing, gathering and transporting by trucks and pipelines operated by us and trucks, pipelines and barges operated by others, and reselling, help to ensure (among other things) a base supply source for our oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell the crude oil less the price at which we purchase that oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks. Our oil gathering and marketing activities provide us with an extensive expertise, knowledge base and skill set that facilitates our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually, this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

When the crude oil markets are in contango, (oil prices for future deliveries are higher than for current deliveries), we may purchase and store crude oil as inventory for delivery in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period, either with a counterparty or in the crude oil futures market. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 17 of the Notes to the Consolidated Financial Statements.

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With the Davison acquisition, we gained approximately 225 trucks, 525 trailers and 1.3 million barrels of existing leased and owned storage and expanded our activities to include transporting, storing and blending intermediate and finished refined products. In our petroleum products marketing operations, we primarily supply fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing their products that do not meet the specifications they desire, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but the contribution to margin as a percentage of the revenues tends to be higher than in the same percentage attributable to our recurring operations.

We also have access through our terminals on waterways in the southeastern United States to provide our customers with product by barge. In combination with our historical focus on crude oil, we believe we are well positioned to provide a full suite of logistical services to both independent and integrated refinery operators, ranging from upstream (the procurement and staging of refinery inputs) to downstream (the transportation, staging and marketing) of refined products.

Customers and Competition

In our supply and logistics segment, we sell crude oil and petroleum products and provide transportation services to hundreds of customers. During 2007, more than ten percent of our consolidated revenues were generated from each of two customers, Shell Oil Company and Occidental Energy Marketing, Inc. We do not believe that the loss of any one customer for crude oil or petroleum products would have a material adverse effect on us as these products are readily marketable commodities.

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

Geographic Segments

All of our operations are in the United States.

Credit Exposure

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

When we market crude oil and petroleum products and NaHS, we must determine the amount, if any, of the line of credit we will extend to any given customer. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

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

Employees

To carry out our business activities, our general partner employed, at February 29, 2008 approximately 655 employees. None of those employees are represented by labor unions, and we believe that relationships with those employees are good.

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Organizational Structure

Genesis Energy, Inc., a Delaware corporation, serves as our sole general partner and as our general partner of all of our subsidiaries. Our general partner is owned by Denbury Gathering & Marketing, Inc., a subsidiary of Denbury. Below is a chart depicting our ownership structure.

(1)The incentive compensation arrangement with which our general partner has undertaken to negotiate definitive agreements with the Senior Executives (see Item 11. Executive Compensation.) would provide them the opportunity to earn up to 14.4% of the equity interest 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—a cost-of-service methodology, competitive market showings ("Market-Based Rates"), or agreements between shippers and the oil pipeline company that the rate is acceptable ("Settlement Rates"). The pipeline tariff rates on our Mississippi and Jay Systems are either rates that were grandfathered and have been changed under the index methodology, or Settlement Rates. None of our tariffs have been subjected to a protest or complaint by any shipper or other interested party.

Our intrastate common carrier pipeline operations in Texas are subject to regulation by the Railroad Commission of Texas. The applicable Texas statutes require that pipeline rates be non-discriminatory and provide a fair return on the aggregate value of the property of a common carrier, after providing reasonable allowance for depreciation and other factors and for reasonable operating expenses. Most of the volume on our Texas System is now shipped under joint tariffs with TEPPCO and Exxon. Although no assurance can be given that the tariffs we charge would ultimately be upheld if challenged, we believe that the tariffs now in effect can be sustained.

Our natural gas gathering pipelines and CO2 pipeline are subject to regulation by the state agencies in the states in which they are located.

Environmental Regulations

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

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons, including current owners and operators of a contaminated facility, owners and operators of the facility at the time of contamination, and those parties arranging for waste disposal at a contaminated facility. Such "responsible persons" may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. In cases of environmental contamination, it is also not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. 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.

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

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

The Clean Air Act, as amended, and analogous state and local laws and regulations restrict the emission of air pollutants, and impose permit requirements and other obligations. Regulated emissions occur as a result of our operations, including the handling or storage of crude oil and other petroleum products. Both federal and state laws impose substantial penalties for violation of these applicable requirements.

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

Safety and Security Regulations

Our crude oil, natural gas and CO2 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.

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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 require 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. At December 31, 2007, we had completed assessments and repairs on the major sections of our pipelines. On the pipeline segments initially tested, we have started the process of reassessment required every five years.

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 CO2 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.

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 required operators to develop and submit a written program. The regulations also required all pipeline operators to develop a training program for pipeline personnel and to qualify them on covered tasks at the operator’s pipeline facilities. The intent of the OQ regulations is to ensure a qualified workforce by pipeline operators and contractors when performing covered tasks on the pipeline and its facilities, thereby reducing the probability and consequences of incidents caused by human error.

Our crude oil, refined products and refinery services operations are also subject to the requirements of OSHA and comparable state statutes. We believe that our operations have been operated in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. Various other federal and state regulations require that we train all operations employees in HAZCOM and disclose information about the hazardous materials used in our operations. Certain information must be reported to employees, government agencies and local citizens upon request.

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

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.

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Website Access to Reports

We make available free of charge on our internet website (www.genesiscrudeoil.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

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

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

We will need new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. Although we intend to continue to expand our business, this strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms, if at all.

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

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

The amount of cash we distribute on our units principally depends upon margins we generate from our refinery services, pipeline transportation, logistics and supply and industrial gases businesses which will fluctuate from quarter to quarter based on, among other things:

- the volumes and prices at which we purchase and sell crude oil, refined products, and caustic soda;
- the volumes of sodium hydrosulfide, or NaHS, that we receive for our refinery services and the prices at which we sell NaHS;
- the demand for our trucking 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.

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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, 2007, we had approximately $80 million outstanding of senior secured indebtedness.

We must comply with various affirmative and negative covenants contained in our credit facilities. Among other things, these covenants limit our ability to:

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- make guarantees;
- enter into any hedging agreement for speculative purposes;
- 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;

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- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

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

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity - oil, refined products, NaHS, natural gas and CO_2 - 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, natural gas and CO_2— volumes. We access commodity volumes through two sources, producers and service providers (including gatherers, shippers, marketers and other aggregators). Depending on the needs of each customer and the market in which it operates, we can either provide a service for a fee (as in the case of our pipeline transportation operations) or we can purchase the commodity from our customer and resell it to another party (as in the case of oil marketing and CO_2 operations).

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

The oil, natural gas and other products available to us are derived from reserves produced from existing wells, and these reserves naturally decline over time. In order to offset this natural decline, our energy infrastructure assets must access additional reserves. Additionally, some of the projects we have planned or recently completed are dependent on reserves that we expect to be produced from newly discovered properties that producers are currently developing.

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

We face intense competition to obtain commodity volumes.

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

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

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

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

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

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Fluctuations in commodity prices could adversely affect our business.

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

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

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

Any decrease in this demand for crude oil by those refineries or connecting carriers to which we deliver could adversely affect our pipeline transportation business. Those refineries' need for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We are exposed to the credit risk of our customers in the ordinary course of our crude oil gathering and marketing activities.

When we market any of our products or services, we must determine the amount, if any, of the line of credit we will extend to any given customer. Since typical sales transactions can involve very large volumes, the risk of nonpayment and nonperformance by customers is an important consideration in our business. In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint. Even if our credit review and analysis mechanisms work properly, we could still experience losses in dealings with other parties.

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

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

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

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

- rate structures;
- rates of return on equity;

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

Given the extent of this regulation, the extensive changes in FERC policy over the last several years, the evolving nature of federal and state regulation and the possibility for additional changes, the current regulatory regime may change and affect our financial position, results of operations or cash flows.

A substantial portion of our CO2 operations involves us supplying CO2 to industrial customers using reserves attributable to our volumetric production payment interests, which are a finite resource and projected to terminate around 2016.

The cash flow from our CO2 operations involves us supplying CO2 to industrial customers using reserves attributable to our volumetric production payments, which are projected to terminate around 2016. 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 2016.

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

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

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

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

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

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 CO_2 and transports the CO_2 to our customers (including Denbury), any major failure of its operations could have an impact on our ability to meet our obligations to our CO_2 customers (including Denbury). We have no other supply of CO_2 or method to transport it to our customers. Sandhill relies on us for its supply of CO_2 therefore our share of the earnings of Sandhill would also be impacted by any major failure of Denbury's operations.

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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 the last five months of 2007, 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 acid gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if Conoco is excused from performing, or refuses or is unable to perform, its obligations under that contract for an extended period of time, such non-performance could have a material adverse effect on our profitability and cash flow.

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

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

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

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

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

Our forecast contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets, including some construction and development projects with technological challenges. We may not be able to complete our projects at the costs currently estimated. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional debt or equity.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations.

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Fluctuations in interest rates could adversely affect our business.

In addition to our exposure to commodity prices, we also have exposure to movements in interest rates. The interest rates on our credit facility are variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases or decreases in interest rates.

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

We use financial derivative instruments and other hedging mechanisms from time to time to limit a portion of the adverse effects resulting from changes in commodity prices, although there are times when we do not have any hedging mechanisms in place. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, we could experience losses resulting from our hedging and other derivative positions. Such losses could occur under various circumstances, including if our counterparty does not perform its obligations under the hedge arrangement, our hedge is imperfect, or our hedging policies and procedures are not followed.

A natural disaster, accident, terrorist attack or other interruption event involving us could result in severe personal injury, property damage and/or environmental damage, which could curtail our operations and otherwise adversely affect our assets and cash flow.

Some of our operations involve significant risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations and otherwise expose us to liability and adversely affect our cash flow. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes.

If one or more facilities that are owned by us or that connect to us is damaged or otherwise affected by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. Additionally, the proceeds of any property insurance maintained by us may not be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur, and we may not be able to renew it or obtain other desirable insurance on commercially reasonable terms, if at all.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the U.S. government has issued warnings that energy assets, specifically the nation’s pipeline infrastructure, may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

We cannot cause our joint ventures to take or not to take certain actions unless some or all of the joint venture participants agree.

Due to the nature of joint ventures, each participant (including us) in our joint ventures has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that consists of a management committee composed of four members, only two of which are appointed by us. In addition, the other 50% owner in each of our joint ventures operates the joint venture facilities. Thus, without the concurrence of the other joint venture participant, we cannot cause our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the joint ventures or us.

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Our refinery services operations are dependent upon the supply of caustic soda and the demand for NaHS, as well as the operations of the refiners for whom we process sour gas.

Caustic soda is a major component used in the provision of sour gas treatment services provided by us to refineries. NaHS, the resulting product from the refinery services we provide, is a vital ingredient in a number of industrial and consumer products and processes. Any decrease in the supply of caustic soda could affect our ability to provide sour gas treatment services to refiners and any decrease in the demand for NaHS by the parties to whom we sell the NaHS could adversely affect our business. The refineries' need for our sour gas services is also dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

Our operating results from our trucking operations may fluctuate and may be materially adversely affected by economic conditions and business factors unique to the trucking industry.

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

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

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

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

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

Risks Related to Our Partnership Structure

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

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

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

- Denbury may compete with us. Denbury owns the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River and may manage these reserves in a manner that could adversely affect our CO_2 business;

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- our general partner is allowed to take into account the interest of parties other than us, such as Denbury, in resolving conflicts of interest;

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

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, including for incentive distributions, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and its affiliates, retention of counsel, accountants and service providers, and cash reserves, each of which can also affect the amount of cash that is distributed to our unitholders;

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us and the reimbursement of these costs and of any services provided by our general partner could adversely affect our ability to pay cash distributions to our unitholders;

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

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

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

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

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

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

In addition, we have announced that Denbury and we are negotiating several significant transactions. See "Our General Partner and Our Relationship with Denbury Resources Inc." under Item 1 – Business.

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

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.

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

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

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

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

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

Our general partner and its affiliates 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, 2007 our general partner and its affiliates own 2,829,055 (approximately 7.4%) of our common units. In the future, they may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, the sale could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its subsidiaries to cause us to register for sale the partnership interests held by such persons, including common units. These registration rights allow our general partner and its subsidiaries to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us.

Our general partner has anti-dilution rights.

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

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

Through its subsidiaries, Denbury owns 100 percent of our general partner, is a significant stakeholder in our limited partner interests and has historically, with its affiliates, employed the personnel who operate our businesses. In addition, we are parties to numerous agreements with Denbury, and we plan to enter into additional agreements, for example Denbury is a significant customer of our Mississippi System. See "Our General Partner and Our Relationship with Denbury Resources Inc." under Item 1 – Business. We could be adversely affected if Denbury experiences any adverse developments or fails to pay us timely.

We may issue additional common units without unitholder's approval, which would dilute their ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

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

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

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to make payments on indebtedness or cash distributions to our unitholders.

We are a holding company. As such, our primary assets are the equity interests in our subsidiaries and joint ventures. Consequently, our ability to fund our commitments (including payments on our indebtedness) and to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. Further, each joint venture's charter documents typically vest in its management committee sole discretion regarding distributions. Accordingly, our joint ventures may not continue to make distributions to us at current levels or at all.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

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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, 2007, our balance sheet reflected $320.7 million of goodwill and $211.1 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. 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.

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the "Qualifying Income Exception," exists with respect to publicly traded partnerships 90% or more of the gross income of which for every taxable year consists of "qualifying income." If less than 90% of our gross income for any taxable year is "qualifying income" from transportation or processing of natural resources including crude oil, natural gas or products thereof, interest, dividends or similar sources, we will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years.

In addition, current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code section 7704(d). It is possible that these efforts could result in changes to the existing U.S. tax laws that affect publicly-traded partnerships, including us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders.

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

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

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Unitholders will be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if unitholders receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from that income.

Tax gain or loss on disposition of common units could be different than expected.

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, a significant amount of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, may be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding tax at the highest effective tax rate applicable to individuals, and non-U.S. persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the common unitholder’s tax returns.

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

In addition to federal income taxes, unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if unitholders do not live in any of those jurisdictions. Unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in more than 25 states including Texas, Louisiana, Mississippi, Alabama, Florida, Arkansas and Oklahoma. Many of the states we currently do business in currently impose a personal income tax. It is unitholders’ responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

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.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

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

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 18 of the Notes to Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

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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 18 of the Notes to Consolidated Financial Statements.)

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

The board of directors of our general partner (which we refer to as our board of directors), called a special meeting for December 18, 2007. At that meeting, unitholders were asked to consider and vote upon:

- a proposal to amend certain provisions of our partnership agreement which we refer to as the "Amendment Proposal," to allow any affiliated persons or group who hold more than 20% of our outstanding voting units to vote on all matters on which holders of our voting units have the right to vote, other than matters relating to the succession, election, removal, withdrawal, replacement or substitution of our general partner and to clarify and expand the concept of "group"; and

- a proposal to approve the terms of the Genesis Energy, Inc. 2007 Long Term Incentive Plan, which provides for awards of our units and other rights to our employees and, possibly, our directors (the "Incentive Plan Proposal").

Of the unitholders entitled to vote at this special meeting, over 60% voted in favor of these proposals. The voting results were as follows:

Matter	For	Votes Cast Against	Abstain	Broker Non-Votes
Approve Amendment Proposal	8,121,986	889,239	100,104	n/a
Approve Incentive Plan Proposal	8,607,575	438,332	65,419	n/a

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 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 High	Price Range Low	Cash Distributions (1)
2008			
First Quarter (through February 29, 2008)	$ 25.00	$ 15.07	$ 0.285
2007			

Fourth Quarter	$	28.62	$	20.01	$	0.270
Third Quarter	$	37.50	$	27.07	$	0.230
Second Quarter	$	35.98	$	20.01	$	0.220
First Quarter	$	22.01	$	18.76	$	0.210
2006						
Fourth Quarter	$	20.65	$	14.48	$	0.200
Third Quarter	$	19.18	$	11.20	$	0.190
Second Quarter	$	14.14	$	10.25	$	0.180
First Quarter	$	12.85	$	11.25	$	0.170

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

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At February 29, 2008, we had 38,253,264 common units outstanding, including 2,829,055 common units held by our general partner. As of December 31, 2007, we had approximately 10,200 record holders of our common units, which include holders who own units through their brokers "in street name."

We distribute all of our available cash, as defined in our partnership agreement, within 45 days after the end of each quarter to Unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements, adjusted for net changes to cash reserves. Cash reserves are the amounts deemed necessary or appropriate, in the reasonable discretion of our general partner, to provide for the proper conduct of our business or to comply with applicable law, any of our debt instruments or other agreements. The full definition of available cash is set forth in our partnership agreement and amendments thereto, which is filed as an exhibit to this Form 10-K.

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

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes information about our equity compensation plans as of December 31, 2007.

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)	39,362	(1)	960,638

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

Recent Sales of Unregistered Securities

On December 10, 2007, we sold 734,732 common units to our general partner for $15.5 million in a private transaction that was exempt from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof. This sale, made concurrently with a public offering, was made pursuant to our general partner's preemptive rights to maintain its pro rata interest in our common units under Section 5.6 of our partnership agreement.

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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, 2007, 2006, 2005, 2004, and 2003 (in thousands, except per unit and volume data).

	Year Ended December 31,				
	2007 (1)	2006	2005	2004	2003
Income Statement Data:					
Revenues:					
Supply and logistics (2)	$ 1,094,189	$ 873,268	$ 1,038,549	$ 901,902	$ 641,684
Refinery services	62,095	-	-	-	-
Pipeline transportation, including natural gas sales	27,211	29,947	28,888	16,680	15,134
CO2 marketing	16,158	15,154	11,302	8,561	1,079
Total revenues	1,199,653	918,369	1,078,739	927,143	657,897
Costs and expenses:					
Supply and logistics costs (2)	1,078,859	865,902	1,034,888	897,868	633,776
Refinery services operating costs	40,197	-	-	-	-
Pipeline transportation, including natural gas purchases	14,176	17,521	19,084	8,137	10,026
CO2 marketing transportation costs	5,365	4,842	3,649	2,799	355
General and administrative expenses	25,920	13,573	9,656	11,031	8,768
Depreciation and amortization	38,747	7,963	6,721	7,298	4,641
Loss (gain) from sales of surplus assets	266	(16)	(479)	33	(236)
Impairment Expense (3)	1,498	-	-	-	-
Total costs and expenses	1,205,028	909,785	1,073,519	927,166	657,330
Operating (loss) income from continuing operations	(5,375)	8,584	5,220	(23)	567
Earnings from equity in joint ventures	1,270	1,131	501	-	-
Interest expense, net	(10,100)	(1,374)	(2,032)	(926)	(986)
(Loss) income from continuing operations before cumulative effect of change in accounting principle, income taxes and minority interest	(14,205)	8,341	3,689	(949)	(419)
Income tax benefit	654	11	-	-	-
Minority interest	1	(1)	-	-	-
(Loss) income from continuing operations before cumulative effect of change in accounting principle	(13,550)	8,351	3,689	(949)	(419)
(Loss) income from discontinued operations	-	-	312	(463)	13,741
Cumulative effect of changes in accounting principle	-	30	(586)	-	-
Net (loss) income	$ (13,550)	$ 8,381	$ 3,415	$ (1,412)	$ 13,322
Net (loss) income per common unit - basic and diluted:					
Continuing operations	$ (0.64)	$ 0.59	$ 0.38	$ (0.10)	$ (0.05)

Discontinued operations		-		-		0.03		(0.05)		1.55
Cumulative effect of change in accounting principle		-		-		(0.06)		-		-
Net (loss) income	$	(0.64)	$	0.59	$	0.35	$	(0.15)	$	1.50
Cash distributions per common unit	$	0.93	$	0.74	$	0.61	$	0.60	$	0.15

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	Year Ended December 31,				
	2007 (1)	2006	2005	2004	2003
Balance Sheet Data (at end of period):					
Current assets	$ 214,240	$ 99,992	$ 90,449	$ 77,396	$ 88,211
Total assets	908,523	191,087	181,777	143,154	147,115
Long-term liabilities	101,351	8,991	955	15,460	7,000
Minority interests	570	522	522	517	517
Partners' capital	631,804	85,662	87,689	45,239	52,354
Other Data:					
Maintenance capital expenditures (4)	3,840	967	1,543	939	4,178
Volumes - continuing operations:					
Crude oil pipeline (bpd)	59,335	61,585	61,296	63,441	66,959
Crude oil wellhead (bpd)	30,363	33,853	39,194	45,919	45,015
CO2 sales (Mcf per day)	77,309	72,841	56,823	45,312	36,332

(1) Our operating results and financial position have been affected by acquisitions in 2007, most notably the Davison acquisition, which was completed on July 25, 2007. The aggregate value of the total consideration we paid or issued to complete the Davison acquisition was approximately $623 million. The operating results of the acquired Davison entities are included in our financial results prospectively from the acquisition date. For additional information regarding the Davison acquisition, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

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

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

(5) Represents average daily volume for the two month period in 2003 that we owned the assets.

The table below summarizes our unaudited quarterly financial data for 2007 and 2006 (in thousands, except per unit data).

	2007 Quarters			
	First	Second	Third	Fourth
Revenues	$ 183,564	$ 201,016	$ 354,270	$ 460,803
Operating income (loss)	$ 1,580	$ (1,319)	$ 7,043	$ (12,679)
Income (loss) from continuing operations	$ 1,585	$ (1,372)	$ 1,699	$ (15,462)
Net income (loss)	$ 1,585	$ (1,372)	$ 1,699	$ (15,462)
Income (loss) from continuing operations per common unit - basic and diluted	$ 0.11	$ (0.09)	$ 0.07	$ (0.49)
Net income (loss) per common unit - basic and diluted	$ 0.11	$ (0.09)	$ 0.07	$ (0.49)

	2006 Quarters			
	First	Second	Third	Fourth
Revenues	$ 263,602	$ 233,343	$ 229,551	$ 191,873
Operating income	$ 2,370	$ 3,357	$ 1,688	$ 1,169
Income from continuing operations	$ 2,561	$ 3,444	$ 1,695	$ 651

Cumulative effect adjustment	$	30	$	-	$	-	$	-
Net income	$	2,591	$	3,444	$	1,695	$	651
Income from continuing operations per common unit - basic and diluted	$	0.18	$	0.24	$	0.12	$	0.05

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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 2007
- Significant Events
- Capital Resources and Liquidity
- Commitments and Off-Balance Sheet Arrangements
- Results of Operations
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

In the discussions that follow, we will focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves. Our profitability depends to a significant extent upon our ability to maximize segment margin. Segment margin is revenues less cost of sales and operating expenses (excluding depreciation and amortization) plus our equity in the operating income of joint ventures. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant, and maintenance capital investment. A reconciliation of segment margin to income from continuing operations is included in our segment disclosures in Note 12 to the consolidated financial statements.

Available Cash before Reserves is a non-GAAP measure is net income as adjusted for specific items, the most significant of which are the elimination of gains and losses on asset sales (except those from the sale of surplus assets) 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, 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 2007

The year 2007 was a significant year for us. We acquired five energy-related businesses from the Davison family of Ruston, Louisiana and a crude oil terminal on the Mississippi River from BP Pipelines North America Inc. To finance our acquisitions and other activities, we increased the size of our revolving credit facility to $500 million (from $125 million) and issued 24,468,823 common units, including 13,459,209 units to the Davisons and 9,200,000 units in a public offering. We used the proceeds from our public offering to temporarily reduce the balance on our revolving credit facility, which had $80 million outstanding as of December 31, 2007.

We also are negotiating with Denbury several potential "drop-down" transactions involving midstream assets with an aggregate value of approximately $250 million.

Increases in cash flow generally result in increases in Available Cash before Reserves, which we distribute quarterly to holders of our common units and our general partner. During 2007, we generated $28.2 million of Available Cash before Reserves, and we distributed $17.2 million to holders of our common units and general partner. Cash provided by operating activities in 2007 was $33.9 million.

In 2007, we reported a net loss of $13.6 million, or $0.64 per common unit, resulting primarily from non-cash depreciation and amortization of the assets acquired in the Davison transaction totaling $30.1 million. See additional discussion of our depreciation and amortization expense in “Results of Operations – Other Costs and Interest” below.

Additionally, on January 28, 2008, we declared that our distribution to our common unitholders relative to the fourth quarter of 2007 would be $0.285 per unit (paid in February 2008), which is an increase of 5.6% relative to the distribution for the third quarter of 2007. That distribution amount represents a 36% increase from our distribution of $0.21 per unit for the fourth quarter of 2006. During the fourth quarter of 2007 we paid a distribution of $0.27 per unit related to the third quarter of 2007. Our total distributions attributable to 2007 increased 29% over the total distributions attributable to 2006.

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We manage our business through four divisions, which constitute our reportable segments – pipeline transportation (primarily of crude oil), refinery services, industrial gases and supply and logistics (crude oil, petroleum products, terminaling, and truck transportation).

Significant Events

Davison Businesses Acquisition

On July 25, 2007, we acquired substantially all of the operating assets of five energy- related businesses from entities owned and controlled by the Davison family of Ruston, Louisiana. The businesses that we acquired from the Davison family include refinery services, petroleum products marketing, terminaling, trucking, and fuel procurement. Additional information on those operations is included in "Item 1. Business" above.

For financial reporting purposes, the total consideration for the transaction was $623 million, comprised of common units and cash. In that transaction, we issued 13,459,209 of our common units, which were contractually valued at $20.8036 per unit. The units issued are reflected in our consolidated balance sheet at a total value of $330 million. In accordance with EITF No. 99-12, "Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination," the fair value of Genesis common units issued was determined using an average price of $24.52, which was the average closing price of Genesis common units for the two days before and after the terms of the acquisition were agreed to and announced. The remainder of the net purchase price of $293 million (adjusted for purchase price adjustments), along with working capital of an additional $32.5 million (excluding cash acquired), was paid with cash borrowed under our credit facility.

Additionally, 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 a result of that purchase, our general partner continued to hold 7.4% of our outstanding common units. As required under our partnership agreement, our general partner also contributed approximately $6.2 million to maintain its two percent general partner capital account balance.

Pursuant to a unitholder agreement executed on July 25, 2007, the Davison unitholders have the right to designate up to two directors to our board of directors, depending on their continued level of ownership in us. Until July 25, 2010, the Davison unitholders have the right to designate two directors to our board of directors. Thereafter, the Davison unitholders will have the right to designate (i) one director if they beneficially own at least 10% but less than 35% of our outstanding common units, or (ii) two directors if they beneficially own 35% or more of our outstanding common units. If their percentage ownership in our common units drops below 10% after July 25, 2010, the Davison unitholders would have no rights to designate directors. At December 31, 2007, the Davison unitholders held approximately 33% of our outstanding common units.

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

Our operational results for the year ended December 31, 2007, include five months of activity from the Davison acquisition. We have included pro forma information in Note 3 of the Notes to the Consolidated Financial Statements for the year ended December 31, 2007 as if this transaction had occurred January 1, 2007.

Credit Agreement Amendment

In connection with our acquisition from the Davison family, we also amended our credit facility. That amendment increased the committed amount under our facility from $125 million to $500 million, of which a maximum of $100 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement.

December 2007 Equity Offering

On December 10, 2007, we received $194 million in proceeds (net to us after expenses) from a public offering of 9,200,000 common units. We also received $15.5 million from our general partner for its purchase of 734,732 common units to maintain its 7.4% proportionate share of our outstanding common units and $4.4 million to maintain its two percent general partner capital account balance. We used the net proceeds from the offering to repay outstanding borrowings under our credit facility.

Port Hudson Assets Acquisition

Effective July 1, 2007, we acquired the Port Hudson Crude Oil truck terminal, marine terminal, and marine dock of BP Pipelines (North America) Inc. for $8.1 million. The assets acquired in that transaction include docking facilities on the Mississippi River, 215,000 barrels of tankage, a pipeline and other related assets in East Baton Rouge Parish, Louisiana. That acquisition was funded with borrowings under our credit facility. We allocated $4.1 million of the purchase price to the tangible assets we acquired and $4.0 million to goodwill. The assets we acquired in that transaction should provide us with the increased ability to gather, blend and store crude oil from south Louisiana for delivery to markets that can be reached by barge from the Mississippi River.

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Drop-down Transactions

As a result of our acquisition from the Davisons, we anticipate that during the first quarter of 2008, Denbury will enter into "drop-down" transactions with us involving two of their existing CO2 pipelines - the NEJD and Free State CO2 pipelines. We have reached substantial agreement and are in the process of finalizing the business issues with Denbury and the lenders in our credit facility as to the terms of such drop-downs by Denbury and the terms of a long-term transportation service arrangement for the Free State line and a 20-year financing lease for the NEJD system. We expect to pay for these pipeline assets with $225 million in cash and $25 million of our common units based on the average closing price of our units for the thirty trading days prior to the closing of the transaction. We expect to receive approximately $30 million per annum, in the aggregate, under the lease and the transportation services agreement (and a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State pipeline dependant on the volumes of CO2 transported therein. While the business terms of the transactions and associated documentation have been substantially completed, closing remains subject to completion of closing documentation, receipt of a fairness opinion and approval by the audit committee and the board of directors of our general partner.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

In the last eighteen months, we have adopted a growth strategy that has dramatically increased our cash requirements. We now expect our 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.

In November 2006, we entered into a credit facility with a maximum facility amount of $500 million (replacing our $100 million facility). A maximum of $100 million may be used for letters of credit. The borrowing base under the facility at December 31, 2007 was approximately $356 million, and is recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit based on our EBITDA, computed in accordance with the provisions of our credit facility.

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

Uses of Cash

Our cash requirements include funding day-to-day operations, maintenance and expansion capital projects, debt service, refinancings 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.

Operating. Our operating cash flows are affected significantly by changes in items of working capital. We have had situations where other parties have prepaid for purchases or paid more than was due, resulting in fluctuations in one period as compared to the next until the party recovers the excess payment. The timing of capital expenditures and the related effect on our recorded liabilities also affects operating cash flows.

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The majority of the accounts receivable amount on our consolidated balance sheets relate to our crude oil operations. These accounts receivable settle monthly and collection delays generally relate only to discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered. Accounts receivable in our fuel procurement business also settle within 30 days of delivery. Over 75% of our $180.1 million aggregate receivables on our consolidated balance sheet at December 31, 2007 relate to our crude oil and fuel procurement businesses.

Investing. We utilized cash flows to make acquisitions and for capital expenditures. The most significant investing activities in 2007 have been the Davison acquisition for which we expended $301.6 million in cash as consideration and for related acquisition costs. We also paid $8.1 million for our acquisition of the Port Hudson assets. We paid $8.2 million for capital expenditures. We received distributions from our T&P Syngas joint venture that exceeded our share of the earnings of T&P Syngas of $0.4 million during 2007.

During 2006, we utilized cash flows in investing activities by acquiring a 50% interest in Sandhill for $5.0 million. We expended $2.3 million for other investments and capital improvements. Offsetting those expenditures was the receipt of returns of our investment in T&P Syngas in the form of distributions totaling $0.5 million.

We utilized cash flows in investing activities in 2005 by making a $13.4 million investment in T&P Syngas, acquiring a CO2 contract for $14.4 million and making investments in property and equipment of $6.1 million, including $3.1 million for the natural gas gathering assets acquired from Multifuels. Offsetting these expenditures was the receipt of $1.6 million for the sale of idle assets. We also received returns of our investment in T&P Syngas in the form of distributions totaling $0.4 million.

Financing. Our financing activities provided net cash of $297.0 million. Our net borrowings under our credit facility were $72.0 million. In an offering in December 2007, we sold 9,200,000 common units to the public and received $193.6 million, net of offering costs. We received $37.9 million from our general partner for 1,809,614 common units it acquired as part of the Davison acquisition and the common unit offering in December 2007 in order to maintain its 7.4% limited partner interest. Our general partner also contributed $10.6 million during 2007 as required under our partnership agreement to maintain its two percent general partner capital account balance and $1.4 million to offset the costs of a portion of the severance payment to an executive. In connection with the increase in the committed amount of our credit facility, we incurred credit facility fees of $2.3 million. We paid distributions totaling $17.2 million to our limited partners and our general partner during 2007, and received $0.9 million on other financing activities.

In 2006, we utilized net cash of $5.2 million in financing activities. We paid distributions totaling $10.4 million to our limited partners and our general partner during the year. We borrowed $8.0 million under our credit facility, and paid $2.7 million in legal and bank fees in November 2006 to obtain our new credit facility.

In 2005, financing activities provided net cash of $23.3 million. We issued 4,140,000 new limited partner units to the public and 330,630 new limited partner units to our general partner. Additionally, our general partner contributed funds to maintain its 2% general partner interest. In total these activities provided $44.8 million to us. A portion of these funds were utilized to eliminate our bank debt, and we also paid distributions totaling $5.8 million to our partners.

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Capital Expenditures and Business Acquisitions

A summary of our expenditures for fixed assets and businesses in the three years ended December 31, 2007, 2006, and 2005 is as follows:

	Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Capital expenditures for business combinations and asset purchases:			
Davison acquisition:			
Cash payments to Davison	$ 314,227	-	-
Transaction fees and other direct costs	8,915	-	-
Cash received from Davison	(21,686)	-	-
Net cash payments	301,456	-	-
Value of non-cash consideration issued or granted	330,020	-	-
Total Davison acquisition consideration	631,476	-	-
Port Hudson acquisition	8,103	-	-
CO2 contracts	-	-	14,446
Natural gas gathering assets	-	-	3,110
Total	639,579	-	17,556
Capital expenditures for property, plant and equipment:			
Maintenance capital expenditures:			
Pipeline transportation assets	2,880	611	1,256
Supply and logistics assets	440	175	34
Refinery services assets	469	-	-
Administrative and other assets	51	181	253
Total maintenance capital expenditures	3,840	967	1,543
Growth capital expenditures:			
Pipeline transportation assets	3,712	360	1,059
Supply and logistics assets	650	-	260
Refinery services assets	979	-	-
Total growth capital expenditures	5,341	360	1,319
Total	9,181	1,327	2,862
Capital expenditures attributable to unconsolidated affiliates:			
T&P Syngas investment	-	-	13,418
Sandhill investment	-	5,042	-
Faustina project	1,104	1,016	-
Total	1,104	6,058	13,418
Total capital expenditures	$ 649,864	$ 7,385	$ 33,836

During 2008, we expect to expend approximately $6.1 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $3.3 million of improvements in our refinery services business, $0.6 million in our crude oil pipeline operations, $1.5 million related to the relocation of our headquarters office when our existing lease ends in October 2008 and the remainder on projects related to our truck transportation and information technology areas. Most of our truck fleet is less than two years old, so we do not anticipate making any significant expenditures for vehicles in 2008; however, in future years we expect to spend $4 million to $5 million per year on vehicle replacements. Based on the information available to us at this time, we do not anticipate that future capital expenditures for compliance with regulatory requirements will be material.

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We have started construction of an expansion of our existing Jay System that will extend the pipeline to producers operating in southern Alabama. That expansion will consist of approximately 33 miles of pipeline and gathering connections to approximately 30 wells and will include storage capacity of 20,000 barrels. We expect to spend a total of approximately $9.9 million on this project in 2008. Our refinery services segment expects to expend approximately $3.9 million on projects currently in progress to expand its operations in 2008 to two additional refineries.

As discussed above in “Significant Events”, we are currently in the process of finalizing drop down transactions with Denbury related to two of its CO2 pipelines that are expected to occur in the first quarter of 2008.

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

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 nine quarters, including the distribution paid for the fourth quarter of 2007, as shown in the table below (in thousands, except per unit amounts)

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2005	February 2006	$ 0.170	$ 2,343	$ 48	$ -	$ 2,391
First quarter 2006	May 2006	$ 0.180	$ 2,481	$ 51	$ -	$ 2,532
Second quarter 2006	August 2006	$ 0.190	$ 2,619	$ 53	$ -	$ 2,672
Third quarter 2006	November 2006	$ 0.200	$ 2,757	$ 56	$ -	$ 2,813
Fourth quarter 2006	February 2007	$ 0.210	$ 2,895	$ 59	$ -	$ 2,954
First quarter 2007	May 2007	$ 0.220	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.230	$ 3,170(1)	$ 65	$ -	$ 3,235(1)
Third quarter 2007	November 2007	$ 0.270	$ 7,646	$ 156	$ 90	$ 7,892(2)
Fourth quarter 2007	February 2008	$ 0.285	$ 10,902	$ 222	$ 245	$ 11,369(3)

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

(2) The increased amount of distributions that were paid is primarily a result of the additional units issued in connection with the Davison acquisition in July 2007 and the offering of common units in December 2007 as discussed above.

(3) This distribution was paid on February 14, 2008 to our general partner and unitholders of record as of February 7, 2008.

Our credit facility also includes a restriction on the amount of distributions we can pay in any quarter. At December 31, 2007, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $593.7 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.

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Available Cash before Reserves for the year ended December 31, 2007 is as follows (in thousands):

Net loss	$ (13,550)
Depreciation, amortization, and impairment expense	40,245
Cash received from direct financing leases not included in income	568
Cash effects of sales of certain assets	195
Effects of available cash generated by investments in joint ventures not included in income	975
Denbury contribution toward executive severance	1,412
Cash effects of stock appreciation rights plan	(1,614)
Non-cash charges	3,788
Maintenance capital expenditures	(3,840)
Available Cash before Reserves	$ 28,179

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the year ended December 31, 2007 below. For the year ended December 31, 2007, cash flow provided by operating activities was $33.9 million.

Non-GAAP Financial Measure

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.

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.

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The reconciliation of Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the year ended December 31, 2007, is as follows (in thousands):

Cash flows from operating activities	$ 33,929
Adjustments to reconcile operating cash flows to Available Cash:	
Maintenance capital expenditures	(3,840)
Proceeds from sales of certain assets	195
Amortization and write-off of credit facility issuance fees	(779)
Effects of available cash generated by investments in joint ventures not included in cash flows from operating activities	400
Denbury contribution toward executive severance	1,412
Other items affecting Available Cash	142
Net effect of changes in operating accounts not included in calculation of Available Cash	(3,280)
Available Cash before Reserves	$ 28,179

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. The table below summarizes our obligations and commitments at December 31, 2007.

	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)	$ -	$ -	$ 80,000	$ -	$ 80,000
Estimated interest payable on long-term debt (2)	6,819	13,600	5,924	-	26,343
Operating lease obligations	6,885	7,166	3,563	10,779	28,393
Capital expansion projects (3)	6,751	-	-	-	6,751
Additional investment in the Faustina Project (4)	763	-	-	-	763
Unconditional purchase obligations (5)	183,927	29,072	4,097	-	217,096
Other Cash Commitments:					
Asset retirement obligations (6)	100			3,771	3,871
FIN 48 tax liabilities (7)				1,168	1,168
Total	$ 205,245	$ 49,838	$ 93,584	$ 15,718	$ 364,385

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of November 15, 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, 2007 remained outstanding through the final

maturity date of November 15, 2011 and interest rates remained at the December 31, 2007 market levels through November 15, 2011.

(3) We have signed commitments to expand our Jay System and to construct sour gas processing facilities at an additional refinery in Utah. See "Capital Expenditures and Business Acquisitions" under "Liquidity and Capital Resources – Uses of Cash" above.

(4) We made an additional investment in the Faustina Project in January 2008 in the amount of $0.8 million.

(5) Unconditional purchase obligations includes 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, 2007, 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.

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(6) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $1.2 million, as determined under FIN 47 and SFAS 143, and is further discussed in Note 5 to the Consolidated Financial Statements.

(7) The estimated FIN 48 tax liabilities will be settled as a result of expiring statutes or audit activity. The timing of any particular settlement will depend on the length of the tax audit and related appeals process, if any, or an expiration of statute. If a liability is settled due to a statute expiring or a favorable audit result, the settlement of the FIN 48 tax liability would not result in a cash payment.

In additional to the contractual cash obligations included above, we also have a contingent obligation related to our acquisition of a 50% interest in Sandhill, which could require us to pay an additional $2 million for our interest. See additional discussion in the section on Sandhill in Note 8 to the consolidated financial statements.

We have guaranteed 50% of the $3.9 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. See additional discussion in the section on Sandhill in Note 8 to the consolidated financial statements.

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, nor do we have any debt or equity triggers based upon our unit or commodity prices.

Results of Operations

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Pipeline transportation	$ 13,035	$ 12,426	$ 9,804
Refinery services	21,898	-	-
Industrial gases	12,063	11,443	8,154
Supply and logistics	15,330	7,366	3,661
Total segment margin	$ 62,326	$ 31,235	$ 21,619

Pipeline Transportation Segment

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

Pipeline System	2007	2006	2005
Mississippi	21,680	16,931	16,021
Jay	13,309	13,351	13,725
Texas	24,346	31,303	31,550

The Mississippi System begins in Soso, Mississippi and extends to Liberty, Mississippi. At Liberty, shippers can transfer the crude oil to a connection to Capline, a pipeline system that moves crude oil from the Gulf Coast to refineries in the Midwest. The system has been improved to handle the increased volumes produced by Denbury and transported on the pipeline. In order to handle future increases in production volumes in the area that are expected, we have made capital expenditures for tank, station and pipeline improvements and we intend to make further improvements. See “Capital Expenditures and Business Acquisitions” under “Liquidity and Capital Resources – Uses of Cash” above.

Denbury is the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury’s existing and prospective oil fields. As Denbury continues to acquire and develop old oil fields using CO2 based tertiary recovery operations, Denbury expects to add crude oil gathering and CO2 supply infrastructure to those fields, which could create some opportunities for us.

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Beginning in September 2004, Denbury became a shipper on the Mississippi System, under an incentive tariff designed to encourage shippers to increase volumes shipped on the pipeline. Prior to this point, Denbury sold its production to us before it entered the pipeline.

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline to connect producing fields operated by Denbury to our Mississippi System. One of these segments was placed in service in 2004 and the other began operations in the first quarter of 2005. Denbury pays us a minimum payment each month for the right to use these pipeline segments. We account for these arrangements as direct financing leases.

The Jay Pipeline system in Florida and Alabama ships crude oil from fields with relatively short remaining production lives. Recent changes in the ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development of these fields which may lead to increases in production. Additionally, new wells have been drilled in the area. This new production 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 increase our cash flows from the Jay System.

Volumes on our Texas System averaged 24,346 barrels per day during 2007. 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. In 2003, we sold a portion of our Texas System to TEPPCO. Since such sale, volumes on the Texas System have declined as a result of changes in the supply available for the two refineries to acquire and ship on our pipeline and changes TEPPCO made to the operations of the pipeline segments. As we have consistently been able to increase our pipeline tariffs as needed and due to the insignificance of the Texas Systems’ net book value at December 31, 2007, we do not believe that the decline in volumes will affect the recoverability of the net investment that remains on the Texas System. We lease tankage in Webster on the Texas System of approximately 165,000 barrels. We have a tank rental reimbursement agreement effective January 1, 2005 with the primary shipper on our Texas System to reimburse us for the expense of leasing of that storage capacity. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets connected to TEPPCO’s pipeline systems.

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

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.

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

	Year Ended December 31, 2007	2006	2005
		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 14,906	$ 14,309	$ 13,490
Sales of crude oil pipeline loss allowance volumes	6,875	6,472	4,672
Revenues from direct financing leases of CO2 pipelines	319	340	359
Tank rental reimbursements and other miscellaneous revenues	655	621	566
Total revenues from crude oil and CO2 tariffs, including revenues from direct financing leases	22,755	21,742	19,087
Revenues from natural gas tariffs and sales	4,456	8,205	9,801
Natural gas purchases	(4,122)	(7,593)	(9,343)
Pipeline operating costs	(10,054)	(9,928)	(9,741)
Segment margin	$ 13,035	$ 12,426	$ 9,804
Volumes per day:			
Crude oil pipeline - barrels	59,335	61,585	61,296

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

Pipeline segment margin increased $0.6 million, or 5%, for 2007, as compared to 2006. Revenues from crude oil and CO2 tariffs and related sources were responsible for the increase for the period. Net profit from natural gas transportation and sales decreased slightly and pipeline operating costs increased, slightly offsetting the increase from tariffs and other sources.

Tariff revenues from transportation of crude oil and CO2 increased $0.6 million in 2007 compared to the prior year period due primarily to increased volumes on the Mississippi System of 4,749 barrels per day and tariff increases on the Jay System. The tariff on the Mississippi System is an incentive tariff, such that the average tariff per barrel decreases as the volumes increase. However, because of the overall impact of an annual tariff increase on July 1, 2007 and increased volume, our revenues improved. The volumes on the Jay System were almost identical to the prior year period. As a result of the annual tariff increase on July 1, 2007, average tariffs on the Jay System increased by approximately $0.04 per barrel between the two periods. Although volumes on the Texas System declined by 6,957 barrels per day, the impact on revenues was not significant due to the relatively low tariffs on that system. Approximately 74% of the volume on that system is shipped on a tariff of $0.31 per barrel.

Higher market prices for crude oil added $0.4 million to pipeline loss allowance revenues. During 2007, average crude oil market prices, as referenced by the prices posted by Shell Trading (US) Company for West Texas/New Mexico Intermediate grade crude oil, were $6.2 higher than in 2006. Fluctuations in the future in crude oil market prices will affect our revenues from sales of crude oil pipeline loss allowance volumes. Tank rental reimbursements and other miscellaneous revenues increased by $0.1 million.

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

Operating costs increased $0.1 million. The increase in 2007 was due to higher compensation costs of $0.2 million and an increase in costs related to our stock appreciation right plan expense that relates to our pipeline operations personnel of $0.1 million. These increases in costs were offset by a decrease of $0.2 million related to pipeline lease fees and insurance related to our pipeline operations.

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Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Pipeline segment margin increased $2.6 million, or 27%, for 2006, as compared to 2005. Revenues from crude oil and CO2 tariffs and related sources were responsible for the increase for the period. Net profit from natural gas transportation and sales increased slightly, with that increase offset by an increase in pipeline operating costs.

Tariff revenues from transportation of crude oil and CO2 increased $0.8 million in 2006 compared to the prior year period due primarily to increased tariffs on all systems. Additionally the receipt and delivery points for the crude oil varied in 2006, with proportionately more volume at locations with higher per barrel tariffs. Total volumes on all three systems were consistent with 2005 volumes.

Higher market prices for crude oil added $1.8 million to pipeline loss allowance revenues. During 2006, average crude oil market prices, as referenced by the prices posted by Shell Trading (US) Company for West Texas/New Mexico Intermediate grade crude oil, were $9.71 higher than in 2005. Fluctuations in the future in crude oil market prices will affect our revenues from sales of crude oil pipeline loss allowance volumes. Tank rental reimbursements and other miscellaneous revenues increased by $0.1 million.

Net profit from natural gas pipeline activities increased in total $0.1 million from 2005 amounts. Fluctuations in natural gas market prices created variances between the annual periods in revenues from natural gas sales and costs of natural gas purchases.

Operating costs increased $0.2 million. A decrease in 2006 in costs for regulatory testing and repairs of $0.6 million was offset by increased power costs of $0.2 million, increases in safety and insurance costs totaling $0.3 million and expense related to our stock appreciation rights ("SAR") plan of $0.3 million.

Refinery Services Segment

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

Typically, we receive 100% of the NaHS, as compensation for providing the sour gas processing services. The largest cost component of providing the service is acquiring and delivering caustic soda to our operations. Caustic soda, or NaOH, is the scrubbing agent introduced in the sour gas stream to remove the sulfur and generate the by-product, NaHS. Therefore the contribution to segment margin involves the revenues generated from the sales of NaHS less our total cost of providing the services, including the costs of acquiring and delivering caustic soda to our service locations. We estimate that approximately 65% of our NaHS sales are indexed, in one form or another, to our cost of caustic soda. Because the activities of these service arrangements can fluctuate, we do, from time to time engage in other activities such as selling caustic soda, buying NaHS from other producers for re-sale to our customers and buying and selling sulfur, the financial results of which are also reported in our refinery services segment.

Segment margin from our refinery services for the five months we owned this business in 2007 was $21.9 million. On a pro forma basis, refinery services segment margin would have been $50.8 million for 2007 and $44.7 million for 2006.

We believe the most meaningful measure of our success in this segment is the revenue generated from sales of NaHS after deducting delivery expenses, from both the volumes received as payment for rendering service as well as volumes obtained from third party producers.

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	Five Months Ended December 31, 2007	Pro Forma Year Ended December 31, 2007	2006
NaHS Sales			
Dry Short Tons (DST)	69,853	164,059	159,952
Net Sales per DST	$ 620	$ 591	$ 561
Contribution Margin per DST	$ 257	$ 260	$ 237

During the five months that we owned this operation, sales of NaHS, measured in dry short tons (DST) were 69,853 DST, or an average of 456 DST per day. The average sales price of the NaHS, net of delivery expenses, for the period was $620 per DST. Combining the historical results of this operation for January through July 2007 with our results and comparing it to the historical results of the predecessor for 2006 indicates that the average sales price per DST of NaHS, net of delivery expenses, increased between 2006 and 2007 by 5%. The total DST sold between the periods, including the sales of the predecessor for the first seven months of 2007, was 4,107 DST more in 2007 than in 2006. As we expand our sour gas processing services to additional refineries, we expect these NaHS sales volumes to continue to increase. The increased worldwide demand for copper has contributed to the increased demand for NaHS.

The largest input to processing of the sour gas streams that result in NaHS is NaOH. We also market NaOH and sulfidic NaOH not used for our processing. During 2007, the average market price for NaOH was $425 per DST, an increase of 12% over the 2006 market price. We have generally been successful in increasing the sales price for NaHS to compensate for increases in NaOH prices and maintaining or expanding the contribution of NaHS sales to our segment margin.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO2 sales to industrial customers and our share of the operating income of our 50% joint venture interests in T&P Syngas and Sandhill.

CO2 – Industrial Customers

We supply CO2 to industrial customers under seven long-term CO2 sales contracts. We acquired those contracts, as well as the CO2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with Denbury. Since 2003, we have purchased those contracts, along with three VPPs representing 280.0 Bcf of CO2 (in the aggregate), from Denbury for a total of $43.1 million in cash. 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 or for uses in tertiary crude oil recovery or chemical processes. 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 from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. At December 31, 2007, we have 182.3 Bcf of CO2 remaining under the VPPs.

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. In the three years ended December 31, 2007, all of our customers purchased more than their minimum take-or-pay quantities.

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

Based on historical data for 2004 through 2007, we expect some seasonality in our sales of CO_2. 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 CO_2 for each quarter in 2007 and 2006 under these contracts were as follows:

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Quarter	2007	2006
First	67,158	66,565
Second	75,039	73,980
Third	85,705	82,244
Fourth	80,667	68,452

Syngas

We recognize our share of the earnings of T&P Syngas in each period. We are amortizing the excess of the price we paid for our interest in T&P Syngas over our share of the equity of T&P Syngas over the remaining useful life of the assets of T&P Syngas. This excess of $4.0 million is being amortized over eleven years. We receive cash distributions from T&P Syngas quarterly.

Sandhill

We recognize our share of the earnings of Sandhill in each period. We paid $3.8 million more for our interest in Sandhill than our share of the equity on the balance sheet of Sandhill at the date of acquisition. This excess of the purchase price over our share of the equity of Sandhill has been allocated to the property and equipment and intangible assets based on the fair value of those assets, with the remaining $0.7 million allocated to goodwill. We are amortizing the amount allocated to property, equipment and intangibles over the remaining useful lives of those assets. The amount allocated to goodwill will be reviewed for impairment periodically. We receive cash distributions from Sandhill quarterly.

Operating Results

Operating results for our industrial gases segment were as follows.

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Revenues from CO2 marketing	$ 16,158	$ 15,154	$ 11,302
CO2 transportation and other costs	(5,365)	(4,842)	(3,649)
Equity in earnings of joint ventures	1,270	1,131	501
Segment margin	$ 12,063	$ 11,443	$ 8,154
Volumes per day:			
CO2 marketing - Mcf (1)	77,309	72,841	56,823

(1) 2005 volumes only include volumes sold by us.

The increasing margins from the industrial gases segment between 2007 and 2006 were the result of an increase in volumes of 4,468 Mcf per day and an increase of 1% in the average revenue per Mcf sold. Our margins from 2005 to 2006 increased primarily due to the acquisitions we made in 2005 and 2006 in this segment. The average revenue per Mcf sold increased by 5% from 2005 to 2006, due to inflation adjustments in the contracts and variations in the volumes sold under each contract.

Transportation costs for the CO2 on Denbury's pipeline have increased due to the increased volume and the effect of the annual inflation factor in the rate paid to Denbury. The average rate per Mcf in 2007 increased 6% over the 2006 rate. The average rate in 2006 increased 3% over the 2005 rate.

Our share of the operating income of T&P Syngas for 2007, 2006 and for the nine month period we owned it in 2005 was $1.6 million, $1.5 million and $0.8 million, respectively. We reduced the amount we recorded as our equity in T&P Syngas by $0.4 million in 2007 and 2006 and $0.3 million in 2005 as amortization of the excess purchase price of T&P Syngas. During 2007, T&P Syngas paid us distributions totaling $2.0 million, and we received a distribution of $0.6 million in 2008 attributable to the fourth quarter of 2007. During 2006 and 2005 we received distributions totaling $2.0 million and $0.8 million, respectively. Financial statements for T&P Syngas are included as a Schedule to this Annual Report.

Our share of the operating income of Sandhill for 2007 and the nine month period we owned it in 2006 was $0.3 million and $0.1 million, respectively. We reduced these amounts by $0.3 million and $0.2 million for the amortization of the excess of the purchase price of Sandhill, respectively. During 2007 and 2006, we received distributions from Sandhill totaling $0.3 million and $0.1 million, respectively.

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Supply and Logistics Segment

Our supply and logistics segment was previously known as our crude oil gathering and marketing segment. With the acquisition of the Davison businesses, we renamed the segment and included in it the petroleum products, fuel logistics, terminaling and truck transportation activities we acquired from the Davisons.

Our crude oil gathering and marketing operations are concentrated in Texas, Louisiana, Alabama, Florida, and Mississippi. Those operations, which involve purchasing, gathering and transporting by trucks and pipelines operated by us and trucks, pipelines and barges operated by others, and reselling, help to ensure (among other things) a base supply source for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell oil less the price at which we purchase that crude oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks. Our crude oil gathering and marketing activities provide us with an extensive expertise, knowledge base and skill set that facilitates our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually, this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

When the crude oil markets are in contango, (oil prices for future deliveries are higher than for current deliveries), we may purchase and store crude oil as inventory for delivery in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period for a higher price, either with a counterparty or in the crude oil futures market. The maximum storage capacity available to us for use in this strategy is approximately 120,000 barrels, although maintenance activities on our pipelines impact the availability of this storage capacity. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 17 of the Notes to the Consolidated Financial Statements.

With the Davison acquisition, we gained approximately 225 trucks, 525 trailers and 1.3 million barrels of existing leased and owned storage and expanded our activities to include transporting, storing and blending intermediate and finished refined products. In our petroleum products marketing operations, we primarily supply fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing their products that do not meet the specifications they desire, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tends to be higher than in the same percentage attributable to our recurring operations.

Most of our contracts for the purchase and sale of crude oil have components in the pricing provisions such that the price paid or received is adjusted for changes in the market price for crude oil. The pricing in the majority of our purchase contracts contain the market price component, an unfixed bonus that is based on another market factor and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts will sometimes also contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

In our petroleum products marketing operations, we primarily supply fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing their products that do not meet the specifications they desire, transporting it to one of our terminals and blending it to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but the contribution to margin tends to be higher than in our recurring operations

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Supply and logistics revenue	$ 1,094,189	$ 873,268	$ 1,038,549
Crude oil and products costs	(1,041,738)	(851,671)	(1,018,896)
Operating costs	(37,121)	(14,231)	(15,992)
Segment margin	$ 15,330	$ 7,366	$ 3,661

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

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

An increase in the operating costs related to our crude oil activities of $4.0 million was the largest contributor to the decrease in segment margin from crude oil operations. Compensation and related costs accounted for $1.8 million of the increased costs, including an increase of $0.2 million for our stock appreciation rights plan. In order to remain competitive in retaining drivers for our crude oil trucking, we increased compensation rates. We also had increased costs for fuel and repairs to our trucks and related equipment that combined to increase our operating costs in the crude oil area by $1.2 million. We increased the accrual for the remediation of a former trucking station by $0.3 million. (See Note 18 of the Notes to the Consolidated Financial Statements). Additionally we incurred costs of $0.7 million related to the operation of the Port Hudson facility which we acquired in 2007.

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

If we had owned our Supply and Logistics segment for all of 2007, our estimated pro forma segment margin would have been $25.5 million. For the comparable period in 2006, the estimated pro forma margin from this segment would have been approximately $24.8 million.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Our crude oil gathering and marketing segment margin increased by slightly more than double in 2006 over the prior year period. A decrease in field costs of $1.8 million combined with $1.9 million of increased segment margin from the two other factors resulted in a total increase of $3.7 million.

The majority of the decrease in field costs from the 2005 level related to a reduction in the size of our fleet. When we leased new trucks late in 2005, we reduced the size of the fleet to better match the volumes being purchased. This reduction in fleet size reduced personnel and truck lease costs. The new trucks also required less repair costs in the first year of the lease. During 2005 we also recorded a reserve of $0.5 million for 40% of the expected costs to remediate Jay Trucking Station, which made costs in that period higher than 2006. (See additional discussion at Note 18 to the Consolidated Financial Statements.) Higher fuel costs offset part of the reduction. Average fuel costs during 2006 increased more than $0.30 per gallon, or 13 percent, over the 2005 level. We also recorded expense in field operating costs in the 2006 period of $0.3 million related to our SAR plan.

A $0.3 million increase in revenues from volumes that we transported for a fee but did not purchase increased segment margin. Approximately 52% of the total transportation fee revenue related to volumes transported for Denbury from its wellhead locations to our pipeline using our trucks. We also provide these transportation services for third parties to move crude oil from wellhead locations to destinations designated by those third parties.

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Approximately $0.7 million of the remaining increase in segment margin resulted again from a focus on eliminating less profitable volumes, and increasing profitability on the volumes retained by maximizing the benefits to us of fluctuations in prices in the regions in which we operate. Additionally, while we were in a contango crude oil price market for most of 2005 and 2006, the contribution to segment margin from our inventory hedges was approximately $0.9 million greater in the 2006 period.

Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Expenses excluding effect of stock appreciation rights plan, bonus plan, Davison locations, management compensation and management team transition	$ 12,125	$ 9,007	$ 8,903
Expenses of Davison locations	4,652	-	-
Bonus plan expense	2,033	1,747	1,235
Stock appreciation rights plan expense (credit)	1,576	1,279	(482)
Compensation expense related to management team	3,434	-	-
Management team transition costs and write-off of deferred charges from prior credit facility	2,100	1,540	-
Total general and administrative expenses	$ 25,920	$ 13,573	$ 9,656

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

Total general and administrative (G&A) expenses, increased by $12.3 million, however expenses related to the operations we acquired, the effects of our SAR and bonus plans, and costs related to changes in our management team caused most of the increase. Excluding these items, G&A expenses were $3.1 million greater in 2007 than in 2006.

Increases in G&A expenses in 2007 are attributable to personnel added in our headquarters office late in 2006, increased legal, audit, tax and other consulting fees, additional director fees and expenses and costs related to our airplane. In the latter half of 2006 we added a new management team and additional support personnel. In 2007 G&A expenses included a full year of the compensation costs and associated expenses related to these personnel as well as wage increases, altogether increasing G&A expense by $0.9 million. The addition of the Davison businesses increased our costs for professional services by approximately $1.3 million. The increase in the size of our board of directors and related costs increased by $0.1 million and costs associated with our company aircraft increased G&A expenses by $0.5 million. The remaining increase in costs of $0.3 million is attributable to general G&A expenses.

As a result of the improvement in our Available Cash before Reserves in 2007, our accrual under our bonus plan increased by $0.3 million. The bonus plan for employees is described in Item 11, “Executive Compensation” below. The plan provides for a bonus pool based on the amount of Available Cash before Reserves generated. In 2007, we generated more available cash than in 2006, resulting in a larger bonus expense.

In 2006, we adopted a new accounting pronouncement that changed the method by which we record expense related to our SAR plan. (See additional discussion in “Cumulative Effect Adjustments” below and in Note 15 to the Consolidated Financial Statements.) 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. Under this new method of accounting for the outstanding

SARs, we determine the fair value of the SARs at the end of each period and the fair value is charged to expense over the period during which the employee vests in the SARs. Changes in our common unit market price affect the computation of the fair value of the outstanding SARs. The change in fair value combined with the elapse of time and its effect on the vesting of SARs create the expense we record. Additionally any difference between the expected value for accounting purposes that an employee will receive upon exercise of his rights and the actual value received when the employee exercise the SARs creates additional expense. During a part of 2007, our unit price increased to over $25 per unit and 37,328 SARs were exercised by plan participants that are included in G&A expense, resulting in additional expense in 2007 of more than $0.6 million.

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Denbury has been negotiating with our management team that was hired in August 2006 to finalize a compensation package for that team which is ultimately expected to include equity-based compensation from an ownership interest in our general partner. When the terms of those arrangements are finalized and the agreements and necessary structure are in place, we expect that the remaining members of the management team hired in August 2006 will have the opportunity to earn up to 14.4% of a General Partner Incentive Interest. Although the terms of this arrangement have not been agreed to and completed (see additional discussion in Item 11. Executive Compensation - Senior Executives), 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 and completion of the Davison transaction. Although this compensation is to ultimately come from our general partner, we have recorded the expense in our Consolidated Statements of Operations in G&A expense due to the "push-down" rules for accounting for transactions where the beneficiary of a transaction is not the same as the parties to the transaction. This estimated expense may be different from what may be recorded as compensation once such arrangements are finalized.

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

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Total G&A expenses, increased by $3.9 million, however the effects of our SAR and bonus plans, transition costs related to the change in our management team and the write-off of deferred charges related to our prior credit facility caused that increase. Excluding these items, G&A expenses in 2006 and 2005 were approximately $9.0 million.

As a result of the improvement in our financial results in 2006, our accrual under our bonus plan increased by $0.5 million. The bonus plan for employees is described in Item 11, "Executive Compensation" below. The plan provides for a bonus pool based on the amount of Available Cash before Reserves generated. In 2006, we generated more available cash than in 2005, resulting in a larger bonus expense.

The change in the method of accounting for our SAR plan in 2006, increased G&A expense by $1.7 million from a credit to expense in 2005 to a charge to expense in 2006 of $1.3 million. In periods prior to 2006, the charge or credit to our earnings related to our SAR plan was primarily a function of the change in the market price for our common units from the prior period end.

As indicated above, we recorded transition costs of $1.4 million, primarily in the form of severance costs, when our management team changed in August 2006. When we replaced our credit facility in November 2006, we wrote-off $0.1 million of unamortized deferred legal costs related to our prior facility.

Depreciation, amortization and impairment expense was as follows:

	December 31, 2007	December 31, 2006	December 31, 2005
Depreciation on Genesis assets excluding acquired Davison assets	$ 3,997	$ 3,719	$ 3,579
Depreciation on acquired Davison property, plant and equipment	4,912	-	-
Impairment expense on natural gas pipeline assets	1,498	-	-
Amortization on acquired Davison intangible assets	25,350		
Amortization of CO2 volumetric production payments	4,488	4,244	3,142
Total depreciation, amortization and impairment expense	$ 40,245	$ 7,963	$ 6,721

Depreciation, amortization and impairment increased $32.3 million between 2006 and 2007. The majority of this increase is related to the depreciation and amortization expense recognized on the fixed assets and intangible assets acquired from the Davison family. The depreciation and amortization expense on the acquired assets reflects our ownership of these assets for the last five months of 2007.

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

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

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

Depreciation, amortization and impairment increased $1.2 million between 2005 and 2006. The majority of this increase related to amortization of our CO2 assets. Amortization of the CO2 assets increased due to the additional CO2 volumes sold in the 2006 period as compared to 2005. These additional sales related primarily to the CO2 contracts acquired in the fourth quarter of 2005.

Interest expense, net was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Interest expense, including commitment fees	$ 10,103	$ 781	$ 1,831
Capitalized interest	(59)	(9)	(35)
Amortization of facility fees	441	300	307
Write-off of facility fees and other fees	-	500	-
Interest income	(385)	(198)	(71)
Net interest expense	$ 10,100	$ 1,374	$ 2,032

As a result of the Davison acquisition which was partially financed with borrowings under our credit facility made on July 25, 2007, our interest expense, including commitment fees increased $9.3 million in 2007. Our average outstanding balance of debt was $118.5 million during 2007, an increase of $115.1 million over 2006. Our average interest rate during 2007 was 7.78%, a decrease of 0.64% from 2006. Our equity offering in December 2007 was used to partially repay our outstanding debt, reducing the balance to $80.0 million at December 31, 2007.

Total net interest expense in 2006 was $0.7 million less than in 2005. Interest expense including commitment fees was $1.1 million lower due to average outstanding bank debt that was $15.8 million lower and an interest rate that was 1.3% higher. Our equity offering in December 2005 was used to repay outstanding debt from acquisitions in 2005 and prior years, resulting in the lower average debt balance in 2006. Market interest rates rose in 2006 from 2005 levels, however the impact to us was minor because of our lower debt balances. During 2006, our average daily debt outstanding was $3.4 million.

As a result of the termination of our prior credit facility to enter into the new facility we obtained in November 2006, we wrote-off $0.5 million of deferred facility fees related to the prior credit facility in 2006.

Interest income has fluctuated as a result of fluctuations in excess cash available to be invested on a daily basis.

Net gain/loss on disposal of surplus assets. In 2007, 2006 and 2005 we sold surplus assets no longer used in our operations, recognizing small gains in each period. In addition, we retired 6.0 miles of pipeline on our Jay System resulting in an approximate $0.3 million loss. The 6.0 miles of pipeline was replaced through one of our capital projects completed in 2007.

Cumulative Effect Adjustments of Adoption of New Accounting Principles

2006

On January 1, 2006, we adopted the provisions of SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123 (revised December 2004), “Share-Based Payments”. The adoption of this statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, “Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans” which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

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At December 31, 2005, we had a recorded liability of $0.8 million, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material.

2005

On December 31, 2005, we adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143", or FIN 47. FIN 47 clarified that the term "conditional asset retirement obligation", as used in SFAS No. 143, "Accounting for Asset Retirement Obligations", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditioned upon a future event that may or may not be within our control. Although uncertainty about the timing and/or method of settlement may exist and may be conditioned upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, we are required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

Some of our assets, primarily related to our pipeline operations segment, have obligations regarding removal activities when the asset is abandoned or retired. Additionally, we generally have obligations to remove crude oil injection stations located on leased sites. These assets are actively in use in our operations and the timing of the abandonment of these assets cannot be determined. Accordingly, under the provisions of FIN 47, we have made an estimate of the fair value of our obligations.

Upon adoption of FIN 47, we recorded a fixed asset and a liability for the estimated fair value of the asset retirement obligations at the time we acquired the related assets. This $0.3 million fixed asset is being depreciated over the life of the related assets. The accretion of the discount on the liability and the depreciation through December 31, 2005 were recorded in the statement of operations as a cumulative effect adjustment totaling $0.5 million. Additionally, we reflected our share of the asset retirement obligation recorded in accordance with FIN 47 of our equity method joint venture as a cumulative affect adjustment of $0.1 million.

See Note 5 to the Consolidated Financial Statements for the pro forma impact for the periods ended December 31, 2005 of the adoption of FIN 47 if it had been adopted at the beginning of that period.

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 changes 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, our stock appreciation rights plan and contingent and environmental liabilities. We discuss these policies below.

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

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, trade names, and non-competes involves professional judgment and is ultimately based on acquisition models and management’s assessment of the value of the assets acquired. 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 Davison and Port Hudson acquisitions, we performed allocations of the purchase price. See Note 3 of the Notes to the Consolidated Financial Statements.

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Depreciation and Amortization of Long-Lived Asset 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 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 over their expected useful lives.

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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 assets may not be recoverable, we review our assets for impairment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. We compare the carrying value of the fixed asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase costs and expenses at that time. During the fourth quarter of 2007, we reviewed the carrying value of our natural gas pipelines due to changes in the source of supply to the pipelines. As a result of this review we recorded an impairment charge of $1.5 million. See Note 4 of the Notes to the Consolidated Financial Statements.

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values and is primarily comprised of $316.7 million associated with the Davison acquisition. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the fourth quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, and (iii) appropriate discount rates. 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, 2007, the carrying value of our goodwill was $320.7 million. We did not record any goodwill impairment charges during 2007. At December 31, 2007, the estimated fair value of our refinery services reporting unit was $9 million more than the carrying value of our net assets of that reporting unit. The estimated fair value of our supply and logistics reporting unit was $45 million more than the carrying value of that reporting unit.

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

Asset Retirement Obligations

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

Stock Appreciation Rights Plan

We accrue for the fair value of our liability for the stock appreciation rights ("SAR") awards we have issued to our employees and directors under the provisions of SFAS No. 123(R), Share-Based Payments, as amended and interpreted. Under our SAR plan, grantees receive cash for the difference between the market value of our common units and the strike price of the award. 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. At December 31, 2007 and 2006, we used an expected distribution yield of 6%. 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.

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We recognize the stock-based compensation expense on a straight-line basis over the requisite service period for the awards. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate at each balance sheet date based on prior experience. As of December 31, 2007, there was $1.2 million of total compensation cost to be recognized in future periods related to non-vested SARs. The cost is expected to be recognized over a weighted-average period of one year. See Note 15 to our Consolidated Financial Statements for further discussion regarding our SAR plan.

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.

We are currently conducting remediation of subsurface soil and groundwater hydrocarbon contamination at the former Jay Trucking Facility. The total estimated remediation and related costs are $2.0 million, which we share with other responsible parties. In 2005, we recorded a liability of $0.5 million as our estimated share of this liability. Based on additional information, we increased this accrual by $0.3 million in 2007. We currently have no reason to believe that this remediation will have a material financial effect on our financial position, results of operation, or cash flows.

Recent Accounting Pronouncements

SFAS 157

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements”, or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. In February 2008, the FASB issued SFAS No. 157-2, “Effective Date of FASB Statement No. 157”, or SFAS 157-2, which delays the effective date of SFAS 157 for non-financial assets and non-financial liabilities. In accordance with SFAS 157-2, SFAS 157 is effective for fiscal years beginning after November 15, 2007 for financial assets and liabilities as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. We adopted SFAS 157 on January 1, 2008 for such assets and liabilties with no material impact on our consolidated financial statements. We will begin the new disclosure requirements in the first quarter of 2008. We do not currently know what the effects of the deferred provisions of SFAS 157 will be on our financial position and results of operations when adopted in 2009.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities”, or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for us beginning on January 1, 2008. We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

SFAS 141(R)

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

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SFAS 160

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

EITF 07-4

In May 2007, the Emerging Issues Task Force (or EITF) of the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." This EITF considers the question of whether the incentive distribution rights ("IDRs") of a master limited partnership represent a participating security and should be considered in the calculation of earnings per unit. Under the "two class" method of computing earnings per unit, earnings are allocated to participating securities as if all of the earnings for the period had been distributed. The EITF also presents alternative methods for inclusion of IDRs in the computation of earnings per unit, depending on whether cash distributions exceed earnings for the period. The EITF has issued a draft abstract on this topic and will address comments it receives before issuing a final consensus. Once a final consensus is issued it is expected to be effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We will assess the impact of EITF 07-4 once a final consensus is issued; however we would expect it to have an impact on our presentation of earnings per unit in the future. For additional information on our incentive distribution rights, see Note 11.

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, 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, as these activities could expose us to significant losses.

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, 2007 were categorized as non-trading. On December 31, 2007, we had entered into NYMEX future contracts that will settle during February 2008 and NYMEX options contracts that will settle during March 2008. Although the intent of our risk-management activities is to hedge our margin, none of our derivative positions at December 31, 2007 qualified for hedge accounting. This accounting treatment is discussed further under Note 17 to our Consolidated Financial Statements.

The table below presents information about our open derivative contracts at December 31, 2007. 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, 2007 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)	74	14
Weighted average price per bbl	$ 90.87	$ 92.27
Contract value (in thousands)	$ 6,724	$ 1,292
Mark-to-market change (in thousands)	378	52
Market settlement value (in thousands)	$ 7,102	$ 1,344
Heating Oil:		
Contract volumes (1,000 bbls)	50	10
Weighted average price per bbl	$ 107.43	$ 110.84
Contract value (in thousands)	$ 5,372	$ 1,108
Mark-to-market change (in thousands)	192	4
Market settlement value (in thousands)	$ 5,564	$ 1,112
NYMEX Option Contracts:		
Crude Oil-Written Calls:		
Contract volumes (1,000 bbls)	47	
Weighted average premium received	$ 2.75	
Contract value (in thousands)	$ 129	
Mark-to-market change (in thousands)	87	
Market settlement value (in thousands)	$ 216	
Natural Gas-Written Calls		
Contract volumes (10,000 mmBtus)	5	
Weighted average premium received	$ 2.50	
Contract value (in thousands)	$ 13	
Mark-to-market change (in thousands)	1	
Market settlement value (in thousands)	$ 14	

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

We are also exposed to market risks due to the floating interest rates on our credit facility. Our debt bears interest at the LIBOR Rate or Prime Rate plus the applicable margin at our option. We do not hedge our interest rates. The carrying values of our debt approximate fair value primarily because interest rates fluctuate with prevailing market rats, and the credit spread on outstanding borrowings reflect market. On December 31, 2007, we had $80.0 million of debt outstanding under our credit facility.

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 93.

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

None.

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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 reasonable assurance of the timely recording, processing, summarizing and reporting of information, and in accumulation and communication to management in all material respects 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.

Davison Acquisition

On July 25, 2007, we completed the Davison Acquisition, which met the criteria of being a significant acquisition for us. For additional information regarding the acquisition, please read Note 3 to the Consolidated Financial Statements and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Acquisitions and Related Activities in 2007" included in Item 7 in this Annual Report.

On June 22, 2004, the Office of the Chief Accountant of the SEC issued guidance regarding the reporting of internal control over financial reporting in connection with a major acquisition. On October 6, 2004, the SEC revised its guidance to include expectations of quarterly reporting updates of new internal control and the status of the control regarding any exempted businesses. This guidance was reiterated in September 2007 to affirm that management may omit an assessment of an acquired business's internal control over financial reporting from its assessment of internal control over financial reporting for a period not to exceed one year.

We are in the process of implementing our internal control structure over the operations we acquired from the Davisons. Due to the magnitude of the businesses, we expect that this effort will be completed in 2008. The assessment and documentation of internal controls requires a complete review of controls operating in a stable and effective environment.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2007. This assessment excluded the Davison Acquisition. 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, 2007, 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, 2007. 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, Inc. 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, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control Over Financial Reporting, Management excluded from its assessment the internal control over financial reporting for the businesses acquired on July 25, 2007 (the "Davison Acquisition" as defined in Note 3) whose financial statements constitute 73% of total assets, 26% of total revenues, and 34% of net loss of the consolidated financial statement amounts as of and for the year ended December 31, 2007. Accordingly, our audit did not include the internal control over financial reporting for the Davison Acquisition. 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, 2007, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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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, 2007 of the Partnership and our report dated March 14, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Partnership's adoption of new accounting standards.

DELOITTE & TOUCHE LLP

Houston, Texas
March 14, 2008

Item 9B. Other Information

Item 3.02. Unregistered Sales of Equity Securities.

On December 10, 2007, we sold 734,732 common units to our general partner for $15.5 million in a private transaction that was exempt from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof. This sale, made concurrently with a public offering, was made pursuant to our general partner's preemptive rights under Section 5.6 of our partnership agreement. We used the proceeds from this sale to pay down our credit facility.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

Our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. However, in connection with the Davison acquisition, our general partner has agreed to let the Davison family designate one director so long as it holds 10% of our common units and two directors so long as it holds 35% of our common units. Our general partner owes a fiduciary duty to our unitholders, but our partnership agreement contains various provisions modifying and restricting the fiduciary duty. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. As of February 29, 2008 our general partner has nine directors. Denbury, indirectly, elects all members to the board of directors of our general partner other than any Davison appointees. The independence standards established by the American Stock Exchange, or AMEX, require us to have at least three independent directors on the board of directors. As we previously disclosed and have reported to AMEX, in December, 2007, one of our independent directors resigned. We expect to replace that director during the first quarter of 2008. (See Item 13. Certain Relationships and Related Transactions, and Director Independence below.) AMEX does not require a listed limited partnership like us to have a majority of independent directors on the board of directors 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 AMEX, and we are not required to maintain a compensation committee in the future.

The compensation committee of our general partner oversees compensation decisions for the employees of our general partner, as well as the compensation plans of our general partner. The members of the Compensation Committee are Gareth Roberts and Susan O. Rheney, both of whom are non-employee directors of our general partner. We expect to add another non-employee director to the Compensation Committee in the first quarter of 2008. 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 AMEX and the Securities Exchange Act of 1934, as amended. Susan O. Rheney and J Conley Stone serve as the members of the audit committee. We expect to add another independent director to the Audit Committee in the first quarter of 2008. 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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- oversees our anonymous complaint procedure established for our employees;
- 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

Our independent registered public accounting firm is given unrestricted access to the audit committee. The Board of Directors 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 AMEX 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
Gareth Roberts	55	Director and Chairman of the Board
Grant E. Sims	52	Director and Chief Executive Officer
Mark C. Allen	40	Director
James E. Davison	70	Director
James E. Davison, Jr.	41	Director
Ronald T. Evans	45	Director
Susan O. Rheney	48	Director
Phil Rykhoek	51	Director
J. Conley Stone	76	Director
Joseph A. Blount, Jr.	47	President and Chief Operating Officer
Ross A. Benavides	54	Chief Financial Officer, General Counsel and Secretary

Karen N. Pape	50	Senior Vice President and Controller

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

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

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

James E. Davison has served as a director of our general partner since July 2007. Mr. Davison has served as chairman of the board of Davison Transport, Inc. for over 30 years. He also serves as President of Sunshine Oil and 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 committee.

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

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.

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

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

Joseph A. Blount, Jr. has served as President and Chief Operating Officer of our general partner since August 2006. Mr. Blount served as President and Chief Operating Officer of Unocal Midstream & Trade from March of 2000 to September of 2005. In such capacity, Mr. Blount oversaw the worldwide marketing of Unocal’s natural gas, crude oil and condensate resources, the development and management of its pipeline, terminal and storage assets, and its commodity risk management activities. Upon the acquisition of Unocal by Chevron in September of 2005, Mr. Blount left to pursue personal interests, including investments.

Ross A. Benavides has served as Chief Financial Officer of our general partner since October 1998. He has served as General Counsel and Secretary since December 1999.

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

Code of Ethics

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the officers and directors of our general partner and persons who own more than ten percent of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC and the American Stock Exchange. Based solely on our review of the copies of such reports received by us, or written representations from certain reporting persons that no Forms 5 was required for those persons, we believe that during 2007 our officers and directors complied with all applicable filing requirements in a timely manner.

Item 11. Executive Compensation

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. See "Certain Relationships and Related Transactions."

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Compensation Discussion and Analysis

The Compensation Committee of our board of directors, or the Committee, currently consists of the Chairman of the Board and one independent director. The Committee is responsible for making recommendations to the Board regarding compensation policies, incentive compensation policies and employee benefit plans, and recommends awards thereunder. The Committee recommends specific compensation levels for our chief executive officer and other executive officers. 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.

We have two classes of executive officers for which we have applied distinct compensation strategies. The Senior Executives are Grant E. Sims, our chief executive officer and Joseph A. Blount, Jr., our president and chief operating officer. The Other Executives are Ross A. Benavides, our chief financial officer and general counsel and Karen N. Pape, our vice president and controller. The treatment of the two classes of executive officers are addressed separately below.

Objectives of the Compensation Program. 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. We reward employees primarily for the effort and results of the team or Partnership as a whole, rather than compensating only for individual performance.

The elements of the compensation program for our Senior Executives consist of:

- base salaries,
- an ability to earn an interest in our general partnership interest and our incentive distribution rights, referred to as the General Partner Incentive Interest below, and
- other compensation (including contributions to the 401(k) plan and annual term life insurance premiums).

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

- base salaries,
- cash bonuses (performance-based cash incentive compensation including a Bonus Plan, discretionary bonus awards, and a Retention Plan),
- Stock Appreciation Rights Plan,
- Long Term Incentive Plans (phantom units and distibution equivalent rights),
- a Severance Protection Plan, and
- other compensation (including contributions to the 401(k) plan and annual term life insurance premiums).

As described in more detail below, we believe that the combination of base salaries, cash bonuses, Long-Term Incentive Plans and the General Partner Incentive Interest Plan provides an appropriate balance of short-term and long-term incentives, cash and non-cash based compensation, and an alignment of the incentives for our executives and employees with the interests of our common unitholders and Denbury, the owner of 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. Our Stock Appreciation Rights Plan and 2007 Long Term Incentive Plan are linked primarily to the appreciation in our common unit price. The General Partner Incentive Interest Plan that has the potential to provide ownership interests in our general partnership interest and our incentive distribution rights to our Senior Executives is based on the completion of accretive third-party acquisitions.

In the event of a financial statement restatement, we do not currently have a specific policy or penalty in most of our compensation programs. However, such an event would likely affect the Bonus Plan and awards under our Stock Appreciation Rights and 2007 Long-Term Incentive Plan by the Committee each year because these plans include consideration of overall company performance.

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Senior Executives

During 2006, we determined that it was in the best interest of our general partner and our unitholders for our executives to focus increased attention on growing our business through transactions with parties other than Denbury. We believe that the value created for our general partner and for the common unitholders would be enhanced if we were to grow our business by making significant third-party investments (i.e. acquisitions, investments in joint ventures, subsequent organic growth projects, etc.) For MLPs, value is created for the unitholders by generating sustainable, long-term, growing distributions. To generate distribution growth, we believe we will need to deploy significant capital, as we currently do not have sufficient organic growth opportunities to generate the distribution growth we want to achieve.

In order to implement this strategy, the Senior Executives were hired on August 8, 2006. As of November 26, 2007, Brad N. Graves, our former Executive Vice President of Business Development and one of our initial Senior Executives, was no longer employed by us. The compensation program for those executives, in the form of base salaries and the General Partner Incentive Interest (described below), is designed to reward them for growing our business by making accretive third-party acquisitions. A significant portion of the compensation awarded to the Senior Executives is expected to ultimately come from this equity based General Partner Incentive Interest.

When the Senior Executives were hired, the Senior Executives and Denbury agreed to negotiate contracts that would provide an opportunity for the Senior Executives to earn up to 20% of the general partner interests based on the conceptual terms described below under “General Partner Incentive Interests”. However, the parties have not completed such negotiations and entered into such agreements for a myriad of factors, including time and resource constraints, the parties’ inability to agree to mechanics relating to certain terms, and the parties’ willingness to consider terms that were not originally contemplated, which terms might have the effect of simplifying the arrangement and achieving the intended objectives with more efficient and effective methods. It is likely that the general partner interest plan will contain a correlation between earning the general partner interest with the successful completion of non-Denbury acquisitions and/or other organic growth that earn a reasonable rate of return (i.e. growth of the Partnership unrelated to Denbury), but that the vesting, measurement, and other ways that such Partnership performance is measured could be significantly different than as described below. Although the parties expect to negotiate and complete a mutually acceptable compensation arrangement, there is no guarantee that they will. Further, with the departure of Mr. Graves, the aggregate general partner incentive interest that will available to the remaining two Senior Executives will be reduced accordingly to approximately 14.4%.

Although the agreements related to the General Partner Interest have not been agreed to and completed as described above and therefore the amount of compensation earned to date by the Senior Executives is uncertain and difficult to measure, we have accrued $3.4 million of compensation in 2007 for the Senior Executives. This amount could change significantly in the future depending on the final terms of the arrangement.

The terms described below are summaries of the conceptual terms included in the initial employment offer when the Senior Executives were employed in August 2006.

Base Salaries. Our General Partner agreed to negotiate employment agreements with the Senior Executives for a four-year term with provisions customary for the industry (including at least the same fringe benefits, other than participation in the cash bonus plan and SAR plan, as are provided to other executive officers of our general partner). The base salaries for the Senior Executives were determined as an aggregate amount of $810,000, to be allocated among the three executives at the discretion of the chief executive officer. The aggregate salary for calendar 2007 was allocated to Messrs. Sims, Blount, and Graves in the amounts of $310,000, $270,000, and $230,000 per year, respectively. The aggregate salaries will increase, if our market capitalization increases for consecutive 90 day periods, to: $600 million market capitalization ($900,000 annual aggregate salaries); to $1.0

billion ($990,000 annual aggregate salaries); and above $1.0 billion (annual aggregate salary increases of 10 percent for each $300 million market capitalization increase), with the aggregate amounts to be adjusted for the departure of Mr. Graves. The base salary was based on several factors. These factors include our objectives to make third-party acquisitions, the nature and responsibility of the positions (including our size and complexity), the expertise of the three executives, the track record of the Senior Executives in creating value at other MLPs or midstream businesses, and the competitiveness of the marketplace. We believe we were competing to hire Mr. Sims with private equity firms seeking to develop midstream energy MLPs. We believe that the aggregate compensation payable to our Senior Executives is comparable to what they potentially would have been offered by private equity firms for similar positions. The formula for salary increases was designed to reward the Senior Executives if they are successful in growing our business and to increase their compensation to be commensurate with the scope of their responsibilities in leading a larger enterprise.

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General Partner Incentive Interests. Our General Partner agreed to negotiate other contracts with the Senior Executives that would include the following conceptual terms relating to the ability of the Senior Executives to earn up to 14.4% (originally 20% before the departure of Mr. Graves) of the General Partner's incentive distribution rights and general partner interest (which currently are owned by a wholly-owned subsidiary of Denbury) if the Senior Executives completed acquisition transactions from parties other than affiliates of our general partner that earn (using a look-back provision) a minimum un-levered internal rate of return of at least 8 percent. In our judgment, the ability to earn up to a 14.4 percent equity position in the General Partner Incentive Interest was intended to be comparable to the earn-in provision that potentially would be offered by private equity firms under similar circumstances. Earning and vesting of the General Partner Incentive Interest was based on the following schedule (which has been adjusted to reflect the departure of Mr. Graves):

Cumulative Amount of Acquisitions from Third Parties	Percentage Vested in General Partner Interest
$150 million	1.44%
$300 million	2.88%
$450 million	4.32%
$600 million	5.76%
$750 million	7.20%
$900 million	8.64%
$1,050 million	10.08%
$1,200 million	11.52%
$1,350 million	12.96%
$1,500 million	14.40%

Additionally, if approved by Denbury's board of directors, our audit committee (including receipt of required fairness opinions for both parties), and Denbury's lenders, Denbury agreed to sell to Genesis midstream CO_2 assets owned by Denbury (expected at that time to be two existing and one planned CO_2 pipeline with an estimated aggregate transaction value of approximately $300 million), and contract for exclusive use of those assets on commercially acceptable terms (including preserving Denbury's uninterrupted exclusive use of those assets in the event of Genesis' sale or bankruptcy) at an expected rate of return of 12 percent to Genesis over 12 years or longer, but only if, at the time of each sale by Denbury, the sale will not make the ratio of gross value of (1) consummated transactions, that at the time of sale are expected to earn a minimum un-levered internal rate of return of 8 percent to (2) assets sold by Denbury to be less than 1.5 to 1.

The General Partner Incentive Interests was intended to create a long-term non-cash equity-based compensation plan for the Senior Executives. As the Senior Executives earn a portion of the general partner interest, they also will earn correlative incentive distribution rights. Consequently, on a long-term basis, the Senior Executives will be incentivized to grow the distributions for our common unitholders. Further, the compensation from our General Partner Incentive Interest would effectively come from Denbury rather than from us, and therefore it will not affect Available Cash before Reserves or cash flow of the Partnership..

While the Senior Executives would be incentivized to make accretive third-party acquisitions, the earning of interests in our General Partner Incentive Interest by the Senior Executives is not contemplated to be dependent upon increasing our distributions. Our distribution policy will continue to be made by our Board of Directors based upon the determination that we are generating sustainable cash flow after adjustments for appropriate reserves. No assurance can be made that our distributions will be increased following the completion of significant third-party acquisitions or drop-down transactions with Denbury.

The conceptual terms also contemplates that the Senior Executives would have change of control protection on 11.5% (originally 16% before the departure of Mr. Graves) of the equity interest in our general partner (if not already vested, but capped at 11.5%) , triggered by a change of control of Denbury or our general partner.

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We have reimbursed the Senior Executives for out-of-pocket transaction costs incurred in connection with the consummation of the employment agreements and general partner interest agreement up to an aggregate amount of $75,000.

The Other Executives

The Other Executives participate in compensation programs that are available to our entire employee population. The elements of the Company-wide compensation program consist of competitive base salaries, a Bonus Plan, a Stock Appreciation Rights plan, a Severance Protection plan, and other benefits. Additionally the Other Executives participated in a Retention plan with a group of senior management personnel during 2006 and the first eight months of 2007. The Other Executives also participate in our 2007 Long-Term Incentive Plan.

Base Salaries. 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 chief executive officer. In making recommendations, the Committee exercises subjective judgment using no specific weights for these factors. Base salaries are the primary part of the compensation package whereby a distinction is made for individual performance of the Other Executives. The other components of their compensation plan are consistent among employee groups and generally are proportional to base salary and bonuses. During 2007, the Compensation Committee approved salary increases effective as of the close of the Davison transaction in the amounts of $27,500 or 13.75%, and $25,000 or 14.29%, for Ross Benavides and Karen Pape, respectively. The salary increases were based on the recommendation of the CEO due in significant part to the Other Executives performance prior to and increased responsibility resulting from the Davison acquisition. The Other Executives did not receive salary increases for 2008. For 2008, all other employees received average salary increases of approximately 4 percent.

Bonus Plan. In May 2003, the Compensation Committee of the Board of our general partner approved a Bonus Plan for all employees of our general partner. The Senior Executives are excluded from participation in the Bonus Plan. The Bonus Plan is paid at the discretion of our Board of Directors based on the recommendation of Compensation 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 Compensation Committee on a company-wide basis, the Other Executives receive bonuses only if all employees receive bonuses.

The Bonus Plan is based on the amount of money we generate for distributions to our unitholders, and is measured on a calendar-year basis. We will make a contribution to the Bonus Pool every time we have earned $2,042,288 of Available Cash (as defined in our partnership agreement) before Reserves excluding the effects of the bonus accrual made so far during the year for bonuses and such other adjustments as are made from time to time in the sole discretion of the Compensation Committee. Each $2,042,288 earned is referred to as a “Bucket”. We expect the primary reason for adjusting the size of the Bucket will be for issuance of additional equity, as discussed below.

If we issue additional common units, the Bucket size will be increased proportionally based on the number of additional common units issued. Whenever we earn a Bucket, we will contribute a portion of that Bucket to the Bonus Pool. For each additional Bucket, a larger percentage of the Bucket will be contributed to the Bonus Pool. Contributions will be deducted from the Bonus Pool if Available Cash before Reserves earned for the year decreases. A maximum of nine Buckets are available under the Bonus Plan. There will be no contribution for partial Buckets.

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Contributions to the Bonus Pool will be made in accordance with the following schedule:

Bucket Number	Bucket Size	Contribution to Bonus Pool	Year-to-Date Available Cash before Reserves and Bonus Accrual	Year-to-Date Contributions to Bonus Pool
1	$ 2,042,288	$ 60,000	$ 2,042,288	$ 60,000
2	$ 2,042,288	$ 120,000	$ 4,084,576	$ 180,000
3	$ 2,042,288	$ 120,000	$ 6,126,864	$ 300,000
4	$ 2,042,288	$ 240,000	$ 8,169,152	$ 540,000
5	$ 2,042,288	$ 300,000	$ 10,211,440	$ 840,000
6	$ 2,042,288	$ 360,000	$ 12,253,728	$ 1,200,000
7	$ 2,042,288	$ 360,000	$ 14,296,016	$ 1,560,000
8	$ 2,042,288	$ 360,000	$ 16,338,304	$ 1,920,000
9	$ 2,042,288	$ 360,000	$ 18,380,592	$ 2,280,000

The Bonus Pool will be distributed as follows:

- Each eligible employee will receive a bonus after the end of the year equal to a specified percentage of their year-to-date gross wages. Certain compensation, such as 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 receive a bonus. The date of payment of the bonuses is at the discretion of management, but bonuses will not be paid until after annual earnings have been released to the public.

- There are four 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 Compensation Committee based on the recommendation of the chief executive officer. The Other Executives are included in Level Four.

- The percentage of adjusted year-to-date gross wages paid as a bonus will be a function of the number of Buckets earned during the year and the employee's Participation Level in the Bonus Plan. The bonus amount each employee is entitled to receive will be determined in accordance with the table shown below. The bonus may be adjusted up or down to reflect individual performance.

- The total of all bonuses paid may not exceed the total Bonus Pool. Should the amount of bonuses calculated in accordance with the table below exceed the total Bonus Pool available, all calculated bonuses will be reduced proportionately. Should the adjusted amount of bonuses calculated in accordance with the table below be less than the Bonus Pool, the Bonus Pool shall be reduced to the calculated amount.

The bonus percentage that each employee group will receive based on the number of Buckets earned is as follows:

	Cumulative Percentage								
Participation Level	1 Bucket	2 Buckets	3 Buckets	4 Buckets	5 Buckets	6 Buckets	7 Buckets	8 Buckets	9 Buckets

One	0.495%	1.480%	2.470%	4.460%	6.000%	7.000%	8.000%	9.000%	10.000%
Two	0.495%	1.480%	2.470%	4.460%	8.000%	11.000%	14.000%	17.000%	20.000%
Three	0.495%	1.480%	2.470%	4.460%	8.000%	15.000%	20.000%	25.000%	30.000%
Four	0.495%	1.480%	2.470%	4.460%	8.000%	16.000%	24.000%	32.000%	40.000%

For 2007, the Compensation Committee decided that the calculation of the number of Buckets under the Bonus Plan would include only the Available Cash before Reserves generated by the businesses owned and operated by the Partnership prior to the acquisition of the Davison businesses and would not be adjusted for the equity issued in the Davison transaction or in December 2007. Additionally, the participants would include only the employees of the general partner in the operations we owned prior to the Davison transaction. For 2007, we achieved nine Buckets under the plan and paid total bonuses under the Bonus Plan of $2.1 million or approximately 19 percent of total eligible compensation. These bonuses were paid in March 2008.

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The Bonus Plan is designed to enhance our financial performance by rewarding employees for achieving financial performance objectives that are aligned with the interests of our unitholders. 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. The plan is designed so that six buckets generate a bonus equal to 10 percent of total base compensation if we generate sufficient Available Cash before Reserves and after bonus compensation to meet our targeted minimum quarterly distribution of $0.80 per unit on total units outstanding. The maximum of nine buckets is designed to limit the bonus to approximately 20 percent of total compensation and to limit the bonus to 40 percent of the compensation for the highest compensated Group Four, to which the Other Executives are assigned. 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.

The Compensation Committee is reviewing the Bonus Plan and expects to make changes to the plan that will affect the Other Executives. See additional discussion in "Compensation Changes in 2008" below.

Retention Plan. On August 29, 2006, the Board of Directors of our general partner also approved retention bonuses for the Other Executives and seven other management employees our general partner. Under this plan, those individuals in the plan received retention bonuses in amounts ranging from 20% to 35% of their base compensation levels as of August 29, 2006, if they were still employed on September 1, 2007. Additionally, the retention bonus paid in 2007 was included in the calculation of the bonus they received for 2007, under the terms of our Bonus Plan. These retention bonuses were designed to reward these individuals for their support in the transition of the new Senior Executive Management Team. Retention bonuses under this plan were paid to Mr. Benavides and Ms. Pape in the amounts of $68,250 and $52,500, respectively. The Retention Plan ceased to exist after payment of these retention bonuses in 2007.

Stock Appreciation Rights Plan. In December 2003, the Board approved a Stock Appreciation Rights plan or SAR plan. Under the terms of this plan, all 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 Compensation Committee of the Board, who shall determine, in its full discretion, the number of rights to award, the grant date of the rights and the formula for allocating rights to the participants and the strike price of the rights awarded.

Generally, each participant will receive an allocation of a number of rights equal to the authorized number of rights multiplied by a fraction, the numerator of which is such participant's maximum annual bonus under the Bonus Plan and the denominator of which is the total of the maximum annual bonuses for all such participants under the Bonus Plan. The Committee has discretion to adjust individual allocations.

In 2003, for the initial grant, we issued SARs equal to approximately 4.5 percent of our outstanding units. Since that time awards have been equal to approximately 1.125 percent of outstanding units (reduced by the number of units that would have been granted to the Senior Executives had they participated in the Plan). Grants of SARs were made to all personnel in February 2008 totaling 500,983 units. This grant included the personnel of the Davison entities, who received initial grants in 2008 totaling 387,512 SARs in individual allocations similar to what they would have received had they been employed in 2003, and 113,471 SARs to the personnel employed in the operations we owned prior to the Davison acquisition. The total SARs allocated to the employees of the legacy operations was approximately the same number of SARs awarded at the end of 2006   Mr. Benavides and Ms. Pape received grants at February 14, 2008 of 5,448 and 4,790 rights, respectively. The number of SARs allocated to these individuals was a product of the total 113,471 and the ratio of the maximum bonus for Mr. Benavides and Ms. Pape under the Bonus Plan to the total of the maximum bonuses for all employees who participated in the Bonus Plan in 2007.

The exercise price of the annual awards of rights has been the average of the closing market price of our units for the ten days prior to the date of the grant. This methodology has been used by the Committee for annual grants so that the exercise price is not unduly influenced by trading of our units on one particular date. The volume of units that trade each day is frequently very small, such that one small trade can occur and 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. This methodology is subject to change for any grant in the future

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Historically, our new employees receive SAR grants at the end of the quarter following their date of hire, with additional Awards to be granted each year as part of the annual review of compensation by our Compensation Committee. Beginning in 2008, employees involved in our trucking-related operations will no longer receive SAR grants. An employee's initial Award generally vests 25% per year over a period of four years, while annual Awards generally cliff vest 100% at four years from the grant date. The goal of our long-term incentive program for all employees is to provide each employee with awards that cliff vest each year. Additional details describing the operation of the SAR plan are included below.

We accrue for the fair value of our liability for the SARs we have issued to our employees and directors under the provisions of SFAS No. 123(R), Share-Based Payments, as amended and interpreted. These provisions require us to make estimates that affect the determination of the fair value of the outstanding stock appreciation rights, including estimates of the expected life of the rights, expected forfeiture rates of the rights, expected future volatility of our unit price and expected future distribution yield on our units. We base our estimates of these factors on historical experience and internal data. A summary of the assumptions used for the valuation at December 31, 2007 is included in Note 15 of the Notes to our Consolidated Financial Statements. The actual timing and amounts of payments to employees that will ultimately be made under the SAR plan will most likely differ from the estimates that are used in determining fair value. Since the value of our common units is affected more by actual cash distributions and Available Cash and expectations for growth of our business, which factors are not fully contemplated under the methodology of SFAS 123(R), our Committee does not consider the accounting method for the SAR plan in determining the amount of SARs to grant our employees and Other Executives.

Our entire long-term incentive compensation plan for the Other Executives and employees is made in the form of cash-based rather than equity-based compensation. All of our employees and directors other than the Senior Executives participate in the SAR plan. We are a partnership. We believe that the administration of issuing small numbers of partnership units to the entire employee population and the tax reporting by the employees of taxable income from a partnership make it excessively complex to administer an equity-based long-term incentive plan. Consequently, we currently do not have any equity based compensation plans for our Other Executives.

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

The 2007 LTIP provides a means to assist our general partner and its affiliates in retaining the services of employees and, possibly, our directors providing services to us, our general partner and its affiliates and provide incentives for them to devote their best efforts to our general partner and us;

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. Although the general partner has no current intent to make award of grants to our directors, the 2007 LTIP allows such grants to be made, which would become available if in the future our general partner determines that making such awards to directors is appropriate and in our best interests.

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For 2007, the Compensation Committee approved awards granting phantom units with a total value as of December 18, 2007 of $965,250 to seven employees of our general partner. Grants were made to Mr. Benavides and Ms. Pape with values in amounts of $225,000 (9,176 phantom units) and $200,000 (8,156 phantom units) respectively, or approximately 100 percent of their base salaries. The amounts awarded were entirely discretionary and were based on the recommendation of the CEO due in significant part to their performance prior to and increased responsibility resulting from the Davison acquisition.

Severance Benefits. We believe that companies should provide reasonable severance benefits to employees. With respect to 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.

As of November 26, 2007, Brad N. Graves, our former Executive Vice President of Business Development was no longer employed by us. The severance compensation paid to Mr. Graves consisted of a lump-sum payment of $2.1 million. Our general partner made a cash contribution of $1.4 million to us to be used to offset the cost of a portion of the severance payment to Mr. Graves.

Change of Control. 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. Our Senior Executives are not covered under the Severance Protection Plan, the 2007 LTIP or the Stock Appreciation Rights Plan. Change in control protection will be provided for them in their employment agreements and our general partner interest agreement when completed. See the Senior Executive section above.

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

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

The severance plan also provides that if our Other Executive Officers are subject to the "parachute payment" excise tax, 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.

Based upon a hypothetical termination date of December 31, 2007, the change of control termination benefits for our named executive officers (excluding Mr. Graves who is no longer employed by us, and the Senior Executives for whom the terms of their change in control benefits have not been completed) would have been as follows (based on the closing price for our units of $23.50 at that time):

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	Ross A. Benavides	Karen N. Pape
If termination date is between January 1, 2008 and December 30, 2008		
Severance plan payment	$ 966,177	$ 831,669
Healthcare and other insurance benefits	12,650	12,193
Fair market value of stock appreciation rights	344,668	264,503
Fair market value of phantom units	215,636	191,666
Total	$ 1,539,131	$ 1,300,031
If termination date is between December 31, 2008 and December 31, 2009		
Severance plan payment	$ 966,177	$ 831,669
Healthcare and other insurance benefits	12,650	12,193
Fair market value of stock appreciation rights	267,882	204,896
Fair market value of phantom units	215,636	191,666
Total	$ 1,462,345	$ 1,240,424

Other Benefits. 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. 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 $66,792 in 2007 for our Senior Executives and Other Executives.

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.

Board Process. During the fourth quarter of each year, management reviews the entire company’s compensation, based on recommendations from their subordinates, and makes a proposal to the Committee. Final review of this recommendation is made by the Committee at our normally-recurring December committee and board meetings, although depending on the magnitude of the anticipated changes, there may be several Committee meetings and discussions with management in advance of the December meeting. The Committee approves all compensation and long-term awards for all executive officers, considering the recommendation of the Chief Executive Officer with regard to compensation for the Other Executives. Our Committee also reviews and approves our overall compensation programs for all employees or any significant changes to these programs. This Committee is the administrator of all of our compensation plans (other than our 401(k) plan, health and other fringe benefit plans), including our Bonus Plan and Stock Appreciation Rights Plan under which all of our long-term equity awards are granted.   The Board of Directors reviews and ratifies the compensation package based on a recommendation from the Committee. Following approval of the entire compensation program, salary increases have been made during the first quarter of the following year, and bonuses are paid in early March of the following year, and the annual recurring

SAR awards are made effective on the last business day of December.

Compensation Changes for 2008. For 2008, the Compensation Committee and our Board of Directors may make significant changes to the compensation plans for us. After the Davison transaction, the Compensation Committee feels that we have a management team and an employee base that are much larger and are more diversified in terms of skill sets and opportunities to contribute to meeting our objectives. Based on this diversified work force, the Compensation Committee intends to address the overall compensation plans during 2008 to determine the extent to which the plans should be tailored to the different employee bases in each business segment or components of each business segment.

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In December 2007, the Compensation Committee discussed making changes to the Bonus Plan that will give the Other Executives the opportunity to earn bonuses up to 100% of their individual base salaries. The focus in the new bonus plan is expected to be more on individual contribution and performance than the current bonus plan. Further discussion of the restructuring of the plan will occur in 2008.

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 recommended to the Board, and the Board has approved, that the Compensation Discussion and Analysis be included in this Form 10-K.

This report is submitted by the Compensation Committee.

Gareth Roberts (Chairman)
Susan O. Rheney

Executive Compensation
Summary Compensation Table

The following table summarizes certain information regarding the compensation paid or accrued by Genesis during 2007 to those persons who served as chief executive officer and chief financial officer, and the other two executive officers at the end of 2007, and a former executive officer whose compensation exceeded the compensation of the other two executive officers in 2007 (the "Named Executive Officers").

2007 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 Chief Executive Officer (Principal Executive	2007	$ 310,000	-	-	-	-	1,838,476	$ 2,148,476
Officer)	2006	$ 112,077	-	-	-	-	56	$ 112,133
Ross A. Benavides	2007	$ 211,000	$ 68,250	$ 2,511	$ 100,448	$ 111,581	$ 16,680	$ 510,470
Chief Financial Officer and	2006	$ 195,000	-	-	$ 101,231	$ 78,000	$ 16,668	$ 390,899

General Counsel (Principal Financial Officer)								
Joseph A., Blount, Jr.	2007	$ 270,000	-	-	-	-	$ 1,618,984	$ 1,888,984
President & Chief Operating Officer	2006	$ 97,615	-	-	-	-	$ 4,449	$ 102,064
Karen N. Pape Senior Vice President & Controller (Principal Accounting Officer)	2007	$ 184,000	$ 52,500	$ 2,232	$ 77,139	$ 94,577	$ 16,680	$ 427,128
	2006	$ 150,000	-	-	$ 77,430	$ 60,000	$ 15,032	$ 302,462
Brad N. Graves Former Executive Vice President, Business Development	2007	$ 218,000	-	-	-	-	$ 2,109,972	$ 2,327,972
	2006	$ 83,154	-	-	-	-	$ 1,871	$ 85,025

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(1) Amounts in this column represent the amount that was paid as a retention bonus in September 2007.

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

(3) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for in each period under the provisions of SFAS 123(R) for awards under our Stock Appreciation Rights plan. The forfeiture rate that was applied to these amounts at December 31, 2007 and 2006 was 10%.

(4) Amounts in this column represent the amount that will be paid to the Named Executive Officer as an award under our Bonus Plan. In each case with an amount shown, the amount is equal to 40% of the sum of the Named Executive Officer's annual salary and the retention bonus paid to that officer in September 2007. Mr. Sims and Mr. Blount do not participate in the Bonus Plan.

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

	Year	401(k) Matching Contributions (a)	401(k) Profit-Sharing Contributions (b)	Insurance Premiums (c)	Severance Payment (d)	Other Compensation (e)
Grant E. Sims	2007	$ -	$ 6,600	$ 180	$ -	$ 1,831,696
	2006	$ -	$ -	$ 56	$ -	$ -
Ross A. Benavides	2007	$ 9,900	$ 6,600	$ 180	$ -	$ -
	2006	$ 9,900	$ 6,600	$ 168	$ -	$ -
Joseph A. Blount, Jr.	2007	$ 9,900	$ 6,600	$ 180	$ -	$ 1,602,304
	2006	$ 4,393	$ -	$ 56	$ -	$ -
Karen N. Pape	2007	$ 9,900	$ 6,600	$ 180	$ -	$ -
	2006	$ 8,264	$ 6,600	$ 168	$ -	$ -
Brad N. Graves	2007	$ 9,792	$ -	$ 180	$ 2,100,000	$ -
	2006	$ 1,815	$ -	$ 56	$ -	$ -

Amounts in this table represent:

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

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

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

(d) Severance paid to Mr. Graves when he ceased to be employed by us. While the expense for this severance was recognized by us, Denbury contributed $1.4 million to its general partner capital account for a portion of the cash cost.

(e) Represents an amount for the estimated value of the compensation earned in 2007 under the proposed arrangements in the General Partner Incentive Interests discussion above. While the General Partner Incentive Interests may ultimately qualify as an equity award under SFAS 123(R), there is no mutual understanding of the terms of the award at December 31, 2007; therefore an amount could not be calculated in accordance with the provisions of SFAS 123(R). The expense recorded for this arrangement was an amount agreed to by the parties as a fair representation of the value provided and earned in 2007. As the purpose of the General Partner Incentive Interests 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.

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Long Term Incentive Plan

As discussed in the Compensation Discussion and Analysis, our unitholders approved the Genesis Energy, Inc. 2007 Long Term Incentive Plan on December 18, 2007 which provides for awards of Phantom Units and Distribution Equivalent Rights to non-employee directors and employees of Genesis Energy, Inc., 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 Compensation 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 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 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 Compensation Committee.

Stock Appreciation Rights Plan

As discussed in the Compensation Discussion and Analysis, we have a Stock Appreciation Rights plan or SAR for all employees, with the exception of our new senior management team. Under the terms of this plan, all regular, full-time active employees and the members of the Board are eligible to participate in the plan. The plan is administered by the Compensation Committee, who shall determine, in its full discretion, 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. The initial award to a participant will vest one-fourth each year beginning with the first anniversary of the grant date of the award. Subsequent awards to participants will vest on the fourth anniversary of the grant date. 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 Plan

As discussed in the Compensation Disclosure and Analysis, we have a Bonus Plan for all employees of our general partner, with the exception of our new senior management team. This non-equity incentive plan provides for our Other Executives to receive bonuses ranging from zero to forty percent based on our achieving certain levels of Available Cash before Reserves and bonus expense. The table below shows the minimum and maximum amounts that each of the Executive Officers named in the table could have achieved for 2007. The maximum amounts were achieved and paid to the individuals in March 2008.

The following tables show the phantom units and non-equity incentive plan awards granted to the other Executive Officers for 2007 and the outstanding SARs and phantom units awards at December 31, 2007 that were issued to our other Executive Officers. Information on rights granted to non-employee directors is included in the section entitled Director Compensation. These tables do not include the awards made to Mr. Benavides and Ms. Pape in February 2008 of 5,448 and 4,790 stock appreciation rights, respectively, at a strike price of $20.92 per unit.

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Grants of Plan-Based Awards in Fiscal Year 2007

Name	Grant Date	Board Approval Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Threshold $	Maximum $	All Other Stock Awards: Number of Shares of Stock or Units (#) (2)	Grant Date Fair Value of Stock and Option Awards (3)
Ross A. Benavides	12/18/2007	12/18/2007			9,176	$ 196,733
		5/27/2003	$ 0	$ 111,581		
Karen N. Pape	12/18/2007	12/18/2007			8,156	$ 174,865
		5/27/2003	$ 0	$ 94,577		

(1) Under the terms of our Bonus Plan, the Executive Officers named in this table were eligible to receive cash bonus awards in an amount that ranged from no award to the amounts shown as the Maximum, which represent 40% of the sum of their base salary and the retention bonus they were paid in September 2007. The amount of the award is based on the amount of Available Cash before bonus expense generated by us for the year. Each of these Executive Officers received the maximum award for 2007.

(2) The amounts in this column represent the phantom units granted to the named Executive Officer during 2007.

(3) The amounts in this column represent the fair value of the award on the date of the grant, December 18, 2007, as calculated in accordance with the provisions of SFAS 123(R).

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Oustanding Equity Awards at 2007 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 ($)	Stock Appreciation Rights Expiration Date	Number of Units of Phantom Units That Have Not Vested (#) (2)	Market Value of Phantom Units That Have Not Vested ($)
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		
					9,176	$ 215,636
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		
					8,156	$ 191,666

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

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

Director Compensation

The table below reflects compensation for the directors. Mr. Goodman resigned as a director of Genesis in December 2007. Directors who are employees of our general partner, like Mr. Sims, do not receive compensation for service as a director. During 2007, compensation for the three independent directors consisted of an annual fee of $40,000. The Audit Committee Chairman received an additional annual fee of $4,000. We paid Denbury fees totaling $120,000 for providing four of its executives as directors of Genesis. Additionally, non-employee directors received a fee for attendance at meetings of $2,000 for each meeting attended in person and $1,000 for meetings attended telephonically. This fee was applicable to meetings of the Board of Directors 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 $30,000 were paid to Denbury.

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Director Compensation in Fiscal 2007

Name	Fees Earned or Paid in Cash ($)(1)
Mark C. Allen (2)	$ 40,000
James E. Davison	$ 24,000
James E. Davison, Jr.	$ 24,000
Ronald T. Evans (2)	$ 38,000
Herbert I. Goodman (3)	$ 57,000
Susan O. Rheney	$ 57,000
Gareth Roberts (2)	$ 34,000
Phil Rykhoek (2)	$ 38,000
J. Conley Stone	$ 54,000

(1) Amounts include annual retainer fees and fees for attending meetings.
(2) Fees were paid in cash for these directors to Denbury.
(3) Mr. Goodman resigned as a director of our general partner in December 2007.

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

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Oustanding Equity Awards at 2007 Fiscal Year-End to Directors

	Stock Appreciation Rights				
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
Mark C. Allen (1)	644	1,932	$	15.77	9/29/2016
	-	1,000	$	19.57	12/29/2016
Ronald T. Evans (2)	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
Herbert I. Goodman (3)	3,092	-	$	9.26	12/12/2008
	735	-	$	12.48	12/12/2008
	781	-	$	11.17	12/12/2008
	1,000	-	$	19.57	12/12/2008
Susan O. Rheney (2)	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
Gareth Roberts (2)	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
Phil Rykhoek (4)	1,932	644	$	11.00	8/25/2014
	-	612	$	12.48	12/31/2014
	-	651	$	11.17	12/31/2015
	-	1,000	$	19.57	12/29/2016
J. Conley Stone (2) (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)

Mr. Allen's first award will vest one-fourth annually beginning September 29, 2007 through September 29, 2010. Mr. Allen's second award will vest on January 1, 2011.

(2) The unexercisable rights of this director vest on the following dates in the order they are listed: January 1, 2009, January 1, 2010 and January 1, 2011.

(3) Mr. Goodman qualified under the provisions of the SAR Plan for retirement; therefore upon his resignation from the Board of our general partner, he is vested in all outstanding awards. He has until December 12, 2008 to exercise these awards.

(4) The unexercisable portion of Mr. Rykhoek's first award will vest 644 rights on August 25, 2008. Mr. Rykhoek's remaining awards will vest on January 1, 2009, January 1, 2010 and January 1, 2011.

(5) Mr. Stone exercised 2,319 rights in 2007 and received $57,836 in value upon exercise.

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Compensation Committee Interlocks and Insider Participation

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

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

Securities Authorized for Issuance Under Equity Compensation Plans

See Item 5 – Equity Compensation Plans.

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 29, 2008, 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.

		Beneficial Ownership of Common Units	
Title of Class	Name and Address of Beneficial Owner	Number of Units	Percent of Class
Genesis Energy, L.P.	Genesis Energy, Inc.	2,829,055	7.4
Common Units	Gareth Roberts	10,000	*
	Grant E. Sims (1)	1,000	*
	James E. Davison (2)	1,434,416	3.7
	James E. Davison, Jr. (3)	3,728,217	9.7
	Ronald T. Evans	11,000	*
	Susan O. Rheney	700	*
	Phil Rykhoek	5,000	*
	J. Conley Stone	2,000	*
	Ross A. Benavides (4)	18,459	*
	Karen N. Pape (5)	11,542	*
	All directors and executive officers as a group (12 in total)	5,222,334	13.7
	Davison Petroleum Products, LLC (6) (7) (8)	9,225,618	24.1
	Fargo Transport, Inc. (6) (8) (9)	1,565,690	4.1
	Davison Terminal Service, Inc. (6) (10)	1,010,835	2.6
	Sunshine Oil and Storage, Inc. (6) (10)	423,581	1.1
	Transport Company (6) (8)	393,345	1.0
	Swank Capital, LLC, Swank Energy Income Advisors, L.P. and Mr. Jerry V. Swank (11)	3,627,906	9.5

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(1) Common units are held by Mr. Sims' father. Mr. Sims disclaims beneficial ownership of these units.

(2) James E. Davison is the sole stockholder of Davison Terminal Service, Inc. and Sunshine Oil and Storage, Inc., which directly own 1,010,835 and 423,581 units, respectively.

(3) James E. Davison, Jr. is a one-third equity holder in Davison Petroleum Products, L.L.C., Fargo Transport, Inc. (formerly known as Davison Transport, Inc.), and Transport Company, Inc. These entities own 9,225,618, 1,565,690 and 393,345 units, respectively. We have been granted a lien on certain of these units as discussed in footnote 7 below.

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

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

(6) The address for this entity is PO Box 607, Ruston, Louisiana 71273.

(7) We have been granted a lien on 5,383,684 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 equally by James E. Davison, Jr., Todd A. Davison and Steven K. Davison, all of whom are sons of James E. Davison.

(9) This entity was formerly known as Davison Transport, Inc.

(10) This entity is owned by James E. Davison.

(11) Information based on Schedule 13G filed with the SEC on February 14, 2008. 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.

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, Inc. and all officers and directors is 500 Dallas, Suite 2500, Houston, Texas, 77002.

Beneficial Ownership of General Partner Interest

Genesis Energy, Inc. owns all of our 2% general partner interest and all of our incentive distribution rights, in addition to 7.4% of our units. Genesis Energy, Inc. is a wholly-owned subsidiary of Denbury. Denbury has advised us that it has not pledged any of its interest in our general partner under any agreements or arrangements.

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

Our General Partner

Our operations are managed by, and our employees are employed by, Genesis Energy, Inc., our general partner. Our general partner does not receive any management fee or other compensation in connection with the management of our business, but is reimbursed for all direct and indirect expenses incurred on our behalf. During 2007, these reimbursements totaled $22.5 million. As of December 31, 2007, we owed our general partner $0.7 million related to these services.

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

Our general partner also owns 2,829,055 limited partner units and has the same rights and is entitled to receive distributions as the other limited partners with respect to those units. Our general partner acquired 1,074,882 of these units in July 2007 for $20.8036 per unit and 734,732 of these units in December 2007 for $21.12 per unit under its preferential right to maintain its 7.4% interest in our common units.

During 2007, our general partner received a total of $1.7 million from us as distributions, with $1.2 million attributable to its limited partner units, $0.4 million for its general partner interest, and $0.1 million related to its incentive distribution rights.

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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 have instituted specific procedures for evaluating and valuing our material transactions with Denbury and its subsidiaries. Before we consider entering into a transaction with Denbury or any of its subsidiaries, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, (3) would comply with our partnership agreement, and (4) would be fair to us and our limited partners. In addition, our general partner's board of directors seeks "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 acquisition or disposition with Denbury only when we have evaluated the transaction, our Audit Committee has approved and recommended the transaction and our general partner's full board has approved the transaction, however, such approvals are not required under our partnership agreement.

During 2005, 2004 and 2003, we acquired CO2 volumetric production payments and related wholesale marketing contracts from Denbury for $14.4 million, $4.7 million and $24.4 million, respectively. Additionally we enter into transactions with Denbury in the ordinary course of our operations. During 2007, these transactions included:

- Purchases of crude oil from Denbury totaling $0.1 million.
- Provision of transportation services for crude oil by truck totaling $1.8 million.
- Provision of crude oil pipeline transportation services totaling $5.3 million.
- Provision of crude oil from and CO2 transportation to the Brookhaven field and crude oil from the Olive field for $1.2 million.
- Provision of CO2 transportation services to our wholesale industrial customers by Denbury's pipeline. The fees for this service totaled $5.2 million in 2007.
- Provision of pipeline monitoring services to Denbury for its CO2 pipelines totaling $120,000 in 2007.
- Provision of services by Denbury officers as directors of our general partner. We paid Denbury $150,000 for these services in 2007.

At December 31, 2007, we owed Denbury $1.0 million for provision of CO2 transportation services. Denbury owed us $0.9 million for crude oil trucking and pipeline transportation services.

We have reached substantial agreement and are in the process of finalizing the business issues with Denbury and the lenders in our credit facility as to the terms of the drop-down by Denbury to us and the terms of a long-term transportation service arrangement for the Free State line and a 20-year financing lease for the NEJD system. We expect to pay for these pipeline assets with $225 million in cash and $25 million of our common units based on the average closing price of our units for the thirty trading days prior to the closing of the transaction. We expect to receive approximately $30 million per annum, in the aggregate, under the lease and the transportation services agreement (and a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State pipeline dependant on the volumes of CO2 transported therein. While the business terms of the transactions and associated documentation have been substantially completed, closing remains subject to completion of closing documentation, receipt of a fairness opinion and approval by the audit committee and the board of directors of our general partner.

In 2002, we amended our partnership agreement to broaden the right of the common unitholders to remove our general partner. Prior to this amendment, our general partner could only be removed for cause and with approval by holders of two-thirds or more of the outstanding limited partner interests in us. As amended, the 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.

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The amendment further provides that if it is proposed that the removal is without cause and an affiliate of Denbury is our general partner to be removed and not proposed as a successor, then any action for removal must also provide for Denbury to be granted an option effective upon its removal to purchase our Mississippi pipeline system at a price that is 110 percent of its fair market value at that time. Denbury also has the right to purchase the Mississippi CO2 pipeline to Brookhaven field at its fair market value at that time. Fair value is to be determined by agreement of two independent appraisers, one chosen by the successor general partner and the other by Denbury or if they are unable to agree, the mid-point of the values determined by them.

Relationship with Davison family

From July 25, 2007 through December 31, 2007, the Davison family provided certain transition services to us related to the payroll for persons who provide services to us. These persons became employees of our general partner on January 1, 2008; however, to create the least disruption for employees while we evaluated benefit plan arrangements, the personnel in our Supply and Logistics operations acquired from Davison were paid by entities owned by the Davison family and we reimbursed them for all direct costs.

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, 2007 was approximately $16,000.

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

These rights include the following provisions:

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

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

Pursuant to a unitholder agreement between the Davison unitholders and us, executed on July 25, 2007, the Davison unitholders have the right to designate up to two directors to our board of directors, depending on their continued level of ownership in us. Until July 25, 2010, the Davison unitholders have the right to designate two directors to our board of directors. Thereafter, the Davison unitholders will have the right to designate (i) one director if they beneficially own at least 10% but less than 35% of our outstanding common units, or (ii) two directors if they beneficially own 35% or more of our outstanding common units. If their percentage ownership in our common units drops below 10% after July 25, 2010, the Davison unitholders would have no rights to designate directors. At December 31, 2007, the Davison unitholders held approximately 33% of our outstanding common units.

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

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

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Director Independence

Susan O. Rheney and J. Conley Stone, both members of our Audit Committee, meet the listing standard requirements of AMEX, and the SEC rules to be considered independent directors of Genesis. 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.

On January 3, 2008, we received a letter from AMEX informing us that we are currently not in compliance with Rule 121(B)(2)(a) of the AMEX Company Guide, which requires our Audit Committee to consist of at least three independent directors. Our Audit Committee membership decreased to two directors upon Herbert I. Goodman’s resignation from the Board of Directors of our general partner, on December 12, 2007. The letter from AMEX is a “warning letter” and provides us until April 2, 2008 to regain compliance with the Amex requirements by appointing an additional independent director to serve on the Audit Committee. We have commenced a search for a qualified individual to fill our Audit Committee vacancy and expect to fill the vacancy before April 2, 2008.

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, 2007 and 2006.

	2007	2006
	(in thousands)	
Audit Fees (1)	$ 3,107	$ 632
Audit-Related Fees (2)	1,945	25
Tax Fees (3)	165	88
All Other Fees (4)	2	1
Total	$ 5,219	$ 746

(1) Includes fees for the annual audit and quarterly reviews, SEC registration statements, accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles and the audit of the effectiveness of our internal controls over financial reporting.
(2) Includes fees for audits of acquired businesses and the audit of our employee benefit plan.
(3) Includes fees for tax return preparation and tax consultations.
(4) Includes fees associated with a license for accounting research software.

Pre-Approval Policy

The services by Deloitte in 2007 and 2006 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 2007 and 2006, 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.

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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 93.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements and Financial Statement Schedules" set forth on page 93.

(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
	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 Incorporation of Genesis Energy, Inc.
*	3.7	Certificate of Amendment of Certificate of Incorporation of Genesis Energy, Inc.
*	3.8	Bylaws of Genesis Energy, Inc.
*	4.1	Form of Unit Certificate of Genesis Energy, L.P.
	10.1	Purchase & Sale and Contribution & Conveyance Agreement dated December 3, 1996 among Basis Petroleum, Inc., Howell Corporation ("Howell"), certain subsidiaries of Howell, Genesis, the Operating Partnership and Genesis Energy, L.L.C. (incorporated by reference to Exhibit 10.1 to Form 10-K for the year ended December 31, 1996)
	10.2	First Amendment to Purchase & Sale and Contribution and Conveyance Agreement (incorporated by reference to Exhibit 10.2 to Form 10-K for the year ended December 31, 1996)
	10.3	Credit Agreement dated as of November 15, 2006 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 10.1 to Form 8-K dated November 15, 2006)
	10.4	

		First Amendment to Credit Agreement and Guarantee and Collateral Agreement dated as of July 25, 2007 among Genesis Crude Oil, L.P., Genesis Energy, L.P. and the Lenders, Issuing Banks and Guarantors (incorporated by reference to Exhibit 10.6 to Form 8-K dated July 31, 2007)
10.5	+	Letter dated August 3, 2006 to Grant E. Sims regarding Offer to Enter into Employment Agreements (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarterly period ended September 30, 2006)
10.6		Pipeline Sale and Purchase Agreement between TEPPCO Crude Pipeline, L.P. and Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K dated October 31, 2003)

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	10.7		Purchase and Sale Agreement between TEPPCO Crude Pipeline, L.P. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K dated October 31, 2003)
	10.8		Production Payment Purchase and Sale Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.7 to Form 10-K for the year ended December 31, 2003)
	10.9		Carbon Dioxide Transportation Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.8 to Form 10-K for the year ended December 31, 2003)
	10.10	+	Genesis Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.9 to Form 10-K for the year ended December 31, 2004)
	10.11	+	Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.10 to Form 10-K for the year ended December 31, 2004)
	10.12	+	Summary of Genesis Energy, Inc. Bonus Plan (incorporated by reference to Exhibit 10.12 to Form 10-K for the year ended December 31, 2006)
	10.13	+	Genesis Energy Amended and Restated Severance Protection Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2006)
	10.14		Second Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed August 26, 2004 (incorporated by reference to Exhibit 99.1 to Form 8-K dated August 26, 2004)
	10.15		Second Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.2 to Form 8-K dated August 24, 2004)
	10.16		Third Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed October 11, 2005 (incorporated by reference to Exhibit 99.2 to Form 8-K dated October 11, 2005)
	10.17		Third Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.3 to Form 8-K dated October 11, 2005)
	10.18		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)
	10.19		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)
	10.20		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)
*	10.21		Amendment No. 3 to the Contribution and Sale Agreement dated March 3, 2008

10.22	Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K dated July 31, 2007)
10.23	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)
10.24	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)

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	10.25		Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to Form 8-K dated July 31, 2007)
	10.26		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)
	10.27		Pledge and Security Agreement (incorporated by reference to Exhibit 10.5 to Form 8-K dated July 31, 2007)
	10.28	+	Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 21, 2007)
	10.29	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Graded) (incorporated by reference to Exhibit 10.2 to Form 8-K dated December 21, 2007)
	10.30	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Cliff) (incorporated by reference to Exhibit 10.3 to Form 8-K dated December 21, 2007)
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 11 to the Consolidated Financial Statements
*	21.1		Subsidiaries of the Registrant
*	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, INC.,
as General Partner

Date: March 17, 2008

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, INC.)*	DATE
/s/	Grant E. Sims Grant E. Sims	Director and Chief Executive Officer (Principal Executive Officer	March 17, 2008
/s/	Ross A. Benavides Ross A. Benavides	Chief Financial Officer, General Counsel and Secretary (Principal Financial Officer)	March 17, 2008
/s/	Karen N. Pape Karen N. Pape	Vice President and Controller (Principal Accounting Officer)	March 17, 2008
/s/	Gareth Roberts Gareth Roberts	Chairman of the Board and Director	March 17, 2008
/s/	Mark C. Allen Mark C. Allen	Director	March 17, 2008
/s/	James E. Davison James E. Davison	Director	March 17, 2008
/s/	James E. Davison, Jr. James E. Davison, Jr.	Director	March 17, 2008
/s/	Ronald T. Evans Ronald T. Evans	Director	March 17, 2008
/s/	Susan O. Rheney	Director	March 17, 2008

	Susan O. Rheney		
/s/	Phil Rykhoek Phil Rykhoek	Director	March 17, 2008
/s/	J. Conley Stone J. Conley Stone	Director	March 17, 2008

*Genesis Energy, Inc. 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 are not required under the relevant instructions or are inapplicable and therefore have been omitted.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, Inc. 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, 2007 and 2006, and the related consolidated statements of operations, partners' capital, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Genesis Energy, L.P. and subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As described in Note 2 to the consolidated financial statements and effective as of January 1, 2006, the Partnership adopted Statement of Financial Accounting Standards (“SFAS”) No. 123R, which established new accounting and reporting standards for share-based compensation. Additionally, as described in Note 5 to the consolidated financial statements and effective as of December 15, 2005, the Partnership adopted FASB Interpretation 47, which established new accounting and reporting standards for asset retirement obligations.

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, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2008 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Houston, Texas
March 14, 2008

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

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 11,851	$ 2,318
Accounts receivable - trade	178,658	88,006
Accounts receivable - related party	1,441	1,100
Inventories	15,988	5,172
Net investment in direct financing leases, net of unearned income - current portion - related party	609	568
Other	5,693	2,828
Total current assets	214,240	99,992
FIXED ASSETS, at cost	150,413	70,382
Less: Accumulated depreciation	(48,413)	(39,066)
Net fixed assets	102,000	31,316
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	4,764	5,373
CO2 ASSETS, net of amortization	28,916	33,404
JOINT VENTURES AND OTHER INVESTMENTS	18,448	18,226
INTANGIBLE ASSETS, net of amortization	211,050	-
GOODWILL	320,708	-
OTHER ASSETS, net of amortization	8,397	2,776
TOTAL ASSETS	$ 908,523	$ 191,087
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 154,614	$ 85,063
Accounts payable - related party	2,647	1,629
Accrued liabilities	17,537	9,220
Total current liabilities	174,798	95,912
LONG-TERM DEBT	80,000	8,000
DEFERRED TAX LIABILITIES	20,087	-
OTHER LONG-TERM LIABILITIES	1,264	991
MINORITY INTERESTS	570	522
COMMITMENTS AND CONTINGENCIES (Note 18)		
PARTNERS' CAPITAL:		
Common unitholders, 38,253 and 13,784 units issued and outstanding at December 31, 2007 and 2006, respectively	615,265	83,884
General partner	16,539	1,778

Total partners' capital		631,804		85,662
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	908,523	$	191,087

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,		
	2007	2006	2005
REVENUES:			
Supply and logistics:			
Unrelated parties (including revenues from buy/sell arrangements of $69,772 and $365,067 in 2006 and 2005, respectively)	$ 1,092,398	$ 872,443	$ 1,037,577
Related parties	1,791	825	972
Refinery services	62,095	-	-
Pipeline transportation, including natural gas sales:			
Transportation services - unrelated parties	17,153	17,119	14,760
Transportation services - related parties	5,754	4,948	4,591
Natural gas sales revenues	4,304	7,880	9,537
CO2 marketing:			
Unrelated parties	13,376	13,098	11,302
Related parties	2,782	2,056	-
Total revenues	1,199,653	918,369	1,078,739
COSTS AND EXPENSES:			
Supply and logistics costs:			
Product costs - unrelated parties (including costs from buy/sell arrangements of $68,899 and $363,208 in 2006 and 2005, respectively)	1,041,637	850,106	1,014,249
Product costs - related parties	101	1,565	4,647
Operating costs	37,121	14,231	15,992
Refinery services operating costs	40,197	-	-
Pipeline transportation costs:			
Pipeline transportation operating costs	10,054	9,928	9,741
Natural gas purchases	4,122	7,593	9,343
CO2 marketing costs:			
Transportation costs - related party	5,213	4,640	3,501
Other costs	152	202	148
General and administrative	25,920	13,573	9,656
Depreciation and amortization	38,747	7,963	6,721
Net loss (gain) on disposal of surplus assets	266	(16)	(479)
Impairment expense	1,498	-	-
Total costs and expenses	1,205,028	909,785	1,073,519
OPERATING (LOSS) INCOME	(5,375)	8,584	5,220
Equity in earnings of joint ventures	1,270	1,131	501
Interest income	385	198	71
Interest expense	(10,485)	(1,572)	(2,103)
(Loss) income from continuing operations before income taxes and minority interest	(14,205)	8,341	3,689
Income tax benefit	654	11	-
Minority interest	1	(1)	-
(LOSS) INCOME FROM CONTINUING OPERATIONS	(13,550)	8,351	3,689
Income from discontinued operations	-	-	312
Cumulative effect adjustment of adoption of new accounting principles	-	30	(586)

NET (LOSS) INCOME	$ (13,550)	$ 8,381	$ 3,415

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

	Year Ended December 31, 2007	2006	2005
NET (LOSS) INCOME PER COMMON UNIT - BASIC AND DILUTED:			
(Loss) income from continuing operations	$ (0.64)	$ 0.59	$ 0.38
Income from discontinued operations	-	-	0.03
Cumulative effect adjustment	-	-	(0.06)
NET (LOSS) INCOME	$ (0.64)	$ 0.59	$ 0.35
Weighted average number of common units outstanding - basic	20,754	13,784	9,547

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

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

		Partners' Capital		
	Number of Common Units	Common Unitholders	General Partner	Total
Partners' capital, January 1, 2005	9,314	$ 44,326	$ 913	$ 45,239
Net income	-	3,347	68	3,415
Cash distributions	-	(5,682)	(116)	(5,798)
Issuance of units	4,470	43,879	954	44,833
Partners' capital, December 31, 2005	13,784	85,870	1,819	87,689
Net income	-	8,214	167	8,381
Cash distributions	-	(10,200)	(208)	(10,408)
Partners' capital, December 31, 2006	13,784	83,884	1,778	85,662
Net loss	-	(13,279)	(271)	(13,550)
Cash contributions	-	-	1,412	1,412
Contribution for management compensation (Note 11)	-	-	3,434	3,434
Cash distributions	-	(16,743)	(432)	(17,175)
Issuance of units	24,469	561,403	10,618	572,021
Partners' capital, December 31, 2007	38,253	$ 615,265	$ 16,539	$ 631,804

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, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$ (13,550)	$ 8,381	$ 3,415
Adjustments to reconcile net (loss) income to net cash provided by operating activities -			
Depreciation, amortization and impairment	35,757	3,719	3,579
Amortization of CO2 contracts	4,488	4,244	3,142
Amortization and write-off of credit facility issuance costs	779	969	373
Amortization of unearned income on direct financing leases	(620)	(655)	(689)
Deferred tax benefit	(2,658)	(11)	-
Payments received under direct financing leases	1,188	1,186	1,185
Equity in earnings of investments in joint ventures	(1,270)	(1,131)	(501)
Distributions from joint ventures - return on investment	1,845	1,565	435
Loss (gain) on disposal of assets	266	(16)	(791)
Cumulative effect adjustment	-	(30)	586
Non-cash effect of stock appreciation rights plan	910	1,929	(481)
Non-cash compensation charge	3,434	-	-
Other non-cash charges (credits)	80	(15)	427
Changes in components of operating assets and liabilities, net of working capital acquired -			
Accounts receivable	(35,362)	(6,472)	(13,313)
Inventories	(143)	(4,664)	790
Other current assets	(1,887)	870	132
Accounts payable	34,523	1,359	10,431
Accrued liabilities and taxes payable	6,149	34	770
Net cash provided by operating activities	33,929	11,262	9,490
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed assets	(8,235)	(1,260)	(6,106)
Distributions from joint ventures - return of investment	395	528	388
Investments in joint ventures and other investments	(1,104)	(6,042)	(13,418)
Acquisition of Davison assets, net of cash acquired	(301,640)	-	-
Acquisition of Port Hudson assets	(8,103)	-	-
CO2 contracts acquisition	-	-	(14,446)
Other, net	(2,655)	(68)	1,773
Net cash used in investing activities	(321,342)	(6,842)	(31,809)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Bank borrowings	392,200	8,000	-
Bank repayments	(320,200)	-	(15,300)
Credit facility issuance fees	(2,297)	(2,726)	-
Issuance of common units for cash	231,433	-	44,833
General partner contributions	12,030	-	-
Minority interest contributions, net of distributions	49	(1)	5
Other, net	906	(66)	(400)

Distributions to common unitholders	(16,743)	(10,200)	(5,682)
Distributions to general partner	(432)	(208)	(116)
Net cash provided by (used in) financing activities	296,946	(5,201)	23,340
Net (decrease) increase in cash and cash equivalents	9,533	(781)	1,021
Cash and cash equivalents at beginning of period	2,318	3,099	2,078
Cash and cash equivalents at end of period	$ 11,851	$ 2,318	$ 3,099

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 publicly traded Delaware limited partnership formed in December 1996. Our operations are conducted through our operating subsidiary, Genesis Crude Oil, L.P., and its subsidiary partnerships and corporations. We are engaged in pipeline transportation of crude oil, and, to a lesser degree, natural gas and carbon dioxide, or CO2, crude oil gathering and marketing, and we engage in industrial gas activities, including wholesale marketing of CO2 and processing of syngas through a joint venture. Our assets are located in the United States Gulf Coast area.

Our 2% general partner interest is held by Genesis Energy, Inc., a Delaware corporation and indirect wholly-owned subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner also owns 7.4% of our common units.

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

2. Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2007 and 2006 and our results of operations, cash flows and changes in partners' capital for the years ended December 31, 2007, 2006 and 2005. All intercompany transactions have been eliminated. The accompanying consolidated financial statements include Genesis Energy, L.P., its operating subsidiary and its subsidiary partnerships. Our general partner owns a 0.01% general partner interest in Genesis Crude Oil, L.P., which is reflected in our financial statements as a minority interest.

In July 2007, we acquired the energy-related businesses of the Davison family. The results of the operations of these businesses have been included in the consolidated financial statements of Genesis Energy, L.P. since August 1, 2007.

In 2005, we acquired a 50% interest in T&P Syngas Supply Company. In 2006, we acquired a 50% interest in Sandhill Group, LLC. These investments are accounted for by the equity method, as we exercise significant influence over their operating and financial policies. See Note 8.

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, (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 our outstanding stock appreciation rights and awards under our long-term incentive plan, 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. Cash and cash equivalents are stated at cost which approximates market value.

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

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 which approximates first-in, first-out.

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, 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

In general, our future asset retirement obligations relate to future costs associated with the removal of our oil, natural gas and CO_2 pipelines, 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.

Direct Financing Leasing Arrangements

We lease three pipelines to Denbury under direct financing leases. These leases to Denbury of pipeline segments will expire in eight to ten years.

When a direct financing lease is consummated, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in pipeline revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets. See Note 6.

CO2 Assets

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

Intangible Assets

Statement of Financial Accounting Standards No. 142, “Goodwill and Other Intangible Assets,” (SFAS 142) requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are recording amortization of our customer and supplier relationships, licensing agreements and trade name based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The favorable lease and other intangible assets are being amortized on a straight-line basis.

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

We test intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2007, no impairment has occurred of intangible assets.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We account for goodwill under SFAS 142, which prohibits amortization of goodwill, but instead requires testing for impairment at least annually. We test goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. In the event that we determine that goodwill has become impaired, we will incur a charge for the amount of impairment during the period in which the determination is made.

Other Assets

Other assets consist primarily of deferred credit facility fees, deferred charges, and deposits. We are amortizing the deferred credit facility fees over the period the facility is in effect.

Deferred charges consist of third-party costs related to projects or planned acquisitions in the preliminary stages. We review these deferred charges at each reporting date and charge costs related to projects that have been cancelled or abandoned to expense.

Environmental Liabilities

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

Unit-Based Compensation

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

At a special meeting of our unitholders on December 18, 2007, our unitholders approved the 2007 Long-term Incentive Plan, which provides for awards of phantom units to our non-employee directors and to the employees of our general partner. SFAS No. 123(R) requires that compensation cost related to phantom units issued under our 2007 Long-term Incentive Plan be recognized in our consolidated financial statements based on estimated fair value at the date of the grant. See Note 15.

Revenue Recognition

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

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

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

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

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

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

Cost of Sales and Operating Expenses

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

When we enter into buy/sell arrangements concurrently or in contemplation of one another with a single counterparty, we reflect the amounts of revenues and purchases for these transactions as a net amount in our consolidated statements of operations beginning with April 2006. Transactions for periods prior to April 2006 are not reflected as a net amount; however the amounts are disclosed parenthetically on the consolidated statements of operations, in accordance with the provision of Emerging Issues Task Force Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." Had this provision been in effect in 2005 and the first quarter of 2006, our reported supply and logistics revenues from unrelated parties for the year ended December 31, 2006 and 2005 would have been reduced by $69 million to $803 million and by $365 million to $673 million, respectively. Our reported supply and logistics product costs from unrelated parties for the year ended December 31, 2006 and 2005 would have been reduced by $69 million to $781 million and by $363 million to $651 million, respectively. This change had no effect on operating income, net income or cash flows.

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

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

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 year ended December 31, 2007, 2006 and 2005,, the fee averaged $0.1848, $0.174 and $0.1688 per Mcf, respectively.

Excise and Sales Taxes

The Company collects and remits excise and sales taxes to state and federal governmental authorities on its sales of fuels. These taxes are presented on a net basis, with any differences due to rebates allowed by those governmental entities reflected as a reduction of cost of products.

GENESIS ENERGY, L.P.
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Income Taxes

We are a limited partnership, organized as a pass-through entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statement of operations, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner's tax attributes in us.

Some of our corporate subsidiaries and corporations in which we have an equity investment do 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.

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have any impact on our consolidated financial statements.

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. We account for those derivative transactions in accordance with Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended and interpreted. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded on the balance sheet as assets and liabilities based on the derivative's fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. See Note 17.

Fair Value of Current Assets and Current Liabilities

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable, other current liabilities and derivatives approximates their fair value due to their short-term nature. The fair values of these instruments are represented in our consolidated balance sheets.

Net Income Per Common Unit

Basic net income per common unit is calculated on the weighted average number of outstanding common units, after exclusion of the general partner's interest from net income. The general partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each 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.

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. See Note 11 for a computation of net (loss) income per common unit.

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Recent and Proposed Accounting Pronouncements

SFAS 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements", or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. In February 2008, the FASB issued SFAS No. 157-2, "Effective Date of FASB Statement No. 157", or SFAS 157-2, which delays the effective date of SFAS 157 for all non-financial assets and non-financial liabilities. In accordance with SFAS 157-2, SFAS 157 is effective for fiscal years beginning after November 15, 2007.for financial assets and liabilities as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. We adopted SFAS 157 on January 1, 2008 for such assets and liabilities with no material impact on our consolidated financial statements. We will begin the new disclosure requirements of SFAS 157 in the first quarter of 2008. We do not currently know what the effects of the deferred provisions of SFAS 157 will be on our financial position and results of operations when adopted in 2009.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities", or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS 159 is effective for us beginning Januray 1, 2008. We are currently assessing the impact of SFAS 159 on our financial condition or results of operations.

SFAS 141(R)

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

SFAS 160

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51" (SFAS 160). This statement establishes accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine "minority interest" category); (ii) elimination of minority interest expense as a line item on the statement of operations and, as a result, that net income be allocated between the parent and the noncontrolling interests on the face of the statement of operations; and (iii) enhanced disclosures regarding noncontrolling interests. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We will adopt SFAS 160 on January 1, 2009. We are assessing the impact of this statement on our financial statements, but expect it to impact the presentation of the minority interest in our operating partnership.

EITF 07-4

In May 2007, the Emerging Issues Task Force (or EITF) of the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." This EITF considers the question of whether the incentive distribution rights ("IDRs") of a master limited partnership represent a participating security and should be considered in the calculation of earnings per unit. Under the "two class" method of computing earnings per unit, earnings are allocated to participating securities as if all of the earnings for the period had been distributed. The EITF also presents alternative methods for inclusion of IDRs in the computation of earnings per unit, depending on whether cash distributions exceed earnings for the period. The EITF has issued a draft abstract on this topic and will address comments it receives before issuing a final consensus. Once a final consensus is issued it is expected to be effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We will assess the impact of EITF 07-4 once a final consensus is issued; however we would expect it to have an impact on our presentation of earnings per unit in the future. For additional information on our incentive distribution rights, see Note 11.

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3. Acquisitions

Davison Businesses Acquisition

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

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

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

The purchase price has been allocated to the assets acquired and liabilities assumed based on estimated fair values. Such fair values were developed by management with the assistance of a third-party valuation firm. The allocation of the purchase price is summarized as follows (in thousands):

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

Deferred tax liabilties assumed	(21,794)
Total allocation	$ 653,162

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

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The following table presents selected unaudited pro forma financial information incorporating the historical operating results of the Davison businesses. The effective closing date of our purchase of the Davison businesses was July 25, 2007. As a result, our Consolidated Statements of Operations for the year ended December 31, 2007 includes five months of results of operations of these acquired businesses. The pro forma financial information has been prepared as if the acquisition had been completed on the first day of each period presented rather than the actual closing date. The pro forma financial information has been prepared based upon assumptions deemed appropriate by us and may not be indicative of actual results.

	Year Ended December 31, 2007	2006
Pro Forma Earnings Data:		
Revenue	$ 1,574,730	$ 1,479,174
Costs and expenses	1,572,809	1,477,275
Operating income	1,921	1,899
(Loss) Income before extraordinary items	(29,666)	(19,664)
Net (loss) income	(29,666)	(19,664)
Basic and diluted (loss) earnings per unit:		
As reported units outstanding	20,754	13,784
Pro forma units outstanding	28,319	28,319
As reported net (loss) income per unit	$ (0.64)	$ 0.59
Pro forma net (loss) income per unit	$ (1.05)	$ (0.69)

Port Hudson Assets Acquisition

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

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

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

See additional information on goodwill in Note 9.

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4. Inventories

Inventories are valued at the lower of cost or market. The costs of inventories did not exceed market values at December 31, 2007 and 2006. The major components of inventories were as follows (in thousands):

	December 31,			
	2007		2006	
Crude oil		3,710	$	5,081
Petroleum products		6,527		-
Caustic soda		1,998		-
NaHS		3,557		-
Other		196		91
Total inventories	$	15,988	$	5,172

5. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following (in thousands).

	December 31,			
	2007		2006	
Land, buildings and improvements	$	11,978	$	808
Pipelines and related assets		63,169		58,428
Machinery and equipment		25,097		-
Transportation equipment		32,906		1,257
Office equipment, furniture and fixtures		2,759		2,616
Construction in progress		7,102		78
Other		7,402		7,195
Subtotal		150,413		70,382
Accumulated depreciation and impairment		(48,413)		(39,066)
Total	$	102,000	$	31,316

In 2007, 2006 and 2005, $57,000, $9,000 and $35,000 of interest cost, respectively, was capitalized related to the construction of pipelines and related assets.

Depreciation expense was $8,909,000, $3,719,000 and $3,579,000 for the years ended December 31, 2007, 2006, and 2005, respectively.

Asset Impairment Charge

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

Asset Retirement Obligations

On December 31, 2005, we adopted FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143”, or FIN 47. FIN 47 clarified that the term “conditional asset retirement obligation”, as used in SFAS No. 143, “Accounting for Asset Retirement Obligations”, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within our control. Although uncertainty about the timing and/or method of settlement may exist and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, we are required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

Upon adoption of FIN 47, we recorded a fixed asset and a liability for the estimated fair value of the asset retirement obligations at the time we acquired the related assets. This $0.3 million fixed asset is being depreciated over the life of the related assets. The accretion of the discount on the liability and the depreciation through December 31, 2005 were recorded in the statement of operations as a cumulative effect adjustment totaling $0.5 million. Additionally, we reflected our share of the asset retirement obligation recorded in accordance with FIN 47 of our equity method joint venture as a cumulative affect adjustment of $0.1 million.

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A reconciliation of our liability for asset retirement obligations is as follows (in thousands):

Asset retirement obligations as of December 31, 2005	$	657
Accretion expense		51
Asset retirement obligations as of December 31, 2006		708
Liabilities incurred and assumed in the current period		468
Revisions in estimated retirement obligations		(81)
Accretion expense		78
Asset retirement obligations as of December 31, 2007	$	1,173

At December 31, 2007, $0.1 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 2007. Certain of our unconsolidated affiliates have asset retirement obligations recorded at December 31, 2007 and 2006 relating to contractual agreements. These amounts are immaterial to our financial statements.

The pro forma impact for the period ended December 31, 2005 of the adoption of FIN 47 if it had been adopted at the beginning of that period is as follows (in thousands):

	Year Ended December 31, 2005 (Unaudited)	
Income from continuing operations - as reported	$	3,689
Impact of change in accounting principle		(85)
Pro forma income from continuing operations	$	3,604
Net income - as reported	$	3,415
Add back cumulative effect adjustment		586
Impact of change in accounting principle		(85)
Pro forma income from continuing operations	$	3,916
Basic and diluted net income per common unit:		
Income from continuing operations - as reported	$	0.38
Impact of change in accounting principle		(0.01)
Pro forma income from continuing operations	$	0.37
Net income - as reported	$	0.35
Impact of change in accounting principle and add back of cumulative effect adjustment		0.05
Pro forma income from continuing operations	$	0.40

6. Net Investment in Direct Financing Leases

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline and a CO_2 pipeline segment to transport crude oil from and CO_2 to producing fields operated by Denbury. Denbury pays us a minimum payment each month for the right to use these pipeline segments. These arrangements have been accounted for as direct financing leases.

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

	December 31, 2007	December 31, 2006
Total minimum lease payments to be received	$ 7,039	$ 8,225
Estimated residual values of leased property (unguaranteed)	1,287	1,287
Less unearned income	(2,953)	(3,571)
Net investment in direct financing leases	$ 5,373	$ 5,941

At December 31, 2007, minimum lease payments to be received for each of the five succeeding fiscal years are $1.2 million per year for 2008 through 2011 and $1.1 million for 2012.

7. CO2 Assets

CO2 assets consisted of the following (in thousands).

	December 31, 2007	December 31, 2006
CO2 volumetric production payments	$ 43,570	$ 43,570
Less - Accumulated amortization	(14,654)	(10,166)
Net CO2 assets	$ 28,916	$ 33,404

The volumetric production payments entitle us to a maximum daily quantity of CO2 of 101,375 million cubic feet, or Mcf, per day through December 31, 2009, 91,875 Mcf per day for the calendar years 2010 through 2012 and 73,875 Mcf per day beginning in 2013 until we have received all volumes under the production payments. Under the terms of transportation agreements with Denbury, Denbury will process and deliver this CO2 to our industrial customers and receive a fee of $0.16 per Mcf, subject to inflationary adjustments. During 2007 this fee averaged $0.1848 per Mcf.

The terms of the contracts with the industrial customers include minimum take-or-pay and maximum delivery volumes. The seven industrial contracts expire at various dates between 2010 and 2016.

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 2007, 2006 and 2005, we recorded amortization of $4,488,000, $4,244,000 and $3,142,000, respectively. We have 182.3 Bcf of CO2 remaining under the volumetric production payments at December 31, 2007. 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 $4,488,000 from 2008 to 2010 and $4,187,000 for 2011 and 2012.

8. Joint Ventures and Other Investments

T&P Syngas Supply Company

On April 1, 2005, we acquired a 50% interest in T&P Syngas Supply Company, a Delaware general partnership, for $13.4 million in cash from a subsidiary of ChevronTexaco Corporation. Praxair Hydrogen Supply Inc. owns the remaining 50% partnership interest in T&P Syngas. We paid for our interest in T&P Syngas with proceeds from our credit facilities.

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.

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting. We reflect in our consolidated statements of operations our equity in T&P Syngas' net income, net of the amortization of the excess of our investment over our share of partners' capital of T&P Syngas. We paid $4.0 million more for our interest in T&P Syngas than our share of partners' capital on the balance sheet of T&P Syngas at the date of the acquisition. This excess amount of the purchase price over the equity in T&P Syngas is being amortized using the straight-line method over the remaining useful life of the assets of T&P Syngas of eleven years. Our consolidated statements of operations for the years ended December 31, 2007, 2006 and 2005 included $1.6 million, $1.5 million and $0.8 million, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $0.4 million in 2007 and 2006 and $0.3 million in 2005. Additionally, our consolidated statements of operations for 2005 include our share of the cumulative effect adjustment to record asset retirement obligations of $54,000 of T&P Syngas. We received distributions from T&P Syngas of $2.0 million during the years ended December 31, 2007 and 2006 and $0.8 million during the year ended December 31, 2005, respectively. In February 2008, we received a distribution of $0.6 million from T&P with respect to the fourth quarter of 2007. Our net investment in T&P Syngas at December 31, 2007, 2006 and 2005 was $11.5 million, $12.2 million and $13.0 million, respectively.

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The table below reflects summarized financial information for T&P Syngas at December 31, 2007 and December 31, 2006 (in thousands).

	Year Ended December 31, 2007	Year Ended December 31, 2006	Nine Months Ended December 31, 2005
Revenues	$ 5,040	$ 5,221	$ 3,454
Operating expenses and depreciation	(2,223)	(1,343)	(1,509)
Other income	19	17	9
Income tax expense	(23)	(5)	-
Cumulative effect adjustment			(109)
Net income	$ 2,813	$ 3,890	$ 1,845

	December 31, 2007	December 31, 2006
Current assets	$ 2,535	$ 2,268
Non-current assets	20,261	21,369
Total assets	$ 22,796	$ 23,637
Current liabilities	$ 330	$ 90
Non-current liabilties	180	165
Partners' capital	22,286	23,382
Total liabilites and partners' capital	$ 22,796	$ 23,637

Sandhill Group, LLC

On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC, for $5 million in cash. At December 31, 2007, Reliant Processing Ltd. held the other 50% interest in 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, beverage, chemical and oil industries. The facility acquires CO2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

We paid for our interest in Sandhill with cash on hand. The terms of the acquisition include earnout provisions such that we could pay up to an additional $2 million to Magna Carta, the former 50% owner in Sandhill, for our interest in Sandhill, based on the distributable cash generated by Sandhill during the period 2006 through no later than 2012. Should the cumulative distributable cash of Sandhill in the period beginning with 2006 average at least $1.5 million per year, and distributions to the members average at least $1.2 million per year, we will owe Magna Carta $1.0 million at the end of the year when the target is exceeded. If the distributable cash averages $2.0 million per year and distributions average $1.6 million per year in the period beginning with 2006, we will owe Magna Carta an additional $1.0 million.

During 2003, Sandhill was authorized to issue a series of “Issuer Floating Rate Option Notes” in an amount not to exceed $15,000,000. In 2003, Sandhill issued notes in the amount of $5,900,000 which are backed by a letter of credit from a bank and have a maturity date of December 1, 2013. At December 31, 2007, the outstanding balance of these notes was $3.9 million. We provide a guarantee of 50% of the letter of credit to Sandhill’s bank; therefore, our guaranty represents $1.95 million. Sandhill makes principal payments totaling $0.6 million annually. We recorded the estimated fair value of this guarantee of $0.1 million as a long-term liability in our consolidated balance sheet, with a corresponding increase to our investment in Sandhill.

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We are accounting for our 50% ownership in Sandhill under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in Sandhill's net income, net of the amortization of the excess of our investment over our share of partners' capital of Sandhill that is not considered goodwill. We paid $3.8 million more for our interest in Sandhill than our share of partners' capital on the balance sheet of Sandhill at the date of the acquisition. This excess amount of the purchase price over the equity in Sandhill has been allocated to the property and equipment of Sandhill and certain intangible assets based on the fair value of those assets, with the remainder of the excess purchase price of $0.7 million allocated to goodwill. The amount allocated to property and equipment and intangible assets is being amortized using the straight-line method over the remaining useful lives of those assets. In accordance with Accoutning Principles Board Opinion 18, we annually test our investment in Sandhill to determine if an impairment of our investment that is other than temporary has occurred.

Our consolidated statements of operations for the years ended December 31, 2007 and 2006 included $312,000 and $141,000, respectively as our share of the operating earnings of Sandhill, reduced by amortization of the excess purchase price of $277,000 and $208,000, respectively. We received distributions from Sandhill of $0.3 million during the year ended December 31, 2007 and $0.1 million during the nine month period in 2006 that we owned our interest. Our net investment in Sandhill was $4.7 million at December 31, 2007.

Other Projects

In 2006, we invested $1.0 million in the Faustina Project, a petroleum coke to ammonia project that is in the development stage. We have subsequently invested an additional $1.1 million. All of our investment may later be redeemed, with a return, or converted to equity after the project has obtained construction financing. We have committed to invest an additional $0.8 million in the Faustina Project in 2008. The funds we have invested will be used for project development activities, which include the negotiation of off-take agreements for the products and by-products of the plant to be constructed, securing permits and securing financing for the construction phase of the plant. We have recorded our investment in this debt security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed.

No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair value of our investment at December 31, 2007, therefore the investment is included in our consolidated balance sheet at cost.

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

As explained in Note 3, in connection with the Davison acquisition, 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, 2007:

	December 31, 2007			
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value

Refinery services customer relationships	3	$	94,654	$	9,380	$	85,274
Supply and logistics customer relationships	5		34,630		3,287		31,343
Refinery services supplier relationships	2		36,469		9,241		27,228
Refinery services licensing agreements	6		38,678		2,218		36,460
Supply and logistics trade name	7		17,988		930		17,058
Supply and logistics favorable lease	15		13,260		197		13,063
Other	3		721		97		624
Total	5	$	236,400	$	25,350	$	211,050

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The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The trade name is the Davison name, 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 $25.4 million for the year ended December 31, 2007.

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

	2008	2009	2010	2011	2012
Refinery services customer relationships	16,637	15,433	11,689	8,972	7,056
Supply and logistics customer relationships	6,651	5,481	4,435	3,552	2,769
Refinery services supplier relationships	15,205	4,068	2,925	2,629	2,364
Refinery services licensing agreements	4,958	4,505	4,105	3,690	3,416
Supply and logistics trade name	2,130	1,983	1,812	1,626	1,432
Supply and logistics favorable lease	474	474	474	474	474
Other	232	232	135	-	-
Total	46,287	32,176	25,575	20,943	17,511

Goodwill

As explained in Note 3, in connection with the Davison and Port Hudson acquisitions, the residual of the purchase price over the fair values of the net tangible and identifiable intangible assets acquired was allocated to goodwill. The carrying amount of goodwill by business segment at December 31, 2007 was $297.6 million to refinery services and $23.1 million to 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 (in thousands).

	December 31, 2007	December 31, 2006
Credit facility fees	$ 5,022	$ 2,726
Deferred tax asset	941	-
Other deferred costs and deposits	3,284	119
	9,247	2,845
Less - Accumulated amortization	(850)	(69)
Net other assets	$ 8,397	$ 2,776

Amortization expense of credit facility fees for the years ended December 31, 2007, 2006 and 2005 was $779,000, $394,000 and $373,000, respectively. In the fourth quarter of 2006, we also charged to expense $575,000 of unamortized fees related to the facility that we replaced in November 2006. Amortization of credit facility fees for the next four years will be $1,079,000 for 2008, 2009 and 2010 and $941,000 in 2011.

10. Debt

Our credit facility, with a maximum facility amount of $500 million, of which $100 million could be used for letters of credit, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The maximum facility amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. 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.

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The borrowing base may be increased to the extent of pro forma additional EBITDA attributable to acquisitions or internal growth projects with approval of the lenders. Our borrowing base as of December 31, 2007 was approximately $356 million.

At December 31, 2007, we had $80 million borrowed under our credit facility and we had $5.3 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, 2007 was $270.8 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, 2007, our borrowing rates were the prime rate plus 1.25% or the LIBOR rate plus 2.25%.

- 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, 2007, our letter of credit rate was 2.25%.

- 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, 2007, the commitment fee was 0.50%.

Collateral under the credit facility consists of substantially all our assets. 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) and 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 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.

Financial Covenant	Requirement	Required Ratio through June 30, 2008	Actual Ratio as of December 31, 2007
Debt Service Coverage Ratio	Minimum	2.75 to 1.0	3.39 to 1.0

Leverage Ratio	Maximum	6.5 to 1.0	1.1 to 1.0
Funded Indebtedness Ratio	Maximum	0.80 to 1.0	0.10 to 1.0

Our credit facility includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. The ratios in the table above are the required ratios for the period following a material acquisition. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however the amount of such distributions may not exceed the sum of the distributable cash generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At December 31, 2007, the excess of distributable cash over distributions under this provision of the credit facility was $38.1 million.

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The carrying value of our debt under our credit facility approximates fair value primarily because interest rates fluctuate with prevailing market rates, and the applicable margin on outstanding borrowings reflect what we believe is market.

11. Partners' Capital and Distributions

Partner's capital at December 31, 2007 consists of 38,253,264 common units, including 2,829,055 units owned by our general partner, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest), and a 2% general partner interest. Included in these amounts are the common units issued on July 25, 2007 in connection with the Davison acquisition and common units issued in December 2007 in connection with a public offering.

We issued 13,459,209 common units to the entities owned and controlled by the Davison family. The issuance of the units was recorded in the financial statements at a value of $330 million. In accordance with EITF No. 99-12, "Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination," the fair value of our common units issued was determined using an average price of $24.52, which was the average closing price of our common units for the two days before and after the terms of the acquisition were agreed to and announced. Additionally, 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.

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.

During the four years ended December 31, 2007, 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
			(in thousands, except per unit amounts)				
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
December 2005	Public	4,140	$ 10.500	$ 43,470	$ 887	$ 2,889	$ 41,468
December 2005	General Partner	331	$ 9.975	$ 3,298	$ 67	$ -	$ 3,365
November 2003	General Partner	689	$ 7.150	$ 4,925	$ 101	$ 14	$ 5,012

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. While the incentive interest in our general partner may ultimately qualify as an equity award under SFAS 123(R), there is no mutual understanding of the terms of the award at December 31, 2007; therefore an amount could not be calculated in accordance with the provisions of SFAS 123(R). The expense recorded for this arrangement was an amount agreed to by the parties as a fair representation of the value provided and earned in 2007. 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.

Our general partner owns all of our general partner interest, including incentive distribution rights, all of the 0.01% general partner interest in our operating partnership (which is reflected as a minority interest in the consolidated balance sheet at December 31, 2007) 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.

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Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. As discussed in Note 10, our credit facility limits the amount of distributions we may pay in any quarter. At December 31, 2007, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $593.7 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. Pursuant to our partnership agreement, our general partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds, in addition to its 2% general partner interest. The allocations of distributions between our common unitholders and our general partner, including the incentive distribution rights is as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Common Unit:		
Up to and including $0.25 per Unit	98.00%	2.00%
First Target - $0.251 per Unit up to and including $0.28 per Unit	84.74%	15.26%
Second Target - $0.281 per Unit up to and including $0.33 per Unit	74.26%	25.74%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02%	50.98%

We paid distributions in 2006 and 2007 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 2005	February 2006	$ 0.170	$ 2,343	$ 48	$ -	$ 2,391
First quarter 2006	May 2006	$ 0.180	$ 2,481	$ 51	$ -	$ 2,532
Second quarter 2006	August 2006	$ 0.190	$ 2,619	$ 53	$ -	$ 2,672
Third quarter 2006	November 2006	$ 0.200	$ 2,757	$ 56	$ -	$ 2,813
Fourth quarter 2006	February 2007	$ 0.210	$ 2,895	$ 59	$ -	$ 2,954
First quarter 2007	May 2007	$ 0.220	$ 3,032	$ 62	$ -	$ 3,094
Second quarter 2007	August 2007	$ 0.230	$ 3,170(1)	$ 65	$ -	$ 3,235(1)
Third quarter 2007	November 2007	$ 0.270	$ 7,646	$ 156	$ 90	$ 7,892

Fourth quarter 2007	February 2008	$ 0.285	$ 10,902	$ 222	$ 245	$ 11,369

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

The total amounts in the table above increased with the issuance of new common units in December 2005, July 2007 and December 2007.

Net Income (Loss) Per Common Unit

Subject to the applicability of Emerging Issues Task Force Issue No. 03-06 ("EITF 03-06"), Participating Securities and the Two-Class Method under Financial Accounting Standards Board Statement No. 128," as discussed below, our net income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated 98% to the limited partners and 2% to the general partner. Basic net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period. Diluted net income per common unit is calculated in the same manner, but also considers the impact to common units for the potential dilution from phantom units outstanding.

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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.

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

The following table sets forth the computation of basic net (loss) income per common unit for 2007, 2006, and 2005 (in thousands, except per unit amounts).

	Year Ended December 31,		
	2007	2006	2005
	(in thousands, except per unit amounts)		
Numerators for basic and diluted net (loss) income per common unit:			
(Loss) income from continuing operations	$ (13,550)	$ 8,351	$ 3,689
Less general partner 2% ownership	(271)	167	74
(Loss) income from continuing operations available for common unitholders	$ (13,279)	$ 8,184	$ 3,615
Income from discontinued operations	$ -	$ -	$ 312
Less general partner 2% ownership	-	-	6
Income from discontinued operations available for common unitholders	$ -	$ -	$ 306
Income (loss) from cumulative effect adjustment	$ -	$ 30	$ (586)
Less general partner 2% ownership	-	-	(12)
Income (loss) from cumulative effect adjustment available for common unitholders	$ -	$ 30	$ (574)
Denominator for basic and diluted per common unit -weighted average number of common units outstanding	20,754	13,784	9,547
Basic and diluted net (loss) income per common unit:			
(Loss) income from continuing operations	$ (0.64)	$ 0.59	$ 0.38

Income from discontinued operations		-		-		0.03
Loss from cumulative effect adjustment		-		-		(0.06)
Net (loss) income	$	(0.64)	$	0.59	$	0.35

12. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate and intrastate crude oil, and to a lesser extent, natural gas and CO2 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 CO2 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 crude oil and petroleum products and other dry goods. Our Supply and Logistics segment was previously known as Crude Oil Gathering and Marketing. With the Davison acquisition, we expanded our operations into petroleum products and other transportation services, and combined these operations due to their similarities and our approach to managing these operations. 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. The tables below reflect our segment information as though the current segment designations had existed in all periods presented.

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We evaluate segment performance based on segment margin. We calculate segment margin as revenues less costs of sales and operating expenses, and we include income from investments in joint ventures. We do not deduct depreciation and amortization. All of our revenues are derived from, and all of our assets are located in the United States. The pipeline transportation segment information includes the revenue, segment margin and assets of our direct financing leases.

	Pipeline Transportation	Refinery Services	Industrial Gases (a) (in thousands)	Supply & Logistics	Total
Year Ended December 31, 2007					
Segment margin excluding depreciation and amortization (b)	$ 13,035	$ 21,898	$ 12,063	$ 15,330	$ 62,326
Capital expenditures	$ 6,592	$ 1,448	$ 1,104	$ 1,141	$ 10,285
Maintenance capital expenditures	$ 2,880	$ 469	-	$ 491	$ 3,840
Net fixed and other long-term assets (c)	$ 32,936	$ 468,068	$ 47,364	$ 145,915	$ 694,283
Revenues:					
External customers	$ 23,226	$ 62,095	$ 16,158	$ 1,094,189	$ 1,195,668
Intersegment (d)	3,985	-	-	-	3,985
Total revenues of reportable segments	$ 27,211	$ 62,095	$ 16,158	$ 1,094,189	$ 1,199,653
Year Ended December 31, 2006					
Segment margin excluding depreciation and amortization (b)	$ 12,426	-	$ 11,443	$ 7,366	$ 31,235
Capital expenditures	$ 971	-	$ 6,058	$ 356	$ 7,385
Maintenance capital expenditures	$ 611	-	-	$ 356	$ 967
Net fixed and other long-term assets (c)	$ 31,863	-	$ 51,630	$ 7,602	$ 91,095
Revenues:					
External customers	$ 25,479	-	$ 15,154	$ 873,268	$ 913,901
Intersegment (d)	4,468	-	-	-	4,468
Total revenues of reportable segments	$ 29,947	-	$ 15,154	$ 873,268	$ 918,369

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	Pipeline Transportation	Refinery Services	Industrial Gases (a)	Supply & Logistics	Total
			(in thousands)		
Year Ended December 31, 2005					
Segment margin excluding depreciation and amortization (b)	$ 9,804	-	$ 8,154	$ 3,661	$ 21,619
Capital expenditures	$ 5,425	-	$ 27,864	$ 547	$ 33,836
Maintenance capital expenditures	$ 1,256	-	-	$ 287	$ 1,543
Net fixed and other long-term assets (c)	$ 34,725	-	$ 50,690	$ 5,913	$ 91,328
Revenues:					
External customers	$ 25,613	-	$ 11,302	$ 1,038,549	$ 1,075,464
Intersegment (d)	3,275	-	-	-	3,275
Total revenues of reportable segments	$ 28,888	-	$ 11,302	$ 1,038,549	$ 1,078,739

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

(b) Segment margin was calculated as revenues less cost of sales and operations expense. It includes our share of the operating income of equity joint ventures. A reconciliation of segment margin to income before income taxes and minority interest for each year presented is as follows:

	Year Ended December 31, 2007	2006	2005
		(in thousands)	
Segment margin excluding depreciation and amortization	$ 62,326	$ 31,235	$ 21,619
General and administrative expenses	(25,920)	(13,573)	(9,656)
Depreciation, amortization and impairment	(40,245)	(7,963)	(6,721)
Net (loss) gain on disposal of surplus assets	(266)	16	479
Interest expense, net	(10,100)	(1,374)	(2,032)
(Loss) income from continuing operations before income taxes and minority interest	$ (14,205)	$ 8,341	$ 3,689

(c) Net fixed and other long-term assets are the measure used by management in evaluating the results of its operations on a segment basis. Current assets are not allocated to segments as the amounts are shared by the segments or are not meaningful in evaluating the success of the segment's operations.

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

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13. Transactions with Related Parties

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

	Year Ended December 31, 2007	2006 (in thousands)	2005
Truck transportation services provided to Denbury	$ 1,791	$ 825	$ 796
Pipeline transportation services provided to Denbury	$ 5,290	$ 4,228	$ 3,853
Payments received under direct financing leases from Denbury	$ 1,188	$ 1,186	$ 1,186
Pipeline transportation income portion of direct financing lease fees	$ 641	$ 655	$ 689
Pipeline monitoring services provided to Denbury	$ 120	$ 65	$ 30
Directors' fees paid to Denbury	$ 150	$ 120	$ 120
CO2 transportation services provided by Denbury	$ 5,213	$ 4,640	$ 3,501
Crude oil purchases from Denbury	$ 101	$ 1,565	$ 4,647
Crude oil sales to Denbury	$ -	$ -	$ 176
Purchase of CO2 volumetric production payment from Denbury	$ -	$ -	$ 14,363
Operations, general and administrative services provided by our general partner	$ 22,490	$ 16,777	$ 15,145
Distributions to our general partner on its limited partner units and general partner interest	$ 1,671	$ 963	$ 536
Sales of CO2 to Sandhill (for the period since Sandhill became a related party)	$ 2,783	$ 2,056	$ -
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 gathering and marketing revenues.

Denbury is the only shipper on our Mississippi pipeline other than us, and we earned tariffs for transporting their crude oil. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven CO2 pipeline and recorded pipeline transportation income from these arrangements. See Note 6.

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

Directors' Fees

We paid Denbury for the services of each of four of Denbury's officers who serve as directors of our general partner at a rate that was $10,000 per person less annually than the rate at which our independent directors were paid.

CO2 Operations and Transportation

We acquired contracts, along with volumetric production payments, from Denbury in 2005 and 2004. Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver the CO_2 for us to our customers. See Note 7.

Sales and Purchases of Crude Oil

Denbury began shipping its own crude oil on our Mississippi System in September 2004, so our purchases of crude oil from Denbury (and our related crude oil sales) have declined.

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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.

Transition Services from Davison

Until the end of 2007, the Davison family is providing certain transition services to us related to the payroll for persons who provide services to us. These persons became employees of our general partner on January 1, 2008; however, to create the least disruption for employees while we evaluated benefit plan arrangements, the personnel in our Supply and Logistics operations acquired from Davison were paid by entities owned by the Davison family and we reimbursed them for all direct costs.

Amounts due to and from Related Parties

At December 31, 2007 and 2006, we owed Denbury \$1.0 million and \$0.8 million, respectively, for purchases of crude oil and CO2 transportation charges. Denbury owed us \$0.9 million and \$0.6 million for transportation services at December 31, 2007 and 2006, respectively. We owed our general partner \$0.7 million and \$0.9 million for administrative services at December 31, 2007 and 2006, respectively. At December 31, 2007 and 2006 Sandhill owed us \$0.5 million, respectively for purchases of CO2. At December 31, 2007, we owed the Davison family entities \$0.8 million for reimbursement of costs paid primarily related to employee transition services.

Financing

Our general partner, a wholly owned subsidiary of Denbury, guarantees our obligations under our credit facility. Our general partner's principal assets are its general and limited partnership interests in us. The obligations are not guaranteed by Denbury or any of its other subsidiaries. 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 our operating partnership.

We guarantee 50% of the obligation of Sandhill to a bank. At December 31, 2007, the total amount of Sandhill's obligation to the bank was \$3.9 million; therefore, our guarantee was for \$1.95 million. See Note 8.

As discussed in Note 11, our general partner purchased common units and made general partner contributions in order to maintain its capital account totaling \$37.9 million and \$10.6 million, respectively. In addition, our general partner made a capital contribution of \$1.5 million in December 2007 to offset a portion of the severance payment to a former executive.

14. Supplemental Cash Flow Information

Cash received by us for interest during the years ended December 31, 2007, 2006 and 2005 was \$269,000, \$192,000 and \$46,000, respectively. Payments of interest and commitment fees were \$8,401,000, \$1,041,000 and \$1,468,000, during the years ended December 31, 2007, 2006 and 2005, respectively.

Cash paid for income taxes in during the year ended December 31, 2007 was \$1,600,000.

At December 31, 2007 and 2006, we had incurred liabilities for fixed asset additions totaling $893,000 and $81,000, 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 $271,000 and $46,000 at December 31, 2007 and 2006, respectively 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 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 by which they are expected to earn an interest in our general partner.

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15. Employee Benefit Plans and Unit-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 our 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 $821,000, $660,000, and $620,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Our general partner also provided certain health care and survivor benefits for its active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. Our general partner plans to continue self-insuring these plans in the future. The expenses included in the consolidated statements of operations for these benefits were $1,454,000, $1,269,000, and $1,773,000 in 2007, 2006 and 2005, respectively.

Stock Appreciation Rights Plan

Under the terms of our stock appreciation rights plan, all regular, full-time active employees (with the exception of the new senior management team) 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, 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. The initial award to a participant will vest one-fourth each year beginning with the first anniversary of the grant date of the award. Subsequent awards to participants will vest on the fourth anniversary of the grant date. 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.

Prior to January 1, 2006, we had accounted for this plan under the provisions of FASB Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans", which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. On January 1, 2006, we adopted SFAS No. 123 (revised December 2004), “Share-Based Payments.” The adoption of this statement required that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we include the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount at each balance sheet date with the adjustment reflected in the statement of operations.

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The estimates that we made upon the adoption of this standard included the following assumptions:

- In determining the expected life of the rights, we used the simplified method allowed by the Securities and Exchange Commission. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee exercise patterns. The simplified method produces an initial expected life of 6.25 years for those rights we issued that vest 25% per year for four years, and an initial expected life of 7 years for those rights we issued that fully vest at the end of a four-year period.

- The expected volatility of our units was 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 expected volatility used in the fair value calculations was approximately 34% and 32% at December 31, 2007 and December 31, 2006, respectively.

- 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. At December 31, 2007, the risk-free interest rate ranged from 3.12% to 3.65%. At December 31, 2006, the risk-free interest rate ranged from 4.53% to 4.57%.

- 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. At December 31, 2007 and December 31, 2006, we used an expected future distribution yield of 6%.

- We estimated the expected forfeitures of non-vested rights and expirations of vested rights. We have very limited experience with employee forfeiture and expiration patterns, as our plan was not initiated until December 31, 2003. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also used different estimates for different groups of employees.

At December 31, 2005, we had a recorded liability of $0.8 million, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material. The adjustment of the liability to its fair value of $2.4 million at December 31, 2006, resulted in total expense of $1.9 million for the year ended December 31, 2006, with $0.3 million, $0.3 million and $1.3 million included in field operating costs, pipeline operating costs and general and administrative expenses, respectively. The adjustment of the liability to its fair value of $3.3 million at December 31, 2007, resulted in total expense of $2.5 million for the year ended December 31, 2007, with $0.5 million, $0.4 million and $1.6 million included in field operating costs, pipeline operating costs and general and administrative expenses, respectively.

The following table reflects rights activity under our plan as of January 1, 2007, and changes during the year ended December 31, 2006:

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Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2007	659,010	$ 12.79		
Granted during 2007	99,430	$ 29.06		
Exercised during 2007	(94,267)	$ 10.06		
Forfeited or expired during 2007	(70,715)	$ 16.97		
Outstanding at December 31, 2007	593,458	$ 15.45	8.0	$ 5,177
Exercisable at December 31, 2007	231,021	$ 11.05	6.7	$ 2,912

The weighted-average fair value at December 31, 2007 of rights granted during 2007 was $3.56 per right. The total intrinsic value of rights exercised during 2007 was $1,599,000, which was paid in cash to the participants.

At December 31, 2007, there was $1.2 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. This amount was calculated as the fair value at December 31, 2007 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, 2007, the remaining cost will be recognized over a weighted average period of one year.

Prior to January 1, 2006, the method of accounting for our stock appreciation rights plan required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. In 2005, we recorded a non-cash credit of $0.5 million in general and administrative expense for the decrease in the value of the outstanding rights due to the decrease in the closing market price for common units between December 31, 2005 and December 31, 2004.

2007 Long Term Incentive Plan

At a special meeting of the unitholders of Genesis Energy, L.P on December 18, 2007, our unitholders approved the Genesis Energy, Inc. 2007 Long Term Incentive Plan (the “2007 LTIP”), which provides for awards of Phantom Units and Distribution Equivalent Rights to non-employee directors and employees of Genesis Energy, Inc., 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.

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 960,638 remain authorized for issuance at December 31, 2007. In December 2007, 39,362 Phantom Units were granted with the vesting restrictions on those units follows: (a) 47% of the awards vest 33-1/3% per year over three years and, (b) 53% of the awards vest at the end of three years. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of the units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures. Due to the positions of the small goup of employees 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, 2007.

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As of December 31, 2007, there was $0.8 million of unrecognized compensation expense related to these units. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 3.0 years.

The following table summarizes information regarding our non-vested Phantom Unit grants as of December 31, 2007:

Non-vested Phantom Unit Grants	Number of Units	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2007 Granted	39,362	$ 21.92
Non-vested at December 31, 2007	39,362	

The aggregate grant date fair value of Phantom Unit awards granted during 2007 was $0.9 million based on the grant date market price of our common units of $24.52 per unit, adjusted for distributions that holders of phantom units will not receive during the vesting period. The grant-date fair value of the award was 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. Our expected distribution rate was based on our the rate of the distribution we paid in November 2007 of $0.27 and the risk-free interest rates in calculating the present value of our expected dividends ranged from 3.19% to 3.31%.

Bonus Plan

In March 2003, the Compensation Committee of the Board of Directors of our general partner approved a Bonus Plan for all employees of the general partner (with the exception of the new senior management team.) Through December 31, 2007, the Bonus Plan excluded the personnel in the Davison operations who became employees of the general partner on January 1, 2008. The Bonus Plan is designed to enhance the financial performance of the Partnership by rewarding all employees for achieving financial performance objectives. The Bonus Plan is administered by the Compensation Committee. Under this plan, amounts will be allocated for the payment of bonuses to employees each time our operating partnership earns $2.0 million of available cash, subject to certain adjustments. The amount allocated to the bonus pool increases for each $2.0 million earned, such that a bonus pool of $2.3 million will exist if the Partnership earns $18.4 million of available cash. We accrued $2.0 million, $1.8 million and $1.2 million for the bonus pool for 2007, 2006 and 2005, respectively.

Bonuses will be paid to employees after the end of the year, but only if distributions are made to the common unitholders. The amount in the bonus pool will be allocated to employees based on the group to which they are assigned. Employees in the first group can receive bonuses that range from zero to ten percent of base compensation. The next group includes employees who could earn a total bonus ranging from zero to twenty percent. Certain members are eligible to earn a total bonus ranging from zero to thirty percent. Lastly, our officers, excluding our new senior management team, and other key management are eligible for a total bonus ranging from zero to forty percent. The Bonus Plan will be at the discretion of the Compensation Committee, and our general partner can amend or change the Bonus Plan at any time. Our Compensation Committee will determine what changes are needed in the plan as a result of the Davison acquisition.

Severance Protection Plan

In June 2005, the Compensation Committee of the Board of Directors of our general partner approved the Genesis Energy Severance Protection Plan, or Severance Plan, for employees of our general partner (with the exception of the new senior management team.) The Severance Plan provides that a participant in the Plan is entitled to receive a severance benefit if his employment is terminated during the period beginning six months prior to a change in control and ending two years after a change in control, for any reason other than (x) termination by our general partner for cause or (y) termination by the participant for other than good reason. Termination by the participant for other than good reason would be triggered by a change in job status, a reduction in pay, or a requirement to relocate more than 25 miles.

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

The amount of severance is determined separately for three classes of participants. The first class, which includes two Executive Officers of Genesis, would receive a severance benefit equal to three times that participant's annual salary and bonus amounts. The second class, which includes certain other members of management, would receive a severance benefit equal to two times that participant's salary and bonus amounts. The third class of participant would receive a severance benefit based on the participant's salary and bonus amounts and length of service. Participants would also receive certain medical and dental benefits.

16. Major Customers and Credit Risk

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

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

Shell Oil Company and Occidental Energy Marketing, Inc. accounted for 20.7% and 11.2% of total revenues in 2007, respectively. Occidental Energy Marketing, Inc., Shell Oil Company and Calumet Specialty Products Partners, L.P. accounted for 20.3%, 19.1% and 10.9% of total revenues in 2006, respectively. Occidental Energy Marketing, Inc. and Shell Oil Company accounted for 26.5% and 12.5% of total revenues in 2005, respectively. The revenues from these five customers in all three years relate primarily to our gathering and marketing operations.

17. Derivatives

Our market risk in the purchase and sale of crude oil and petroleum products contracts is the potential loss that can be caused by a change in the market value of the asset or commitment. In order to hedge our exposure to such market fluctuations, we may enter into various financial contracts, including futures, options and swaps. Historically, any contracts we have used to hedge market risk were less than one year in duration, although we have the flexibility to enter into arrangements with a longer term.

We may utilize crude oil futures contracts and other financial derivatives to reduce our exposure to unfavorable changes in crude oil prices and fuel oil prices. Every derivative instrument (including certain derivative instruments embedded in other contracts) must be recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value must be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. We must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

We mark to fair value our derivative instruments at each period end, with changes in the fair value of derivatives that are not designated as hedges being recorded as unrealized gains or losses. Such unrealized gains or losses will change, based on prevailing market prices, at each balance sheet date prior to the period in which the transaction actually occurs. The effective portion of unrealized gains or losses on derivative transactions qualifying as cash flow hedges are reflected in other comprehensive income. Derivative transactions qualifying as fair value hedges are evaluated for hedge effectiveness and the resulting hedge ineffectiveness is recorded as a gain or loss in the consolidated statements of operations.

We review our contracts to determine if the contracts meet the definition of derivatives pursuant to SFAS 133. At December 31, 2007, we had futures contracts that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on December 31, 2007. We marked these contracts to fair value at December 31, 2007. During the year ended December 31, 2007, we recorded losses of $2,155,000 related to derivative transactions, which are included in the consolidated statements of operations under the caption “Supply and logistics costs.”

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For a portion of 2007 we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the year ended December 31, 2007 we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $119,000. These gains are included in the caption "Product costs" in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material. At December 31, 2007, our fair value hedges of inventory were closed.

The consolidated balance sheet at December 31, 2007 includes a decrease in other current assets of $744,000 as a result of these derivative transactions. The consolidated balance sheet at December 31, 2006 included an increase in other current assets of $165,000 as a result of derivative transactions.

We determined that the remainder of our derivative contracts qualified for the normal purchase and sale exemption and were designated and documented as such at December 31, 2007 and December 31, 2006.

18. Commitments and Contingencies

Commitments and Guarantees

We lease office space for our headquarters under a long-term lease that extends until October 31, 2008. We lease office space for field offices under leases that expire between 2008 and 2013. To transport products, we lease tractors and trailers for our crude oil gathering and marketing activities and lease barges and railcars for our refinery services segment. In addition, we lease tanks and terminals for the storage of crude oil, petroleum products, NaHS and caustic soda. Additionally, we lease a segment of pipeline where under the terms we make payments based on throughput. We have no minimum volumetric or financial requirements remaining on our pipeline lease..

The future minimum rental payments under all non-cancelable operating leases as of December 31, 2007, were as follows (in thousands).

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2008	$ 374	$ 4,075	$ 2,437	$ 6,886
2009	121	3,024	1,177	4,322
2010	84	2,263	516	2,863
2011	63	1,576	387	2,026
2012	63	1,135	322	1,520
2013 and thereafter	16	3,488	7,272	10,776
Total minimum lease obligations	$ 721	$ 15,561	$ 12,111	$ 28,393

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

Year ended December 31, 2007	$ 6,079
Year ended December 31, 2006	$ 3,258
Year ended December 31, 2005	$ 3,929

We have guaranteed the payments by our operating partnership to the banks under the terms of our credit facility related to borrowings and letters of credit. To the extent liabilities exist under the letters of credit, such liabilities are included in the consolidated balance sheet. Borrowings at December 31, 2007 were $80.0 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.

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

We guaranteed $1.2 million of residual value related to the leases of trailers from Paccar. 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, 2007, Sandhill owed $3.9 million; therefore our guarantee was $1.95 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year.

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.

Pennzoil Litigation

We were named a defendant in a complaint filed on January 11, 2001, in the 125th District Court of Harris County, Texas, Cause No. 2001-01176. Pennzoil-Quaker State Company, or PQS, was seeking from us property damages, loss of use and business interruption suffered as a result of a fire and explosion that occurred at the Pennzoil Quaker State refinery in Shreveport, Louisiana, on January 18, 2000. PQS claimed the fire and explosion were caused, in part, by crude oil we sold to PQS that was contaminated with organic chlorides. In December 2003, our insurance carriers settled this litigation for $12.8 million.

PQS is also a defendant in five consolidated class action/mass tort actions brought by neighbors living in the vicinity of the PQS Shreveport, Louisiana refinery in the First Judicial District Court, Caddo Parish, Louisiana, Cause Nos. 455,647-A, 455,658-B, 455,655-A, 456,574-A, and 458,379-C. PQS has brought third party claims against us for indemnity with respect to the fire and explosion of January 18, 2000. We believe that the demand against us is without merit and intend to vigorously defend ourselves in this matter. We currently believe that this matter will not have a material financial effect on our financial position, results of operations, or cash flows.

Environmental

In 1992, Howell Crude Oil Company (“Howell”) entered into a sublease with Koch Industries, Inc. (“Koch”), covering a one acre tract of land located in Santa Rosa County, Florida to operate a crude oil trucking station, known as Jay Station. The sublease provided that Howell would indemnify Koch for environmental contamination on the property under certain circumstances. Howell operated the Jay Station from 1992 until December of 1996 when this operation was sold to us by Howell. We operated the Jay Station as a crude oil trucking station until 2003. Koch incurred certain investigative and/or other costs, for which Koch alleges some or all should be reimbursed by us, under the indemnification provisions of the sublease for environmental contamination on the site and surrounding areas. Koch has also alleged that we are responsible for future environmental obligations relating to the Jay Station.

Howell was acquired by Anadarko Petroleum Corporation (“Anadarko”) in 2002. In 2005, we entered into a joint defense and cost allocation agreement with Anadarko. Under the terms of the joint allocation agreement, we agreed to reasonably cooperate with each other to address any liabilities or defense costs with respect to the Jay Station. Additionally under the joint allocation agreement, Anadarko will be responsible for sixty percent of the costs related to any liabilities or defense costs incurred with respect to contamination at the Jay Station.

We were formed in 1996 by the sale and contribution of assets from Howell and Basis Petroleum, Inc. (“Basis”). Anadarko's liability with respect to the Jay Station is derived largely from contractual obligations entered into upon our formation. We believe that Basis has contractual obligations under the same formation agreements. We intend to seek recovery of Basis' share of potential liabilities and defense costs with respect to Jay Station.

We have developed a plan of remediation for affected soil and groundwater at Jay Station which has been approved by appropriate state regulatory agencies. We recorded an estimate of our share of liability for this matter in the amount of $0.5 million, and in 2007 we increased the accrual by $0.3 million based on updated estimates of the costs to complete the remediation. The time period over which our liability would be paid is uncertain and could be several years. This liability may decrease if indemnification and/or cost reimbursement is obtained by us for Basis' potential liabilities with respect to this matter. At this time, our estimate of potential obligations does not assume any specific amount contributed on behalf of the Basis obligations, although we believe that Basis is responsible for a significant part of these potential obligations.

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

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.

In connection with the sale of pipeline assets in Texas in the fourth quarter of 2003, we retained responsibility for environmental matters related to the operations of those pipelines in the periods prior to the date of the sales, subject to certain conditions. On the majority of the pipelines sold, our responsibility for any environmental claim will not exceed an aggregate total of $2 million. Our responsibility for indemnification related to these sales will cease in 2013.

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.

19. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. 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 will pay federal and state income taxes on these operations. The income taxes associated with these operations are accounted for in accordance with SFAS 109 “Accounting for Income Taxes.”

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 will be applied generally will be calculated as our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax purposes), in the State of Texas.

In June 2006, the FASB issued FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109” (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have any impact on our consolidated financial statements.

As of January 1, 2007 we had no unrecognized tax benefits. At December 31, 2007 we have unrecognized tax benefits of $1million. The change in the unrecognized tax benefits are a result of additions related to current year tax positions. If the unrecognized tax benefits at December 31, 2007 were recognized, $1million would affect our effective income tax rate. There are no uncertain tax positions as of December 31, 2007 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly decrease during 2008.

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

Our income tax provision (benefit) is as follows (in thousands):

	December 31, 2007
Current:	
Federal	$ 1,665
State	339
Total current income tax expense	2,004
Deferred:	
Federal	(2,432)
State	(226)
Total deferred income tax benefit	(2,658)
Total income tax benefit	$ (654)

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2007 balance sheet date. We believe we will utilize all of our deferred tax assets at December 31, 2007, and therefore have provided no valuation allowance against our deferred tax assets. Deferred tax assets and liabilities consist of the following (in thousands):

	December 31, 2007
Deferred tax assets:	
Current:	
Other current liabilities	$ 43
Other	17
Total current deferred tax asset	60
Net operating loss carryforwards - federal	861
Net operating loss carryforwards - state	80
Total long-term deferred tax asset	941
Total deferred tax assets	1,001
Deferred tax liabilities:	
Current:	
Other	(24)
Long-term:	
Fixed assets	(11,125)
Intangible assets	(8,962)
Total long-term liability	(20,087)
Total deferred tax liabilities	(20,111)
Total net deferred tax liability	$ (19,110)

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 (in thousands):

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

		December 31, 2007
Loss before income taxes	$	(13,550)
Partnership loss not subject to tax		8,239
Loss subject to income taxes		(5,311)
Tax benefit at federal statutory rate	$	(1,859)
State income taxes, net of federal benefit		33
Effects of FIN 48, federal and state		1,168
Other		4
Income tax benefit	$	(654)
Effective tax rate on loss before income taxes		5%

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Schedule I - Condensed Financial Information

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

Condensed Statements of Operations

	Years Ended December 31, 2007	2006	2005
	(in thousands)		
Equity in (losses) earnings of subsidiary	$ (13,550)	$ 8,381	$ 3,415
Net (loss) income	$ (13,550)	$ 8,381	$ 3,415

Condensed Balance Sheets

	December 31, 2007	2006
	(in thousands)	
Assets		
Cash	$ 10	$ 6
Investment in subsidiary	664,480	118,338
Advances to subsidiary	84	88
Total Assets	$ 664,574	$ 118,432
Partners' Capital		
Limited Partners	$ 647,340	$ 115,960
General Partner	17,234	2,472
Total Partners' Capital	$ 664,574	$ 118,432

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, 2007	2006	2005
	(in thousands)		
Cash Flows from Operating Activities:			
Net (loss) income	$ (13,550)	$ 8,381	$ 3,415
Equity in (earnings) losses of GCO	$ 13,550	$ (8,381)	$ (3,415)
Change in advances to GCO	4	-	-
Net cash provided by operating activities	4	-	-
Cash Flows from Investing Activities:			
Investment in GCO	(216,172)	-	(44,833)
Distributions from GCO - return of investment	17,175	10,408	5,798
Net cash provided by (used in) investing activities	(198,997)	10,408	(39,035)
Cash Flows from Financing Activities:			
Issuance of limited and general partner interests, net	216,172	-	44,833
Distributions to limited and general partners	(17,175)	(10,408)	(5,798)
Net cash (used in) provided by financing activities	198,997	(10,408)	39,035
Net increase in cash	4	-	-
Cash at beginning of period	$ 6	$ 6	$ 6
Cash at end of period	$ 10	$ 6	$ 6

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

As discussed in Note 10 of the Notes to the Consolidated Financial Statements, the terms of the credit facility with Genesis Crude Oil, L.P., or GCO, limit the amount of distributions that GCO and its subsidiaries may pay to Genesis Energy, L.P., or 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 subsidiary.

The parent company only financial statements for GEL summarize the results of operations and cash flows for the years ended December 31, 2007, 2006 and 2005, and the financial position as of December 31, 2007 and 2006. In these statements, GEL's investment in GCO is 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.

2. Contingencies

GEL guarantees the obligations of GCO under our credit facility. See Note 10 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 18 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 $46.8 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.

3. Supplemental Cash Flow Information

In July 2007, GCO common units with a value of $330 million were issued to GEL. GEL issued common units with an equal value as part of the consideration in the Davison acquisition. These transactions are non-cash transactions and are not included in the Statements of Cash Flows in investing or financing activities.