GENESIS ENERGY, L.P.
2010 ANNUAL REPORT TO UNITHOLDERS

LETTER TO OUR UNITHOLDERS

2010 was a solid year for Genesis, with segment margin improving 11.2% as compared to 2009. Our operational highlights and accomplishments for 2010 included the follow:

- Total segment margin increased $15.1 million over 2009, with improvements in our pipeline transportation and refinery services segments leading the way.
- In Pipeline Transportation, onshore crude oil pipeline transportation volumes increased by 13% and CO_2 transportation volumes increased by almost 9%.
- We acquired a 50% interest in Cameron Highway Oil Pipeline in late November. Cameron Highway owns and operates the largest (measured by length and capacity) crude oil pipeline system in the Gulf of Mexico. This investment is strategic for us and complements the integrated midstream services we provide to Gulf Coast producers and refinery complexes.
- In Refinery Services, the global demand for base metals such as copper, molybdenum and aluminum, as well as paper products and packaging materials has led to greater demand for NaHS by our mining and pulp and paper customers.
- In Supply and Logistics, our segment margin declined slightly as market conditions reduced the profitability of storing crude oil and products for future delivery and differentials between grades of petroleum products narrowed. Our barging operations experienced an improvement in day rates, encouraging us to believe we will see improved market conditions. By acquiring the 51% of our barging operations that we did not already own in July 2010, we are positioned to receive the full benefits of the improvements in the black oil barging market.
- In December 2010, we permanently eliminated the partnership's incentive distribution rights by issuing common units and "Waiver Units" to the stakeholders in our general partner. This move by us was strategic, allowing us to lower our equity cost of capital and strengthen our competitive position in the midstream energy space.
- We strengthened our access to credit by restructuring our credit agreement – increasing the amount available for us to borrow, adding an inventory tranche for more efficient financing of crude oil and petroleum products inventory, and extending the term to June of 2015. Additionally, we issued $250 million of long-term debt in a private placement in November 2010.
- We paid total distributions of approximately $79.6 million attributable to our financial and operational results for 2010. Given the total Cash Available before Reserves generated for 2010, the coverage ratio for our total distribution was approximately 1.27 times.
- The distribution for the fourth quarter of 2010 represented the twenty-second consecutive quarter with an increase in the per unit distribution. The distribution of $0.40 per unit represents an 11% increase in the distribution paid over the year earlier period. We paid a total distribution of approximately $25.8 million attributable to our financial and operational results for the fourth quarter of 2010. Given the total Cash Available before Reserves generated for the fourth quarter of 2010, the coverage ratio for our total distribution was approximately 1.13 times.

We believe we are benefiting from an ongoing improvement in our business environment that allows us to take advantage of the business opportunities presented to us by our integrated operations. We are proud of our employees and the hard work they have put into improving our operations. Because of their efforts, we were able to deliver the twenty-second consecutive quarterly increase in the distribution paid to our unitholders. Going forward, we believe that the investments we have made in 2010 along with the structural changes in the elimination of our incentive distribution rights and the additional credit we obtained in the financial markets will position us to continue to grow the partnership's value for the benefit of all of our stakeholders. We hope to be able to take advantage of both organic and/or attractive acquisition opportunities that we believe are likely to develop in 2011. Our goal is unchanged, and that is to create long-term value for all of our stakeholders.

Grant E. Sims

Chief Executive Officer

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, 2010

OR

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

Commission file number 1-12295

GENESIS ENERGY, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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 ✓

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 ✓

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 ✓ No __

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

Yes __ No __

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

✓

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 ✓ 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 ✓

The aggregate market value of the Class A common units held by non-affiliates of the Registrant on June 30, 2010 (the last business day of Registrant's most recently completed second fiscal quarter) was approximately $589,410,000 based on $19.15 per unit, the closing price of the common units as reported on the NYSE. For purposes of this computation, all executive officers, directors and 10% owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates. On March 14, 2011, the Registrant had 64,575,065 Class A common units outstanding.

GENESIS ENERGY, L.P.
2010 FORM 10-K ANNUAL REPORT
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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" as defined under federal law. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions and other such references are forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "goal," "intend," "may," "could," "plan," "position," "projection," "strategy," "should" or "will," or the negative of those 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, among others:

- *demand for, the supply of, ,our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs," NaHS and caustic soda and CO_2, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;*
- *throughput levels and rates;*
- *changes in, or challenges to, our tariff rates;*
- *our ability to successfully identify and consummate strategic acquisitions on acceptable terms, develop or construct energy infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;*
- *service interruptions in our 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;*
- *risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;*
- *changes in laws and regulations to which we are subject, including tax withholding issues, safety, environmental and employment laws and regulations;*
- *planned capital expenditures and availability of capital resources to fund capital expenditures;*
- *our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indenture governing our notes, which contain various affirmative and negative covenants;*
- *loss of key personnel;*
- *an increase in the competition that our operations encounter;*
- *cost and availability of insurance;*
- *hazards and operating risks that may not be covered fully by insurance;*
- *our financial and commodity hedging arrangements;*
    - *capital and credit markets conditions, inflation and interest rates;*
    - *natural disasters, accidents or terrorism;*
    - *changes in the financial condition of customers;*

- *the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes; and*
- *the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price.*

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A and any other risk factors contained in our Current Reports on Form 8-K that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

PART I

Item 1. Business

Unless the context otherwise requires, references to "Genesis Energy, L.P.," "Genesis," "we," "our," "us" or like terms refer to Genesis Energy, L.P. and its operating subsidiaries, including Genesis Energy Finance Corporation; "our general partner" refers to Genesis Energy, LLC, the general partner of Genesis; "Free State" refers to Genesis Free State Pipeline, LLC; "NEJD Pipeline" refers to Genesis NEJD Pipeline, LLC; "Cameron Highway" refers to the Cameron Highway Oil Pipeline Company; "Quintana" refers to Quintana Capital Group II, L.P. and its affiliates; "the Robertson Group" refers to Corbin J. Robertson, Jr., members of his family and certain of their affiliates, including Quintana Capital Group, II, L.P.; "Davison family" refers to, collectively, James E. Davison, James E. Davison, Jr., Steven K. Davison and Todd A. Davison and each of their respective families; "DG Marine" refers to DG Marine Transportation, LLC and its subsidiaries; "CO_2" means carbon dioxide; "NaHS," which is commonly pronounced as "nash," means sodium hydrosulfide; and "NaOH" and "caustic soda" mean sodium hydroxide.

Except to the extent otherwise provided, the information contained in this form is as of December 31, 2010.

General

We are a growth-oriented master limited partnership, or MLP, focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida and in the Gulf of Mexico. Formed in Delaware in 1996, our common units are traded on the New York Stock Exchange under the ticker symbol "GEL." We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, barges and trucks. We provide an integrated suite of services to oil and CO_2 producers; refineries; industrial and commercial enterprises that use NaHS and caustic soda; and businesses that use CO_2 and other industrial gases. Substantially all of our revenues are derived from providing services to integrated oil companies, large independent oil and gas or refinery companies, and large industrial and commercial enterprises.

We conduct our operations through subsidiaries and joint ventures. We manage our businesses through four divisions that constitute our reportable segments:

Pipeline Transportation—We transport crude oil and CO_2 for others for a fee in the Gulf Coast region of the U.S. through approximately 930 miles of pipeline. Our Pipeline Transportation segment owns and operates three onshore crude oil common carrier pipelines and two CO_2 pipelines. Additionally, as of November 23, 2010, we own a 50% interest in a joint venture, Cameron Highway, that operates the largest crude oil pipeline system in the Gulf of Mexico. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage terminals and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. Approximately 35 miles of gathering pipelines bring crude oil to the Jay System. Our 90-mile Texas System transports crude oil from West Columbia to several delivery points near Houston. Our crude oil pipeline systems include access to a total of approximately 0.7 million barrels of crude oil storage.

Our Free State Pipeline is an 86-mile, 20" CO_2 pipeline that extends from CO_2 source fields near Jackson, Mississippi, to oil fields in eastern Mississippi. We have a twenty-year transportation services agreement (through 2028) related to the transportation of CO_2 on our Free State Pipeline.

In addition, a subsidiary of Denbury Resources Inc. has leased from us (through 2028) the NEJD Pipeline System, a 183-mile, 20" CO_2 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana. The NEJD System transports CO_2 to tertiary oil recovery operations in southwest Mississippi.

Refinery Services—We primarily (i) provide services to ten refining operations located predominantly in Texas, Louisiana, Arkansas and Utah; (ii) operate significant storage and transportation assets in relation to those services; and (iii) sell NaHS and caustic soda to large industrial and commercial companies. Our refinery services primarily involve processing refiners' high sulfur (or "sour") gas streams to remove the sulfur. Our refinery services footprint also includes terminals, and we utilize railcars, ships, barges and trucks to transport product. Our refinery services contracts are typically long-term in nature and have an average remaining term of four years. NaHS is a by-product derived from our refinery services process, and it constitutes the sole consideration we receive for these services. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including ConocoPhillips, CITGO, Holly and Ergon. We sell our NaHS to customers in a variety of industries, with the largest customers involved in mining of base metals, primarily copper and molybdenum, and the production of pulp and paper. We believe we are one of the largest marketers of NaHS in North and South America.

Supply and Logistics—We provide services primarily to Gulf Coast oil and gas producers and refineries through a combination of purchasing, transporting, storing, blending and marketing of crude oil and refined products, primarily fuel oil. In connection with these services, we utilize our portfolio of logistical assets consisting of trucks, terminals, pipelines and barges. We have access to a suite of more than 250 trucks, 280 trailers and 1.5 million barrels of terminal storage capacity in multiple locations along the Gulf Coast as well as capacity associated with our three common carrier crude oil pipelines. In addition, our wholly-owned marine transportation subsidiary, DG Marine provides us with access to twenty barges which, in the aggregate, include approximately 660,000 barrels of refined product transportation capacity. Usually, our supply and logistics segment experiences limited commodity price risk because it utilizes back-to-back purchases and sales, matching sale and purchase volumes on a monthly basis. Unsold volumes are hedged with NYMEX derivatives to offset the remaining price risk.

Industrial Gases—We provide CO_2 and certain other industrial gases and related services to industrial and commercial enterprises. We supply CO_2 to industrial customers under long-term contracts, with an average remaining contract life of six 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. 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. In addition to supplying CO_2, we own a 50% joint venture interest in T&P Syngas Supply Company, from which we receive distributions earned from fees for manufacturing syngas (a combination of carbon monoxide and hydrogen) for Praxair Hydrogen Supply Inc., our 50% joint venture partner. Our other joint venture is a 50% interest in Sandhill Group, LLC through which we process raw CO_2 for sale to other customers for uses ranging from completing oil and natural gas producing wells to food processing.

Our Objectives and Strategies

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

Business Strategy

Our primary business strategy is to provide an integrated suite of services to oil and gas producers, refineries and other customers. Successfully executing this strategy should enable us to generate and grow sustainable cash flows. We intend to develop our business by:

- Identifying and exploiting incremental profit opportunities, including cost synergies, across an increasingly integrated footprint;

- Optimizing our existing assets and creating synergies through additional commercial and operating advancement;

- Leveraging customer relationships across business segments;

- Attracting new customers and expanding our scope of services offered to existing customers;

- Expanding the geographic reach of our refinery services and supply and logistics segments;

- Economically expanding our pipeline and terminal operations; and

- Evaluating internal and third party growth opportunities (including asset and business acquisitions) that leverage our core competencies and strengths and further integrate our businesses.

Financial Strategy

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

- Increase the relative contribution of recurring and throughput-based revenues, emphasizing longer-term contractual arrangements;

- Prudently manage our limited commodity price risks;

- Maintain a sound, disciplined capital structure; and

- Create strategic arrangements and share capital costs and risks through joint ventures and strategic alliances.

Competitive Strengths

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

- *Our businesses encompass a balanced, diversified portfolio of customers, operations and assets.* We operate four business segments and own and operate assets that enable us to provide a number of services to oil, and CO_2 producers; refinery owners; industrial and commercial enterprises that use NaHS and caustic soda; and businesses that use CO_2 and other industrial gases. Our business lines complement each other by allowing us to offer an integrated suite of services to common customers across segments.

- *Through our NaHS sales, we have indirect exposure to fast-growing, developing economies outside of the U.S.* We sell NaHS - a by-product of our refinery services process - to the mining and pulp and paper industries. Copper and other mined materials as well as paper products are sold in the global market.

- *We have lower commodity price risk exposure.* The volumes of crude oil, refined products or intermediate feedstocks that we purchase are either subject to back-to-back sales contracts or are hedged with NYMEX derivatives to limit our exposure to movements in the price of the commodity. Our risk management policy requires that we monitor the effectiveness of the hedges to maintain a value at risk of such hedged inventory that does not exceed $2.5 million. In addition, our service contracts with refiners allow us to adjust our processing rates to maintain a balance between NaHS supply and demand.

- *Our businesses provide consistent consolidated financial performance.* During the adverse economic environment that began in the third quarter of 2008 and continued until early in 2010, our businesses provided consistent performance that, when combined with our conservative capital structure, allowed us to increase our distribution for twenty-two consecutive quarters as of our most recent distribution declaration.

- *Our pipeline transportation and related assets are strategically located.* Our owned and operated crude oil pipelines, along with Cameron Highway (referred to below), are located in the Gulf Coast region and provide our customers access to multiple delivery points. In addition, a majority of our terminals are located in areas that can be accessed by truck, rail or barge.

- *We believe we are one of the largest marketers of NaHS in North and South America.* The scale of our well-established refinery services operations as well as our integrated suite of assets provides us with a unique cost advantage over some of our existing and potential competitors.

- *Our expertise and reputation for high performance standards and quality enable us to provide refiners with economic and proven services.* Our extensive understanding of the sulfur removal process and refinery services market can provide us with an advantage when evaluating new opportunities and/or markets.

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

- *We are financially flexible and have significant liquidity.* As of December 31, 2010, we had $160.4 million available under our $525 million credit agreement, including up to $31.1 million of which could be designated as a loan under the $75 million petroleum products inventory loan sublimit, and $95.4 million of which could be used for letters of credit. Our inventory borrowing base was $43.9 million at December 31, 2010.

- *We have an experienced, knowledgeable and motivated executive management team with a proven track record.* Our executive management team has an average of more than 25 years of experience in the midstream sector. Its members have worked in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. Through their equity interest in us, our senior executive management team is incentivized to create value by increasing cash flows.

2010 Developments

The following is a brief listing of developments since December 31, 2009. Additional information regarding most of these items may be found elsewhere in this report.

Permanent Elimination of IDRs

In February 2010, new investors, together with members of our executive management team, acquired our general partner. At that time, our general partner owned all our 2% general partner interest and all of our incentive distribution rights, or IDRs, and consequently was entitled to over 50% of any increased distributions we would pay in respect of our outstanding equity.

On December 28, 2010, we permanently eliminated our IDRs and converted our two percent general partner interest into a non-economic interest. In exchange for our IDRs and the 2% economic interest attributable to our general partner interest, we issued approximately 20 million common units and 7 million “Waiver Units” to the stakeholders of our general partner, less approximately 145,000 common units and 50,000 Waiver units that have been reserved for a new deferred equity compensation plan for employees. Our Waiver Units have the right to convert into common units in four equal installments in the calendar quarter during which each of our common units receives a quarterly distribution of at least $0.43, $0.46, $0.49 and $0.52, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times. Our distribution coverage ratio is computed as the ratio of our Available Cash before Reserves (also known as distributable cash flow) for a quarterly period to the total distribution to be paid with respect to that quarter.

As a result of that transaction, which we refer to as the IDR Restructuring, (i) we now have approximately 64.6 million common units outstanding (with the former stakeholders of the general partner owning approximately 45% of such units, including common units owned prior to the IDR Restructuring), (ii) our general partner has become (by way of merger) one of our wholly-owned subsidiaries, (iii) there has been no change in the composition of our board of directors and (iv) the former stakeholders of our general partner will continue to elect our board of directors in the future.

The IDR Restructuring was unanimously approved by our board of directors based, in part, on the unanimous approval and recommendation of the board’s conflicts committee, which is comprised solely of independent directors. The conflicts committee engaged independent financial and legal advisors and obtained a fairness opinion. The organizational structure resulting from the IDR Restructuring is also shown in the chart below.

Cameron Highway Acquisition

On November 23, 2010, we acquired a 50% interest in Cameron Highway for approximately $330 million. Cameron Highway, a joint venture with Enterprise Products Partners, L.P. (Enterprise Products), owns and operates the largest (measured by both length and capacity) crude oil pipeline system in the Gulf of Mexico. Constructed in 2004, the Cameron Highway oil pipeline system, or CHOPS, is comprised of 380 miles of 24- and 30- inch diameter pipeline with capacity to deliver up to 500,000 barrels per day of crude oil from developments in the Gulf of Mexico to refining markets along the Texas Gulf Coast located in Port Arthur and Texas City, Texas. When we acquired our interest in Cameron Highway, its assets included CHOPS, approximately $50 million of crude oil linefill and $9 million in pumping equipment (in each case, net to acquired 50% interest). Enterprise Products owns the remaining 50% interest in, and operates, the joint venture. We financed the purchase price for the acquisition primarily with the net proceeds of approximately $119 million from an underwritten public offering of 5.2 million of our common units (including the overallotment option that the underwriters exercised in full and including our general partner's proportionate capital contribution to maintain its 2% general partner interest) at $23.58 per common unit and net proceeds of approximately $243 million from a private placement of $250 million in aggregate principal amount of 7.875% senior unsecured notes due 2018. We used $23.8 million in excess net proceeds to temporarily reduce the balance outstanding under our revolving credit agreement.

Acquisition of Remaining 51% Interest in DG Marine

On July 28, 2010, we acquired the 51% economic interest in DG Marine that we did not already own from TD Marine (a related party) for $25.5 million, resulting in DG Marine becoming our wholly-owned subsidiary. Originally formed in 2008, DG Marine was a joint venture in which we owned a 49% economic interest and TD Marine owned the remaining 51% economic interest. DG Marine provides transportation services of petroleum products by barge, which complements our other supply and logistics operations.

Restructured Credit Agreement

On June 29, 2010, we restructured our credit agreement. Our credit agreement now provides for a $525 million senior secured revolving credit facility, includes an accordion feature whereby the total credit available can be increased up to $650 million under certain circumstances, and matures on June 30, 2015. Among other modifications, our credit agreement now includes a $75 million sublimit tranche designed for more efficient financing of crude oil and petroleum products inventory.

Twenty-Two Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for twenty-two consecutive quarters. On February 14, 2011, we paid a quarterly cash distribution of $0.40 (or $1.60 annually) per unit to unitholders of record as of February 2, 2011, an increase per unit of $0.0125 (or 3.2%) from the distribution in the prior quarter, and an increase of 11.1% from the distribution in February 2010. As in the past, future increases (if any) in our quarterly distribution rate will depend on our ability to execute critical components of our business strategy.

Organizational Structure

On February 5, 2010, a group of investors acquired all of the equity interest in our general partner (including the interest owned by our executives), although certain of our executives were allowed to participate as members of that investment group to the extent of their prior ownership interest.

On December 28, 2010, pursuant to the IDR Restructuring, the incentive distribution rights held by our general partner were extinguished and the 2% general partner interest in us that our general partner held was converted into a non-economic general partner interest. The former stakeholders of our general partner, which included certain members of executive management team, received approximately 27,000,000 units in us, consisting of: (i) approximately 19,960,000 traditional common units, or Class A Units, (ii) approximately 40,000 Class B common units, or Class B Units, with rights, preferences and privileges of the Class A Units and rights to elect our board of directors and convertible into Class A Units and (iii) approximately 7,000,000 Waiver Units, convertible into Class A Units. The directors of our general partner before the IDR Restructuring remained as directors after the IDR Restructuring. After the IDR Restructuring, through their Class B Units, the former stakeholders of our general partner retained the right to elect our board of directors.

The Class A Units are traditional common units in us. The Class B Units are identical to the Class A Units and, accordingly, have voting and distribution rights equivalent to those of the Class A Units, and, in addition, Class B Units have the right to elect all of our board of directors, subject to the Davison Family's right to elect up to three directors under certain terms pursuant to a unitholders rights agreement. The Class B Units are convertible into Class A Units under certain circumstances. The Waiver Units are non-voting securities entitled to a minimal preferential quarterly distribution and are comprised of four classes (designated Class 1, Class 2, Class 3 and Class 4) of 1,750,000 authorized units each. The Waiver Units have the right to convert into Class A Units at the rate of one Class A Unit for each Waiver Unit under certain circumstances.

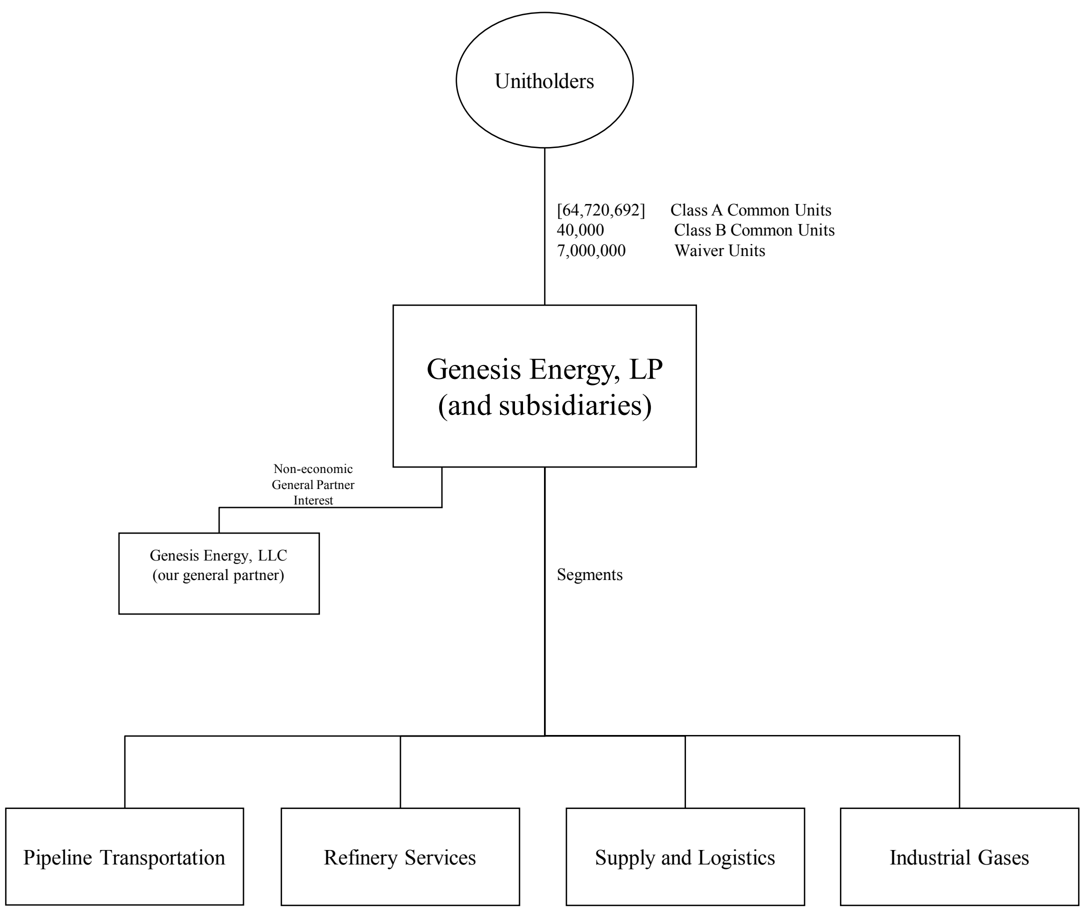
The primary benefit realized from the IDR Restructuring was the elimination of our IDRs, which represented the right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels had been achieved. Our cost of issuing new units to facilitate our continuing growth included not only the distributions payable to such new unitholders, but also the percent of our aggregate quarterly distributions we pay to our general partner in respect of our general partner interest (2%) and IDRs (approximately 49%). The elimination of our IDRs substantially lowers our cost of equity capital and increases the cash available to be distributed to our common unitholders. Additionally, the elimination of the IDRs enhances our ability to compete for new acquisitions and improves the returns to our unitholders on all future expansion projects.

Below are charts depicting our ownership structure before and after the IDR Restructuring.

Organizational Chart

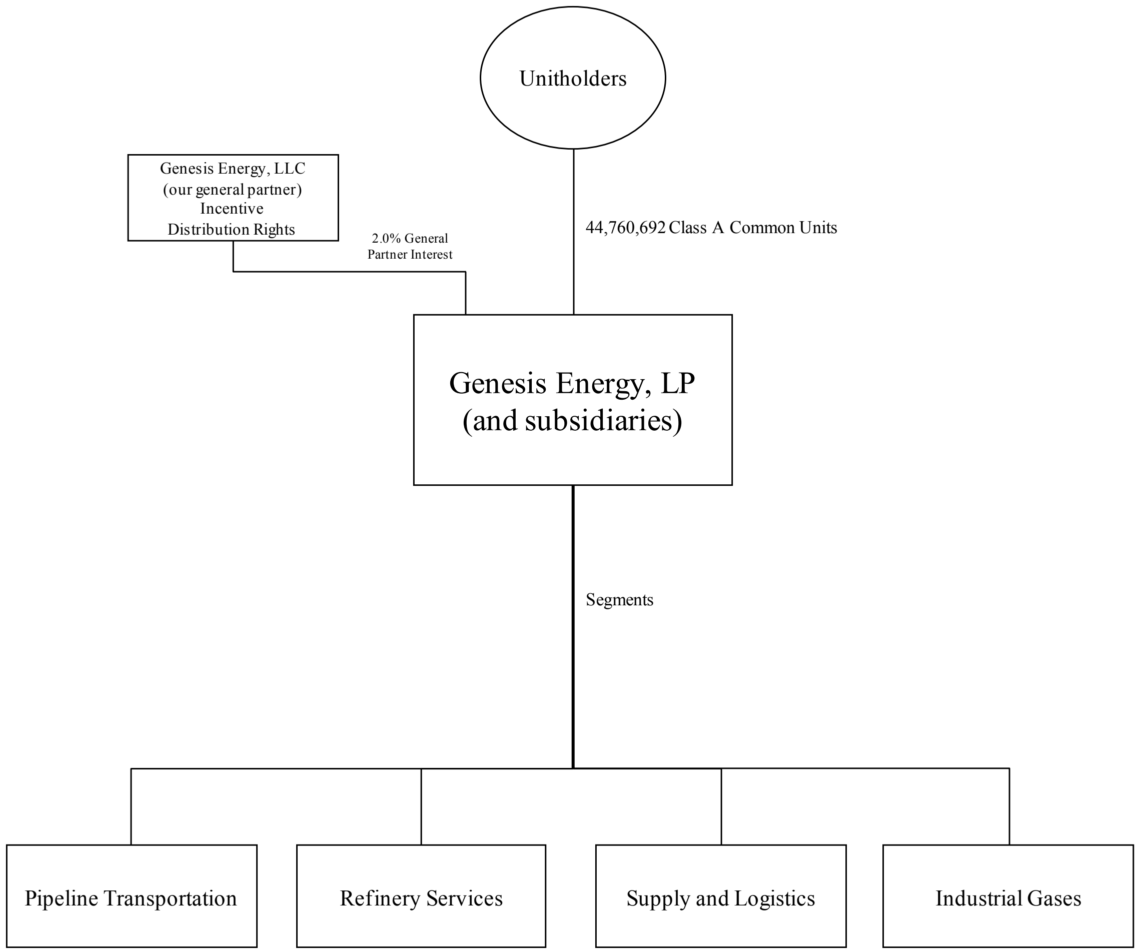
Existing

After the IDR Restructuring on December 28, 2010:



Prior

Before the IDR Restructuring on December 28, 2010:



Description of Segments and Related Assets

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

We own three onshore crude oil common carrier pipelines, a 50% interest in CHOPS and two CO_2 pipelines.

Crude Oil Pipelines

Our core pipeline transportation business is the transportation of crude oil for others for a fee.

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

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

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

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

- *Mississippi System* Our Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminals and other crude oil infrastructure located in the Midwest. The system is adjacent to several oil fields that are in various phases of being produced through tertiary recovery strategy, including CO_2 injection and flooding. Increased production from these fields could create increased demand for our crude oil transportation services because of the close proximity of our pipeline. We provide transportation services on our Mississippi pipeline through an "incentive" tariff which provides that the average rate per barrel that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.
- *Jay System*. Our Jay System provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. We completed construction of a gathering pipeline in 2009 extending to producers operating in southern Alabama and providing access to our Jay System. The lateral consists of approximately 33 miles of 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 system also includes gathering connections to approximately 35 wells, additional oil storage capacity of 20,000 barrels in the field and a delivery connection to a refinery in Alabama.
- *Texas System*. Our Texas System transports crude oil from West Columbia to several delivery points near Houston. The Texas System receives all of its volume from connections to other pipeline carriers. We earn a tariff for our transportation services, with the tariff rate per barrel of crude oil varying with the distance from injection point to delivery point. We entered into a joint tariff with TEPPCO, now known as Enterprise Crude Oil Pipeline Company, 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 Blueknight Energy Partners at Webster. We have a tank rental reimbursement agreement with the primary shipper on our Texas System to reimburse us for the lease of 165,000 barrels of storage capacity at Webster.

Offshore Crude Oil Pipeline. On November 23, 2010, we acquired a 50% interest in Cameron Highway Oil Pipeline Company, a crude oil pipeline joint venture with Enterprise Products Partners, L.P. The Cameron Highway oil pipeline system is the largest (measured by both length and capacity) crude oil pipeline system in the Gulf of Mexico, which represented approximately 30%, 29% and 23% of U.S. oil production during 2010, 2009 and 2008, respectively.

	CHOPS
Product	Crude oil
Interest owned	50%
System miles	380
Location	Gulf of Mexico (primarily offshore of Texas and Louisiana)
Regulated/Unregulated	Unregulated
In-service date	2004
Capacity (Bbls/day)	500,000

CHOPS is comprised of 24- and 30- inch diameter pipelines to deliver crude oil from developments in the Gulf of Mexico to refining markets along the Texas Gulf Coast via interconnections with refineries located in Port Arthur and Texas City, Texas. CHOPS also includes two strategically located multi-purpose offshore platforms. Enterprise Products owns the remaining 50% interest in, and operates, the joint venture.

CHOPS was constructed in response to a need for additional pipeline capacity to handle crude oil production from deepwater region discoveries in the Gulf of Mexico, primarily offshore of Texas and Louisiana. Its anchor customers, subsidiaries of BP p.l.c., BHP Billiton Group and Chevron Corporation, dedicated their production from approximately 86,400 acres to CHOPS for the life of the reserves underlying such acreage, which dedications included the prolific Mad Dog and Atlantis fields as well as other deepwater oil discoveries. Those producer agreements include both firm and, to the extent CHOPS has any remaining capacity, interruptible capacity arrangements. Since its formation, Cameron Highway has entered into handling arrangements with numerous other producers pursuant to both firm and interruptible capacity arrangements covering deepwater discoveries, including Constitution, Ticonderoga, K2, Shenzi, Front Runner, Cottonwood and Tahiti.

The pipeline has significant available capacity to accommodate future growth in the fields from which the production is dedicated to the pipeline as well as to transport volumes from non-dedicated fields both currently in production and to be developed in the future. Since we acquired our interest CHOPS has averaged 149,000 barrels per day of revenue volumes.

CO_2 Pipelines

We transport CO2 on our Free State Pipeline and the Northeast Jackson Dome Pipeline System, or the NEJD System, for a fee.

	Free State Pipeline	NEJD System *
Product	CO_2	CO_2
Interest owned	100%	100%
System miles	86	183
Pipeline diameter	20”	20”
Location	Jackson Dome near Jackson, Mississippi to East Mississippi	Jackson Dome near Jackson, Mississippi to Donaldsonville, Louisiana
Regulated/Unregulated	Unregulated	Unregulated

*Subject to fixed payment agreement.

Our Free State Pipeline extends from CO_2 source fields near Jackson, Mississippi to oil fields in eastern Mississippi. We have a twenty-year transportation services agreement (through 2028) related to the transportation of CO2 on our Free State Pipeline.

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

Customers

Currently greater than 90% of the volume on the Mississippi System originates from oil fields operated by Denbury. Denbury is the largest producer (based upon average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury's existing and prospective fields. Our customers on our Mississippi, Jay and Texas systems are primarily large, energy companies. Denbury has exclusive use of the NEJD Pipeline System and is responsible for all operations and maintenance on that system and will bear and assume all obligations and liabilities with respect to that system. Currently, Denbury also has rights to exclusive use of our Free State Pipeline.

Due to the cost of finding, developing and producing oil properties in the deepwater regions of the Gulf of Mexico, most of Cameron Highway's customers are integrated oil companies and other large producers, and those producers desire to have longer-term arrangements ensuring that their production can access the markets. Usually, Cameron Highway and each of its customers enter into buy-sell arrangements, pursuant to which Cameron Highway acquires from its customer the relevant production at a specified location (often a producer's platform or at another interconnection with CHOPS) and sells such customer an equivalent volume at one or more specified downstream locations (such as a refinery or an interconnection with another pipeline). Most of the production handled by CHOPS is pursuant to life-of-reserve commitments that include both firm and interruptible capacity arrangements.

Revenues from customers of our pipeline transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

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

Cameron Highway's principal competition includes other crude oil pipeline systems (such as Poseidon) as well as producers who may elect to build or utilize their own production handling facilities. Cameron Highway competes for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. In addition, the ability of CHOPS to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production. In general, CHOPS is not subject to regulatory rate-making authority, and the rates it charges for its services are dependent on the quality of the service required by its customer and the amount and term of the reserve commitment by that customer.

Refinery Services

Our refinery services segment primarily (i) provides sulfur-extraction services to ten refining operations predominately located in Texas, Louisiana, Arkansas and Utah, (ii) operate significant storage and transportation assets in relation to our business and (iii) sell NaHS and caustic soda (or NaOH) to large industrial and commercial companies. Our refinery services activities involve processing high sulfur (or "sour") gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses large quantities of caustic soda (the primary raw material used in our process) to act as a scrubbing agent under prescribed temperature and pressure to remove sulfur. Sulfur removal in a refinery is a key factor in optimizing production of refined products such as gasoline, diesel and aviation fuel. Our sulfur removal technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. The resultant NaHS constitutes the sole consideration we receive for our refinery services activities. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including ConocoPhillips, CITGO, Holly, and Ergon.

Our refinery services footprint also includes terminals, and we utilize railcars, ships, barges and trucks to transport product. In conjunction with our supply and logistics segment, we sell and deliver NaHS and caustic soda to over 100 customers. We believe we are one of the largest marketers of NaHS in North and South America. By minimizing our costs by utilizing our own logistical assets and leased storage sites, we believe we have a competitive advantage over other suppliers of NaHS. Our refinery services contracts are typically long-term in nature and have an average remaining term of four years.

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

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

We believe that the demand for sulfur removal at U.S. refineries will increase in the years ahead as the quality of the oil supply used by refineries in the U.S. continues to drop (or become more "sour") and the residual level of sulfur allowed in lubricants and fuels is required to be reduced by regulatory agencies domestically and internationally. As that occurs, we believe more refineries will seek economic and proven sulfur removal processes from reputable service providers that have the scale and logistical capabilities to efficiently perform such services. Because of our existing scale, we believe we will be able to attract some of these refineries as new customers for our sulfur handling/removal services, providing us the capacity to meet any increases in NaHS demand.

Customers

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

We sell our NaHS to customers in a variety of industries, with the largest customers involved in mining of base metals, primarily copper and molybdenum and the production of pulp and paper. We sell to customers in the copper mining industry in the western United States, Canada and Mexico. We also export the NaHS to South America for sale to customers for mining in Peru and Chile. No customer of the refinery services segment is responsible for more than ten percent of our consolidated revenues. Approximately 11% of the revenues of the refinery services segment in 2010 resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc. Many of the industries that our NaHS customers are in (such as copper mining and the pulp and paper industry) participate in global markets for their products. As a result, this creates an indirect exposure for NaHS to global demand for the end products of our customers. During 2010, global demand for copper, molybdenum and paper increased, providing increased demand for our NaHS. Provisions in our service contracts with refiners allow us to adjust our sour gas processing rates (sulfur removal) to maintain a balance between NaHS supply and demand.

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

Competition

We believe that the U.S. refinery industry's demand for sulfur extraction services will increase because we believe sour oil will constitute an increasing portion of the total worldwide supply of crude oil and the phase in of stricter passenger vehicle emission standards will require refiners to produce additional quantities of low sulfur fuels. Both of these conditions can be met by refineries installing our sulfur removal technology under refinery service agreements. While other options exist for the removal of sulfur from sour oil, we believe our existing customers are unlikely to change to another method due to the costs involved, our proven reliability and the regulatory permit processes required when changing methods of handling sulfur. NaHS technology is a reliable and cost effective manner to control refinery operating costs regardless of the crude slate being processed. In addition, we have an increasing array of services we can offer to our refinery customers, and we believe our proprietary knowledge, scale, logistics capabilities and safety and service record will encourage these refineries to continue to outsource their existing refinery services functions to us.

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

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

Supply and Logistics

Through our supply and logistics segment we provide a wide array of services to oil producers and refiners in the Gulf Coast region. In connection with these services, we utilize our portfolio of logistical assets consisting of trucks, terminals, pipelines and barges. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by truck to pipeline injection points and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via truck, railcar or barge, and sell refined products to customers in wholesale markets. For our supply and logistics services, we generate fee-based income and profit from the difference between the price at which we re-sell the crude oil and petroleum products less the price at which we purchase the oil and products, minus the associated costs of aggregation and transportation.

Our crude oil supply and logistics operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations help to ensure (among other things) a base supply source for our oil pipeline systems and our refinery customers while providing our producer customers with a market outlet for their production. Usually, our supply and logistics segment experiences limited commodity price risk because it involves back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis. Unsold volumes are hedged with NYMEX derivatives to offset the remaining price risk. By utilizing our network of trucks, terminals and pipelines, we are able to provide transportation related services to crude oil producers and refiners as well as enter into back-to-back gathering and marketing arrangements with these same parties. Additionally, our crude oil gathering and marketing expertise and knowledge base, provides us with an ability to capitalize on opportunities that arise from time to time in our market areas. Given our network of terminals, we have the ability to store crude oil during periods of contango (oil prices for future deliveries are higher than for current deliveries) for delivery in future months. When we purchase and store crude oil during periods of contango, we limit commodity price risk by simultaneously entering into a contract to sell the inventory in the future period, either with a counterparty or in the crude oil futures market. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with generally accepted accounting principles. The most substantial component of the costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks.

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

Within our supply and logistics business segment, to meet our customer needs, we employ many types of logistically flexible assets. These assets include 250 trucks, 280 trailers, 20 barges with approximately 660,000 barrels of refined products transportation capacity, 1.5 million barrels of leased and owned terminal storage capacity in multiple locations along the Gulf Coast, accessible by truck, rail or barge.

Customers

Our supply and logistics business encompasses hundreds of producers and customers, for which we provide transportation related services, as well as gather from and market to crude oil and refined products. During 2010, more than ten percent of our consolidated revenues were generated from Shell Oil Company. We do not believe that the loss of any one customer for crude oil or petroleum products would have a material adverse effect on us as these products are readily marketable commodities.

Competition

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

Industrial Gases

Overview

Our industrial gases segment is a natural outgrowth from our pipeline transportation business. We (i) supply CO_2 to industrial customers, (ii) process raw CO_2 and sell that processed CO_2, and (iii) manufacture and sell syngas, a combination of carbon monoxide and hydrogen.

CO_2 – Industrial Customers

We supply CO_2 to industrial customers currently under six long-term contracts, with an average remaining contract life of six years. Our compensation for supplying CO_2 to our industrial customers, who treat the CO_2 and sell it to end users for use in beverage carbonation and chilling and freezing food, 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. 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. At December 31, 2010, we had 100.2 Bcf of CO_2 remaining under the VPPs.

All of our CO_2 supply is currently from our interests—our VPPs—in fields producing naturally occurring CO_2. The agreements we executed when we acquired the VPPs provide that we may acquire additional CO_2 under terms similar to the original agreements should additional volumes be needed to meet our obligations under the existing customer contracts. These contracts expire between 2011 and 2023. Based on the current volumes being sold to our customers, we believe that we will need to acquire additional volumes pursuant to our VPPs in 2014. When our VPPs expire, we will have to obtain additional CO_2 supply if we choose to remain in the CO_2 supply business.

CO_2 – Processing

Our other joint venture is a 50% interest in Sandhill Group, LLC, or Sandhill, through which we process raw CO_2 for sale to other customers for uses ranging from completing oil and natural gas producing wells to food processing. Reliant Processing Ltd. owns the remaining 50% of Sandhill. Sandhill's facility acquires CO_2 from us under a long-term supply contract. This contract expires in 2023 and provides for a maximum daily contract quantity of 16,000 Mcf per day with a take-or-pay minimum quantity of 2,500,000 Mcf per year.

Syngas

We own a 50% joint venture interest in T&P Syngas Supply Company, from which we receive distributions earned from fees for manufacturing syngas (a combination of carbon monoxide and hydrogen) by Praxair Hydrogen Supply Inc., or Praxair, our 50% joint venture partner. Under a long-term processing agreement, the joint venture receives fees from its sole customer, Praxair, during periods when processing occurs, and Praxair has the exclusive right to use the facility through at least 2016, which Praxair has the option to extend for two additional five-year terms. Praxair owns the remaining 50% interest in that joint venture.

Customers

A majority of our contracts for supplying CO_2 are with large international companies. One of our sales contracts expired on January 31, 2011. Sales under this contract accounted for $1.8 million, or 11%, of our industrial gases revenues in 2010. Revenues from this segment did not account for more than ten percent of our consolidated revenues. The sole customer of T&P Syngas is Praxair, a worldwide provider of industrial gases. Sandhill sells to approximately 30 customers, with sales to three of those customers representing approximately 70% of Sandhill's total revenues of approximately $9.8 million in 2010. In 2010, Sandhill sold approximately $1.4 million of CO_2 to affiliates of Reliant Processing Ltd., our partner in Sandhill, as discussed above. Sandhill has long-term relationships with those customers and has not experienced collection problems with them.

Competition

Currently, all of our CO_2 supply is from our interest—our VPPs—in fields producing naturally occurring sources. In the future, we may have to obtain our CO_2 supply from manufactured processes. Naturally-occurring CO_2, like that from the Jackson Dome area, occurs infrequently, and only in limited areas east of the Mississippi River. Our industrial CO_2 customers have facilities that are connected to the NEJD Pipeline, which makes delivery easy and efficient. Once our existing VPPs expire, we will have to obtain additional CO_2 should we choose to remain in the CO_2 supply business, and the competition and pricing issues we will face at that time are uncertain. Due to the long-term contract and location of our syngas facility, as well as the costs involved in establishing facilities, we believe it is unlikely that competing facilities will be established for our syngas processing services. Sandhill has competition from the other industrial customers to whom we supply CO_2. As discussed above, the limited amounts of naturally-occurring CO_2 east of the Mississippi River makes it difficult for competitors of Sandhill to significantly increase their production or sales and, thereby, increase their market share.

Geographic Segments

All of our operations are in the United States. Additionally, we transport and sell NaHS to customers in South America and Canada. Revenues from customers in foreign countries totaled approximately $14.5 million and $9.5 million in 2010 and 2009, respectively. The remainder of our revenues in 2010 and 2009 and all of our revenues in 2008 were generated from sales to customers in the United States.

Credit Exposure

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

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

Some of our customers experienced cash flow difficulties in 2010 and 2009 as a result of the state of the credit markets and the economic recession in the United States. These customers generally purchase petroleum products and NaHS from us. Our credit monitoring procedures includes frequent reviews of our customer base. As a result of cash flow difficulties of some of our customers, we have experienced a delay in collections from these customers and established an allowance for possible uncollectible receivables at December 31, 2010 and 2009 in the amount of $1.3 million and $1.4 million, respectively. During 2010, we charged approximately $0.5 million to bad debt expense in our Consolidated Statements of Operations.

Employees

To carry out our business activities, we employed approximately 690 employees at December 31, 2010. None of our employees are represented by labor unions, and we believe that relationships with our employees are good.

Regulation

<u>*Pipeline Rate and Access Regulation*</u>

The rates and the terms and conditions of service of our interstate common carrier pipeline operations are subject to regulation by FERC under the Interstate Commerce Act, or ICA. Under the ICA, rates must be "just and reasonable," and must not be unduly discriminatory or confer any undue preference on any shipper. FERC regulations require that oil pipeline rates and terms and conditions of service be filed with FERC and posted publicly.

Effective January 1, 1995, FERC promulgated rules simplifying and streamlining the ratemaking process. Previously established rates were "grandfathered", limiting the challenges that could be made to existing tariff rates. Increases from grandfathered rates of interstate oil pipelines are currently regulated by the FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the year-to-year change in an index. Under the FERC regulations, we are able to change our rates within prescribed ceiling levels that are tied to the Producer Price Index for Finished Goods. Rate increases made pursuant to the index will be subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs.

In addition to the index methodology, FERC allows for rate changes under three other methods—cost-of-service, competitive market showings ("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.

CHOPS is neither an interstate nor a common carrier pipeline. However, it is subject to federal regulation under the Outer Continental Shelf Lands Act, which requires all pipelines operating on or across the outer continental shelf to provide nondiscriminatory transportation service.

Our intrastate common carrier pipeline operations in Texas are subject to regulation by the Railroad Commission of Texas. The applicable Texas statutes require that pipeline rates and practices be reasonable and non-discriminatory and that pipeline rates provide a fair return on the aggregate value of the property of a common carrier, after providing reasonable allowance for depreciation and other factors and for reasonable operating expenses. Most of the volume on our Texas System is now shipped under joint tariffs with 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 CO_2 pipelines are subject to regulation by the state agencies in the states in which they are located.

<u>*Marine Regulations*</u>

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues. Federal regulations also require that all tank barges engaged in the transportation of oil and petroleum in the U.S. be double hulled by 2015. All of our barges are double-hulled.

Jones Act. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. We are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. Jones Act requirements significantly increase operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Further, the USCG and American Bureau of Shipping ("ABS") maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

Merchant Marine Act of 1936. The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the president of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

Environmental Regulations

General

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

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons. These persons include current owners and operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. We currently own or lease, and have in the past owned or leased, properties that have been in use for many years with the gathering and transportation of hydrocarbons including crude oil and other activities that could cause an environmental impact. Persons deemed "responsible persons" under CERCLA may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

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

Water

The Federal Water Pollution Control Act, as amended, also known as the "Clean Water Act", and analogous state laws impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including oil, into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The Oil Pollution Act, or OPA, is the primary federal law for oil spill liability. OPA contains numerous requirements relating to the prevention of and response to oil spills into waters of the

United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with the Clean Water Act or OPA may result insubstantial civil and criminal penalties. We believe we are in material compliance with each of these requirements.

Air Emissions

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

NEPA

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

Climate Change

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security (ACES) Act that, among other things, would have established a cap-and-trade system to regulate greenhouse gas emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to again consider a climate change bill in the future. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Any laws or regulations that may be adopted to restrict or reduce emissions of GHG emissions could require us to incur increased operating costs, and could have an adverse affect on demand for the refined products produced by our refining customers.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO2 emissions from automobiles as “air pollutants” under the Clean Air Act, or the CAA. Thereafter, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because, according to the EPA, emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA recently adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

Safety and Security Regulations

Our crude oil and CO_2 pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation, or DOT, and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines pursuant to detailed regulations set forth in 49 C.F.R. Parts 190 to 195. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

We are subject to the DOT Integrity Management, or IM, regulations, which require that we perform baseline assessments of all pipelines that could affect a High Consequence Area, or HCA, including certain populated areas and environmentally sensitive areas. Due to the proximity of all of our pipelines to water crossings and populated areas, we have designated all of our pipelines as affecting HCAs. The integrity of these pipelines must be assessed by internal inspection, pressure test, or equivalent alternative new technology.

The IM regulations required us to prepare an Integrity Management Plan, or IMP, that details the risk assessment factors, the overall risk rating for each segment of pipe, a schedule for completing the integrity assessment, the methods to assess pipeline integrity, and an explanation of the assessment methods selected. The regulations also require periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address pipeline integrity issues. No assurance can be given that the cost of testing and the required rehabilitation identified will not be material costs to us that may not be fully recoverable by tariff increases.

We have developed a Risk Management Plan required by the EPA as part of our IMP. This plan is intended to minimize the offsite consequences of catastrophic spills. As part of this program, we have developed a mapping program. This mapping program identified HCAs and unusually sensitive areas along the pipeline right-of-ways in addition to mapping of shorelines to characterize the potential impact of a spill of crude oil on waterways.

Our crude oil, refined products and refinery services operations are also subject to the requirements of OSHA and comparable state statutes. Various other federal and state regulations require that we train all operations employees in HAZCOM and disclose information about the hazardous materials used in our operations. Certain information must be reported to employees, government agencies and local citizens upon request.

States are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to hazardous liquids pipelines, including crude oil, natural gas, and CO_2 pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

Our trucking operations are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety, and many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

The USCG regulates occupational health standards related to our marine operations. Shore-side operations are subject to the regulations of OSHA and comparable state statutes. The Maritime Transportation Security Act requires, among other things, submission to and approval of the USCG of vessel security plans.

Since the terrorist attacks of September 11, 2001, the United States Government has issued numerous warnings that energy assets could be the subject of future terrorist attacks. We have instituted security measures and procedures in conformity with federal guidance. We will institute, as appropriate, additional security measures or procedures indicated by the federal government. None of these measures or procedures should be construed as a guarantee that our assets are protected in the event of a terrorist attack.

Website Access to Reports

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

Item 1A. Risk Factors

Risks Related to Our Business

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

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

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

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

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

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

Continued uncertainty in the credit markets and concerns about local and global economic growth have had a significant adverse impact on global financial markets. If these disruptions, which have occurred over the last several years, reappear, they could negatively impact our cash flows and profitability. Tightening of the credit markets, lower levels of liquidity in many financial markets, and extreme volatility in fixed income, credit and equity markets could limit our access to capital. Our credit facility arrangements involve twelve different lending institutions. While none of these institutions have combined or ceased operations, further consolidation of the credit markets could result in lenders desiring to limit their exposure to an individual enterprise. Additionally, some institutions may desire to limit exposure to certain business activities in which we are engaged. Such consolidations or limitations could impact us when we desire to extend or make changes to our existing credit arrangements.

Additionally, significant decreases in our operating cash flows could affect the fair value of our long-lived assets and result in impairment charges. At December 31, 2010, we had $325 million of goodwill recorded on our Consolidated Balance Sheet.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our credit facility are variable. Interest rates in 2010 remained low, reducing our interest costs. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases in interest rates.

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

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, barge and pipeline transportation services;
- the volumes of CO_2 we sell and the prices at which we sell it;
- the demand for our terminal storage services;
- the level of our operating costs;
- the level of our general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors that include:

- the level of capital expenditures we make, including the cost of acquisitions (if any);
- our debt service requirements;
- fluctuations in our working capital;
- restrictions on distributions contained in our debt instruments;
- our ability to borrow under our working capital facility to pay distributions; and
- the amount of cash reserves required in the conduct of our business.

Our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

Our indebtedness could adversely restrict our ability to operate, affect our financial condition, and prevent us from complying with our requirements under our debt instruments and could prevent us from paying cash distributions to our unitholders.

We have outstanding debt and the ability to incur more debt. As of December 31, 2010, we had approximately $360 million outstanding of senior secured indebtedness of Genesis and an additional $250 million of senior unsecured indebtedness.

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

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- make guarantees;

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

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

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

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

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity - oil, refined products, NaHS and caustic soda - volumes, which often depends on actions and commitments by parties beyond our control.

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

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

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

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

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

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

A substantial portion of our CO_2 operations involves us supplying CO_2 to industrial customers using reserves attributable to our volumetric production payment interests, which are a finite resource and projected to begin to decline significantly around 2015.

The cash flow from our CO_2 operations involves us supplying CO_2 to industrial customers using reserves attributable to our volumetric production payments. Unless we are able to obtain a replacement supply of CO_2 and enter into sales arrangements that generate substantially similar economics, our cash flow from those contracts could begin to decline around 2015 as some of our CO_2 industrial sales contracts expire.

Fluctuations in demand for CO_2 by our customers could have an 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 CO_2.

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

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

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

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

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

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

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

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

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

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

Fluctuations in commodity prices could adversely affect our business.

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

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

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

In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all of the interest owners. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint.

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

Additionally, many of our customers were impacted by the weakened economic conditions experienced in recent years in a manner that influenced the need for our products and services and their ability to pay us for those products and services.

Our wholesale CO_2 industrial operations are dependent on five customers and our syngas operations are dependent on one customer.

If one or more of those customers experience financial difficulties or any deterioration in its ability to satisfy its obligations, (including failing to purchase their required minimum take-or-pay volumes), our cash flows could be adversely affected.

Our Syngas joint venture has dedicated 100% of its syngas processing capacity to one customer pursuant to a processing contract. The contract term expires in 2016, unless our customer elects to extend the contract for one or two additional five year terms. If our customer reduces or discontinues its business with us, or if we are not able to successfully negotiate a replacement contract with our sole customer after the expiration of such contract, or if the replacement contract is on less favorable terms, the effect on us will be adverse. In addition, if our sole customer for syngas processing were to experience financial difficulties or any deterioration in its ability to satisfy its obligations to us (including failing to provide volumes to process), our cash flow from the syngas joint venture could be adversely affected.

Our refinery services division is dependent on contracts with less than fifteen refineries and much of its revenue is attributable to a few refineries.

If one or more of our refinery customers that, individually or in the aggregate, generate a material portion of our refinery services revenue experience financial difficulties or changes in their strategy for sulfur removal such that they do not need our services, our cash flows could be adversely affected. For example, in 2010, approximately 70% of our refinery services' division NaHS by-product was attributable to Conoco's refinery located in Westlake, Louisiana. That contract requires Conoco to make available minimum volumes of sour gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if, for any reason, Conoco does not meet its obligations under that contract for an extended period of time, such non-performance could have a material adverse effect on our profitability and cash flow.

Our CO_2 operations are exposed to risks related to Denbury's operation of its CO_2 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. 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 CO_2-related operations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Some of our operations involve significant risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations and otherwise expose us to liability and adversely affect our cash flow. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes. A significant portion of our operations are located along the U.S. Gulf Coast, and Cameron Highway is located in the Gulf of Mexico. These areas can be subject to hurricanes.

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

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

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

Due to the nature of joint ventures, each participant (including us) in our 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% owners in our Cameron Highway, T&P Syngas and Sandhill joint ventures operate those 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.

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

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

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

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

- being subject to the Jones Act and other federal laws that restrict U.S. maritime transportation to vessels built and registered in the U.S. and owned and manned by U.S. citizens, with any failure to comply with such laws potentially resulting in severe penalties, including permanent loss of U.S. coastwise trading rights, fines or forfeiture of vessels;
- relying on a limited number of customers;
- having primarily short-term charters which DG Marine may be unable to renew as they expire; and
- competing against businesses with greater financial resources and larger operating crews than DG Marine.

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

Our business would be adversely affected if we failed to comply with the Jones Act foreign ownership provisions.

We are subject to the Jones Act and other federal laws that restrict maritime cargo transportation between points in the United States only to vessels operating under the U.S. flag, built in the United States, at least 75% owned and operated by U.S. citizens (or owned and operated by other entities meeting U.S. citizenship requirements to own vessels operating in the U.S. coastwise trade and, in the case of limited partnerships, where the general partner meets U.S. citizenship requirements) and manned by U.S. crews. To maintain our privilege of operating DG Marine's vessels in the Jones Act trade, we must maintain U.S. citizen status for Jones Act purposes. To ensure compliance with the Jones Act, we must be U.S. citizens qualified to document vessels for coastwise trade. We could cease being a U.S. citizen if certain events were to occur, including if non-U.S. citizens were to own 25% or more of our equity interest or were otherwise deemed to control us or our general partner. We are responsible for monitoring ownership to ensure compliance with the Jones Act. The consequences of our failure to comply with the Jones Act provisions on coastwise trade, including failing to qualify as a U.S. citizen, would have an adverse effect on us as we may be prohibited from operating DG Marine's vessels in the U.S. coastwise trade or, under certain circumstances, permanently lose U.S. coastwise trading rights or be subject to fines or forfeiture of DG Marine's vessels.

Our business would be adversely affected if the Jones Act provisions on coastwise trade or international trade agreements were modified or repealed or as a result of modifications to existing legislation or

regulations governing the oil and gas industry in response to the Deepwater Horizon drilling rig incident in the U.S. Gulf of Mexico and subsequent oil spill.

If the restrictions contained in the Jones Act were repealed or altered or certain international trade agreements were changed, the maritime transportation of cargo between U.S. ports could be opened to foreign flag or foreign-built vessels. The Secretary of the Department of Homeland Security, or the Secretary, is vested with the authority and discretion to waive the coastwise laws if the Secretary deems that such action is necessary in the interest of national defense. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign product carrier and barge operators, which could reduce our revenues and cash available for distribution. In the past several years, interest groups have lobbied Congress to repeal or modify the Jones Act to facilitate foreign-flag competition for trades and cargoes currently reserved for U.S. flag vessels under the Jones Act. Foreign-flag vessels generally have lower construction costs and generally operate at significantly lower costs than we do in U.S. markets, which would likely result in reduced charter rates. We believe that continued efforts will be made to modify or repeal the Jones Act. If these efforts are successful, foreign-flag vessels could be permitted to trade in the United States coastwise trade and significantly increase competition with our fleet, which could have an adverse effect on our business. Events within the oil and gas industry, such as the April 2010 fire and explosion on the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico and the resulting oil spill and moratorium on certain drilling activities in the U.S. Gulf of Mexico implemented by the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly, the Minerals Management Service), may adversely affect our customers' operations and, consequently, our operations. Such events may also subject companies operating in the oil and gas industry, including us, to additional regulatory scrutiny and result in additional regulations and restrictions adversely affecting the U.S. oil and gas industry.

A decrease in the cost of importing refined petroleum products could cause demand for U.S. flag product carrier and barge capacity and charter rates to decline, which would decrease our revenues and our ability to pay cash distributions on our units.

The demand for U.S. flag product carriers and barges is influenced by the cost of importing refined petroleum products. Historically, charter rates for vessels qualified to participate in the U.S. coastwise trade under the Jones Act have been higher than charter rates for foreign flag vessels. This is due to the higher construction and operating costs of U.S. flag vessels under the Jones Act requirements that such vessels be built in the United States and manned by U.S. crews. This has made it less expensive for certain areas of the United States that are underserved by pipelines or which lack local refining capacity, such as in the Northeast, to import refined petroleum products carried aboard foreign flag vessels than to obtain them from U.S. refineries. If the cost of importing refined petroleum products decreases to the extent that it becomes less expensive to import refined petroleum products to other regions of the East Coast and the West Coast than producing such products in the United States and transporting them on U.S. flag vessels, demand for DG Marine's vessels and the charter rates for them could decrease.

Risks Related to Our Partnership Structure

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

As of December 31, 2010, Corbin J. Robertson, Jr., together with members of his family and certain of their affiliates (or the Robertson Group), members of the Davison family and management owned approximately 29 million or 45% of our common units. We also have other unitholders that may have large positions in our common units. In the future, any such parties may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, the sale could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow members of the Davison family to cause us to register for sale the partnership interests held by such persons, including common units. Those registration rights allow those unitholders to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us. In connection with our IDR Restructuring, certain agreements were executed which allow the unitholders other than members of the Davison family that received units in that transaction to request registration subsequent to June 30, 2011 of 50% of the common units issued in our IDR Restructuring and to request registration subsequent to December 31, 2011 of the remaining 50% of those common units. Additionally, we have filed shelf registration statements for the units held by some holders of large blocks of our units, and those holders may sell their common units at any time, subject to certain restrictions under securities laws.

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

Corbin J. Robertson, Jr., together with members of his family and certain of their affiliates (or the Robertson Group), owns approximately 15% of our Class A Units and 74% of our Class B Units. Consequently, the Robertson Group is able to exert substantial influence over us, including electing at least a majority of the members of our board of directors and controlling most matters requiring board approval, such as business strategies, mergers, business combinations, acquisitions or dispositions of significant assets, issuances of common stock, incurrence of debt or other financing and the payment of dividends. In addition, the existence of a controlling group may have the effect of making it difficult for, or may discourage or delay, a third party from seeking to acquire us, which may adversely affect the market price of our units. Further, directors elected by the Robertson Group who are also directors and/or officers of other entities may have a fiduciary duty to make decisions based on the best interests of the equity holders of such other entities.

The Robertson Group owns, controls and has an interest in a wide array of companies, some of which may compete directly or indirectly with us. As a result, that group's interests may not always be consistent with our interests or the interests of our other unitholders. The Robertson Group may also pursue acquisitions or business opportunities that may be complementary to our business. Our organizational documents allow the Robertson Group to take advantage of such corporate opportunities without first presenting such opportunities to us. As a result, corporate opportunities that may benefit us may not be available to us in a timely manner, or at all. To the extent that conflicts of interest may arise among us and members of the Robertson Group, those conflicts may be resolved in a manner adverse to us or you. Other potential conflicts may involve, among others, the following situations:

- our general partner is allowed to take into account the interest of parties other than us, such as one or more of its affiliates, in resolving conflicts of interest;
- our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and its affiliates, retention of counsel, accountants and service providers, and cash reserves, each of which can also affect the amount of cash that is distributed to our unitholders; and
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us and the reimbursement of these costs and of any services provided by our general partner could adversely affect our ability to pay cash distributions to our unitholders.

Our Class B Units may be transferred to a third party without unitholder consent, which could affect our strategic direction.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Only holders of our Class B Units have the right to elect our board of directors. Holders of our Class B Units may transfer such units to a third party without the consent of the unitholders. The new holders of our Class B Units may then be in a position to replace our board of directors and officers of our general partner with its own choices and to control the strategic decisions made by our board of directors and officers.

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

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

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

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

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

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

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

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

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

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

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

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

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states in which we do business or may do business in from time to time in the future. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Tax Risks to Common Unitholders

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

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

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

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

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

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

Unitholders will be required to pay taxes on income(as well as deemed distributions, if any) from us even if they do not receive any cash distributions from us.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. Business. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See "Commitments and Off-Balance Sheet Arrangements" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 19 of the Notes to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved from time to time in various claims, lawsuits and administrative proceedings incidental to our business. In our opinion, the ultimate outcome, if any, of such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. (See Note 19 of the Notes to the Consolidated Financial Statements.)

Item 4. (Removed and Reserved)

PART II

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

Our Class A common units are listed on the New York Stock Exchange ("NYSE") under the symbol "GEL". Until September 15, 2010, our common units were listed on the NYSE Amex LLC. The following table sets forth, for the periods indicated, the high and low sale prices per common unit and the amount of cash distributions paid per common unit.

	Price Range		Cash
	High	Low	Distributions (1)
2010			
Fourth Quarter	$ 27.24	$ 22.77	$ 0.3875
Third Quarter	$ 23.52	$ 18.43	$ 0.3750
Second Quarter	$ 20.64	$ 15.47	$ 0.3675
First Quarter	$ 21.67	$ 17.94	$ 0.3600
2009			
Fourth Quarter	$ 19.95	$ 15.10	$ 0.3525
Third Quarter	$ 16.89	$ 12.01	$ 0.3450
Second Quarter	$ 13.92	$ 9.82	$ 0.3375
First Quarter	$ 12.60	$ 7.57	$ 0.3300

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

At March 11, 2011, we had 64,575,065 Class A common units outstanding. As of December 31, 2010, the closing price of our common units was $26.40 and we had approximately 24,500 record holders of our common units, which include holders who own units through their brokers "in street name."

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

Prior to the IDR Restructuring, our general partner was entitled to receive distributions in respect of its 2% general partner interest and incentive distributions if the amount we distributed with respect to any quarter exceeded 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 – Capital Expenditures and Distributions Paid to our Unitholders and General Partner” and Note 10 of the Notes to our Consolidated Financial Statements for further information regarding restrictions on our distributions. See Item 12.”Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” for information regarding securities authorized for issuance under equity compensation plans.

Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2010, 2009, 2008, 2007, and 2006 *(in thousands, except per unit and volume data)*.

	Year Ended December 31,				
	2010 (1)	2009	2008 (1)	2007 (1)	2006
Income Statement Data:					
Revenues:					
Supply and logistics (2)	$ 1,878,780	$ 1,226,838	$ 1,852,414	$ 1,094,189	$ 873,268
Refinery services	151,060	141,365	225,374	62,095	-
Pipeline transportation	55,652	50,951	46,247	27,211	29,947
CO_2 marketing	15,832	16,206	17,649	16,158	15,154
Total revenues	$ 2,101,324	$ 1,435,360	$ 2,141,684	$ 1,199,653	$ 918,369
Net (loss) income (3)	$ (50,541)	$ 6,178	$ 25,825	$ (13,551)	$ 8,382
Net (loss) income attributable to Genesis Energy, L.P. (3)	$ (48,459)	$ 8,063	$ 26,089	$ (13,550)	$ 8,381
Net income (loss) available to Common Unitholders	$ 19,929	$ 20,186	$ 23,006	$ (13,608)	$ 8,214
Net income (loss) attributable to Genesis Energy, L.P. per Common Unit: Basic and Diluted	$ 0.49	$ 0.51	$ 0.59	$ (0.66)	$ 0.59
Cash distributions declared per Common Unit	$ 1.4900	$ 1.3650	$ 1.2225	$ 0.9300	$ 0.7400
Balance Sheet Data (at end of period):					
Current assets	$ 252,538	$ 189,244	$ 168,127	$ 214,240	$ 99,992
Total assets	1,506,735	1,148,127	1,178,674	908,523	191,087
Long-term liabilities	630,757	387,766	394,940	101,351	8,991
Partners' capital:					
Genesis Energy, L.P.	669,264	595,877	632,658	631,804	85,662
Noncontrolling interests	-	23,056	24,804	570	522
Total partners' capital	669,264	618,933	657,462	632,374	86,184
Other Data:					
Maintenance capital expenditures (4)	2,856	4,426	4,454	3,840	967
Volumes - continuing operations:					
Onshore crude oil pipeline (barrels per day)	67,931	60,262	64,111	59,335	61,585
CO_2 pipeline (Mcf per day) (5)	167,619	154,271	160,220	-	-
CO_2 sales (Mcf per day)	73,228	73,328	78,058	77,309	72,841
NaHS sales (DST) (6)	145,213	107,311	162,210	69,853	-
NaOH sales (DST) (6)	93,283	88,959	68,647	20,946	-

(1) Our operating results and financial position have been affected by acquisitions in 2010, 2008 and 2007, most notably the 50% equity interest acquisition in Cameron Highway in November 2010, the acquisition of the remaining 50% ownership interest in DG Marine in July 2010, the Grifco acquisition in July 2008 and the Davison acquisition, which was completed in July 2007. The results of these operations are included in our financial results prospectively from the acquisition date. For additional information regarding these acquisitions, see Note 3 of the Notes to the Consolidated Financial Statements included under Item 8 of this annual report.
(2) Includes net presentation of buy/sell arrangements for all periods after the first quarter of 2006.
(3) Includes executive compensation expense related to Series B and Class B awards borne entirely by our general partner in the amounts of $76.9 million for 2010, $14.1 million for 2009 and $3.4 million for 2007. See Note 15.
(4) Maintenance capital expenditures are capital expenditures to replace or enhance partially or fully depreciated assets to sustain the existing operating capacity or efficiency of our assets and extend their useful lives.
(5) Volume per day for the period we owned the Free State CO_2 pipeline in 2008.
(6) Volumes relate to operations acquired in July 2007.

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

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

- Significant Events
- Overview of 2010
- Available Cash before Reserves
- Results of Operations
- Capital Resources and Liquidity
- Commitments and Off-Balance Sheet Arrangements
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

In the discussions that follow, we will focus on our revenues, expenses and net income, as well as two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves.

We define segment margin as revenues less cost of sales, operating expenses (excluding depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. In addition, our segment margin definition excludes the non-cash effects of our equity-based compensation plans and the unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Segment margin includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant, and maintenance capital investment. A reconciliation of segment margin to income before income taxes is included in our segment disclosures in Note 12 to the Consolidated Financial Statements.

Available Cash before Reserves (a non-GAAP measure) is net income as adjusted for specific items, the most significant of which are the addition of non-cash expenses (such as depreciation), the substitution of distributable cash generated by our joint ventures in lieu of our equity income attributable to our joint ventures, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) and unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, the elimination of expenses related to acquiring assets that provide new sources of cash flows, the elimination of earnings of DG Marine in excess of distributable cash until July 29, 2010 when DG Marine's credit facility was repaid, and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows. 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.

Significant Events

Permanent Elimination of IDRs

In February 2010, new investors, together with members of our executive management team, acquired our general partner. At that time, our general partner owned all our 2% general partner interest and all of our incentive distribution rights, or IDRs. At that time, in respect of its general partner interest and IDRs, our general partner was entitled to over 50% of any increased distributions we would pay in respect of our outstanding equity.

On December 28, 2010, we permanently eliminated our IDRs and converted our two percent general partner interest into a non-economic interest. In exchange for our IDRs and the 2% economic interest attributable to our general partner interest, we issued approximately 20 million common units and 7 million "Waiver" units to the stakeholders of our general partner, less approximately 145,000 common units and 50,000 Waiver Units that have been reserved for a new deferred equity compensation plan for employees.

Our Waiver Units have the right to convert into Genesis common units in four equal installments in the calendar quarter during which each of our common units receives a quarterly distribution of at least $0.43, $0.46, $0.49 and $0.52, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times.

As a result of the IDR Restructuring, (i) we now have approximately 64.6 million common units outstanding (with the former stakeholders of the general partner owning approximately 45% of such units, including common units owned prior to the IDR Restructuring), (ii) our general partner has become (by way of merger) one of our wholly-owned subsidiaries, (iii) there has been no change in the composition of our board of directors and (iv) the former stakeholders of our general partner will continue to elect our board of directors in the future. See additional discussion under "Liquidity and Capital Resources – Capital Expenditures and Distributions paid to our Common Unitholders and General Partner" below and in Note 11 to our Consolidated Financial Statements.

Cameron Highway Acquisition, Notes Issuance and Equity Issuance

On November 23, 2010, we acquired a 50% interest in Cameron Highway for approximately $330 million. Cameron Highway, a joint venture with Enterprise Products Partners, L.P., owns and operates the largest (measured by both length and capacity) crude oil pipeline system in the Gulf of Mexico. We financed the purchase price for the acquisition primarily with the net proceeds of approximately $119 million from an underwritten public offering of 5.2 million of our common units (including the overallotment option that the underwriters exercised in full and including our general partner's proportionate capital contribution to maintain its 2% general partner interest) at $23.58 per common unit and net proceeds of approximately $243 million from a private placement of $250 million in aggregate principal amount of 7.875% senior unsecured notes due 2018. We used $23.8 million in excess net proceeds to temporarily reduce the balance outstanding under our revolving credit agreement. See additional discussion under "Liquidity and Capital Resources" below and in Notes 3, 10 and 11 to our Consolidated Financial Statements.

Acquisition of Remaining 51% Interest in DG Marine Acquisition

On July 29, 2010, we acquired the 51% interest in DG Marine held by a related party for $25.5 million, resulting in DG Marine becoming a wholly-owned subsidiary. Additionally, we paid off DG Marine's stand-alone credit facility with proceeds from our credit agreement.

Credit Facility Restructuring

On June 29, 2010, we restructured our credit agreement. Our credit agreement now provides for a $525 million senior secured revolving credit facility, includes an accordion feature whereby the total credit available can be increased up to $650 million under certain circumstances, and matures on June 30, 2015. Among other modifications, our credit agreement now includes a $75 million sublimit tranche designed for more efficient financing of crude oil and petroleum products inventory. See additional discussion under "Liquidity and Capital Resources – Debt and Equity Financing Activities" below and in Note 10 to our Consolidated Financial Statements.

Distribution Increase

On January 12, 2011, we declared our twenty-second consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2010. This distribution of $0.40 per unit (paid in February 2011) represents an 11% increase from our distribution of $0.36 per unit for the fourth quarter of 2009.

Overview of 2010

In 2010, we reported a net loss attributable to Genesis Energy, L.P. of $48.5 million, which included $76.9 million of non-cash compensation charges borne entirely by our general partner. As a result, net income attributable to our common units for 2010 was $19.9 million, or $0.49 per common unit. See additional discussion of the charge related to executive compensation in "Results of Operations – Other Costs and Interest" below.

Segment margin increased by $15.1 million, or 11.2%, in 2010 as compared to 2009. The majority of this increase was attributable to our pipeline transportation and refinery services segments. Onshore crude oil pipeline transportation volumes increased by 13% and CO2 pipeline transportation volumes increased by almost 9%. Our NaHS sales volumes in our refinery services segment increased by 35%. Partially offsetting the increased contribution from these segments was a 10% decline in segment margin from our supply and logistics operations as market conditions reduced the profitability of storing crude oil and products for future delivery and differentials between grades of petroleum products narrowed as discussed in more detail below.

Increases in cash flow generally result in increases in Available Cash before Reserves, from which we pay distributions quarterly to holders of our common units and, until December 28, 2010, our general partner. During 2010, we generated $101.5 million of Available Cash before Reserves, and we distributed $70.4 million to holders of our common units and general partner. Cash provided by operating activities in 2010 was $90.5 million. Our total distributions attributable to 2010 increased 17% over the total distributions attributable to 2009.

Available Cash before Reserves

Available Cash before Reserves for the years ended December 31, 2010, 2009 and 2008 is as follows:

	Year Ended December 31,		
	2010	2009	2008
		(in thousands)	
Net (loss) income attributable to Genesis Energy, L.P.	$ (48,459)	$ 8,063	$ 26,089
Depreciation, amortization and impairment	53,557	67,586	71,370
Cash received from direct financing leases not included in income	4,203	3,758	2,349
Cash effects of sales of certain assets	1,158	873	760
Effects of available cash generated by equity method investees not included in income	2,285	(495)	1,830
Cash effects of equity-based compensation plans	(1,350)	(121)	(385)
Non-cash tax expense (benefit)	1,337	1,914	(2,782)
Earnings of DG Marine in excess of distributable cash	(848)	(4,475)	(2,821)
Non-cash equity-based compensation expense	82,979	18,512	-
Expenses related to acquiring or constructing assets that provide new sources of cash flow	11,260	-	-
Other items, net	(1,767)	(203)	(2,172)
Maintenance capital expenditures	(2,856)	(4,426)	(4,454)
Available Cash before Reserves	$ 101,499	$ 90,986	$ 89,784

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flows from operating activities (the most comparable GAAP measure) for the each of the periods in the table above in "Capital Resources and Liquidity – Non-GAAP Reconciliation" below. For the years ended December 31, 2010, 2009 and 2008, net cash provided by operating activities was $90.5 million, $90.1 million and $94.8 million, respectively.

Results of Operations

Revenues, Costs and Expenses and Net Income

Our revenues for the year ended December 31, 2010 increased $666 million, or 46% from 2009. Excluding non-cash charges for executive compensation borne by our general partner, our costs and expenses increased $652 million, or 47%, between the two periods. The majority of our revenues and our costs are derived from the purchase and sale of crude oil and petroleum products. The significant increase in our revenues and costs between 2009 and 2010 is primarily attributable to the fluctuations in the market prices for crude oil and petroleum products. In 2010, prices for West Texas Intermediate crude oil on the New York Mercantile Exchange averaged $79.53, as compared to $61.80 in 2009 - a 29% increase. Also contributing to the increase in our revenues and costs was an increase in volumes in all of our segments; although the impact of the increase in our supply and logistics segment was the most significant to revenues and costs. Supply and logistics sales volumes increased by almost 30% between 2010 and 2009.

Net income attributable to Genesis Energy, L.P. declined $56.5 million to a net loss in 2010 of $48.5 million from net income of $8.1 million in 2009. An increase in non-cash charges included in general and administrative expenses related to executive compensation and equity-based compensation borne by our general partner totaling $62.8 million provided the decline in net income. Also reducing net income for 2010 was $7.0 million of one-time costs related to the acquisition of our interest in Cameron Highway and to the IDR Restructuring. A $15.1 million increase in our segment margin somewhat offset these increased costs. See additional discussion of the one-time charges in "Other Costs and Interest" below.

Revenues and costs and expenses in 2009 decreased as compared to 2008 primarily as a result of a 38% decline in market prices for crude oil. Revenues decreased $706 million, or 33%, while costs decreased $690 million, or 33%, between the two periods. Net income attributable to Genesis Energy, L.P. declined from income of $26.1

million in 2008 to $8.1 million in 2009. An increase in non-cash charges included in general and administrative expenses related to executive compensation and equity-based compensation totaling $16.6 million provided most of the decline in net income.

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

Segment Margin

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

	Year Ended December 31,		
	2010	2009	2008
		(in thousands)	
Pipeline transportation	$ 48,305	$ 42,162	$ 33,149
Refinery services	62,923	51,844	55,784
Supply and logistics	26,176	29,052	32,448
Industrial gases	12,160	11,432	13,504
Total segment margin	$ 149,564	$ 134,490	$ 134,885

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

Pipeline Transportation Segment

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

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases - onshore crude oil pipelines	$ 20,351	$ 17,202
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	26,413	26,279
Sales of crude oil pipeline loss allowance volumes	5,519	4,462
Available cash generated by Cameron Highway	2,384	-
Pipeline operating costs, excluding non-cash charges for equity-based compensation	(11,522)	(10,477)
Payments received under direct financing leases not included in income	4,202	3,758
Other	958	938
Segment margin	$ 48,305	$ 42,162

We operate three onshore common carrier crude oil pipeline systems and a CO_2 pipeline in a four state area. We refer to these pipelines as our Mississippi System, Jay System, Texas System and Free State Pipeline. Additionally, we own a 50% interest in Cameron Highway. Volumes shipped on these systems for the last two years are as follows (barrels or Mcf per day):

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

(1) Daily average for the period from November 23, 2010 to December 31, 2020 when we owned an interest in Cameron Highway.

Crude Oil Volumes

Volumes on our Mississippi pipeline fluctuate primarily as a result of the operations of Denbury and other producers. The tariff on the Mississippi System is an incentive tariff, such that the average tariff per barrel decreases as the volumes increase; therefore the effect of the decline in the volumes of 555 barrels per day between 2009 and 2010 on that system was mitigated by the relatively low incremental tariff rate. Additional development of surrounding fields using CO_2 based operations could offset a portion of any future declines from existing fields.

The Jay Pipeline system in Florida and Alabama ships crude oil from mature producing fields in the area as well as production from new wells drilled in the area. A producer connected to our Jay System shut in production at the end of 2008 due to the decline in crude oil prices in the latter half of 2008. As crude oil market prices increased in late 2009 and 2010, the producer restored production capabilities to his fields resulting in a volumetric increase on the Jay system of approximately 49% as compared to 2009. New production in the area also contributed to the volumetric increase with a greater impact on tariff revenue for us due to the greater distance that the crude oil is transported on the pipeline.

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 connecting carriers for supply, and on the two refineries for demand for our services. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets.

During the five weeks we owned an interest in Cameron Highway, the average daily revenue volume of that joint venture was 149,270 barrels per day.

CO_2 Volumes

Under the terms of a transportation services agreement extending through 2028, we deliver CO_2 on the Free State pipeline for use in tertiary recovery operations in east Mississippi. We are responsible for owning, operating, maintaining and making improvements to the pipeline. Denbury currently has rights to exclusive use of the pipeline and is required to use the pipeline to supply CO_2 to its current and certain of its other tertiary operations in east Mississippi. Variations in Denbury's CO2 tertiary recovery activities create the fluctuations in the volumes transported on the Free State pipeline. The transportation services agreement provides for a $0.1 million per month minimum payment plus a tariff based on throughput. Denbury has two renewal options, each for five years on similar terms.

We operate a CO_2 pipeline in Mississippi to transport CO_2 to Brookhaven oil field. Denbury has the exclusive right to use this CO_2 pipeline. This arrangement has been accounted for as a direct financing lease.

We also have a twenty-year financing lease (through 2028) with Denbury initially valued at $175 million related to Denbury's North East Jackson Dome (NEJD) Pipeline System. Denbury makes fixed quarterly base rent payments to us of $5.2 million per quarter or approximately $20.7 million per year.

Segment Margin

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

- Our share of the available cash before reserves generated by Cameron Highway beginning in the latter part of November 2010 added $2.4 million to Segment Margin,
- An increase in volumes transported on our crude oil pipelines between the two periods increased segment margin by $2.1 million,
- Tariff rate changes in July 2009 and July 2010 resulted in an increase of approximately $0.4 million between the two periods.
- An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $1.1 million. This revenue increase is due primarily to increased crude oil market prices, although the increase in volumes transported in our onshore pipelines also contributed to the additional revenue.
- Pipeline operating costs increased approximately $1.0 million due to an increase in pipeline integrity tests and other maintenance costs. In the first quarter of 2010 pipeline integrity tests on a segment of our Texas System cost approximately $0.6 million.

As is common in the industry, our crude oil tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The increase in market prices for crude oil increased the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices increased approximately $18 per barrel between the two periods. Pipeline loss allowance volumes decreased by approximately 8,300 barrels between the annual periods. Based on historic volumes, a change in crude oil market prices of $10 per barrel has the effect of decreasing or increasing our pipeline loss allowance revenues by approximately $0.1 million per month.

Refinery Services Segment

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

	Year Ended December 31,	
	2010	2009
Volumes sold:		
NaHS volumes (Dry short tons "DST")	145,213	107,311
NaOH volumes (DST)	93,283	88,959
Total	238,496	196,270
NaHS revenues	$ 119,688	$ 97,962
NaOH revenues	29,578	38,773
Other revenues	9,190	10,505
Total external segment revenues	$ 158,456	$ 147,240
Segment margin	$ 62,923	$ 51,844
Average index price for NaOH per DST (1)	$ 353	$ 424
Raw material and processing costs as % of segment revenues	37%	44%
Delivery costs as a % of segment revenues	15%	12%

(1) Source: Harriman Chemsult Ltd.

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

- An increase in NaHS volumes of 35%. As the world economies, particularly outside of the United States and European Union, are recovering from the depths of the greatest recession in the last 70 years, the demand for base metals such as copper and molybdenum has increased over the prior period. As a result, we have experienced a noticeable increase in the demand for NaHS from our mining customers in North and South America. Additionally, with the return of industrialization and urbanization in the world's more underdeveloped economies, the demand for paper products and packaging materials has increased. This trend has led to an increase in demand for NaHS from our pulp/paper customers primarily in North America. The pricing in the majority of our sales contracts for NaHS includes an adjustment for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments can be applied varies by geographic region and supply point.
- An increase in NaOH (or caustic soda) sales volumes of 5%. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. We are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties. Fluctuations in volumes sold are affected by the demand we have in our operations that consume caustic soda.

- Index prices for caustic soda averaged approximately $424 per DST in 2009. Market index prices of caustic soda decreased to an average of approximately $353 per DST during 2010. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers.
- Somewhat mitigating the increase in segment margin was an increase in delivery logistics costs.. Although our logistics costs per unit increased only modestly, our logistics costs expressed as a percentage of revenues increased by 3% (to 15%) primarily because our sales price per unit, along with our cost per unit declined. Quantities delivered to customers also increased. Freight demand and fuel prices increased modestly in the 2010 period as economic conditions improved, increasing demand for transportation services and the increase in crude oil prices increased the cost of fuel used in transporting these products.

Supply and Logistics Segment

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

- purchasing and/or transporting crude oil from the wellhead to markets for ultimate use in refining;
- supplying petroleum products (primarily fuel oil, asphalt, diesel and gasoline) to wholesale markets and some end-users such as paper mills and utilities;
- purchasing products from refiners, transporting the products to one of our terminals and blending the products to a quality that meets the requirements of our customers; and
- utilizing our fleet of trucks and trailers and barges to take advantage of logistical opportunities primarily in the Gulf Coast states and inland waterways.

We also use our terminal facilities to take advantage of contango market conditions for crude oil gathering and marketing , and to capitalize on regional opportunities which arise from time to time for both crude oil and petroleum products.

Many U.S. refineries have distinct configurations and product slates that require crude oil with specific characteristics, such as gravity, sulfur content and metals content. The refineries evaluate the costs to obtain, transport and process their preferred feedstocks. Despite crude oil being considered a somewhat homogenous commodity, many refiners are very particular about the quality of crude oil feedstock they process. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources meeting their requirements, and to purchase the crude oil and transport it to the refineries for sale. The imbalances and inefficiencies relative to meeting the refiners' requirements can provide opportunities for us to utilize our purchasing and logistical skills to meet their demands and take advantage of regional differences. The pricing in the majority of our purchase contracts contain a market price component, unfixed bonuses that are based on several other market factors and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts sometimes contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

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

In our petroleum products marketing operations, we supply primarily fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing "heavier" petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tend to be higher than the same percentage attributable to our recurring operations. We utilize our fleet of 250 trucks and 280 trailers and DG Marine's twenty "hot-oil" barges in combination with our 1.5 million barrels of existing leased and owned storage to service our refining customers and to store and blend the intermediate and finished refined products.

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

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Supply and logistics revenue	$ 1,878,780	$ 1,226,838
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(1,761,161)	(1,115,809)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(91,443)	(81,977)
Segment margin	$ 26,176	$ 29,052
Volumes of crude oil and petroleum products (mbbls)	22,823	17,563

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

The key factors affecting the change in segment margin between 2010 and 2009 were as follows:

- The contango price market narrowed beginning late in the fourth quarter of 2009 and extended through most of 2010 decreasing the effects on contribution to Segment Margin of our crude oil activities.
- Fluctuations in differentials related to heavy end petroleum products decreased segment margin from our petroleum products marketing activities.

Beginning late in 2008 and throughout most of 2009, the crude oil market was in wide contango. When crude oil markets are in contango, oil prices for future deliveries are higher than for current deliveries, providing an opportunity for us to purchase crude oil at current market prices, re-sell it through futures contracts at future prices, and store it as inventory until delivery. In 2009, we took advantage of contango conditions, holding an average of 174,000 barrels of crude oil in storage throughout the year. In 2010, contango market conditions had narrowed and we reduced the volumes of crude oil stored to take advantage of the contango conditions to an average of 101,000 barrels of crude oil throughout the year. This change in contango market conditions was the primary factor in the $1.1 million decrease in the contribution to segment margin of our crude oil gathering and marketing activities.

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

An increase of $0.5 million in the contribution to segment margin by our barge operations in 2010 as compared to 2009 partially offset these decreases. In 2010, we were successful in increasing the average day rates for utilization of our barges and overall utilization rate of our fleet improved as market conditions for refiners increased the volumes of heavy end products to be transported throughout the U.S. inland waterways and along the Gulf Coast.

Industrial Gases Segment

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

Operating Results

Operating results for our industrial gases segment were as follows.

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Revenues from CO_2 marketing	$ 15,832	$ 16,206
CO_2 transportation and other costs	(5,928)	(5,825)
Available cash generated by equity investees	2,256	1,051
Segment margin	$ 12,160	$ 11,432
Volumes per day:		
CO_2 marketing - Mcf	73,228	73,328

The increase in Segment Margin from the Industrial gases segment between 2010 and 2009 was the result of increased available cash generated by equity investees offset by a decrease in the average sales price of CO_2 of $0.01 per Mcf, or 2%.

CO_2 – Industrial Customers

We supply CO_2 to industrial customers under six long-term CO_2 sales contracts. The terms of our contracts with the industrial CO_2 customers include minimum take-or-pay and maximum delivery volumes. The maximum daily contract quantity per year in the contracts totals 97,625 Mcf. Under the minimum take-or-pay volumes, the customers must purchase a total of 51,048 Mcf per day whether received or not. Any volume purchased under the take-or-pay provision in any year can then be recovered in a future year as long as the minimum requirement is met in that year. At December 31, 2010, we have no liabilities to customers for gas paid for but not taken.

At December 31, 2010 we had seven industrial contracts that expire at various dates beginning in 2011 and extending through 2023. The volume sold under the contract that expired January 31, 2011 averaged 4,874 Mcf per day, with a net contribution to Segment Margin in 2010 of $1.4 million.

The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price. These inflation adjustments and variations in the volumes sold under each contract cause the slight changes in average revenue per Mcf between periods.

Transportation costs for the CO_2 remained consistent as a percentage of revenues at approximately 36% to 37%. The transportation rate we pay Denbury is adjusted annually for inflation in a manner similar to the sales prices for the CO_2.

Equity Method Joint Ventures

Our share of the available cash before reserves generated by equity investments in each year primarily resulted from our investment in T&P Syngas. Our share of the available cash before reserves generated by T&P Syngas for 2010 and 2009 was $2.3 million and $0.9 million, respectively. In the third quarter of 2009, T&P Syngas performed a scheduled turnaround at its facility that decreased its revenues and increased maintenance expenses. Additionally, T&P Syngas incurred expenses related to improving its treatment of waste water. These activities were completed in 2009 and the expenses were paid from funds generated by T&P Syngas, reducing the amounts available to be distributed to the partners in T&P Syngas. In 2010, T&P Syngas did not perform a turnaround which resulted in additional cash being distributed to the partners as compared to 2009.

Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,	
	2010	2009
	(in thousands)	
General and administrative expenses not separately identified below	$ 20,469	$ 20,277
Expenses related to change in owner of our general partner	1,762	-
Transaction costs related to IDR restructuring and growth projects including acquisition of interest in Cameron Highway	7,290	-
Bonus plan expense	5,007	3,900
Equity-based compensation plan expense	1,955	2,132
Non-cash compensation expense related to management team	76,923	14,104
Total general and administrative expenses	$ 113,406	$ 40,413

Although our general and administrative expenses increased substantially, 86% of the increase was due to non-cash compensation expense related to our management team and borne by the former owners of our general partner, as described in more detail below. Routine general and administrative expense increased by $0.2 million to $20.7 million in 2010 as compared to 2009, primarily as a result of additions to personnel consistent with our growth during 2010.

Transaction costs related to the restructuring of our IDRs and growth projects including the acquisition of our 50% interest in Cameron Highway totaled $7.3 million in 2010, or 10% of the remaining increase in general and administrative expenses. These transaction costs consisted primarily of fees paid to legal and financial advisors for their assistance in the evaluation and completion of these transactions.

The amounts paid under our bonus plan are a function of both the Available Cash before Reserves that we generate in a year and the improvement in our safety record, and are approved by our compensation committee of our board of directors. As a result of our performance in 2010, the pool available for bonuses was determined to be $1.1 million more than 2009. The bonus plan for employees is described in Item 11, "Executive Compensation" below.

Due to fluctuations in the market price for our common units, expense for outstanding and exercised SARs and phantom units issued under our 2010 Long-Term Incentive Plan has varied significantly between the periods. In 2009 and the first quarter of 2010, we also had phantom units issued and outstanding under our 2007 Long-Term Incentive Plan. The fair value of phantom units issued under this long-term incentive plan are calculated at the grant date and charged to expense over the vesting period of the phantom units. Unlike the accounting for the SAR plan and 2010 LTIP, the total expense to be recorded was determined at the time of the award and did not change. The change in control of our general partner in February 2010 resulted in the vesting of the outstanding phantom units under our 2007 LTIP and the recognition of the remaining grant date fair value as an expense in 2010.

We finalized a compensation structure in December 2008 for members of our management team. The terms of these compensation arrangements provided that our management team would vest in the package and receive certain payments upon a change in control of our general partner. During 2009, we recorded compensation expense of $14.1 million related to these arrangements, and we recorded a reduction in compensation expense of $2.1 million in 2010 upon vesting of the package when the change in control occurred in February 2010 in which a group of investors acquired all of the equity interest in our general partner.

In February 2010, certain members of our management received new equity interests in our general partner (Series B units) that would increase in value as the net cash distributions to the owners of our general partner increased, with a conversion to Series A units in our general partner at the end of seven years or under certain other conditions. As a result of the IDR Restructuring, the Series B units were exchanged for units issued by us, which is characterized as compensation expense. The management team members received Class A Common Units and

Waiver Units in the restructuring, with a total fair value of approximately $79.1 million attributable to the Series B units, which was recorded as expense in 2010.

Although the compensation under both of these arrangements ultimately came from our general partner, we recorded the fair value of the compensation expense in our Consolidated Statements of Operations in general and administrative expenses due to the rules for accounting for transactions where the beneficiary of a transaction is not the same as the parties to the transaction. See additional discussion of the compensation arrangements with our senior management team in Item 11, "Executive Compensation."

Depreciation, amortization and impairment expense was as follows:

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

Depreciation and amortization expense decreased $9 million between 2010 and 2009 primarily as a result of the lower amortization expense recognized on intangible assets. We amortize our intangible assets over the period which we expect them to contribute to our future cash flows. The amortization we record on those assets is greater in the initial years following their acquisition because the value of our intangible assets such as customer relationships and trade names are generally more valuable in the first years after an acquisition. Accordingly, the amount of amortization we have recorded has declined since we acquired those assets in 2007. See Note 9 of the Notes to the Consolidated Financial Statements for information on the amount of amortization we expect to record in each of the next five years.

Amortization of our CO_2 volumetric payments is based on the units-of-production method. We acquired three volumetric production payments totaling 280 Mcf of CO_2 from Denbury between 2003 and 2005. Amortization is based on volumes sold in relation to the volumes acquired. Amortization of CO_2 volumetric payments fluctuate as a result of increases or decreases in the volume of CO_2 sold..

In 2009, we recorded a $5.0 million impairment charge related to our investment in the Faustina Project. The Faustina Project is a petroleum coke to ammonia project in which we first made an investment in 2006. As a result of a review of the financing alternatives available for the project to use as construction financing and a determination not to continue making investments in the project beginning in 2010, we determined that the likelihood of a recovery of our investment was remote and the fair value of the investment was zero. For additional information related to this charge, see Note 8 of the Notes to the Consolidated Financial Statements.

Interest expense, net was as follows:

	Year Ended December 31,	
	2010	2009
	(in thousands)	
Genesis Facilities and Notes:		
Interest expense, credit facility, including commitment fees	$ 10,624	$ 8,148
Interest expense, senior unsecured notes	2,406	-
Bridge financing fees	3,219	-
Amortization and write-off of facility and notes issuance fees	1,953	662
DG Marine Facility:		
Interest expense and commitment fees	2,512	4,446
Interest rate swaps settlement	1,553	-
Write-off of facility fees	794	586
Capitalized interest	(84)	(112)
Interest income	(53)	(70)
Net interest expense	$ 22,924	$ 13,660

Our average outstanding credit facility balance (excluding interest on DG Marine's stand-alone facility), was $31.4 million higher in 2010 than 2009. The increase in the credit facility balance is attributable primarily to the acquisition of the 51% ownership interest in DG Marine we did not own and the elimination of the DG Marine credit facility with borrowings under our credit facility.

We also incurred interest expense of $2.4 million in connection with the issuance of $250 million of senior unsecured notes in November 2010 to partially finance our acquisition of a 50% equity interest in Cameron Highway. At the time we agreed to acquire the interest in Cameron Highway, we had not yet issued the senior unsecured notes, nor had we issued the equity that was used to finance the acquisition. In order to ensure that we would have funds available at the time of the closing of the Cameron Highway transaction, we entered into a bridge arrangement that would have provided financing for the acquisition for a period of time until we could secure longer term financing. These fees totaled $3.2 million.

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

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

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

Pipeline Transportation Segment

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

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases - onshore crude oil pipelines	$ 17,202	$ 16,280
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	26,279	15,733
Sales of crude oil pipeline loss allowance volumes	4,462	8,542
Pipeline operating costs, excluding non-cash charges for equity-based compensation	(10,477)	(10,529)
Payments received under direct financing leases not included in income	3,758	2,349
Other	938	774
Segment margin	$ 42,162	$ 33,149

Volumes shipped on our pipeline systems in 2009 and 2008 are as follows (barrels or Mcf per day):

Pipeline System	2009	2008
Mississippi-Bbls/day	24,092	25,288
Jay - Bbls/day	10,523	13,428
Texas - Bbls/day	25,647	25,395
Free State - Mcf/day	154,271	160,220 (1)

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

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

- An increase in revenues from CO_2 financing leases and tariffs of $10.5 million and a related increase in payments from the same financing leases of $1.4 million not included as income (non-income payments under direct financing leases).
- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines that went into effect July 1, 2009. The rate increases increased segment margin between the two periods by approximately $1.9 million.
- Partially offsetting the increase in segment margin was a decrease in revenues from sales of pipeline loss allowance volumes of $4.1 million,
- A decline in volumes transported on our crude oil pipelines between the two periods decreased segment margin by $1.0 million.

Revenues for 2008 only included results from the NEJD and Free State CO_2 pipelines for a seven-month period while 2009 included results for a twelve-month period. The average volume transported on the Free State pipeline for 2009 was 154 MMcf per day, with the transportation fees and the minimum payments totaling $7.3 million and $1.2 million, respectively. Transportation fees and the minimum payments for the seven months in 2008 were $4.4 million and $0.7 million, respectively, with an average transportation volume of 160 MMcf per day.

The decline in market prices for crude oil reduced the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil market prices decreased approximately $38 per barrel between the two periods. In addition, pipeline loss allowance volumes decreased by approximately 10,000 barrels between the annual periods.

Refinery Services Segment

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

	Year Ended December 31,	
	2009	2008
Volumes sold:		
NaHS volumes (Dry short tons "DST")	107,311	162,210
NaOH volumes (DST)	88,959	68,647
Total	196,270	230,857
NaHS revenues	$ 97,962	$ 167,715
NaOH revenues	38,773	53,673
Other revenues	10,505	12,483
Total external segment revenues	$ 147,240	$ 233,871
Segment margin	$ 51,844	$ 55,784
Average index price for NaOH per DST (1)	$ 424	$ 702
Raw material and processing costs as % of segment revenues	44%	41%
Delivery costs as a % of segment revenues	12%	8%

(1) Source: Harriman Chemsult Ltd.

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

- NaHS volumes declined 34%. Macroeconomic conditions negatively impacted the demand for NaHS, primarily in mining and industrial activities. A significant decline in the market prices and demand for copper and molybdenum in the last quarter of 2008 continued through most of 2009. Copper and molybdenum prices improved and demand for NaHS increased in the fourth quarter of 2009; however the increases in NaHS sales in that quarter did not offset the declines in the first three quarters of 2009.
- NaOH (or caustic soda) sales volumes increased 30%. With the decline in NaHS production during 2009, we focused on expanding our activities as a NaOH supplier.
- Average index prices for caustic soda were somewhat volatile in 2008, ranging from an average index price of approximately $450 per dry short ton (DST) during the first quarter of 2008 to a high of $950 per DST in the fourth quarter of 2008. During 2009 market prices of caustic soda decreased to approximately $230 per DST by the end of the year. This volatility affected both the cost of caustic soda used to provide our services as well as the price at which we sold NaHS and caustic soda.
- Raw material and processing costs related to providing our refinery services and supplying caustic soda as a percentage of our segment margin increased 3% between periods. As the market price of caustic soda fluctuated in 2008 and 2009, we had to aggressively manage our acquisition costs to minimize purchasing caustic soda for use in our operations in a period of falling market prices. We were generally successful in this management, as reflected by the relatively small percentage increase in costs despite the significant decline in caustic prices. We also took steps to reduce processing costs and to manage our logistics costs related to our caustic soda purchases.

Supply and Logistics Segment

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

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

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

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

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

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

During 2009, crude oil markets were in contango, providing an opportunity for us to purchase and store crude oil as inventory for delivery in future months. The crude oil markets were not in contango during most of 2008. During 2009, we held an average of approximately 174,000 barrels of crude oil per month in our storage tanks and hedged this volume with futures contracts on the NYMEX. The effect on segment margin of storing this inventory was a $2.2 million gain in 2009.

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

Industrial Gases Segment

Operating results for our industrial gases segment were as follows.

	Year Ended December 31,	
	2009	2008
	(in thousands)	
Revenues from CO_2 marketing	$ 16,206	$ 17,649
CO_2 transportation and other costs	(5,825)	(6,484)
Available cash generated by equity investees	1,051	2,339
Segment margin	$ 11,432	$ 13,504
Volumes per day:		
CO_2 marketing - Mcf	73,328	78,058

The decreased margins from the industrial gases segment between 2008 and 2009 were due to a decline in CO_2 marketing volumes and a slight decrease in the average sales price of CO_2 of $0.01 per Mcf, or 2%.

Transportation costs for the CO_2 remained consistent as a percentage of revenues at approximately 36% to 37%. The transportation rate we pay Denbury is adjusted annually for inflation in a manner similar to the sales prices for the CO_2. We also recorded a charge for approximately $0.3 million in 2009 and $0.9 million in 2008 related to a commission on one of the industrial gas sales contracts.

Due to a scheduled turnaround at T&P Syngas in 2009, available cash generated by our equity investees decreased in 2009 as compared to 2008.

Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,	
	2009	2008
	(in thousands)	
General and administrative expenses not separately identified below	$ 20,277	$ 25,131
Bonus plan expense	3,900	4,763
Equity-based compensation plan expense (credit)	2,132	(394)
Non-cash compensation expense related to management team	14,104	-
Total general and administrative expenses	$ 40,413	$ 29,500

The primary reason for the $10.9 million increase in general and administrative expenses between 2008 and 2009 was $14.1 million of non-cash compensation we recorded related to the arrangements between our executive management team and our general partner. Partially offsetting that increase was a decline in routine general and administrative expenses of approximately $4.9 million, resulting primarily from a reduction in professional fees and services. Between 2009 and 2008, our bonus pool decreased by $0.9 million as a function of our operating results.

Depreciation, amortization and impairment expense was as follows:

	Year Ended December 31,	
	2009	2008
	(in thousands)	
Depreciation on fixed assets	$ 25,208	$ 20,415
Amortization of intangible assets	33,099	46,418
Amortization of CO_2 volumetric production payments	4,274	4,537
Impairment expense	5,005	-
Total depreciation, amortization and impairment expense	$ 67,586	$ 71,370

Depreciation and amortization expense decreased $8.5 million between 2009 and 2008 primarily as a result of the lower amortization expense recognized on intangible assets. As discussed above, we amortize our intangible assets over the period which we expect them to contribute to our future cash flows, and that amortization has declined since we acquired the assets. We recorded an impairment charge in 2009 that partially offset the decline in intangible amortization.

Interest expense, net was as follows:

	Year Ended December 31,	
	2009	2008
	(in thousands)	
Genesis Facilities and Notes:		
Interest expense, credit facility, including commitment fees	$ 8,148	$ 10,738
Amortization and write-off of facility and notes issuance fees	662	664
DG Marine Facility:		
Interest expense and commitment fees	4,446	2,269
Write-off of facility fees	586	-
Capitalized interest	(112)	(276)
Interest income	(70)	(458)
Net interest expense	$ 13,660	$ 12,937

Net interest expense (excluding interest on DG Marine's credit facility) increased from 2008 to 2009 as the average outstanding debt balance increased $114 million primarily due to the CO_2 pipeline dropdown transactions in May 2008 and the DG Marine acquisition in July 2008. The increase in outstanding debt during 2009 partially offset the effect of the lower interest rates, with the result of an overall decrease in 2009 for interest and commitment fees of $2.6 million.

DG Marine incurred interest expense in 2009 of $4.4 million under its credit facility. Interest expense for DG Marine in 2008 included only five months of activity subsequent to the acquisition of the Grifco assets in July 2008, resulting in an increase in net interest expense between 2009 and 2008.

Liquidity and Capital Resources

General

As of December 31, 2010, we believe our balance sheet and liquidity position remained strong. We had $160.4 million of borrowing capacity available under our $525 million senior secured bank revolving credit facility. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our short-term capital needs.

Our primary cash requirements consist of:

- Routine operating expenses;
- Capital expansion and maintenance projects;
- Acquisitions of assets or businesses;
- Interest payments on our debt obligations; and
- Quarterly cash distributions to our unitholders.

We continue to pursue a growth strategy that requires significant capital. As discussed above in the *Overview*, we acquired a 50% interest in Cameron Highway for $330 million in November 2010. We funded this acquisition with a combination of equity and debt. Additionally, in 2010, we acquired the portion of DG Marine we did not already own utilizing funds from our revolving credit facility.

During 2010, we amended and expanded our credit facility to provide additional financial flexibility, issued senior unsecured notes for the first time in a private placement, permanently eliminated our IDRs, and issued new equity for cash in a public offering. See additional discussion below in "Debt and Equity Financing Activities".

While our credit facility provides additional flexibility and committed borrowing capacity, our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, including through equity and debt offerings (public and private) from time to time and other financing transactions, to utilize our 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.

Debt and Equity Financing Activities

On June 29, 2010, we restructured our credit facility – which we entered into in November 2006 and which was to mature in November 2011 – to reflect and better accommodate our larger and more diversified operations and resulting credit metrics. Our restructured credit facility is a $525 million senior secured revolving credit facility maturing on June 30, 2015. It includes an accordion feature whereby the total credit available can be increased up to $650 million for acquisitions or internal growth projects, with lender approval. Among other modifications, our credit facility also includes a $75 million inventory sublimit tranche. This inventory tranche is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Additionally, our restructured credit facility does not include a "borrowing base" limitation except with respect to our inventory loans. Twelve lenders participate in our credit facility, and we do not anticipate any of them being unable to satisfy their obligations under the credit facility. Additional information on our restructured credit facility is included in Note 10 to the Consolidated Financial Statements.

In November 2010, we raised approximately $362 million with a combination of an equity and debt issuance. We issued 5,175,000 common units at $23.58, providing total net proceeds, after deducting underwriting discounts and commissions and estimated offering expenses and including our general partner's proportionate capital contribution to maintain its 2% general partner interest, of approximately $119 million. We also issued $250 million of senior unsecured notes in a private placement. The notes bear interest at 7.875% and will mature on December 15, 2018. We have agreed to register these notes with the SEC within one year of the date of issuance. We have the option to redeem the notes, in whole or in part, at any time after December 15, 2014, at varying redemption prices. These funds were primarily utilized for the acquisition of our interest in Cameron Highway, and the excess funds were utilized to temporarily reduce the balance under our revolving credit facility. See Note 10 to the Consolidated Financial Statements for additional information about the notes we issued.

In December 2010, we permanently eliminated our IDRs and converted our two percent general partner interest into a non-economic interest. In exchange for the IDRs and the 2% economic interest attributable to our general partner interest, we issued approximately 20 million common units and 7 million "Waiver" units to the stakeholders of our general partner, less approximately 145,000 common units and 50,000 Waiver Units that have been reserved for a new deferred equity compensation plan for employees. The Waiver Units have the right to convert into Genesis common units in four equal installments in the calendar quarter during which each of our common units receives a quarterly distribution of at least $0.43, $0.46, $0.49 and $0.52, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times. Prior to the elimination of our IDRs, our general partner was entitled to over 50% of any increased distributions we would pay in respect of our outstanding equity. We believe the elimination of our IDRs will lower our cost of capital and enhance our ability to grow the partnership.

On July 29, 2010, in connection with our acquisition of the 51% interest of DG Marine that we did not own, we paid off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, with proceeds from our credit agreement. See Note 3 to our Consolidated Financial Statements.

Cash Flows from Operations

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

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

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

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

Net cash flows provided from our operating activities for the twelve months ended December 31, 2010 were approximately $90.5 million. As discussed above, changes in our inventory levels due to storage impact the cash provided from operating activities. Additionally, changes in the market prices for crude oil and petroleum products can result in fluctuations in our operating cash flows between periods as the cost to acquire a barrel of oil or products will require more cash. At December 31, 2010, the cost of the inventory on our balance sheet increased by $15.2 million over the cost at December 31, 2009. Prepayments by customers for crude oil at December 31, 2010 increased, however, partially offsetting the increased use of cash for inventory.

Capital Expenditures and Distributions Paid to our Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We finance internal growth projects and distributions primarily with cash generated by our operations. Acquisition activities have historically been funded with borrowings under our credit facility and equity issuances and, beginning in 2010, the issuance of senior unsecured notes.

Capital Expenditures, and Business and Asset Acquisitions

The most significant investing activities in 2010 were expenditures related to the acquisition of a 50% equity interest in Cameron Highway and our project to upgrade our information technology systems discussed below. Additionally we utilized funds to acquire the 51% interest in DG Marine that we did not already own for approximately $26.3 million, including transaction costs.

A summary of our expenditures for fixed assets, businesses and other asset acquisitions in the three years ended December 31, 2010, 2009, and 2008 is as follows:

	Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Capital expenditures for fixed and intangible assets:			
Maintenance capital expenditures:			
Pipeline transportation assets	$ 522	$ 1,281	$ 719
Supply and logistics assets	901	1,667	729
Refinery services assets	1,433	1,246	1,881
Administrative and other assets	-	232	1,125
Total maintenance capital expenditures	2,856	4,426	4,454
Growth capital expenditures:			
Pipeline transportation assets	573	1,762	7,589
Supply and logistics assets	839	19,099	22,659
Refinery services assets	-	1,326	3,609
Information technology systems upgrade project	10,613	-	-
Total growth capital expenditures	12,025	22,187	33,857
Total	14,881	26,613	38,311
Capital expenditures for business combinations and asset purchases:			
DG Marine acquisition	-	-	94,072
Free State Pipeline acquisition, including transaction costs	-	-	76,193
NEJD Pipeline transaction, including transaction costs	-	-	177,699
Acquisition of intangible assets	-	2,500	-
Total	-	2,500	347,964
Capital expenditures related to equity investees and other investments	332,462	83	2,397
Total	332,462	83	2,397
Total capital expenditures	$ 347,343	$ 29,196	$ 388,672

In 2010, we acquired our 50% interest in Cameron Highway for $330 million, plus an additional $2.5 million purchase price adjustment related to the working capital of Cameron Highway and its operating activities for November. We also substantially completed a project to upgrade and integrate our existing information technology systems in order to be positioned for further growth.

In 2010, we acquired TD Marine's effective 51% interest in DG Marine for $25.5 million in cash plus $0.8 million in direct transaction costs associated with the acquisition, resulting in DG Marine becoming wholly-owned by us. We funded the acquisition with proceeds from our credit agreement, including (i) paying off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, and (ii) settling DG Marine's interest rate swaps, which resulted in $1.3 million being reclassified from Accumulated Other Comprehensive Loss ("AOCL") to interest expense in the third quarter of 2010.

During 2011, we expect to expend approximately $3.0 million to $4.0 million for maintenance capital projects in progress or planned. Those expenditures are expected to include improvements in all of our businesses. In future years we expect to spend $4 million to $5 million per year on maintenance capital projects. We also expect to expend approximately $2 million for the completion of the remaining phases of our information systems project.

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

Distributions to Unitholders and our General Partner

Our partnership agreement requires us to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last twenty-two quarters, including the distribution paid for the fourth quarter of 2010, as shown in the table below (in thousands, except per unit amounts). Each quarter, our board of directors determines the distribution amount per unit based upon various factors such as our operating performance, available cash, future cash requirements and the economic environment. As a result, the historical trend of distribution increases may not be a good indicator of future increases.

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579
First quarter 2010	May 2010	$ 0.3675	$ 14,548	$ 297	$ 2,339	$ 17,184
Second quarter 2010	August 2010	$ 0.3750	$ 14,845	$ 303	$ 2,642	$ 17,790
Third quarter 2010	November 2010	$ 0.3875	$ 15,339	$ 313	$ 3,147	$ 18,799
Fourth quarter 2010	February 2011 (1)	$ 0.4000	$ 25,846	$ -	$ -	$ 25,846

(1) This distribution was paid on February 14, 2011 to unitholders of record as of February 2, 2011.

On December 28, 2010, we permanently eliminated our IDRs and converted our general partner interest into a non-economic interest. In connection with this transaction, we issued approximately 20 million common units. These common units and the new units sold to the public in November 2010 participated in the distribution for the fourth quarter of 2010 included in the table above.

We also issued approximately 7 million Waiver Units in connection with the elimination of our IDRs. The Waiver Units, which are entitled to a minimal preferential distribution, have the right to convert into Genesis common units, on a one-for-one basis, in four equal installments in the calendar quarter during which each of our common units receives a quarterly distribution of at least $0.43, $0.46, $0.49 and $0.52, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times.

Non-GAAP Reconciliation

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

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

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

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

	Year Ended December 31,		
	2010	2009	2008
		(in thousands)	
Cash flows from operating activities	$ 90,463	$ 90,079	$ 94,808
Adjustments to reconcile operating cash flows to Available Cash:			
Maintenance capital expenditures	(2,856)	(4,426)	(4,454)
Proceeds from sales of certain assets	1,146	873	760
Amortization of credit facility issuance fees	(3,082)	(2,503)	(1,437)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	1,017	101	1,067
Earnings of DG Marine in excess of distributable cash	(848)	(4,475)	(2,821)
Other items affecting available cash	(1,088)	1,768	(2,561)
Expenses related to acquiring or constructing assets that provide new sources of cash flow	11,260	-	-
Net effect of changes in operating accounts not included in calculation of Available Cash	5,487	9,569	1,262
Available Cash before Reserves	$ 101,499	$ 90,986	$ 86,624

Commitments and Off-Balance Sheet Arrangements

Contractual Obligation and Commercial Commitments

In addition to our credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil and petroleum products. The table below summarizes our obligations and commitments at December 31, 2010.

Commercial Cash Obligations and Commitments	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 Years	More than 5 years	Total
Contractual Obligations:					
Long-term debt and notes payable [1]	$ -	$ -	$ 360,000	$ 250,000	$ 610,000
Estimated interest payable on					
long-term debt and notes payable [2]	37,688	75,478	66,301	56,797	236,264
Operating lease obligations	11,055	11,570	5,501	21,410	49,536
Unconditional purchase obligations [3]	229,162	8,970	-	-	238,132
Other Cash Commitments:					
Asset retirement obligations [4]	-	-	-	13,777	13,777
Liabilities associated with unrecognized					
tax benefits and associated interest [5]	6,241	-	-	-	6,241
Total	$ 284,146	$ 96,018	$ 431,802	$ 341,984	$ 1,153,950

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

(2) Interest on our long-term debt under our credit facility is at market-based rates. The interest rate on our senior unsecured notes is 7.875%. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2010 under our credit facility remained outstanding through the final maturity dates of June 30, 2015 and interest rates remained at the December 31, 2010 market levels through the final maturity dates. Also included is the interest on our senior unsecured notes through the maturity date.

(3) Unconditional purchase obligations include agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at December 31, 2010, were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.

(4) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $5.2 million and is further discussed in Note 5 to the Consolidated Financial Statements.

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

We have guaranteed 50% of the $2.2 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

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

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

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

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, trade names, and non-compete agreements involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired, and to the extent available, third party assessments. Uncertainties associated with these estimates include fluctuations in economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. In connection with the Grifco acquisition in 2008, we performed allocations of the purchase price. See Note 3 of the Notes to the Consolidated Financial Statements.

Depreciation and Amortization of Long-Lived Assets and Intangibles

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

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

Impairment of Long-Lived Assets including Intangibles and Goodwill

When events or changes in circumstances indicate that the carrying amount of a fixed asset or intangible asset may not be recoverable, we review our assets for impairment. We compare the carrying value of the fixed asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase costs and expenses at that time.

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment on October 1 of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill impairment test involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates, and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value.

We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value. One of our monitoring procedures is the comparison of our market capitalization to our book equity on a quarterly basis to determine if there is an indicator of impairment. As of December 31, 2010, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform an interim goodwill impairment test as of December 31, 2010. We did not have any goodwill impairments in 2010, 2009 or 2008.

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

Asset Retirement Obligations

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

Equity Compensation Plan Accruals

We accrue for the fair value of our liability for the stock appreciation rights ("SAR") awards we have issued to our employees and directors. Under our SAR plan, grantees receive cash for the difference between the market value of our common units and the strike price of the award at the time of exercise. We estimate the fair value of SAR awards at each balance sheet date using the Black-Scholes option pricing model. The Black-Scholes valuation model requires the input of somewhat subjective assumptions, including expected stock price volatility and expected term. Other assumptions required for estimating fair value with the Black-Scholes model are the expected risk-free interest rate and our expected distribution yield. The risk-free interest rates used are the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant.

We recognize the equity-based compensation expense on a straight-line basis over the requisite service period for the awards. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate at each balance sheet date based on prior experience. As of December 31, 2010, there was $0.8 million of total compensation cost to be recognized in future periods related to non-vested SARs. The cost is expected to be recognized over a weighted-average period of approximately one year. We also record compensation cost for changes in the estimated liability for vested SARs. The liability recorded for vested SARs fluctuates with the market price of our common units.

Our 2010 Long-Term Incentive Plan provides for grantees, which may include key employees and directors, to receive cash at the vesting of the phantom units equal to the average of the closing market price of our common units for the twenty trading days prior to the vesting date. Until the vesting date, we calculate estimates of the fair value of the awards and record that value as compensation expense during the vesting period. These estimates are based on the current trading price of our common units and an estimate of the forfeiture rate we expect may occur. At December 31, 2010, 62,927 phantom units had been granted and $0.4 million of expense had been recorded. The liability recorded for phantom units expected to vest fluctuates with the market price of our common units. At the date of vesting, any difference between the estimates recorded and the actual cash paid to the grantee will be charged to expense.

For phantom unit awards granted under our 2007 Long-Term Incentive Plan, the total compensation expense recognized over the service period was determined by the grant date fair value of our common units that become earned. Uncertainties involved in the estimate of the compensation cost we record for our phantom units relate to the assumptions regarding the continued employment of personnel who have been awarded phantom units. As a result of the change in control of our general partner in February 2010 when Denbury sold its interest in our general partner to The Robertson Group, the outstanding phantom units at December 31, 2009 vested. We recorded \$0.5 million of compensation expense in the first quarter of 2010 related to this accelerated vesting. No awards are outstanding at December 31, 2010 under the 2007 LTIP.

In connection with the settlement of the Series B awards to members of management, we made estimates of the fair value of the awards on the settlement date and recorded compensation expense for the awards totaling \$79.1 million in 2010. This estimate included a value for the Class A Units received by the holders of the Series B units in our general partner based on the number of units received and the market price of our common units on the date of the transaction. Compensation expense also included an estimate of the fair value of the Waiver Units issued to the holders of the Series B units based estimates by management of the likelihood and timing of conversion of the Waiver Units into Class A Units and an estimate of the value of those Class A Units. No expense is required to be recorded related to the awards in any future period.

See Note 15 of the Notes to our Consolidated Financial Statements for further discussion regarding our equity compensation plans.

Liability and Contingency Accruals

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

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

At December 31, 2010, we are not aware of any contingencies or liabilities that will have a material effect on our financial position, results of operations, or cash flows.

Allowance for Doubtful Accounts

We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 4 to our Consolidated Financial Statements for additional information on our allowance for doubtful accounts.

Recent Accounting Pronouncements.

Future Implementation

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for public entities, for impairment tests performed during entities' fiscal years (and interim periods within those years) that begin after December 15, 2010. Early application is not permitted. We will adopt the new guidance in the first quarter of 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, we do not expect the adoption of this guidance to have an impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. Early adoption is permitted. We will adopt the new disclosures in the first quarter of 2011. We do not believe that the adoption of this guidance will have a material impact to our financial position, results of operations or cash flows.

Implemented in 2010

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires additional disclosures regarding transfers into and out of level 1 and level 2 measurements and requires a gross presentation of activities within the level 3 roll forward. This guidance was effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance relating to level 1 and level 2 transfers as of January 1, 2010, and we adopted the guidance relating to level 3 measurements on January 1, 2011. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation, rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance was effective for us beginning January 1, 2010, and had no impact on our conclusions regarding consolidation of our VIEs.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

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

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

We utilize NYMEX commodity based futures contracts and option contracts to hedge our exposure to these market price fluctuations as needed. All of our open commodity price risk derivatives at December 31, 2010 were categorized as non-trading. On December 31, 2010, we had entered into NYMEX future contracts that will settle between January and April 2011 and NYMEX options contracts that will settle during February and March 2011. This accounting treatment is discussed further in Note 17 to our Consolidated Financial Statements.

The table below presents information about our open derivative contracts at December 31, 2010. Notional amounts in barrels or mmBtus, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars of our open positions are presented below. Fair values were determined by using the notional amount in barrels or mmBtus multiplied by the December 31, 2010 quoted market prices on the NYMEX. All of the hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the table below.

	Unit of Measure for Volume	Contract Volumes (in 000's)	Unit of Measure for Price	Weighted Average Market Price	Contract Value (in 000's)	Mark-to Market Change (in 000's)	Settlement Value (in 000's)
NYMEX Futures Contracts							
Sell (Short) Contracts:							
Crude Oil	Bbl	565	Bbl	$ 89.63	$ 50,642	$ 1,090	$ 51,732
Heating Oil	Bbl	207	Gal	$ 2.52	$ 21,920	$ 185	$ 22,105
RBOB Gasoline	Bbl	9	Gal	$ 2.28	$ 862	$ 57	$ 919
#6 Fuel Oil	Bbl	300	Bbl	$ 76.34	$ 22,903	$ 382	$ 23,285
Natural Gas	mmBtu	5	mmBtu	$ 4.40	$ 220	$ -	$ 220
Buy (Long) Contracts:							
Crude Oil	Bbl	260	Bbl	$ 90.17	$ 23,443	$ 316	$ 23,759
#6 Fuel Oil	Bbl	80	Bbl	$ 76.33	$ 6,107	$ 94	$ 6,201
NYMEX Option Contracts							
Crude Oil Written Calls	Bbl	210	Bbl	$ 1.97	$ 413	$ 115	$ 528

(1) Weighted average premium received/paid.

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

We are also exposed to market risks due to the floating interest rates on our credit facility. Obligations under our Senior Secured Credit Facility bear interest at the LIBOR Rate or Alternate Base Rate (which approximates the prime rate), at our option, plus the applicable margin. We have not, historically hedged our interest rates. On December 31, 2010, we had $360 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 100.

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

None.

Item 9A. Controls and Procedures

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

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

Management's Report on Internal Control over Financial Reporting

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

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2010. 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, 2010, 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, 2010. 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.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Genesis Energy, L.P. and subsidiaries (the "Partnership") as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Partnership and our report dated March 16, 2011 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 16, 2011

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

We are a Delaware limited partnership. Our general partner manages and operates our day to day activities subject to the supervision and oversight of its/our board of directors. Prior to the IDR Restructuring, the investors who owned our general partner elected our board. In conjunction with the IDR Restructuring, the primary objective of which was to permanently eliminate our IDRs, we acquired our general partner on December 28, 2010 in exchange for issuing to its former stakeholders approximately 27 million units, comprised of Class A Units, Class B Units and Waiver Units. Today, the holders of our Class B Units elect all of our directors subject to the Davison Family's right to elect a specified number of directors, as described in more detail below. Thus, the IDR Restructuring did not have an effect on our management team or the election of our board, so the former stakeholders of our general partner and the Davison family continue to have the right to elect our directors.

Corbin J. Robertson, Jr.-together with members of his family and certain of their affiliates (or the Robertson Group), owns approximately 15% of our Class A Units and 74% of our Class B Units. Consequently, through its Class B Units, the Robertson Group is able to control or exert substantial influence over us, including electing at least a majority of the members of our board of directors and controlling most matters requiring board approval, such as business strategies, mergers, business combinations, acquisitions or dispositions of significant assets, issuances of common stock, incurrence of debt or other financing and the payment of dividends. The Davison family is entitled to elect up to three directors under terms of the unitholders rights agreement with the Davison family. If members of the Davison family own (i) 15% or more of our common units, they have the right to appoint three directors, (ii) less than 15% but more than 10%, they have the right to appoint two directors, and (iii) less than 10%, they have the right to appoint one director. So long as the Davison family has the right to elect three directors, the board of directors cannot have more than 11 directors without the Davison family's consent. Pursuant to his employment agreement, Mr. Sims is entitled to be a director. Additionally, EIV Capital Fund LP, a former stakeholder in our general partner, has the right to vote for directors due to its ownership of Class B units.

As is common with MLPs, our partnership structure does not allow unitholders to directly or indirectly participate in our management or operation. The holders of our Waiver Units are not, generally, entitled to vote on any matters. The holders of Class B Units are entitled to elect directors and to vote on substantially all other matters on which our Class A holders are entitled to vote. The holders of our Class A Units are entitled to vote in only a limited number of circumstances, although they are entitled to remove our general partner (or the director election rights of our Class B unitholders) under specified circumstances. For example, our unitholders may remove our general partner by a vote of the holders of not less than a majority of the outstanding common units, excluding units held by our general partner and its affiliates, if we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units.

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

The Robertson Group appointees are Robert C. Sturdivant, Donald L. Evans, Corbin J. Robertson III, William K. Robertson, Kenneth M. Jastrow, II and S. James Nelson; the Davison family appointees are James E. Davison, James E. Davison, Jr. and Sharilyn S. Gasaway; and the EIV Capital Fund LP appointee is Carl A. Thomason.

Board Leadership Structure and Risk Oversight

Board Leadership Structure

The board has no policy that requires that the positions of the Chairman of the Board (the "Chairman") and the Chief Executive Officer be held by the same or different persons or that we designate a lead or presiding independent director. The board believes that those determinations should be based on circumstances existing from time to time, including the composition, skills and experience of the board and its members, specific challenges faced by the company or the industry in which it operates, and governance efficiency. Presently, Mr. Sturdivant, a representative of the Robertson Group, serves as the Chairman and Mr. Sims serves as Chief Executive Officer and a director of the board of directors, and we have not designated anyone as a presiding or lead independent director. However, as a result of the IDR Restructuring, we are reviewing certain features of our governance structure.

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders. We believe independent directors are a key element for strong governance, although we have exercised our right as a limited partnership under the listing standards of the NYSE, not to comply with certain requirements of the NYSE. For example, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that our board of directors be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that our board of directors maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Risk Oversight

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

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

Independence Determinations and Audit Committee

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

Governance, Compensation and Business Development Committee

The governance, compensation and business development committee of the board of directors generally (i) monitors compliance with corporate governance guidelines, (ii) reviews and makes recommendations regarding board of directors and committee composition, structure, size, compensation and related matters, and (iii) oversees compensation plans and compensation decisions for our employees. Before the IDR Restructuring, all the members of the board of directors served as members of the compensation committee. Kenneth M. Jastrow, II is the chairperson. The charter of the governance, compensation and business development committee are available on our website (www.genesisenergy.com) free of charge.

Conflicts Committee

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

Executive Sessions of Non-Management Directors

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

Directors and Executive Officers

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

Name	Age	Position
Robert C. Sturdivant	65	Director and Chairman of the Board
Grant E. Sims	55	Director and Chief Executive Officer
James E. Davison	73	Director
James E. Davison, Jr.	44	Director
Donald L. Evans	64	Director
Sharilyn S. Gasaway	42	Director
Kenneth Jastrow II	63	Director
S. James Nelson	68	Director
Corbin J. Robertson III	40	Director
William K. Robertson	35	Director
Carl A Thomason	58	Director
Robert V. Deere	56	Chief Financial Officer
Steven R. Nathanson	55	President and Chief Operating Officer
Stephen M. Smith	34	Vice President
Karen N. Pape	52	Senior Vice President and Controller

Robert C. Sturdivant was named a director of our general partner by the Robertson Group on February 5, 2010. Mr. Sturdivant currently serves as Vice President – Finance and Managing Director – Risk Management of certain Quintana affiliates, and has served in various roles with Quintana and its affiliates since 1974. Mr. Sturdivant represents Quintana's interests as a director on the boards of several private entities. We believe that Mr. Sturdivant's background and knowledge coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to our board of directors.

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

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

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

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

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

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

S. James Nelson was named a director of our general partner by the Robertson Group on March 1, 2010, and serves as chairman of the conflicts committee and as a member of the audit committee and the governance, compensation and business development committee. In 2004, Mr. Nelson retired after 15 years of service from Cal Dive International, Inc. (now known as Helix Energy Solutions Group, Inc.), a marine contractor and operator of offshore oil and natural gas properties and production facilities, where he was a founding shareholder, the Chief Financial Officer from 1990 to 2000, Vice Chairman from 2000 to 2004, and a director. Mr. Nelson is also a director of three other public companies: W&T Offshore, Inc., Oil States International, Inc. and ION Geophysical (formerly Input/Output, Inc.). Mr. Nelson also serves on the audit committee of the board of directors of each such company and, with respect to W&T Offshore, on the compensation committee. In addition, from 2005 through the company's sale in 2008, Mr. Nelson was a member of the board of directors of Quintana Maritime LLC where he was also chairman of the audit committee and a member of the compensation committee. Mr. Nelson's role as a director of multiple public companies and energy industry experience enables him to provide our board of directors with valuable insight and guidance.

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

William K. Robertson was named a director of our general partner by the Robertson Group on February 5, 2010. Mr. Robertson served as a Managing Director for Quintana from 2005 to 2010 and continues to serve as a director of Quintana's general partner and management company. Since October 31, 2007, Mr. Robertson has served as president of Quintana Minerals Corporation, a privately-held management company. Prior to joining Quintana, Mr. Robertson worked in private investments with The CapStreet Group, LLC, and, prior to that, in the energy and power investment banking department of Merrill Lynch, Pierce, Fenner & Smith Inc.. Mr. Robertson is the brother of Corbin J. Robertson III. We believe that Mr. Robertson brings to our board of directors experience analyzing industry transactions through his experiences in the energy and power investment banking industry.

Carl A. Thomason was named a director of our general partner by EIV Capital on March 1, 2010, and serves on the audit committee, conflicts committee and governance, compensation and business development committee. Mr. Thomason has been a marketing consultant to Yessup Oil Corp., a crude oil marketing company, since 2004 and prior to that he served for over thirty years in various roles in the crude oil gathering business, including as an owner of a regional crude oil gathering and transportation company. Mr. Thomason's experience in the crude oil gathering business and familiarity with the energy industry enhances his contributions to our board of directors.

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

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

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

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

Code of Ethics

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

Section 16(a) Beneficial Ownership Reporting Compliance

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

Item 11. Executive Compensation

We are managed by our general partner, which recently became one of our wholly-owned subsidiaries. Our general partner employs our executive officers and most of our employees. Under the terms of our partnership agreement, we are required to reimburse our general partner for expenses relating to managing our operations, including salaries and bonuses of employees employed on our behalf, as well as the costs of providing benefits to such persons under employee benefit plans.

The compensation of our executives including our named executive officers, or NEOs, identified below, was significantly affected in 2010 as a result of our general partner being owned by three different groups during those twelve months. At the beginning of 2010, our general partner was a substantially wholly-owned subsidiary of Denbury Resources Inc. with certain of our executives owning a minority interest in our general partner (which interests are described in more detail below). On February 5, 2010, a group of investors acquired all of the equity interest in our general partner (including the interest owned by our executives), although certain of our NEOs were allowed to participate as members of that investment group to the extent of their prior ownership interest and certain of our NEOs were awarded additional interest in our general partner as incentive compensation. In connection with the IDR Restructuring, we acquired all of the equity interest in our general partner on December 28, 2010 in exchange for issuing approximately 27 million of our units to the then-existing owners of our general partner (including certain of our executives).

As is common with MLPs, the equity holders of our general partner effectively determine the compensation philosophy, structure and amounts pertaining to our executives. Thus, our compensation structure at the beginning of 2010 was determined by Denbury. As part of Denbury's strategy to transform us from a small and relatively inactive enterprise into a mid-cap, growth-oriented MLP, our general partner hired Mr. Grant Sims as Chief Executive Officer on August 8, 2006. One of Mr. Sims's primary objectives was to build a capable management team that would be economically incentivized to ensure growth. By the end of 2008, our new senior executives and our general partner finalized such a compensation structure, the primary components of which were (i) awards of equity interest in our general partner to our senior executives (subject to specified performance-based vesting conditions) and (ii) four year employment agreements.

The change in control that occurred on February 5, 2010 (the "February Change in Control")--when a group of investors acquired all of the equity interest in our general partner--had four primary effects on our executive compensation. It (i) triggered some "change in control" provisions in certain of our employment arrangements (equity vesting and similar matters), (ii) created the opportunity for certain of our NEOs to receive cash or new equity interest in our general partner in exchange for their then-existing equity interest, (iii) resulted in our NEOs receiving awards of additional, restricted equity interest in our general partner (subject to specified vesting conditions), and (iv) resulted in certain of our NEOs being required to enter into new employment agreements with our general partner, if so requested by our Board. Prior to finalizing the terms of such employment agreements, we consummated the IDR Restructuring on December 28, 2010. We anticipate finalizing such agreements in 2011. Until such form of employment agreement is finalized, the existing employment agreements remain in effect. Subsequent references in this document refer to the terms of the existing agreements.

As a result of the IDR Restructuring (which also constituted a "change in control" under certain of our compensation arrangements), we have become the sole equity owner of our general partner, and our Board is in the process of revising our governance, compensation and other structures affected thereby.

The Compensation Discussion and Analysis below discusses our compensation process, objectives and philosophy with respect to our NEOs, for the fiscal year ended December 31, 2010.

Compensation Discussion and Analysis

Named Executive Officers

Our NEOs for 2010 are:

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

Our General Partner, Board and Governance, Compensation and Business Development Committee

Prior to the IDR Restructuring, like most MLPs, we had no employees; our general partner was responsible for our operations, and it provided all necessary personnel. Accordingly, the stakeholders of our general partner effectively were responsible for, and effectively determined, our compensation policies (including incentive compensation) and the terms of our employee benefit plans through their election of our Board. Because of the IDR Restructuring, which resulted in us owning our general partner, our Board is responsible for, and effectively determines, such compensation matters today.

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

Committee/Board Process

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

Committee/Board Approval

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

Role of Compensation Consultant

Our G&C Committee's charter authorizes the committee to retain independent compensation consultants from time to time to carry out certain of its duties. In 2010, our G&C Committee engaged BDO USA, LLP(BDO) an independent compensation consultant, to assist the Committee in assessing and structuring competitive compensation packages for the executive officers that are consistent with our compensation philosophy. At the request of our G&C Committee, BDO reviewed and provided input on the compensation of our NEOs, trends in executive compensation, meeting materials prepared for and circulated to our G&C Committee and management's proposed executive compensation plans. BDO also developed assessments of market levels of compensation through an analysis of peer data and information disclosed in our peer companies' public filings. The peer group used for this analysis consisted of Blueknight Energy Partners, Buckeye Partners, Copano Energy, LLC, Crosstex Energy Partners, DCP Midstream Partners, Eagle Rock Energy Partners, Holly Energy Partners, Magellan Midstream Partners, NuStar Energy, LP, Penn Virginia Resource Partners, Regency Energy Partners, Sunoco Logistics, LP, Targa Resource Partners, Amerigas Partners, Calumet Specialty Products Partners, Frontier Oil, Natural Resource Partners and Western Refining. The companies were selected because they reflect our industry competitors due to products, services, markets or geographical reach, are of similar size and maturity to us, or are companies that had similar credit profiles, comparable debt and equity markets or similar growth or capital programs to us. The information that BDO compiled included compensation trends for MLPs, and levels of compensation for similarly-situated executive officers of companies within this group and in other companies with revenues generally comparable to ours. We believe that compensation levels of executive officers in our peer group are relevant to our compensation decisions because we compete with those companies for executive management talent.

Compensation Objectives and Philosophy

The primary objectives of our compensation program are to attract, retain, and motivate key personnel through a total compensation plan that is intended to align compensation with our short-term and long-term financial goals (including unitholder distribution growth) as well as to achieve objectives contemplated by our strategic plans. Our compensation program is also designed to reward for past performance (including enterprise, segment and individual performance) and to provide incentives for future performance, including balancing rewards for short-term results with rewards for long-term value creation and encouraging a long-term commitment to us. We strive to accomplish these objectives by compensating all employees, including our NEOs, with a total compensation package that is market competitive and performance-based. In our assessment of the market competitiveness of compensation, we take into consideration the compensation offered by companies in our peer group but we have not targeted a specific percentile of peer company as a pay target. Rather we use market information as one consideration in setting compensation along with individual performance, skill sets and our performance.

We pay base salaries at a level that we feel are appropriate for the skills and qualities of the individual NEOs based on their past performance, current scope of responsibilities and future potential. The other incentive-based components of each NEO's compensation, including annual cash incentive opportunities and participation in the long-term incentive program, are generally linked to base salary and are consistent in general with our understanding of market practice and with our judgment regarding each individual's role in the organization.

As described in more detail below, we believe that the combination of base salaries, cash bonuses, long-term incentive plans and equity provide an appropriate balance of short-term and long-term incentives, cash and non-cash based compensation, and an alignment of the incentives for our executives, including our NEOS, with the interests of our common unitholders. Our bonus plan is driven by the generation of Available Cash before Reserves, which is an important metric of value for our unitholders, and our safety record. Our long term incentive plan is linked primarily to the appreciation in our common unit price.

Prior to the IDR Restructuring, the most significant component of our NEOs' long term incentive compensation arrangement was their equity interest in our general partner. That equity interest was represented by their Class B membership interest in our general partner on January 1, 2010. That arrangement matured with the February Change in Control. A similar arrangement of incentive compensation was put in place with new awards of Series B units pursuant to the February Change in Control. Through that equity interest in our general partner, our NEOs had the potential to participate in payments pursuant to, and redemption, of our IDRs. Payments pursuant to our IDRs were largely driven by the generation of available cash as well as the level of distributions we paid to our common unitholders and general partner. Pursuant to the IDR Restructuring, our IDRs were eliminated and replaced with our units. Accordingly, our G&C Committee is re-evaluating the long term incentive compensation of our NEOs.

Elements of Our Compensation Program and Compensation Decisions for 2010

The following table describes the elements of our compensation program for 2010 for our NEOs.

Elements of Compensation Program

January 1, 2010	**February 5, 2010**	**December 28, 2010**
• base salaries • equity interests* (Class B membership interest in our general partner) • other long-term incentive compensation • cash bonus • other compensation	• base salaries • equity interests* (Series B units in our general partner) • other long-term incentive compensation • cash bonus • other compensation	• base salaries • other long-term incentive compensation • cash bonus • other compensation

*See "—Long-Term Incentive Compensation—Equity Interest in Our General Partner" below for further discussion of the equity interests.

**In connection with the February Change in Control, Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape received 367, 200, 67, 100 and 33 Series B units, respectively. In connection with the IDR Restructuring, our NEOs exchanged their Series B equity interest in our general partner for approximately 2.4 million of our Class A Units and 0.8 million of our Waiver Units.

Base Salaries

In December 2008, our general partner, its stakeholders and Messrs. Sims and Deere finalized the compensation philosophy and structure for our executive officers, at which time Messrs. Sims and Deere entered into four year employment agreements and were awarded equity interests in our general partner. In connection with the February Change in Control, Messrs. Sims and Deere each entered into a waiver agreement, which amended the terms of their respective employment agreements waiving certain change of control and severance payment rights and agreed to a form of employment agreement and related release that our general partner may require each executive to execute in the future. As a result of the IDR Restructuring, our Board is revising such form of employment agreement as well as evaluating the employment arrangements of our other NEOs as part of the process of revising our governance, compensation and other structures. Our Board will seek to establish base salaries that are consistent with our compensation objectives and philosophy described above.

In connection with the February Change in Control, the salaries of our NEOs were reset to amounts shown below that were deemed to be consistent with market practices as we understood them and that we believed would be sufficient to retain and motivate our NEOs,

	Base Salary	
	January 1, 2010	February 5, 2010
Grant E. Sims	$ 340,000	$ 460,000
Steven R. Nathanson	$ 270,400	$ 330,000
Robert V. Deere	$ 379,000	$ 420,000
Stephen M. Smith (1)		$ 200,000
Karen N. Pape	$ 225,000	$ 225,000

(1) Mr. Smith became an employee effective February 5, 2010.

See further discussion of the employment agreements with certain of our NEOs below under "—Employment Agreements."

Bonuses

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

Bonuses under our Bonus Plan are paid at the discretion of our G&C Committee. Because the determination of whether bonuses will be paid each year and in what amounts they will be paid is determined by our G&C Committee on a company-wide basis, the NEOs only receive bonuses if other employees receive bonuses.

In 2010, two metrics were used to determine the general bonus pool – the level of Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) that we generated and our company-wide safety record improvement which included a targeted reduction in our company-wide incident injury rate. The level of Available Cash before Reserves generated for the year as a percentage of a target set by our G&C Committee was weighted 90% and the achieved level of the targeted improvement in our safety record was weighted 10%. The sum of the weighted percentage achievement of these targets was multiplied by the eligible compensation and the target percentages established by our G&C Committee for the various levels of our employees to determine the maximum general bonus pool. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation" for a description of Available Cash before Reserves.

For 2010, our G&C Committee established a target of approximately $98 million for Available Cash before Reserves and before bonus expense and related employer tax burdens and subject to certain other adjustments, with an achievement of 105% required for a full payout of the targeted bonus. We achieved 96% of the target for 2010. We achieved our safety incident rate goal for 2010. As a result, the bonus pool for 2010 bonuses to be paid in March 2011 was calculated as 90% of 96% plus 10% for the safety performance, or 97%. The total pool approved for such bonuses, inclusive of other discretionary downward adjustments, was approximately $5.1 million.

To award our NEOs for performance, G&C Committee approved 2010 bonuses of $446,200, $320,100, $101,850 ,$194,000, and $218,250 to Messrs. Sims, Nathanson, Deere, and Smith and Ms. Pape, respectively, in March 2011. Because target bonus amounts had not been approved for the NEOs in 2010, the amounts of these bonuses were determined subjectively considering each NEO's performance and contribution to overall results in 2010 in the context of the Committee's understanding of competitive market practices.

Long-Term Incentive Compensation

Equity Interest in Our General Partner

Prior to the IDR Restructuring, the most significant component of our NEOs' long term incentive compensation arrangement was their equity interest in our general partner. That equity interest was represented by their Class B membership interest in our general partner on January 1, 2010. That interest was effectively replaced with new awards of Series B units pursuant to the February Change in Control. Through that equity interest in our general partner, our NEOs had the potential to participate in payments pursuant to, and redemption, of our IDRs. Payments pursuant to our IDRs were largely driven by the generation of available cash as well as the level of distributions we paid to our common unitholders and general partner. Pursuant to the IDR Restructuring, our IDRs were eliminated and replaced with our units. Accordingly, our G&C Committee is evaluating the long term incentive compensation of our NEOs as part of the process of revising our governance, compensation and other structures in connection with the IDR Restructuring.

As a result of the February Change in Control, our general partner was required to redeem the individual Class B membership interests under our general partner's existing limited liability company agreement. Messrs. Sims and Deere were allowed to invest in proportion to their prior ownership interest. A portion of the Class B membership interests in our general partner held by Messrs. Sims and Deere was converted into Series A units in our general partner and our general partner redeemed the remaining portion for cash in the amount of $221,868 and $431,684, respectively. In addition, Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape received 367, 200, 67, 100 and 33 Series B units in our general partner, respectively, as incentive compensation (subject to certain vesting conditions).

In connection with the IDR Restructuring, we acquired all the equity interest in our general partner on December 28, 2010 in exchange for issuing approximately 27 million of our units to the then-existing owners of our general partner (including our NEOs who received approximately 3.2 million of the units in exchange for their Series B units). Our NEOs received the following consideration in exchange for their Series B units in the IDR

Restructuring as incentive compensation consistent with our compensation objectives and philosophy described above:

	Class A Units	Waiver Units	Total Units
Grant E. Sims	1,131,255	395,936	1,527,191
Steven R. Nathanson	616,512	215,776	832,288
Robert V. Deere	206,486	72,268	278,754
Stephen M. Smith	308,256	107,888	416,144
Karen N. Pape	101,770	35,616	137,386

Pursuant to the IDR Restructuring, we are required to establish an equity incentive plan in 2011 for our eligible employees, including our NEOs, for the issuance of approximately 145,620 Class A Units and 50,967 Waiver Units. However, if unitholder approval is required for such plan and our Board determines not to seek such approval, which determination has not yet been made, we are required to establish a cash-settled or cash-based plan not subject to such approval that would provide substantially equivalent economic benefits to such participants as the equity incentive plan. In 2011, our G&C Committee intends to establish a philosophy and strategy regarding long-term incentive compensation including how this plan will be integrated with long-term opportunities under the 2010 Long-Term Incentive Plan as discussed below.

2010 Long Term Incentive Plan

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

Our G&C Committee administers the 2010 LTIP. Under the 2010 LTIP, our G&C Committee (at its discretion) has the authority to determine the terms and conditions of any awards granted under the 2010 LTIP and to adopt, alter and repeal rules, guidelines and practices relating to 2010 LTIP. Our G&C Committee has full discretion to administer and interpret the 2010 LTIP and to establish such rules and regulations as it deems appropriate and to determine, among other things, the time or times at which the awards may be exercised and whether and under what circumstances an award may be exercised. Our G&C Committee designates participants in the 2010 LTIP, determines the types of awards to grant to participants and determines the number of units to be covered by any award. To enhance our ability to attract and retain the services of individuals who are essential for our growth and profitability and to encourage such individuals to devote their best efforts to our business, our G&C Committee made initial awards of 44,829 phantom units with tandem DERs under the 2010 LTIP in April 2010. Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape received 16,795, 8,030, 5,110, 2,430 and 2,735 phantom units with tandem DERS, respectively, based on the Committee's assessment of their performance and long-term role in the organization and in the context of its general understanding of market practices. To encourage a longer term commitment to us, the phantom units will vest on the third anniversary of the date of issuance.

Termination or Change of Control Benefits

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

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

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

Other Compensation and Benefits

We offer certain other benefits to our NEOs, including medical, dental, disability and life insurance, and contributions on their behalf to our 401(k) plan. In addition, because of their status as owners in our general partner and not "employees" during a portion of the year, during 2010 our NEOs were reimbursed for the additional benefit costs and taxes they paid or will owe individually related to their medical, dental, disability and life insurance, as well as self-employment taxes. After the IDR Restructuring, the NEOs are no longer owners of our general partner and such reimbursements will not occur in the future

The only retirement benefit that we provide for our NEOs is a 401(k) plan that is open to all employees. We do not have any pension plan or post-retirement medical benefits.

Tax Implications

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

For our equity-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 15 to our consolidated financial statements.

Compensation Committee Report

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

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

Kenneth M. Jastrow, II, Chairman
S. James Nelson
James E. Davison
James E. Davison, Jr.
Sharilyn S. Gasaway
Donald L. Evans
Corbin J. Robertson III
William K. Robertson
Robert C. Sturdivant
Carl A. Thomason

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

Compensation Risk Assessment

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

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

- the Company has strong internal financial controls;
- base salaries are consistent with employees' responsibilities so that they are not motivated to take excessive risks to achieve a reasonable level of financial security;
- the determination of incentive awards is based on a review of a variety of indicators of performance as well as a meaningful subjective assessment of personal performance, thus diversifying the risk associated with any single indicator of performance;
- goals are appropriately set to avoid targets that, if not achieved, result in a large percentage loss of compensation;
- incentive awards are capped by our G&C Committee;
- compensation decisions include discretionary authority to adjust annual awards and payments, which further reduces any business risk associated with our plans; and
- long-term incentive awards are designed to provide appropriate awards for dedication to a corporate strategy that delivers long-term returns to unitholders.

2010 SUMMARY COMPENSATION TABLE

The following Summary Compensation Table summarizes the total compensation paid or accrued to our NEOs in 2010, 2009 and 2008.

Name & Principal Position	Year	Salary ($)	Bonus (1) ($)	Stock Awards (2) ($)	Option Awards (3) ($)	All Other Compen-sation (4) ($)	Total ($)
Grant E. Sims	2010	440,000	446,200	4,186,488	-	72,262	5,144,950
Chief Executive Officer	2009	340,000	-	-	-	50,904	390,904
(Principal Executive Officer)	2008	310,000	107,751	6,395,234	-	9,834	6,822,819
Steven R. Nathanson (5)	2010	320,067	320,100	2,259,069	-	66,187	2,965,423
President & Chief Operating Officer							
Robert V. Deere (6)	2010	413,167	101,850	805,066	-	61,696	1,381,779
Chief Financial Officer	2009	369,600	-	-	-	52,574	422,174
(Principal Financial Officer)	2008	89,557	-	443,724	-	621	533,902
Stephen M. Smith (7)	2010	226,247	194,000	1,097,914	-	38,766	1,556,927
Vice President							
Karen N. Pape	2010	225,000	218,250	400,877	-	44,227	888,354
Senior Vice President &	2009	225,000	170,000	58,408	-	20,238	473,646
Controller (Principal Accounting Officer)	2008	200,000	180,000	-	14,699	19,356	414,055

(1) The 2008 amount in this column for Mr. Sims represents the amount that was paid as a bonus at the time of execution of his employment agreement. The amounts in this column for Ms. Pape for 2009 and 2008 represent bonuses paid in March 2010 relative to 2009 and March 2009 relative to 2008 under our bonus program that was effective for 2009 and 2008.
(2) The amounts shown in this column for 2010 for each of our NEOs represent the aggregate grant date fair value for each NEO's Series B Award and Phantom Units issued to such NEO in 2010 under our 2010 Long-Term Incentive Plan. Amounts in this column for Messrs. Sims and Deere for 2008 represent the grant-date fair value for each NEO's Class B membership interest. Amounts in this column for Ms. Pape represent the aggregate grant date fair value of the phantom units granted under our 2007 Long Term Incentive Plan, or 2007 LTIP, in 2009. The grant date fair value of each award was determined in accordance with accounting guidance for equity-based compensation. Assumptions used in the calculation of these amounts are included in Note 15 to the Consolidated Financial Statements.
(3) The amounts shown in this column represent the aggregate grant date fair value for Ms. Pape's award under our Stock Appreciation Rights Plan, or SAR Plan, granted in 2008, determined in accordance with accounting guidance for equity-based compensation. Assumptions used in the calculation of these amounts are included in Note 15 to the Consolidated Financial Statements.
(4) Information on the amounts included in this column is included in the table below.
(5) Mr. Nathanson became an executive officer of our general partner on February 5, 2010.
(6) Mr. Deere was employed by our general partner effective October 6, 2008.
(7) Mr. Smith became an executive officer of our general partner on December 28, 2010.

Name	Year	401(k) Matching and Profit Sharing Contributions (a)	Insurance Premiums (b)	Other Compensation (c)	Totals
Grant E. Sims	2010	$ 7,350	$ -	$ 64,912	$ 72,262
	2009	$ 7,350	$ -	$ 43,554	$ 50,904
	2008	$ 7,350	$ 2,484	$ -	$ 9,834
Steven R. Nathanson	2010	$ 19,677	$ 207	$ 46,303	$ 66,187
Robert V. Deere	2010	$ 7,350	$ -	$ 54,346	$ 61,696
	2009	$ 7,350	$ -	$ 45,224	$ 52,574
	2008	$ -	$ 621	$ -	$ 621
Stephen M. Smith	2010	$ 6,870	$ 138	$ 31,758	$ 38,766
Karen N. Pape	2010	$ 20,606	$ 155	$ 23,466	$ 44,227
	2009	$ 18,375	$ 1,863	$ -	$ 20,238
	2008	$ 17,700	$ 1,656	$ -	$ 19,356

The amounts in this table represent

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

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

(c) For 2010, the amount represents reimbursement for estimate of additional benefit costs and taxes of the NEO related to the NEO's status as a Series B Member in our general partner. Reimbursements for additional benefits costs were $14,605, $16,112, $17,163, $13,201 and $7,267 for Messrs. Sims, Nathanson, Deere and Smith and Ms. Pape, respectively. Reimbursements for taxes were $31,329,

$21,117, $31,409, $15,811, and $13,108 for Messrs. Sims, Nathanson, Deere and Smith and Ms Pape, respectively. Amounts paid for DERs were $18,978, $9,074, $5,774, $2,746 and $3,091 for Messrs. Sims, Nathanson, Deere and Smith and Ms Pape, respectively. In 2009, amount for Mr. Sims was $16,127 for reimbursements for additional benefits costs and $27,427 for tax reimbursements. Amount for Mr. Deere in 2009 was $16,160 for reimbursements for additional benefits costs and $29,064 for tax reimbursements.

GRANTS OF PLAN-BASED AWARDS IN FISCAL YEAR 2010

The following table shows the equity and non-equity incentive plan awards granted to our NEOs in 2010.

Grants of Plan-Based Awards in Fiscal Year 2010

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#) (1)	Exercise or Base Price of Option Awards ($/Sh)	Market Price of Common Units on Award Date (2)	Grant Date Fair Value of Stock and Option Awards (3)
Grant E. Sims	4/20/2010	16,795	$ -	$ 20.54	$ 335,060
	2/5/2010				$3,851,428
Steven R. Nathanson	4/20/2010	8,030	$ -	$ 20.54	$ 160,199
	2/5/2010				$2,098,871
Robert V. Deere	4/20/2010	5,110	$ -	$ 20.54	$ 101,945
	2/5/2010				$ 703,122
Stephen M. Smith	4/20/2010	2,430	$ -	$ 20.54	$ 48,479
	2/5/2010				$1,049,435
Karen N. Pape	4/20/2010	2,735	$ -	$ 20.54	$ 54,563
	2/5/2010				$ 346,314

(1) Represents the number of phantom units awarded to the NEO on April 20, 2010.
(2) Represents the closing market price of our common units on the date of the phantom unit award.
(3) The initial amounts in this column for each NEO represent the fair value of the award on the date of the grant, April 20, 2010, as calculated in accordance with accounting guidance for equity-based compensation. The second amounts in this column for each NEO represent the fair value of the Series B awards on the date of the grant, February 5, 2010.

Employment Agreements

In December 2008, the stakeholders of our general partner, our general partner and Messrs. Sims and Deere finalized a compensation philosophy and structure for our executive officers, at which time Messrs. Sims and Deere entered into four year employment agreements. The employment agreements automatically terminate after four years unless terminated earlier pursuant to the agreements. Messrs. Sims' and Deere's employment agreements provide for annual salary of $340,000 and $369,600, respectively, subject to certain upward adjustments. Each agreement provides for increasing the annual salaries of Messrs. Sims and Deere rate by (i) $30,000 if our market capitalization is at least $1.0 billion for any 90-consecutive-day period, and (ii) an additional amount equal to 10% of his then effective base salary each time our market capitalization increases by an additional $300 million.

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

Each of Messrs. Sims and Deere (or his respective family) would be entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through December 31, 2012 if he dies, if he is terminated due to a disability or if he terminates his employment for good reason. If our general partner terminates Messrs. Sims or Deere (other than for cause) within two years after a change of control, he would be entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through the later of December 31, 2012 or three years from his date of termination.

As used in the employment agreements of Messrs. Sims and Deere, the terms “cause,” “good reason,” “change of control” and “disability” are generally described below:

- “Cause” means, in general, if an executive commits willful fraud or theft of our assets, is convicted of a felony or crime of moral turpitude, materially violates certain provisions of his employment agreement, substantially fails to perform, is grossly negligent, acts with willful misconduct, acts in a way materially injurious to us, willfully violates material written rules, regulations or policies, or fails to follow reasonable instructions from the audit committee, and such failure to follow instructions could reasonably be expected to be materially injurious to us.
- “Good reason” means, in general, an executive’s duties, responsibilities, base salary, or benefits are materially diminished, if either our principal executive office or that executive is based anywhere outside of metropolitan Houston without his consent, if our general partner fails to make a material payment under, or perform a material provision of, his employment agreement, or our general partner amends or changes certain equity interests in a manner that materially and adversely affects the executive’s right to distributions or redemptions payable because of such amendment or change, subject to certain exceptions.
- “Change of control” means, among other things, if all or substantially all of the assets of Denbury or our general partner are transferred to a non-Denbury affiliate, if Denbury and its affiliates cease to own 50% or more of certain equity interests (or other economic and voting equity interests) in our general partner, or 50% or more than the general partner interest in us, if Denbury is merged or consolidated into a third party and pre-merger holders hold less than half of the voting securities of the post-merger survivor, if a majority of Denbury’s board of directors is replaced during any 12-month period, or if more than 50% of the voting securities of Denbury are acquired by a third-party or affiliated group of third parties.
- “Disability” means, in general, if the executive has been absent from his duties with us on a full-time basis for 180 out of any 220 consecutive calendar days as a result of incapacity due to mental or physical illness or injury that is determined to be total and permanent by a selected physician or if the Social Security Administration has determined that executive is totally disabled.

In connection with the February Change in Control, Messrs. Sims and Deere each entered into a waiver agreement, which amended the terms of their respective employment agreements waiving certain change of control and severance payment rights and agreed to a form of employment agreement, subject to our G&C Committee’s approval and, if needed, our Board’s approval, and related release that our general partner may require each to execute in the future. Until such form of employment agreement is finalized, the 2008 employment agreements of Messrs. Sims and Deere remain in effect. As a result of the IDR Restructuring, our Board is revising such form of employment agreement as well as evaluating the employment arrangements of our other NEOs as part of the process of revising our governance, compensation and other structures.

Mr. Nathanson entered into an employment agreement in July 2007 with our general partner under which his base salary is $250,000, subject to discretionary upward adjustments. The agreement also provides that the executive is eligible to participate in all other benefit programs (e.g., health, dental, disability, life and/or other insurance plans) for which executive officers are generally eligible. Mr. Nathanson's employment arrangement includes customary non-competition restrictions following his termination.

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

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

- "Cause" means, in general, if the executive commits theft, embezzlement, forgery, any other act of dishonesty relating the executive's employment or violates our policies or any law, rule, or regulation applicable to us, is convicted of a felony or lesser crime having as its predicate element fraud, dishonesty, or misappropriation, fails to perform his duties under the employment agreement or commits an act or intentionally fails to act, which act or failure to act amount amounts to gross negligence or willful misconduct.
- "Change of control" means, in general, any sale of equity of us or our general partner or substantially all of the assets of us or our general partner, merger, conversion or consolidation of us or our general partner, or other event that, in each case, results in any person or entity (or other persons or entities acting in concert) having the ability to elect a majority of the members of the Board.

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

Equity Incentive Plans

In the second quarter of 2010, our general partner adopted the 2010 LTIP. The 2010 LTIP provides for the award of phantom units and DERs to directors of our general partner, and employees and other representatives of our general partner and its affiliates who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. DERs are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on the phantom units had they been limited partner units issued by us. Our G&C Committee administers the 2010 LTIP.

Our G&C Committee (at its discretion) designates participants in the 2010 LTIP, determines the types of awards to grant to participants, determines the number of units to be covered by any award, and determines the conditions and terms of any award including vesting, settlement and forfeiture conditions. Our Board can terminate the 2010 LTIP at any time, and our G&C Committee can amend or make equitable adjustments to awards under the 2010 LTIP. Our G&C Committee made the initial awards of 44,829 phantom units with tandem DERs under the 2010 LTIP in April 2010. The phantom units will vest on the third anniversary of the date of issuance.

The SAR Plan was administered by our G&C Committee, which determined, in its full discretion, the number of rights to award, the grant date of the rights, the vesting period of the rights awarded and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit. The rights have a term of 10 years from the date of grant. If the right has not been exercised at the end of the ten year term and the participant has not terminated employment with us, the right will be deemed exercised as of the date of the right's expiration and a cash payment will be made as described below.

Upon vesting, the participant may exercise his rights to receive a cash payment equal to the difference between the average of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. The cash payment to the participant will be net of any applicable withholding taxes required by law. If our G&C 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 our G&C Committee may authorize deferral of the cash payments until a later date.

OUTSTANDING EQUITY AWARDS AT 2010 FISCAL YEAR-END

The following table presents information regarding the outstanding equity awards to our NEOs at December 31, 2010.

	Stock Appreciation Rights				Stock Awards	
Name	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable (1)	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable (2)	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date	Number of Phantom Units That Have Not Vested (#) (3)	Market Value of Phantom Units That Have Not Vested ($) (4)
Grant E. Sims					16,795	$ 443,388
Steven R. Nathanson	12,348	4,117	$20.92	2/14/2018		
					8,030	$ 211,992
Robert V. Deere					5,110	$ 134,904
Stephen M. Smith					2,430	$ 64,152
Karen N. Pape	12,153		$9.26	12/31/2013		
	2,889		$12.48	12/31/2014		
	3,071		$11.17	12/31/2015		
	767		$16.95	8/29/2016		
	4,254		$19.57	12/29/2016		
		4,790	$20.92	2/14/2018		
					2,735	$ 72,204

(1) All rights in this column were vested at December 31, 2010.

(2) The unexercisable rights of each named executive officer vest on January 1, 2012.

(3) The phantom unit award listed for each NEO vests on April 20, 2013.

(4) The amounts in this column were calculated by multiplying the closing market price of the units at the end of the fiscal year by the number of units.

OPTION EXERCISES AND STOCK VESTED IN 2010

	Stock Awards		
Name	Number of Shares Acquired on Vesting (#) - Class A Units	Number of Shares Acquired on Vesting (#) - Waiver Units	Value Realized on Vesting ($)
Grant E. Sims	1,131,255	395,936	$ 39,050,274
Steven R. Nathanson	616,512	215,776	$ 21,281,604
	8,960		$ 167,014
Robert V. Deere	206,486	72,268	$ 7,127,740
Stephen M. Smith	308,256	107,888	$ 10,640,802
Karen N. Pape	101,770	35,616	$ 3,512,960
	11,359		$ 211,732

As a result of the IDR Restructuring, the Series B awards of our NEOs vested and our NEOs received Class A Units and Waiver Units. The amounts in this table reflect the units received and the value of those units at the date of vesting.

As a result of the change in control of our general partner on February 5, 2010, all outstanding phantom units issued pursuant to our 2007 LTIP vested. Mr. Nathanson and Ms. Pape received 8,960 and 11,359 Class A Units for the phantom units that vested.

NONQUALIFIED DEFERRED COMPENSATION

Name	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at December 31, 2010 ($)
Grant E. Sims	$ 1,007,229	$ -

Our general partner adopted an unfunded, nonqualified deferred compensation plan effective December 31, 2008 and on December 31, 2008 made awards under that plan to Mr. Sims in a maximum amount of $1,007,229. The awards represented compensation for the substantial growth in our cash available before reserves, or CABR, under his management. Most of that growth was attributable to our acquisition of five energy related businesses from the Davison family in 2007 and our formation of the DG Marine joint venture in 2008. The awards were paid on February 5, 2010, and the plan was terminated in connection with the February Change in Control. No contributions were made in 2010 to this plan. The total of $1,007,229 was paid to Mr. Sims on February 5, 2010.

Potential Payments upon Termination or Change in Control

Each of Messrs. Sims and Deere is entitled under his employment agreement to specified severance benefits under certain circumstances. Neither executive would be entitled to severance benefits if our general partner terminates him for cause. Each of Messrs. Sims and Deere (or his family) would be entitled to continued health benefits for 18 months to the extent such benefits are subsidized by the Partnership for its active employees after his termination and to the payment of his base salary through December 31, 2012 if he dies, if he is terminated due to a disability or if he terminates his employment for good reason. If our general partner terminates Messrs. Sims or Deere (other than for cause) within two years after a change of control, he would be entitled to continued health benefits for 18 months after his termination to the extent that such benefits are subsidized by the Partnership for its active employees and to the payment of his base salary through the later of December 31, 2012 or three years from his date of termination.

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

Based on a hypothetical termination date of December 31, 2010, the change in control termination benefits for Messrs. Sims, Nathanson and Deere would have been as follows:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere
Severance payment pursuant to employment agreement	$ 1,380,000	$ 330,000	$ 1,260,000
Healthcare	24,180	20,551	30,826
Total	$ 1,404,180	$ 350,551	$ 1,290,826

Based upon a hypothetical termination date of December 31, 2010, the termination benefits for Messrs. Sims, Nathanson and Deere for voluntary termination or termination for cause would be zero. Based upon a hypothetical termination date of December 31, 2010, the termination benefits for of Messrs. Sims, Nathanson and Deere for termination without cause or for good reason, including death or disability would have been:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere
Severance payment pursuant to employment agreement	$ 920,000	$ 330,000	$ 840,000
Healthcare	24,180	20,551	30,826
Total	$ 944,180	$ 350,551	$ 870,826

DIRECTOR COMPENSATION FOR FISCAL YEAR 2010

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

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

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

Director Compensation in Fiscal 2010

Name	Fees Earned or Paid in Cash ($)[1]	Stock Awards ($) [2] [3]	All Other Compensation ($) [4]	Total
James E. Davison	$ 69,917	$ 55,688	$ 2,119	$ 127,724
James E. Davison, Jr.	$ 69,917	$ 55,688	$ 2,119	$ 127,724
Donald L. Evans [5]	$ 59,750	$ 55,688	$ 2,119	$ 117,557
Sharilyn S. Gasaway	$ 79,250	$ 63,083	$ 2,400	$ 144,733
Kenneth M. Jastrow, II	$ 86,000	$ 59,388	$ 2,259	$ 147,647
S. James Nelson	$ 90,000	$ 59,293	$ 2,256	$ 151,549
Corbin J. Robertson III [5]	$ 59,750	$ 55,688	$ 2,119	$ 117,557
William K. Robertson III [5]	$ 61,750	$ 55,688	$ 2,119	$ 119,557
Robert C. Sturdivant [5]	$ 61,750	$ 55,688	$ 2,119	$ 119,557
Carl A. Thomason	$ 86,750	$ 55,688	$ 2,119	$ 144,557
Former Directors [6]	$ 46,169			$ 46,169

(1) Amounts include annual retainer fees and fees for attending meetings.
(2) Amounts in this column represent the fair value of the awards of phantom units under our 2010 LTIP on the date of grant, as calculated in accordance with accounting guidance for equity-based compensation.
(3) Outstanding awards to directors at December 31, 2010 consist of phantom units granted under our 2010 LTIP and stock appreciation rights pursuant to our SAR Plan. Messrs. James Davison and James Davison Jr. each hold 2,711 outstanding phantom units and 1,000 stock appreciation rights. Messrs. Jastrow, Nelson and Thomason and Ms. Gasaway hold 2,891, 2,888, 2,711 and 3,071 outstanding phantom units, respectively. Each of Messrs. Evans, C. Robertson, W. Robertson and Sturdivant hold 2,711 phantom units, of which all proceeds will be paid to an affiliate of Quintana.
(4) Amounts in this column represent the amounts paid for tandem DERs related to outstanding phantom units granted under our 2010 LTIP.
(5) These directors have agreed to give all compensation for their services as directors to an affiliate of Quintana. All fees paid and amounts paid for DERs related to phantom unit awards in 2010 for these directors were paid to an affiliate of Quintana.
(6) Amounts paid to former directors in February 2010.

Compensation Committee Interlocks and Insider Participation

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

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

Securities Authorized for Issuance Under Equity Compensation Plans

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

There are no outstanding phantom units under this plan as of December 31, 2010. For additional discussion of our 2007 LTIP, see Note 15 of the Notes to the Consolidated Financial Statements.

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of March 1, 2011, regarding the beneficial ownership of our Class A Common Units and Class B Common Units by beneficial owners of 5% or more of such units, by directors and the executive officers of our general partner and by all directors and executive officers as a group. This information is based on data furnished by the persons named.

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class	2010 LTIP Phantom Units (1)
James E. Davison (2)	Class A Common Units	2,877,610	4.5	2,711
James E. Davison, Jr. (3) (4)	Class A Common Units	4,209,973	6.5	2,711
Donald L Evans (5)	Class A Common Units	-	*	2,711
Sharilyn S Gasaway	Class A Common Units (6)	174,374	*	3,071
	Class B Common Units	526	1.3	
Kenneth M. Jastrow, II	Class A Common Units	-	*	2,891
S. James Nelson	Class A Common Units	-	*	2,888
Corbin J. Robertson III (5)	Class A Common Units	-	*	2,711
William K. Robertson (5)	Class A Common Units	-	*	2,711
Robert C. Sturdivant (5)	Class A Common Units	-	*	2,711
Carl A Thomason	Class A Common Units	-	*	2,711
Grant E. Sims	Class A Common Units (7)	2,270,690	3.5	16,795
	Class B Common Units	3,421	8.6	
Robert V. Deere	Class A Common Units (8)	555,235	*	5,110
	Class B Common Units	1,052	2.6	
Steven R. Nathanson (9)	Class A Common Units	746,419	1.2	8,030
Stephen M. Smith (10)	Class A Common Units	308,256	*	2,430
Karen N. Pape (11)	Class A Common Units	116,515	*	2,735
All directors and executive officers as a group (15 in total)	Class A Common Units	11,259,072	17.4	62,927
	Class B Common Units	4,999	12.5	
Quintana (12)	Class A Common Units	9,881,904	15.3	
	Class B Common Units	29,735	74.3	
EIV Capital Fund LP (13)	Class A Common Units	1,743,746	2.7	
	Class B Common Units	5,263	13.2	

* Less than 1%

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

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

(3) 1,049,406 of these units are held by the James E Davison, Jr. Grantor Retained Annuity Trust. Additionally this trust holds 91,823 of each class of our Waiver Units.

(4) Mr. Davison pledged 700,000 of these units as collateral for a loan from a bank.

(5) Mr. Evans is a member of the board of managers of QEP Management Co. GP, LLC, a Delaware limited liability company ("Management Co GP"), a member of the board of directors and senior partner of Quintana Capital Group GP, Ltd., a Cayman Islands company ("QCG GP"), and partner of Quintana Capital Group II, L.P., a Cayman Islands limited partnership ("QCG II"); the Don Evans Group, Ltd. is a member of Q GEI Holdings, LLC, a Delaware limited liability company ("Q GEI"). Mr. Robertson is a member of the board of managers of Management Co GP, a member of the board of directors and managing director of QCG GP, a member of Q GEI and a partner in QCG II; The William Keen Robertson 2009 Family Trust is a member of Q GEI. Mr. Robertson, III is the chief executive officer, president and a member of the board of managers of Q GEI, a manager of Management Co GP, a member of the board of directors and managing director of QCP GP, a member of Q GEI and a partner in QCG II; The Corbin J. Robertson III 2009 Family Trust is a member of Q GEI. Mr. Sturdivant is a partner of QCG II and a member of Q GEI. Each such person disclaims beneficial ownership of all the units reported by such entities. See note (12) below.

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

(7) 1,000 of these common units are held by Mr. Sims' father. Mr. Sims disclaims beneficial ownership of these units. Includes 3,421 of our Class B Units. Mr. Sims also holds 198,459 of each class of our Waiver Units.

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

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

(10) Mr. Smith also holds 26,972 of each class of our Waiver Units.

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

(12) Information based on Schedule 13D filed by Q GEI, QEP II, GEP Genesis, the Management Entities, QCG II and QCG GP (as defined herein or note (5)) with the Securities and Exchange Commission on January 7, 2011. Q GEI is the beneficial owner of 7,083,865 Class A Units it holds directly (approximately 11.0% of outstanding Class A Units), including 21,316 Class A Units issuable upon conversion of an identical number of Class B Units. Quintana Energy Partners II, L.P., a Cayman Islands limited partnership ("QEP II"), is the beneficial owner of 2,503,680 Class A Units it holds directly (approximately 3.9% of outstanding Class A Units), including 7,534 Class A Units issuable upon conversion of an identical number of Class B Units. QEP II Genesis TE Holdco, LP, a Delaware limited partnership ("QEP Genesis"), is the beneficial owner of 294,359 Class A Units it holds directly (approximately 0.5% of outstanding Class A Units), including 885 Class A Units issuable upon conversion of an identical number of Class B Units. Each of Q GEI, QEP II and QEP Genesis may be deemed to have sole voting and dispositive power over the Class A Units held directly by them. By the nature of their relationship or interests in QEP II and QEP Genesis, QEP Management Co., L.P., a Delaware limited partnership ("Management Co"), which provides management services to QEP II and QEP Genesis, Management Co GP, the general partner of Management Co (together with Management Co, the "Management Entities"), Quintana Capital Group II, L.P., a Cayman Islands limited partnership and general partner of QEP II and GEP Genesis ("QCG II"), and QCG GP, the general partner of QCG II (together with the Management Entities and QCG II, the "Managing Entities") may be deemed to be the beneficial owners of 2,798,039 Class A Units (approximately 4.3% of outstanding Class A Units), including 8,419 Class A units issuable upon conversion of an identical number of Class B Units. The Managing Entities may be deemed to have shared voting and dispositive power over the Class A Units beneficially held directly by QEP II and QEP Genesis. Q GEI, QEP II and QEP Genesis also hold approximately 619,838, 219,072 and 25,756 of each class of our Waiver Units, respectively. The principal business and office address of each entity is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

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

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

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

Beneficial Ownership of General Partner Interest

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

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

Transactions with Related Persons

Our general partner was owned by three different groups during 2010. Consequently, what we considered to be related party transactions changed over the course of 2010. At the beginning of 2010, our general partner was a substantially wholly-owned subsidiary of Denbury with certain of our executives owning a minority interest in our general partner. Pursuant to the February Change in Control, a group of investors acquired all the equity interest in our general partner (including the interest owned by our executives). In connection with the IDR Restructuring, we acquired all of the equity interest in our general partner on December 28, 2010.

We are managed by our general partner, which became one of our wholly-owned subsidiaries pursuant to the IDR Restructuring. Our general partner employs our executive officers and all of our employees. Under the terms of our partnership agreement, we are required to reimburse our general partner for expenses relating to managing our operations. During 2010, these reimbursements totaled $47 million.

Prior to the IDR Restructuring, our general partner was entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Our general partner was generally entitled to 13.3% of amounts we distributed to our common unitholders in excess of $0.25 per unit, 23.5% of the amounts we distributed to our common unitholders in excess of $0.28 per unit, and 49% of the amounts we distributed to our common unitholders in excess of $0.33 per unit. During 2010, our general partner received a total of $11.4 million from us as distributions, $1.2 million for its general partner interest, and $10.2 million related to its incentive distribution rights. Pursuant to the IDR Restructuring, our IDRs were eliminated.

The group of investors that acquired all of the equity interest in our general partner in connection with the February Change in Control included certain of our executives, affiliates of the Robertson Group and members of the Davison family. See Item 10. “Directors, Executive Officers and Corporate Governance” for a discussion of certain arrangements with the Robertson Group and members of the Davison family to appoint directors and Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for a description of such investors’ ownership interest in us.

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, 2010 was approximately $16,000.

During 2010, we sold $1.1 million of petroleum products to businesses owned and operated by members of the Davison family in the ordinary course of our operations.

Prior to the February Change in Control, Denbury controlled our general partner. During 2010, we entered into the following transactions with Denbury, which we considered to be related party transactions in the ordinary course of our operations:

- Provision of transportation services for crude oil by truck totaling $0.2 million.
- Provision of crude oil pipeline transportation services totaling $1.4 million.
- Provision of CO_2 and crude oil pipeline transportation services under lease arrangements for which we received payments totaling $0.1 million.
- Provision of CO_2 transportation services to our wholesale industrial customers by Denbury’s pipeline. The fees for this service totaled $0.4 million.

Review or Special Approval of Material Transactions with Related Persons

Before we consider entering into a material transaction with our general partner or any of its affiliates, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, (3) would comply with our partnership agreement, and (4) would be fair to us and our limited partners. In addition, the Board may request that the Conflicts Committee review specific matters that the Board believes may involve conflicts of interest between our general partner or any of its affiliates and us. Messrs. Nelson, Thomason and Jastrow and Ms. Gasaway serve as the members of the Conflicts Committee. The Conflicts 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.

For example, the Conflicts Committee approved our acquisition of the 51% economic interest in DG Marine that we did not own in July 2010. Additionally the Conflicts Committee, excluding Ms. Gasaway who recused herself, approved the IDR Restructuring.

Director Independence

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

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

Item 14. Principal Accounting Fees and Services

The following table summarizes the fees for professional services rendered by Deloitte & Touche LLP for the years ended December 31, 2010 and 2009.

	2010	2009
	(in thousands)	
Audit Fees (1)	$ 3,001	$ 3,122
Audit-Related Fees (2)	241	80
Tax Fees (3)	421	479
All Other Fees (4)	4	4
Total	$ 3,667	$ 3,685

(1) Includes fees for the annual audit and quarterly reviews (including internal control evaluation and reporting), SEC registration statements and accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles. Also includes separate audits of certain of our consolidated subsidiaries and joint ventures and, in 2009, an audit of our general partner.
(2) Includes fees for the audit of our employee benefit plan and review of correspondence with the SEC. In 2010, also includes fees related to reviewing our documentation of controls and process for conversion related to our project to upgrade our information technology systems. In 2009, includes fees for services related to third-party review of workpapers.
(3) Includes fees for tax return preparation and tax consultations.
(4) Includes fees associated with licenses for accounting research software.

Pre-Approval Policy

The services by Deloitte in 2010 and 2009 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 2010 and 2009, the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte and management of our general partner to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements and Financial Statement Schedules" set forth on page 100.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements and Financial Statement Schedules" set forth on page 100.

(a)(3) Exhibits

2.1	Contribution and Sale Agreement by and between TD Marine, LLC and Genesis Energy, L.P. dated July 28, 2010 (incorporated by reference to Exhibit 2.1 to Form 8-K dated August 3, 2010)
2.2	Purchase and Sale Agreement by and between Valero Energy Corporation, Valero Services, Inc., Valero Unit Investments, L.L.C., Genesis Energy, L.P., Genesis CHOPS I, LLC, and Genesis CHOPS II, LLC dated October 22, 2010 (incorporated by reference to Exhibit 2.2 to Form 10-Q for the quarter ended September 30, 2010)
2.3	Agreement and Plan of Merger by and among Genesis Energy, L.P., Genesis Acquisition, LLC and Genesis Energy, LLC dated as of December 28, 2010 (incorporated by reference to Exhibit 2.1 to Form 8-K dated January 3, 2011)
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	Fifth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 3, 2011)
3.3	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, File No. 001-12295)
3.4	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, File No. 001-12295)
3.5	Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)
3.6	Certificate of Formation of Genesis Energy, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009)

3.9	Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011)
4.1	Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007)
4.2	Indenture dated November 18, 2010 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K dated November 23, 2010)
4.3	Registration Rights Agreement dated November 18, 2010 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and, as representative of the several initial purchasers named therein, Merrill Lynch, Pierce, Fenner & Smith Incorporated (incorporated by reference to Exhibit 4.2 to Form 8-K dated November 23, 2010)
10.1	Second Amended and Restated Credit Agreement dated as of June 29, 2010 among Genesis Energy, L.P., as borrower, BNP Paribas as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 2, 2010)
10.2	First Amendment to Second Amended and Restated Credit Agreement, dated November 17, 2010, among Genesis Energy, L.P. as borrower, BNP Paribas, as administrative agent, and each of the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated November 23, 2010)
10.3	Registration Rights Agreement, dated as of December 28, 2010, by and among Genesis Energy, L.P. and the former unitholders of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to Form 8-K dated January 3, 2011)
10.4	Contribution and Sale Agreement by and among Davison Petroleum Products, L.L.C., Davison Transport, Inc., Transport Company, Davison Terminal Service, Inc., Sunshine Oil & Storage, Inc., T&T Chemical, Inc. Fuel Masters, LLC, TDC, L.L.C. and Red River Terminals, L.L.C. dated April 25, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 31, 2007)
10.5	Amendment No. 1 to the Contribution and Sale Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.2 to Form 8-K dated July 31, 2007)
10.6	Amendment No. 2 to the Contribution and Sale Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated October 19, 2007)
10.7	Amendment No. 3 to the Contribution and Sale Agreement dated March 3, 2008 (incorporated by reference to Exhibit 10.21 to Form 10-K for the year ended December 31, 2007)
10.8	Davison Registration Rights Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K dated July 31, 2007)
10.9	Amendment No. 1 to the Davison Registration Rights Agreement dated November 16, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated November 16, 2007)
10.10	Amendment No. 2 to the Davison Registration Rights Agreement dated December 6, 2007 (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2007)
10.11	Amendment No. 3 to the Davison Registration Rights Agreement, dated as of December 28, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K dated January 3, 2011)

10.12 Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to Form 8-K dated July 31, 2007)

10.13 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)

10.14 Amendment No. 2 to the Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.3 to Form 8-K dated January 3, 2011)

10.15 Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC, as Lessor and Denbury Onshore, LLC, as Lessee for the North East Jackson Dome Pipeline dated May 30, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated June 5, 2008)

10.16 Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Free State Pipeline, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K dated June 5, 2008)

10.17 Transportation Services Agreement between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 5, 2008)

10.18 Form of Indemnity Agreement, among Genesis Energy, L.P., Genesis Energy, LLC and Quintana Energy Partners II, L.P. and each of the Directors of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to Form 8-K dated March 5, 2010)

10.19 Amendment No. 1 to the Indemnity Agreement dated March 4, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K dated January 3, 2011)

10.20 + Genesis Energy, LLC First Amended and Restated Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.24 to Form 10-K for the year ended December 31, 2008)

10.21 + Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.25 to Form 10-K for the year ended December 31, 2008)

10.22 + Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 21, 2007)

10.23 + Genesis Energy, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2010)

10.24 + Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Directors Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2010)

10.25 + Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Employee Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2010)

10.26 + 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)

10.27 + Form of 2007 Phantom Unit Grant Agreement (3-Year Cliff) (incorporated by reference to Exhibit 10.3 to Form 8-K dated December 21, 2007)

10.28 + Employment Agreement by and between Genesis Energy, LLC and Grant E. Sims, dated December 31, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated January 7, 2009)

10.29 + Employment Agreement by and between Genesis Energy, LLC and Robert V. Deere, dated December 31, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated January 7, 2009)

	10.30	+	Employment Agreement by and between Genesis Energy, Inc. and Steve Nathanson dated July 25, 2007 (incorporated by reference to Exhibit 10.30 to Form 10-K for the year ended December 31, 2009)
	10.31	+	Waiver Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.32	+	Waiver Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to Form 8-K dated February 11, 2010)
	10.33		Purchase Agreement dated November 12, 2010 relating to 7.875% Senior Notes due 2018 (incorporated by reference to Exhibit 10.1 to Form 8-K dated November 18, 2010)
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 11 of the Notes to the Consolidated Financial Statements)
*	21.1		Subsidiaries of the Registrant
*	23.1		Consent of Deloitte & Touche LLP
*	23.2		Consent of Deloitte & Touche LLP
*	31.1		Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
*	31.2		Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
*	32.1		Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*	32.2		Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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* Filed herewith

\+ A management contract or compensation plan or arrangement.

SIGNATURES

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

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

By: GENESIS ENERGY, LLC,
as General Partner

Date: March 16, 2011

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

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

NAME	TITLE (OF GENESIS ENERGY, LLC)*	DATE
/s/ GRANT E. SIMS Grant E. Sims	Director and Chief Executive Officer (Principal Executive Officer	March 16, 2011
/s/ ROBERT V. DEERE Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	March 16, 2011
/s/ KAREN N. PAPE Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	March 16, 2011
/s/ ROBERT C. STURDIVANT Robert C. Sturdivant	Chairman of the Board and Director	March 16, 2011
/s/ JAMES E. DAVISON James E. Davison	Director	March 16, 2011
/s/ JAMES E. DAVISON, JR. James E. Davison, Jr.	Director	March 16, 2011
/s/ DONALD L. EVANS Donald L. Evans	Director	March 16, 2011
/s/ SHARILYN S. GASAWAY Sharilyn S. Gasaway	Director	March 16, 2011
/s/ KENNETH M. JASTROW, II Kenneth M. Jastrow, II	Director	March 16, 2011
/s/ S. JAMES NELSON S. James Nelson	Director	March 16, 2011
/s/ CORBIN J. ROBERTSON, III Corbin J. Robertson, III	Director	March 16, 2011
/s/ WILLIAM K. ROBERTSON William K. Robertson	Director	March 16, 2011
/s/ CARL A THOMASON Carl A. Thomason	Director	March 16, 2011

*Genesis Energy, LLC is our general partner.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. and subsidiaries (the "Partnership") as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive (loss) income, partners' capital, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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, 2010, 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 16, 2011 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 16, 2011

GENESIS ENERGY, L.P.
CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,762	$ 4,148
Accounts receivable - trade, net	171,550	129,865
Inventories	55,428	40,204
Other	19,798	15,027
Total current assets	252,538	189,244
FIXED ASSETS, at cost	373,339	373,927
Less: Accumulated depreciation	(108,283)	(89,040)
Net fixed assets	265,056	284,887
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	168,438	173,027
EQUITY INVESTEES AND OTHER INVESTMENTS	343,434	15,128
INTANGIBLE ASSETS, net of amortization	120,175	136,330
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	32,048	24,465
TOTAL ASSETS	$ 1,506,735	$ 1,148,127
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 165,978	$ 117,625
Accrued liabilities	40,736	23,803
Total current liabilities	206,714	141,428
SENIOR SECURED CREDIT FACILITIES	360,000	366,900
SENIOR UNSECURED NOTES	250,000	-
DEFERRED TAX LIABILITIES	15,193	15,167
OTHER LONG-TERM LIABILITIES	5,564	5,699
COMMITMENTS AND CONTINGENCIES (Note 19)		
PARTNERS' CAPITAL:		
Class A common unitholders, 64,575 and 39,488 units issued and outstanding at December 31, 2010 and 2009, respectively	669,261	585,554
Class B common unitholders, 40 units issued and outstanding at December 31, 2010	3	-
General partner	-	11,152
Accumulated other comprehensive loss	-	(829)
Total Genesis Energy, L.P. partners' capital	669,264	595,877
Noncontrolling interests	-	23,056
Total partners' capital	669,264	618,933
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,506,735	$ 1,148,127

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

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per unit amounts)

	Year Ended December 31, 2010	2009	2008
REVENUES:			
Supply and logistics	$ 1,878,780	$ 1,226,838	$ 1,852,414
Refinery services	151,060	141,365	225,374
Pipeline transportation services	55,652	50,951	46,247
CO_2 marketing	15,832	16,206	17,649
Total revenues	2,101,324	1,435,360	2,141,684
COSTS AND EXPENSES:			
Supply and logistics costs:			
Product costs	1,761,161	1,115,809	1,736,637
Operating costs	91,773	82,262	78,453
Refinery services operating costs	88,094	88,910	166,096
Pipeline transportation operating costs	14,777	13,024	15,224
CO_2 marketing costs	5,928	5,825	6,484
General and administrative	113,406	40,413	29,500
Depreciation and amortization	53,557	62,581	71,370
Net loss on disposal of surplus assets	12	160	29
Impairment expense	-	5,005	-
Total costs and expenses	2,128,708	1,413,989	2,103,793
OPERATING (LOSS) INCOME	(27,384)	21,371	37,891
Equity in earnings of joint ventures	2,355	1,547	509
Interest expense	(22,924)	(13,660)	(12,937)
(Loss) income before income taxes	(47,953)	9,258	25,463
Income tax (expense) benefit	(2,588)	(3,080)	362
NET (LOSS) INCOME	(50,541)	6,178	25,825
Net loss attributable to noncontrolling interests	2,082	1,885	264
NET (LOSS) INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$ (48,459)	$ 8,063	$ 26,089
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:			
Basic and Diluted	$ 0.49	$ 0.51	$ 0.59
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
Basic and Diluted	40,560	39,471	38,961

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

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

	Year Ended December 31,		
	2010	2009	2008
Net (loss) income	$ (50,541)	$ 6,178	$ 25,825
Change in fair value of derivatives:			
Current period reclassification to earnings	2,112	784	33
Changes in derivative financial instruments - interest rate swaps	(424)	(508)	(1,997)
Comprehensive (loss) income	(48,853)	6,454	23,861
Comprehensive loss attributable to noncontrolling interests	1,223	1,742	1,266
Comprehensive (loss) income attributable to Genesis Energy, L.P.	$ (47,630)	$ 8,196	$ 25,127

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 Class A Common Units	Class A Common Unitholders	Class B Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interests	Total
Partners' capital, January 1, 2008	38,253	$ 615,265	$ -	$ 16,539	$ -	$ 570	$ 632,374
Comprehensive income:							
Net income (loss)	-	23,485	-	2,604	-	(264)	25,825
Interest rate swap losses reclassified to interest expense	-	-	-	-	16	17	33
Interest rate swap loss	-	-	-	-	(978)	(1,019)	(1,997)
Cash contributions	-	-	-	511	-	25,505	26,016
Cash distributions	-	(47,529)	-	(3,005)	-	(5)	(50,539)
Issuance of units for cash	2,037	41,667	-	-	-	-	41,667
Issuance of units under LTIP	5	750	-	-	-	-	750
Redemption of units	(838)	(16,667)	-	-	-	-	(16,667)
Partners' capital, December 31, 2008	39,457	616,971	-	16,649	(962)	24,804	657,462
Comprehensive income:							
Net income (loss)	-	21,469	-	(13,406)	-	(1,885)	6,178
Interest rate swap losses reclassified to interest expense	-	-	-	-	383	401	784
Interest rate swap loss	-	-	-	-	(250)	(258)	(508)
Cash contributions	-	-	-	9	-	-	9
Contribution for management compensation (Note 11)	-	-	-	14,104	-	-	14,104
Cash distributions	-	(53,876)	-	(6,204)	-	(6)	(60,086)
Issuance of units under LTIP	31	990	-	-	-	-	990
Partners' capital, December 31, 2009	39,488	585,554	-	11,152	(829)	23,056	618,933
Comprehensive loss:							
Net income (loss)	-	17,933	-	(66,392)	-	(2,082)	(50,541)
Interest rate swap losses reclassified to interest expense	-	-	-	-	1,035	1,077	2,112
Interest rate swap loss	-	-	-	-	(206)	(218)	(424)
Issuance of units for cash	5,175	116,347	-	-	-	-	116,347
Cash contributions	-	-	-	2,528	-	13	2,541
Contribution for management compensation (Note 11)	-	-	-	76,923	-	-	76,923
Cash distributions	-	(58,983)	-	(11,369)	-	(7)	(70,359)
Acquisition of noncontrolling interest in DG Marine (Note 3)	-	(4,920)	-	(100)	-	(21,268)	(26,288)
Issuance of units in exchange for general partner interest (Note 11)	19,814	13,310	3	(12,742)	-	(571)	-
Issuance of units under LTIP	98	20	-	-	-	-	20
Partners' capital, December 31, 2010	64,575	$ 669,261	$ 3	$ -	$ -	$ -	$ 669,264

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

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

	Year Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$ (50,541)	$ 6,178	$ 25,825
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, amortization and impairment	53,557	67,586	71,370
Amortization and write-off of credit facility issuance costs	3,082	2,503	1,437
Amortization of unearned income and initial direct costs on direct financing leases	(17,651)	(18,095)	(10,892)
Payments received under direct financing leases	21,854	21,853	11,519
Equity in earnings of investments in joint ventures	(2,355)	(1,547)	(509)
Distributions from joint ventures - return on investment	3,623	950	1,272
Non-cash effect of equity-based compensation plans	4,706	4,248	(2,063)
Non-cash compensation charge	76,923	14,104	-
Deferred and other tax liabilities	1,337	1,914	(2,771)
Other, net	1,415	(46)	882
Net changes in components of operating assets and liabilities (See Note 14)	(5,487)	(9,569)	(1,262)
Net cash provided by operating activities	90,463	90,079	94,808
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(12,400)	(30,332)	(37,354)
CO_2 pipeline transactions and related costs	-	-	(228,891)
Distributions from joint ventures - return of investment	2,859	-	886
Investments in joint ventures and other investments	(332,462)	(83)	(2,397)
Acquisition of Grifco assets	-	-	(66,686)
Other, net	1,265	1,182	718
Net cash used in investing activities	(340,738)	(29,233)	(333,724)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Bank borrowings	691,829	255,300	531,712
Bank repayments	(698,729)	(263,700)	(236,412)
Proceeds from issuance of senior unsecured notes	250,000	-	-
Credit facility and senior unsecured notes issuance fees	(14,586)	(422)	(2,255)
Issuance of common units for cash	116,347	-	-
Redemption of common units for cash	-	-	(16,667)
General partner contributions	2,528	9	511
Noncontrolling interests contributions, net of distributions	6	(6)	25,500
Acquisition of noncontrolling interest in DG Marine	(26,288)	-	-
Distributions to common unitholders	(58,983)	(53,876)	(47,529)
Distributions to general partner interest	(11,369)	(6,204)	(3,005)
Other, net	1,134	(6,784)	(5,805)
Net cash provided by (used in) financing activities	251,889	(75,683)	246,050
Net increase (decrease) in cash and cash equivalents	1,614	(14,837)	7,134
Cash and cash equivalents at beginning of period	4,148	18,985	11,851
Cash and cash equivalents at end of period	$ 5,762	$ 4,148	$ 18,985

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

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

1. Organization

We are a growth-oriented limited partnership focused on the midstream segment of the oil and gas industry in the Gulf Coast area of the United States. We conduct our operations through our operating subsidiaries and joint ventures. We manage our businesses through four divisions:

- Pipeline transportation of crude oil and carbon dioxide (or “CO_2”);
- Refinery services involving processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and sale of the related by-product, sodium hydrosulfide (or “NaHS”, commonly pronounced nash) and supplying caustic soda (or “NaOH”);
- Supply and logistics services, which includes terminaling, blending, storing, marketing, and transporting by trucks and barge of crude oil and petroleum products; and
- Industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture.

In February 2010, new investors, together with members of our executive management team, acquired our general partner. At that time, our general partner owned all our 2% general partner interest and all of our incentive distribution rights, or IDRs. At that time, in respect of its general partner interest and IDRs, our general partner was entitled to over 50% of any increased distributions we would pay in respect of our outstanding equity.

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

2. Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2010 and 2009 and our results of operations, cash flows and changes in partners’ capital for the years ended December 31, 2010, 2009 and 2008. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries, and Genesis Energy, LLC.

The inclusion of Genesis Energy, LLC in our Consolidated Financial Statements was effective December 28, 2010 due to our IDR Restructuring. See Notes 1 and 11.

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

Joint Ventures

We participate in three joint ventures: Cameron Highway Oil Pipeline Company (“Cameron Highway”), T&P Syngas Supply Company (“T&P Syngas”) and Sandhill Group, LLC (“Sandhill”). We account for our 50% investments in Cameron Highway, T&P Syngas and Sandhill by the equity method of accounting. See Notes 3 and 8.

Cameron Highway Oil Pipeline Company

On November 23, 2010, we acquired a 50% equity interest in Cameron Highway Oil Pipeline Company, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. Enterprise Products Partners, L.P. indirectly owns the remaining 50% interest in, and operates, the joint venture.

T&P Syngas Supply Company

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

Sandhill Group, LLC

We own a 50% interest in Sandhill. Reliant Processing Ltd. holds the other 50% interest in Sandhill and manages the daily operations of the joint venture. Sandhill 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, beverage, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

Noncontrolling Interests

Until December 28, 2010, our general partner, which owns a 0.01% general partner interest in Genesis Crude Oil, L.P., was not one of our subsidiaries See Note 1.

Until July 29, 2010, TD Marine, LLC, a related party, owned the remaining 51% economic interest in DG Marine. See Note 3.

As a result of our IDR Restructuring and the acquisition of the 51% of DG Marine from TD Marine, we reclassified the acquired noncontrolling interest in Genesis Crude Oil, L.P. and DG Marine to Genesis Energy, L.P. partners' capital. The net interest of those parties in our results of operations and financial position are reflected in our Consolidated Financial Statements as noncontrolling interests for the periods prior to the dates of the respective transactions.

Use of Estimates

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

Cash and Cash Equivalents

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

Accounts Receivable

Our accounts receivable are primarily from purchasers of crude oil and petroleum products, and, to a lesser extent, purchasers of NaHS and CO_2. These purchasers include refineries, marketing and trading companies. The majority of our accounts receivable relate to our supply and logistics activities that can be described as high volume and low margin activities.

We utilize our credit review process to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial performance assurances most commonly provided to us include standby letters of credit, “parental” guarantees and advance cash payments.

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

Inventories

Crude oil and petroleum products inventories held for sale are valued at the lower of cost or market. Fuel inventories are carried at the lower of cost or market. Caustic soda and NaHS inventories are stated at the lower of cost or market. Cost is determined principally under the average cost method within specific inventory pools.

Fixed Assets

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

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

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

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

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

Asset Retirement Obligations

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

Direct Financing Leasing Arrangements

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

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

CO_2 Assets

Our CO_2 assets include three volumetric production payments and long-term contracts to sell the CO_2 volume. The contract values are being amortized on a units-of-production method. These assets are included in Other Assets in our Consolidated Balance Sheets. See Note 9.

Intangible and Other Assets

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

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

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

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We test goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. 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 may be necessary to reduce the carrying value of the goodwill to its implied fair value. In the event that we determine that goodwill has become impaired, we will incur a charge for the amount of impairment during the period in which the determination is made. No goodwill impairment has occurred in any of the periods presented. See Note 9.

Environmental Liabilities

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

Equity-Based Compensation

The compensation cost associated with our stock appreciation rights plan and phantom units issued under our 2010 Long-Term Incentive Plan, which will result in the payment of cash to our employee or directors or our general partner upon exercise, is re-measured each reporting period. The liability and related compensation cost is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates and management’s assumptions about expectation of forfeitures prior to vesting.

See Note 15 for information on these plans.

Revenue Recognition

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

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

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

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

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

CO_2 Sales - Revenues from CO_2 marketing activities are recorded when title transfers to the customer at the inlet meter of the customer's facility.

Cost of Sales and Operating Expenses

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

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

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

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

Cost of sales for the CO_2 marketing activities consists of a transportation fee charged by Denbury to transport the CO_2 to the customer through Denbury's pipeline and insurance costs. The transportation fee charged by Denbury is adjusted annually for inflation. For the years ended December 31, 2010, 2009 and 2008, the fee averaged $0.2094, $0.2043, and $0.1927 per Mcf, respectively.

Excise and Sales Taxes

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

Income Taxes

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

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

Derivative Instruments and Hedging Activities

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. Until July 29, 2010, DG Marine used interest rate swap contracts to manage its exposure to interest rate risk.

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

Fair Value of Current Assets and Current Liabilities

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

Net Income Per Common Unit

Income was first allocated to our general partner based on the amount of incentive distributions to our general partner. We then allocated to our general partner loss in the amount of equity-based compensation costs which our general partner agreed to pay. The remainder was 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 under our 2007 Long-term Incentive Plan (2007 LTIP). (See Note 15 for discussion of our equity-based compensation.)

In a period of net operating losses, incremental phantom units are excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. During 2009 and 2008, we reported net income; therefore incremental phantom units have been included in the calculation of diluted earnings per unit.

Recent and Proposed Accounting Pronouncements

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for public entities, for impairment tests performed during entities' fiscal years (and interim periods within those years) that begin after December 15, 2010. Early application is not permitted. We will adopt the new guidance in the first quarter of 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, we do not expect the adoption of this guidance to have an impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. Early adoption is permitted. We will adopt the new disclosures in the first quarter of 2011. We do not believe that the adoption of this guidance will have a material impact to our financial position, results of operations or cash flows.

In July 2010, the FASB issued guidance which requires companies that hold financing receivables, which include loans, lease receivables, and the other long-term receivables to provide more information in their disclosures about the credit quality of their financing receivables and the credit reserves held against them. On December 31, 2010, we adopted all amendments that require disclosures as of the end of a reporting period, and on January 1, 2011, we adopted all amendments that require disclosures about activity that occurs during a reporting period (the remainder of the accounting guidance). The adoption of this accounting guidance did not have a material impact on our consolidated financial statements.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as Level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, Level 2 measurements generally reflect the use of significant observable inputs and Level 3 measurements typically utilize significant unobservable inputs. This new guidance requires additional disclosures regarding transfers into and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. This guidance was effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance relating to Level 1 and Level 2 transfers as of January 1, 2010, and we adopted the guidance relating to Level 3 measurements on January 1, 2011. Our adoption had no material impact on Consolidated Financial Statements.

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for Variable Interest Entities, or VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation, rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance was effective for us beginning January 1, 2010, and there was no material impact on our Consolidated Financial Statements.

3. Acquisitions

2010 Cameron Highway Oil Pipeline Company Investment

On November 23, 2010, we acquired a 50% equity interest in Cameron Highway Oil Pipeline Company, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. The purchase price was approximately $330 million plus approximately $2.5 million of purchase price adjustments.

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

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

The following table presents selected unaudited pro forma financial information incorporating the historical 50% equity interest in Cameron Highway. The effective closing date of our purchase of a 50% equity interest in Cameron Highway was November 23, 2010. As a result, our Consolidated Statements of Operations for the year ended December 31, 2010 includes our 50% equity investment in Cameron Highway for the last five weeks of

2010. The pro forma financial information has been prepared as if the acquisition had been completed on the first day of each period presented rather than the actual closing date. The pro forma financial information has been prepared based upon assumptions deemed appropriate by us and may not be indicative of actual results.

	Year Ended December 31,			
	2010		2009	
Pro forma earnings data:				
Revenue	$	2,101,324	$	1,435,360
Costs and expenses	$	2,130,430	$	1,415,909
Operating (loss) income		(29,106)		19,451
Net loss attributable to				
Genesis Energy, L.P.	$	(55,001)	$	(538)
Basic and diluted earnings per unit:				
As reported units outstanding		40,560		39,471
Pro forma units outstanding		44,969		44,646
As reported net income per unit	$	0.49	$	0.51
Pro forma net income per unit	$	0.30	$	0.26

DG Marine Transportation

2008 Initial Investment in DG Marine

On July 18, 2008, DG Marine completed the acquisition of the inland marine transportation business of Grifco Transportation, Ltd. ("Grifco") and two of Grifco's affiliates. DG Marine is a joint venture we formed with TD Marine, LLC, an entity owned by members of the Davison family. Until July 29, 2010, TD Marine owned (indirectly) a 51% economic interest in the joint venture, DG Marine, and we owned (directly and indirectly) a 49% economic interest. This acquisition gives us the capability to provide transportation services of petroleum products by barge and complements our other supply and logistics operations.

Grifco received initial purchase consideration of approximately $80 million, comprised of $63.3 million in cash and $16.7 million, or 837,690 of our common units. A portion of the units are subject to certain lock-up restrictions. DG Marine acquired substantially all of Grifco's assets, including twelve barges, seven push boats, certain commercial agreements, and offices. Additionally, DG Marine and/or its subsidiaries acquired the rights, and assumed the obligations, to take delivery of four new barges in late third quarter of 2008 and four additional new barges late in first quarter of 2009 (at a total price of approximately $27 million). Grifco financed $12 million of additional purchase consideration that we agreed to pay after we placed the eight new barges in service. At December 31, 2009, all of the seller-financed additional purchase price consideration was paid.

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

Until July 29, 2010, DG Marine was a VIE as certain of our voting rights were not proportional to our 49% economic interest. Accounting provisions require the primary beneficiary to consolidate variable interest entities. In determining the primary beneficiary of a VIE that is held between two or more related parties the primary beneficiary is considered to be the party that is "most closely associated" with the VIE. We were considered to be the primary beneficiary due to (i) our involvement in the design of DG Marine, (ii) the ongoing involvement with regards to financial and operating decision making of DG Marine, excluding matters related to new contracts and vessel disposal which are decided solely by TD Marine, and (iii) the financial support we provided to DG Marine. TD Marine had no requirements to make any additional contributions to DG Marine.

As we were considered the primary beneficiary, DG Marine was consolidated in our Consolidated Financial Statements and the 51% ownership interest of TD Marine in the net assets and net income of DG Marine was included in noncontrolling interests in our Consolidated Financial Statements.

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

The allocation of the acquisition cost is summarized as follows:

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

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

See additional information on intangible assets in Note 9.

2010 Acquisition of Noncontrolling Interest

On July 29, 2010, we acquired TD Marine's effective 51% interest in DG Marine for $25.5 million in cash, resulting in DG Marine becoming wholly-owned by us. We funded the acquisition with proceeds from our credit agreement, including (i) paying off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, and (ii) settling DG Marine's interest rate swaps, which resulted in $1.3 million being reclassified from Accumulated Other Comprehensive Loss ("AOCL") to interest expense in the third quarter of 2010.

As a result of this transaction, we reclassified the acquired noncontrolling interest in DG Marine of $21.3 million to Genesis Energy, L.P. partners' capital. Additionally, we reduced our partners' capital by $26.3 million for the costs related to the transaction ($25.5 million paid to TD Marine and $0.8 million in direct transaction costs associated with the acquisition). The net effect of Genesis Energy, L.P. partners' capital in our Consolidated Balance Sheet for December 31, 2010 was a decrease of $5.0 million.

2008 Denbury Drop-Down Transactions

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

NEJD Pipeline System

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

Denbury has the rights to exclusive use of the NEJD Pipeline System, will be responsible for all operations and maintenance on that system, and will bear and assume all obligations and liabilities with respect to that system. The NEJD transaction was funded with borrowings under our credit facility.

See additional discussion of this direct financing lease in Note 7.

Free State Pipeline System

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

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

4. Receivables

Accounts receivable – trade, net consisted of the following:

	December 31,	
	2010	2009
Accounts receivable - trade	$ 172,857	$ 131,237
Allowance for doubtful accounts	(1,307)	(1,372)
Accounts receivable - trade, net	$ 171,550	$ 129,865

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

	December 31,		
	2010	2009	2008
Balance at beginning of period	$ 1,372	$ 1,132	$ -
Charged to costs and expenses	491	558	1,152
Amounts written off	(556)	(320)	(20)
Recoveries	-	2	-
Balance at end of period	$ 1,307	$ 1,372	$ 1,132

5. Inventories

The major components of inventories were as follows:

	December 31,	
	2010	2009
Crude oil	$ 6,128	$ 13,901
Petroleum products	38,588	22,150
Caustic soda	6,309	1,985
NaHS	4,387	2,154
Other	16	14
Total inventories	$ 55,428	$ 40,204

At December 31, 2010 and 2009, market values of our inventory exceeded recorded costs.

6. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following.

	December 31, 2010	December 31, 2009
Land, buildings and improvements	$ 14,335	$ 14,028
Pipelines and related assets	156,805	156,274
Machinery and equipment	29,433	27,016
Transportation equipment	29,249	31,669
Barges and push boats	122,992	122,913
Office equipment, furniture and fixtures	3,742	4,412
Construction in progress	4,493	4,813
Other	12,290	12,802
Subtotal	373,339	373,927
Accumulated depreciation	(108,283)	(89,040)
Total	$ 265,056	$ 284,887

Depreciation expense was $22.5 million, $25.2 million and $20.4 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Asset Retirement Obligations

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

Asset retirement obligations as of December 31, 2008	$ 1,430
Liabilities incurred and assumed in the current period	726
Liabilities settled in the current period	(117)
Accretion expense	152
Revisions in estimated cash flows	2,647
Asset retirement obligations as of December 31, 2009	4,838
Accretion expense	341
Asset retirement obligations as of December 31, 2010	$ 5,179

Liabilities incurred and assumed during the period are for properties acquired during the year. Certain of our unconsolidated affiliates have asset retirement obligations recorded at December 31, 2010 and 2009 relating to contractual agreements. These amounts are immaterial to our Consolidated Financial Statements.

7. Net Investment in Direct Financing Leases

As discussed in Note 3, we entered into a lease arrangement with Denbury related to the NEJD Pipeline in May 2008 that is being accounted for as a direct financing lease. Denbury pays us fixed payments of $5.2 million per quarter related to that lease that began in August 2008.

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

	December 31,	
	2010	2009
Total minimum lease payments to be received	$ 365,169	$ 385,565
Estimated residual values of leased property (unguaranteed)	1,287	1,287
Unamortized initial direct costs	2,184	2,380
Less unearned income	(195,586)	(212,003)
Net investment in direct financing leases	173,054	177,229
Less current portion (included in other current assets)	(4,616)	(4,202)
Long-term portion of net investment in direct financing leases	$ 168,438	$ 173,027

At December 31, 2010, minimum lease payments to be received for each of the five succeeding fiscal years are $21.9 million for 2011, $21.8 million for 2012, $21.3 million per year for 2013 through 2014 and $20.9 million for 2015.

We reviewed the credit risk related to our lease receivables from Denbury at December 31, 2010. Under the terms of the lease arrangement with Denbury related to the NEJD Pipeline, should Denbury's credit rating decline below certain minimum levels, Denbury is required to provide us with a letter of credit covering the payments owed for a specific period of time. Should Denbury be unable to meet this requirement, the lease arrangement provides that we will be provided other security interest in the pipeline. As a result of a review of Denbury's current credit rating and the terms of the arrangement, we believe an allowance for credit losses relative to our direct financing leases was not required at December 31, 2010.

8. Equity Investees and Other Investments

Equity Investees

We are accounting for our 50% ownership in each of three joint ventures, Cameron Highway, T&P Syngas and Sandhill under the equity method of accounting. We paid $106.8 million more for our interest in these joint ventures than our share of capital on their balance sheets at the date of the acquisition. This excess amount of the purchase price over the equity in the joint ventures has been allocated to the tangible and intangible assets of the joint ventures based on the fair value of those assets. The table below reflects information included in our Consolidated Financial Statements related to our equity investees.

	Year Ended December 31,		
	2010	2009	2008
Genesis' share of operating earnings	3,224	1,262	1,137
Amortization of excess purchase price	(869)	285	(628)
Net equity in earnings	$ 2,355	$ 1,547	$ 509
Distributions received	$ 6,482	$ 950	$ 2,158

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

BALANCE SHEET DATA:	December 31, 2010	2009
Current Assets	$ 16,402	$ 4,906
Fixed assets, net	459,490	4,717
Other Assets	15,424	17,361
Total Assets	$ 491,316	$ 26,984
Current Liabilities	$ 5,509	$ 1,406
Other Liabilities	3,876	2,868
Equity	481,931	22,710
Total liabilities and combined equity	$ 491,316	$ 26,984

	Year Ended December 31, 2010	2009	2008
INCOME STATEMENT DATA:			
Revenues	$ 20,013	$ 14,793	$ 15,493
Operating Income	5,881	775	3,205
Net Income	5,843	749	3,172

Cameron Highway is only included in the income statement data above for the period in 2010 during which we owned our interest. Audited financial statements for Cameron Highway as of December 31, 2010 and for the period from November 23, 2010 to December 31, 2010 are included in this filing on Form 10-K.

Other Projects

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

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

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

	Weighted Amortization Period in Years	December 31, 2010 Gross Carrying Amount	Accumulated Amortization	Carrying Value	December 31, 2009 Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery services customer relationships	5	$ 94,654	$ 53,139	$ 41,515	$ 94,654	$ 41,450	$ 53,204
Supply and logistics customer relationships	5	35,430	19,981	15,449	35,430	15,493	19,937
Refinery services supplier relationships	2	36,469	31,476	4,993	36,469	28,551	7,918
Refinery services licensing agreements	6	38,678	15,786	22,892	38,678	11,681	26,997
Supply and logistics trade names - Davison and Grifco	7	18,888	7,530	11,358	18,888	5,444	13,444
Supply and logistics lease	15	13,260	1,618	11,642	13,260	1,144	12,116
Other	5	13,776	1,450	12,326	3,823	1,109	2,714
Total	5	$ 251,155	$ 130,980	$ 120,175	$ 241,202	$ 104,872	$ 136,330

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The trade names are the Davison and Grifco names, which we retained the right to use in our operations. The supply and logistics lease relates to a terminal facility in Shreveport, Louisiana.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The supply and logistics lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $26.8 million, $33.1 million and $46.4 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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

	2011	2012	2013	2014	2015
Refinery services customer relationships	$ 8,972	$ 7,056	$ 7,116	$ 5,597	$ 4,405
Supply and logistics customer relationships	3,603	2,819	2,165	1,660	1,275
Refinery services supplier relationships	2,629	2,364	-	-	-
Refinery services licensing agreements	3,690	3,416	3,163	2,928	2,711
Supply and logistics trade name	1,851	1,432	1,237	1,073	932
Supply and logistics lease	474	474	474	474	474
Other	1,747	1,747	1,156	1,103	1,104
Total	$ 22,966	$ 19,308	$ 15,311	$ 12,835	$ 10,901

Goodwill

The carrying amount of goodwill by business segment at December 31, 2010 and 2009 was $301.9 million in refinery services and $23.1 million in supply and logistics. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Other Assets

Other assets consisted of the following.

	December 31, 2010	December 31, 2009
CO_2 volumetric production payments	$ 43,570	$ 43,570
Debt issuance costs - Genesis	15,714	5,022
Credit facility fees - DG Marine	-	2,373
Initial direct costs related to Free State Pipeline lease	1,132	1,132
Deferred tax asset	446	-
Other deferred costs and deposits	78	131
	60,940	52,228
Less - Accumulated amortization	(28,892)	(27,763)
Net other assets	$ 32,048	$ 24,465

Our CO_2 volumetric production payments entitle us to a maximum daily quantity of CO_2 of 91,875 million cubic feet, or Mcf per day for the calendar years 2011 through 2012 and 73,875 Mcf per day beginning in 2013 until we have received all volumes under the production payments. Under the terms of transportation agreements, Denbury processes and delivers this CO_2 to our industrial customers and receives a fee of $0.16 per Mcf, subject to inflationary adjustments from us. During 2010 this fee averaged $0.2094 per Mcf.

The terms of our CO_2 contracts with the industrial customers include minimum take-or-pay and maximum delivery volumes. At December 31, 2010, we had seven industrial contracts that expire at various dates between 2011 and 2016, with one small contract extending until 2023.

The CO_2 assets are being amortized on a units-of-production method. For 2010, 2009 and 2008, we recorded amortization of $4,254,000, $4,274,000 and $4,537,000, respectively. We have 100.2 Bcf of CO_2 remaining under the volumetric production payments at December 31, 2010. Based on the historical deliveries of CO_2 to the customers (which have exceeded minimum take-or-pay volumes), we expect amortization for the next five years to be approximately $4,020,000 for 2011, $4,007,000 for 2012 and $3,271,000 for 2013 through 2015.

Amortization expense of credit facility fees for the years ended December 31, 2010, 2009 and 2008 was $1.8 million, $1.9 million and $1.4 million, respectively. In the second quarter of 2010, we charged to expense $0.4 million of unamortized fees related to the Genesis credit facility that we restructured in June 2010. Additional fees of $7.6 million related to the restructured facility were deferred in June 2010 and will be amortized over the remaining term of the facility.

We incurred $7.0 million of fees in connection with the issuance of $250 million of senior unsecured notes in November 2010. See Note 10. Amortization of note payable issuance fees for the year ended December 31, 2010 was $0.1 million.

In connection with our purchase of TD Marine's interest in DG Marine on July 29, 2010, the outstanding balance on the DG Marine credit facility was repaid. As a result, we charged to expense $0.8 million of unamortized fees related to the DG Marine facility in the third quarter of 2010.

Total amortization of credit facility fees and notes payable issuance fees and other deferred costs for the next five years will be $1.8 million per year for 2011 through 2014 and $0.9 million for 2015.

10. Debt

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

	December 31, 2010	December 31, 2009
Genesis Senior Secured Credit Facility	$ 360,000	$ 320,000
Senior Unsecured Notes	250,000	-
DG Marine Credit Facility (non-recourse to Genesis)	-	46,900
Total Long-Term Debt	$ 610,000	$ 366,900

We believe the amount included in our Consolidated Balance Sheet for the debt outstanding under our revolving credit agreement approximates fair value due to the recent restructuring of our credit agreement. At December 31, 2010, the fair value of our senior unsecured notes was approximately $250.3 million.

Genesis Credit Facility

On June 29, 2010, we restructured our senior secured credit facility with a syndicate of banks led by BNP Paribas. We have a $525 million senior secured credit facility, which includes the ability to increase the size of the facility up to $650 million, with approval of lenders. The credit facility includes a $75 million hedged crude oil and petroleum products inventory loan sublimit based on 90% of the hedged value of the inventory. Our inventory borrowing base is recalculated monthly. Additionally up to $100 million of the credit facility can be used for letters of credit.

At December 31, 2010, we had $360 million borrowed under our credit agreement, with $43.9 million of that amount designated as a loan under the inventory sublimit. Additionally, we had $4.6 million in letters of credit outstanding at December 31, 2010. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of June 30, 2015. The total amount available for borrowings at December 31, 2010 was $160.4 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 an alternate base rate or a Eurodollar rate, at our option. The alternate base rate is equal to the sum of (a) the greatest of (i) the prime rate as established by the administrative agent for the credit facility, (ii) the federal funds effective rate plus ½ of 1% and (iii) the LIBOR rate for a one-month maturity plus 1% and (b) the applicable margin. The Eurodollar rate is equal to the sum of (a) the LIBOR rate for the applicable interest period multiplied by the statutory reserve rate and (b) the applicable margin. The applicable margin varies from 1.5% to 2.5% for alternate base rate borrowings and from 2.5% to 3.5% for Eurodollar rate borrowings, depending on our leverage ratio. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2010, the applicable margins on our borrowings were 1.75% for alternate base rate borrowings and 2.75% for Eurodollar rate borrowings.
- Letter of credit fees will range from 2.50% to 3.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2010, our letter of credit rate was 2.75%.
- We pay a commitment fee on the unused portion of the $525 million maximum facility amount. The commitment fee is 0.50%.

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

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

Senior Unsecured Notes

On November 18, 2010, we completed the issuance of $250 million in aggregate principal amount of 7.875% senior unsecured notes due December 15, 2018. The notes were sold at face value. Interest payments are due on June 15 and December 15 of each year, beginning June 15, 2011. We used the net proceeds from this offering to finance in part the purchase price and related transaction costs for the acquisition of a 50% equity interest in Cameron Highway.

The notes were co-issued by Genesis Energy Finance Corporation (which has no independent asset or operations) and are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly-owned subsidiaries. In connection with the issuance of the notes, we agreed to register the notes with the Securities and Exchange Commission no later than November 18, 2011.

We have the right to redeem the notes at any time after December 15, 2013 at a premium to the face amount of the notes that varies based on the time remaining to maturity of the notes. Prior to December 15, 2013, we may also redeem up to 35% of the principal amount for 107.875% of the face amount with the proceeds from an equity offering of our common units.

Covenants and Compliance

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

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

A default under our credit documents would permit the lenders there under to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit facility, our ability to make distributions of "available cash" is not restricted. As of December 31, 2010, we were in compliance with the financial covenants contained in our credit facility and indenture.

DG Marine Credit Facility

In connection with our purchase of the 51% interest in DG Marine we did not already own on July 29, 2010, the outstanding balance on the DG Marine credit facility was repaid. See Note 3.

11. Partners' Capital and Distributions

Until December 28, 2010, our partners' capital consisted of common units (Class A Units), representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving effect to the general partner interest), and a 2% general partner interest. Our general partner owned all of our general partner interest, all of our incentive distribution rights (IDRs), and all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which was reflected as a noncontrolling interest in the Consolidated Balance Sheet at December 31, 2009.)

On December 28, 2010, the incentive distribution rights held by our general partner were eliminated and the 2% general partner interest in us that our general partner held was converted into a non-economic general partner interest. We refer to this transaction as the IDR Restructuring. The former owners of our general partner received approximately 27,000,000 units in us, consisting of: (i) approximately 19,960,000 traditional common units that were re-named "Common Units – Class A," or Class A Units, (ii) approximately 40,000 common units designated "Common Units – Class B," or Class B Units, with rights, preferences and privileges of the Class A Units and rights to elect our board of directors and convertible into Class A Units and (iii) approximately 7,000,000 units designated "Waiver Units," or Waiver Units, convertible into Class A Units.

The Class A Units are traditional common units in us. The Class B Units are identical to the Class A Units and, accordingly, have voting and distribution rights equivalent to those of the Class A Units, and, in addition, Class B Units have the right to elect all of our board of directors and are convertible into Class A Units under certain circumstances. The Waiver Units are non-voting securities entitled to a minimal preferential quarterly distribution and are comprised of four classes (designated Class 1, Class 2, Class 3 and Class 4) of 1,750,000 authorized units each. The Waiver Units have the right to convert into Genesis common units in four equal installments in the calendar quarter during which each of our common units receives a quarterly distribution of at least $0.43, $0.46, $0.49 and $0.52, if our distribution coverage ratio (after giving effect to the then convertible Waiver Units) would be at least 1.1 times..

At December 31, 2010, our outstanding equity consisted of 64,575,065 Class A Units and 39,997 Class B Units. Additionally, 6,949,004 Waiver Units were outstanding.

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, until December 2010, to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves.

Until December 2010, our general partner received incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds, in addition to its 2% general partner interest. We paid distributions in 2009 and 2010 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 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326
Third quarter 2009	November 2009	$ 0.3525	$ 13,918	$ 284	$ 1,729	$ 15,931
Fourth quarter 2009	February 2010	$ 0.3600	$ 14,251	$ 291	$ 2,037	$ 16,579
First quarter 2010	May 2010	$ 0.3675	$ 14,548	$ 297	$ 2,339	$ 17,184
Second quarter 2010	August 2010	$ 0.3750	$ 14,845	$ 303	$ 2,642	$ 17,790
Third quarter 2010	November 2010	$ 0.3875	$ 15,339	$ 313	$ 3,147	$ 18,799
Fourth quarter 2010	February 2011	$ 0.4000	$ 25,846	$ -	$ -	$ 25,846

Net Income (Loss) per Common Unit

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

	Year Ended December 31,		
	2010	2009	2008
Numerators for basic and diluted net income per common unit:			
(Loss) income attributable to Genesis Energy, L.P.	$ (48,459)	$ 8,063	$ 26,089
Less: General partner's incentive distribution paid or to be paid for the period	(8,128)	(6,318)	(2,613)
Add: Expense allocable to our general partner	76,923	18,853	-
Subtotal	20,336	20,598	23,476
Less: General partner 2% ownership	(407)	(412)	(470)
Income available for common unitholders	$ 19,929	$ 20,186	$ 23,006
Denominator for basic and diluted per common unit	40,560	39,471	38,961
Basic and diluted net income per common unit	$ 0.49	$ 0.51	$ 0.59

Equity Issuances and Contributions

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

In November 2010, we issued 5,175,000 common units in a public offering in connection with the acquisition of a 50% equity interest in Cameron Highway. The new common units issued to the public for cash were as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Issuance Value	GP Contributions	Costs	Net Proceeds
November 2010	Public	5,175	$ 23.580	$ 122,027	$ 2,490	$ (5,680)	$ 118,837

We issued new common units in the acquisitions of assets as follows:

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

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

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

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

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

12. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate, intrastate and offshore crude oil, and to a lesser extent, natural gas and CO_2 pipeline transportation; (2) Refinery Services – processing high sulfur (or "sour") gas streams as part of refining operations to remove the sulfur and sale of the related by-product; (3) Industrial Gases – the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility, and (4) Supply and Logistics – terminaling, blending, storing, marketing, gathering and transporting by truck and barge crude oil and petroleum products. Substantially all of our revenues are derived from, and substantially all of our assets are located in the United States.

We define segment margin as revenues less cost of sales, operating expenses (excluding depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. Our segment margin definition also excludes the non-cash effects of our equity-based compensation plans and the unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes. Segment margin includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant and maintenance capital investment.

	Pipeline Transportation [a]	Refinery Services	Supply & Logistics	Industrial Gases [b]	Total
Year Ended December 31, 2010					
Segment margin [c]	$ 48,305	$ 62,923	$ 26,176	$ 12,160	$ 149,564
Capital expenditures [d]	$ 333,557	$ 1,433	$ 1,740	$ -	$ 336,730
Maintenance capital expenditures	$ 522	$ 1,433	$ 901	$ -	$ 2,856
Net fixed and other long-term assets [e]	$ 604,572	$ 400,164	$ 218,874	$ 30,587	$ 1,254,197
Revenues:					
External customers	$ 45,367	$ 158,456	$ 1,881,669	$ 15,832	$ 2,101,324
Intersegment [f]	10,285	(7,396)	(2,889)	-	-
Total revenues of reportable segments	$ 55,652	$ 151,060	$ 1,878,780	$ 15,832	$ 2,101,324
Year Ended December 31, 2009					
Segment margin [c]	$ 42,162	$ 51,844	$ 29,052	$ 11,432	$ 134,490
Capital expenditures [d]	$ 3,043	$ 2,572	$ 23,498	$ 83	$ 29,196
Maintenance capital expenditures	$ 1,281	$ 1,246	$ 1,899	$ -	$ 4,426
Net fixed and other long-term assets [e]	$ 279,574	$ 409,556	$ 234,421	$ 35,332	$ 958,883
Revenues:					
External customers	$ 44,461	$ 147,240	$ 1,227,453	$ 16,206	$ 1,435,360
Intersegment [f]	6,490	(5,875)	(615)	-	-
Total revenues of reportable segments	$ 50,951	$ 141,365	$ 1,226,838	$ 16,206	$ 1,435,360
Year Ended December 31, 2008					
Segment margin [c]	$ 33,149	$ 55,784	$ 32,448	$ 13,504	$ 134,885
Capital expenditures [d]	$ 262,200	$ 5,490	$ 118,585	$ 2,397	$ 388,672
Maintenance capital expenditures	$ 719	$ 1,881	$ 1,854	$ -	$ 4,454
Net fixed and other long-term assets [e]	$ 285,773	$ 434,956	$ 245,815	$ 44,003	$ 1,010,547
Revenues:					
External customers	$ 39,051	$ 233,871	$ 1,851,113	$ 17,649	$ 2,141,684
Intersegment [f]	7,196	(8,497)	1,301	-	-
Total revenues of reportable segments	$ 46,247	$ 225,374	$ 1,852,414	$ 17,649	$ 2,141,684

(a) The pipeline transportation segment includes the income from our investment in Cameron Highway.

(b) The industrial gases segment includes our CO_2 marketing operations and the income from our investments in T&P Syngas and Sandhill.

(c) A reconciliation of segment margin to (loss) income before income taxes for each year presented is as follows:

	Year Ended December 31,		
	2010	2009	2008
Segment margin	$ 149,564	$ 134,490	$ 134,885
Corporate general and administrative expenses	(110,058)	(36,475)	(22,113)
Depreciation, amortization and impairment	(53,557)	(67,586)	(71,370)
Net loss on disposal of surplus assets	(12)	(160)	(29)
Interest expense	(22,924)	(13,660)	(12,937)
Non-cash expenses not included in segment margin	(4,479)	(4,089)	1,355
Other items excluded from income affecting segment margin	(6,487)	(3,262)	(4,328)
(Loss) income before income taxes	$ (47,953)	$ 9,258	$ 25,463

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

(e) Net fixed and other long-term assets is a measure used by management in evaluating the results of our operations on a segment basis. Current assets are not allocated to segments as the amounts are not meaningful in evaluating the success of the segment's operations. Amounts for our Pipeline Transportation segment include our investment in Cameron Highway totaling \$329.7 million. Amounts for our Industrial Gases segment include investments in equity investees totaling \$13.7 million, \$15.1 million and \$14.5 million at December 31, 2010, 2009 and 2008, respectively.

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

13. Transactions with Related Parties

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

	Year Ended December 31,		
	2010	2009	2008
Operations, general and administrative services provided by our general partner	$ 47,035	$ 50,417	$ 51,872
Sales of CO_2 to Sandhill	2,706	2,867	2,941
Petroleum products sales to Davison family businesses	1,081	757	1,261
Marine operating fuel and expenses provided by an affiliate of the Robertson Group	2,443	-	-
Petroleum products sales to an affiliate of the Robertson Group	3,740	-	-
Truck transportation services provided to Denbury	182	3,167	3,578
Pipeline transportation services provided to Denbury	1,365	14,375	10,727
Payments received under direct financing leases from Denbury	99	21,853	11,519
Pipeline transportation income portion of direct financing lease fees from Denbury	1,502	18,295	11,011
Pipeline monitoring services provided to Denbury	10	120	120
CO_2 transportation services provided by Denbury	373	5,475	6,424
Crude oil purchases from Denbury	-	1,754	-

Until December 28, 2010, we did not directly employ any persons to manage or operate our business. Those functions were provided by our general partner. We reimbursed our general partner for all direct and indirect costs of these services, excluding any payments to our management team pursuant to their Class B or Series B ownership interests in our general partner. See Note 15.

Until February 5, 2010, Denbury owned our general partner. The items in this table include the amounts related to transactions with Denbury while Denbury was a related party. Form February 5, 2010 until December 28, 2010, the Robertson Group controlled our general partner. On December 28, 2010, we acquired our general partner.

Additionally, on July 29, 2010, we acquired the 51% interest of TD Marine in DG Marine. See Note 3.

Amounts due to and from Related Parties

At December 31, 2010, an affiliate of the Robertson Group owed us $1.4 million, and we owed the affiliate $0.2 million. At December 31, 2010 and 2009, Sandhill owed us $0.2 million and $0.7 million for purchases of CO_2, respectively.

At December 31, 2009 we owed Denbury $1.0 million, respectively, for CO_2 transportation charges. Denbury owed us $1.9 million for transportation services at December 31, 2009. We owed our general partner $2.1 million for administrative services at December 31, 2009.

Financing

We guarantee 50% of the obligation of Sandhill to Community Trust Bank. At December 31, 2010, the total amount of Sandhill's obligation to the bank was $2.2 million; therefore, our guarantee was for $1.1 million.

As discussed in Note 11, our general partner made capital contributions in order to maintain its capital account totaling $2.5 million, less than $0.1 million and $0.5 million in 2010, 2009 and 2008, respectively. In 2010 and 2009, we recorded a capital contribution from our general partner of $76.9 million and $14.1 million, respectively, related to compensation recognized for our executive management team. See Note 15.

14. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2010	2009	2008
(Increase) decrease in:			
Accounts receivable	$ (41,648)	$ (7,979)	$ 61,126
Inventories	(16,870)	(16,559)	(5,557)
Other current assets	(4,036)	(2,712)	(2,419)
Increase (decrease) in:			
Accounts payable	47,401	19,203	(58,224)
Accrued liabilities	9,666	(1,522)	3,812
Net changes in components of operating assets and liabilities	$ (5,487)	$ (9,569)	$ (1,262)

Payments of interest and commitment fees were $25.1 million, $13.3 million and $11.3 million, during the years ended December 31, 2010, 2009 and 2008, respectively.

Cash paid for income taxes in during the years ended December 31, 2010, 2009 and 2008 was $2.4 million, $0.2 million and $2.4 million, respectively.

At December 31, 2010, 2009 and 2008, we had incurred liabilities for fixed and intangible asset additions totaling $2.6 million ($2.3 million consists of intangible assets additions related to our information technology systems upgrade project), $0.5 million and $1.7 million, respectively, that had not been paid at the end of the year and, therefore, are not included in the caption "Payments to acquire fixed and intangible assets" on the Consolidated Statements of Cash Flows.

In May 2008, we issued common units with a value of $25 million as part of the consideration for the acquisition of the Free State Pipeline from Denbury. In July 2008, we issued common units with a value of $16.7 million as part of the consideration for the acquisition of the inland marine transportation assets of Grifco. These common unit issuances are non-cash transactions and the value of the assets acquired is not included in investing activities and the issuance of the common units is not reflected under financing activities in our Consolidated Statements of Cash Flows.

Additionally, we deferred payment of $12 million ($11.7 million discounted) of the consideration in the acquisition from Grifco to December 2008 and 2009. This deferral of the payment of consideration was a non-cash transaction and the value of the assets acquired is not included in investing activities in our Consolidated Statements of Cash Flows. The seller-financed consideration payments made in December 2008 and December 2009 are included in financing cash flows.

15. Employee Benefit Plans and Equity-Based Compensation Plans

Until December 28, 2010, we did not directly employ any of the persons responsible for managing or operating our activities.

In order to encourage long-term savings and to provide additional funds for retirement to its employees, we sponsor a profit-sharing and retirement savings plan. Under this plan, our matching contribution is calculated as an equal match of the first 6% of each employee's annual pretax contribution. We also made a profit-sharing contribution of 3% of each eligible employee's total compensation (subject to IRS limitations). The expenses included in the Consolidated Statements of Operations for costs relating to this plan were $2.7 million, $2.2 million, and $2.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

We also provided certain health care and survivor benefits for our active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. We plan to continue self-insuring these plans in the future. The expenses included in the Consolidated Statements of Operations for these benefits were $6.5 million, $6.2 million, and $6.8 million in 2010, 2009 and 2008, respectively.

2010 Long Term Incentive Plan

In the second quarter of 2010, we adopted the Genesis Energy, LLC 2010 Long-Term Incentive Plan (the "2010 Plan"). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to members of our board of directors, and employees who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights ("DERs") are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on the phantom units had they been limited partner units issued by us. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the "G&C Committee") of our board of directors.

The G&C Committee (at its discretion) will designate participants in the 2010 Plan, 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. 62,927 phantom units with tandem DERs were awarded under the 2010 Plan during 2010. The weighted average grant date fair value of these awards was $20.64 per unit. The phantom units will vest on the third anniversary of the date of issuance.

The compensation cost associated with the phantom units is re-measured each reporting period based on the market value of our common units, and is recognized over the vesting period. The liability recorded for the estimated amount to be paid to the participants under the 2010 LTIP is adjusted to recognize changes in the estimated compensation cost and vesting. Management's estimates of the fair value of these awards are adjusted for assumptions about expected forfeitures of units prior to vesting. Due to the positions of the small group of employees and non-employee directors who received these awards, we have assumed as of December 31, 2010 that there will be no forfeitures of these phantom units. .At December 31, 2010, we estimate the fair value of these awards to be approximately $1.6 million, and we recorded $0.4 million of compensation expense for the year ended December 31, 2010 in general and administrative expenses. For the awards outstanding at December 31, 2010, the remaining cost will be recognized over a weighted average period of approximately three years.

2007 Long Term Incentive Plan

As a result of the sale of our general partner on February 5, 2010, all outstanding phantom units issued pursuant to our 2007 Long Term Incentive Plan vested. As a result of this acceleration of the vesting period, we recorded non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested. In 2009 and 2008, we recorded compensation expense of $1.0 million and $0.7 million related to this plan. This expense is primarily included in general and administrative expenses.

Stock Appreciation Rights Plan

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

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

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

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

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

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

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

Assumptions Used for Fair Value of Rights

	December 31, 2010	December 31, 2009	December 31, 2008
Expected life of rights (in years)	0.00 - 4.41	0.25 - 5.50	1.25 - 6.00
Risk-free interest rate	0.12% - 1.73%	0.05% - 2.52%	0.57% - 1.71%
Expected unit price volatility	41.9%	43.8%	42.8%
Expected future distribution yield	6.00%	8.50%	6.00%

The following table reflects rights activity under our plan as of January 1, 2010, and changes during the year ended December 31, 2010:

Stock Appreciation Rights	Rights	Weighted Average Strike Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2010	1,119,998	$ 17.14		
Exercised during 2010	(159,435)	$ 13.39		
Forfeited or expired during 2010	(46,873)	$ 19.95		
Outstanding at December 31, 2010	913,690	$ 17.65	6.6	$ 8,158
Exercisable at December 31, 2010	625,479	$ 17.64	6.1	$ 5,622

The total intrinsic value of rights exercised during 2010, 2009 and 2008 was $1.3 million, $0.1 million and $0.4 million, respectively, which was paid in cash to the participants.

At December 31, 2010, there was $0.8 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, 2010 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, 2010, the remaining cost will be recognized over a weighted average period of approximately one year.

We recorded charges and credits related to our stock appreciation rights for three years ended December 31, 2010 as follows:

Expense (Credits to Expense) Related to Stock Appreciation Rights

Statement of Operations	2010	2009	2008
Supply and logistics operating costs	$ 2,451	$ 1,431	$ (997)
Refinery services operating costs	703	325	23
Pipeline operating costs	572	360	(296)
General and administrative expenses	1,493	1,263	(1,141)
Total	$ 5,219	$ 3,379	$ (2,411)

Series B Units

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

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

Pursuant to the IDR Restructuring, we are required to establish an equity incentive plan in 2011 for our eligible employees, including our executive officers, for the issuance of approximately 145,620 Class A Units and 50,967 Waiver Units. However, if unitholder approval is required for such plan and our Board determines not to seek such approval, which determination has not yet been made, we are required to establish a cash-settled or cash-based plan not subject to such approval that would provide substantially equivalent economic benefits to such participants as the equity incentive plan.

Class B Membership Interests

As part of finalizing the compensation arrangements for our Senior Executives on December 31, 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. The Class B membership interests awarded to our senior executives were accounted for as liability awards under the guidance for equity-based compensation. As such, the fair value of the compensation cost we recorded for these awards was recomputed at each measurement date through final settlement and the expense to be recorded was adjusted based on that fair value.

All of the Class B membership interests in our general partner held by our management team at December 31, 2009 were either (i) converted into Series A units in our general partner or (ii) redeemed by our general partner on February 5, 2010. In total, the value of the Series A units issued and cash payments made by our general partner to settle its obligations under the Class B membership interests and related deferred compensation totaled $14.9 million. This value, when combined with amounts previously paid to our management team during 2009 related to the Class B membership interests, resulted in total compensation expense of $15.4 million. Upon settlement by our general partner of these arrangements with our management team, we recorded a reduction in expense of $2.1 million in the first quarter of 2010. In the year ended December 31, 2009, we recorded expense related to these arrangements of $14.1 million. No expense was required to be recorded in 2008 related to the Class B membership interests.

Bonus Program

In January 2011, our Board and G&C Committee approved a bonus program, referred to as the Bonus Plan, for all employees that is applicable to 2010. Bonuses under the Bonus Plan are paid at the discretion of our G&C Committee to our employees and executive officers.

In 2010, our G&C Committee based bonus amounts primarily on the amount of cash we generated for distributions to our unitholders, measured on a calendar-year basis. Two metrics were used to determine the general bonus pool – the level of Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) that we generated and our company-wide safety record improvement which included a targeted reduction in our company-wide incident injury rate. The level of Available Cash before Reserves generated for the year as a percentage of a target set by our G&C Committee is weighted 90% and the achieved level of the targeted improvement in our safety record is weighted 10%. The sum of the weighted percentage achievement of these targets is multiplied by the eligible compensation and the target percentages established by our G&C Committee for the various levels of our employees to determine the maximum general bonus pool.

For 2010, we accrued $5.0 million for estimated bonuses to be paid pursuant to the Bonus Plan. In 2009 and 2008, we had in place a bonus program similar to the Bonus Plan and we paid bonuses totaling $3.9 million and $4.5 million to our executive officers and employees. 2010 bonuses will be paid to employees in March 2011.

16. Major Customers and Credit Risk

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

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

Shell Oil Company accounted for 13%, 12.5% and 14.6% of total revenues in 2010, 2009 and 2008, respectively. The revenues from Shell Oil Company in all three years relate primarily to our supply and logistics operations.

17. Derivatives

Commodity Derivatives

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

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

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

At December 31, 2010, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	28	-
Weighted average contract price per bbl	$ 85.49	$ -
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	537	260
Weighted average contract price per bbl	$ 89.85	$ 90.17
Heating oil futures:		
Contract volumes (1,000 bbls)	207	-
Weighted average contract price per gal	$ 2.52	$ -
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	9	-
Weighted average contract price per gal	$ 2.28	$ -
#6 Fuel Oil futures:		
Contract volumes (1,000 bbls)	300	80
Weighted average contract price per bbl	$ 76.34	$ 76.33
Natural Gas:		
Contract volumes (mmBtu)	5	-
Weighted average contract price per mmBtu	$ 4.40	$ -
Crude oil written calls:		
Contract volumes (1,000 bbls)	210	-
Weighted average premium received	$ 1.97	$ -

Interest Rate Derivatives

Until July 29, 2010, DG Marine utilized swap contracts with financial institutions to hedge interest payments for its outstanding debt. DG Marine expected these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates; therefore, we designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represented the change in fair value of the hedge that offset the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts was reported as a component of AOCL and was reclassified into future earnings contemporaneously, as interest expense associated with the underlying debt under the DG Marine credit facility was recorded. In the third quarter of 2010, we settled the DG Marine interest rate swaps in connection with our acquisition of the 51% of DG Marine that we did not own. See Note 3.

Financial Statement Impacts

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

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

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

The following tables reflect the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at December 31, 2010 and 2009:

Fair Value of Derivative Assets and Liabilities

	Asset Derivatives		
	Consolidated Balance Sheets Location	Fair Value December 31, 2010	Fair Value December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other current assets	$ 14	$ 53
Undesignated hedges	Other current assets	493	307
Total asset derivatives		$ 507	$ 360

	Liability Derivatives		
	Consolidated Balance Sheets Location	Fair Value December 31, 2010	Fair Value December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other current assets	$ (191) [1]	$ (159) [1]
Undesignated hedges	Other current assets	(2,283) [1]	(2,118) [1]
Total commodity derivatives		(2,474)	(2,277)
Interest rate swaps designated as cash flow hedges under accounting rules:			
Portion expected to be reclassified into earnings within one year	Accrued liabilities	-	(1,176)
Portion expected to be reclassified into earnings after one year	Other long-term liabilities	-	(512)
Total liability derivatives		$ (2,474)	$ (3,965)

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

	Supply & Logistics Product Costs Year Ended December 31, 2010	Supply & Logistics Product Costs Year Ended December 31, 2009	Interest Expense Reclassified from AOCL Year Ended December 31, 2010	Interest Expense Reclassified from AOCL Year Ended December 31, 2009	Other Comprehensive Loss Effective Portion Year Ended December 31, 2010	Other Comprehensive Loss Effective Portion Year Ended December 31, 2009
	Effect on Consolidated Statements of Operations and Other Comprehensive Loss					
	Amount of Gain (Loss) Recognized in Income					
Commodity derivatives - futures and call options:						
Contracts designated as hedges under accounting guidance	$ 307 (1)	$ (5,321) (1)	$ -	$ -	$ -	$ -
Contracts not considered hedges under accounting guidance	(4)	(2,446)	-	-	-	-
Total commodity derivatives	303	(7,767)	-	-	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance	-	-	(2,112)	(784)	(424)	(508)
Total derivatives	$ 303	$ (7,767)	$ (2,112)	$ (784)	$ (424)	$ (508)

(1) Represents the amount of gain (loss) recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $1.0 million and $7.5 million for the year ended 2010 and 2009, respectively.

We have no derivative contracts with credit contingent features.

18. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value at December 31, 2010			Fair Value at December 31, 2009		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives :						
Assets	$ 507	$ -	$ -	$ 360	$ -	$ -
Liabilities	$ (2,474)	$ -	$ -	$ (2,277)	$ -	$ -
Interest rate swaps	$ -	$ -	$ -	$ -	$ -	$ (1,688)

Level 1

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

Level 2

At December 31, 2010 and 2009, we had no Level 2 fair value measurements.

Level 3

At December 31, 2010, we had no Level 3 fair value measurements. Included within Level 3 of the fair value hierarchy at December 31, 2009 were our interest rate swaps. These swaps were settled in July 2010 in connection with the acquisition of the 51% of DG Marine we did not own and the termination of DG Marine's credit facility. See Note 3.

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,			
	2010		2009	
Balance at beginning of period	$	(1,688)	$	(1,964)
Realized and unrealized gains (losses)-				
Reclassified into interest expense for settled contracts		2,112		784
Included in other comprehensive income		(424)		(508)
Balance at end of period	$	-	$	(1,688)
Total amount of losses for the year ended included in earnings attributable to the change in unrealized losses relating to liabilities still held at December 31, 2010 and 2009, respectively	$	-	$	(10)

See Note 17 for additional information on our derivative instruments.

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

19. Commitments and Contingencies

Commitments and Guarantees

In 2008, we entered into a new office lease for our corporate headquarters that extends until January 31, 2016. We lease office space for field offices under leases that expire between 2011 and 2013. To transport products, we lease tractors and trailers for our crude oil gathering and marketing activities and lease barges and railcars for our refinery services segment. In addition, we lease tanks and terminals for the storage of crude oil, petroleum products, NaHS and caustic soda. Additionally, we lease a segment of pipeline where under the terms we make payments based on throughput. We have no minimum volumetric or financial requirements remaining on our pipeline lease.

The future minimum rental payments under all non-cancelable operating leases as of December 31, 2010, were as follows (in thousands).

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2011	$ 901	$ 3,510	$ 6,875	$ 11,286
2012	777	2,152	4,897	7,826
2013	735	1,432	1,577	3,744
2014	731	1,243	1,027	3,001
2015	741	732	1,027	2,500
2016 and thereafter	62	1,239	20,109	21,410
Total minimum lease obligations	$ 3,947	$ 10,308	$ 35,512	$ 49,767

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

Year ended December 31, 2010	$ 15,692
Year ended December 31, 2009	$ 12,023
Year ended December 31, 2008	$ 8,757

We have also guaranteed the payments by our operating partnership under the terms of our operating leases of tractors and trailers. Such obligations are included in future minimum rental payments in the table above.

We guaranteed $1.2 million of residual value related to the leases of trailers. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

We guaranty 50% of the obligations of Sandhill under a credit facility with a bank. At December 31, 2010, Sandhill owed $2.2 million; therefore our guarantee was $1.1 million. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot be accurately estimated at this time, we expect that our annual expenditures for integrity testing, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines to average from $1.0 million to $1.5 million.

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

Other Matters

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

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

20. Income Taxes

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

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

Our income tax expense (benefit) is as follows:

	Year Ended December 31, 2010	2009	2008
Current:			
Federal	$ 1,664	$ 1,458	$ 2,979
State	1,494	1,442	872
Total current income tax expense	3,158	2,900	3,851
Deferred:			
Federal	(573)	168	(3,850)
State	3	12	(363)
Total deferred income tax (benefit) expense	(570)	180	(4,213)
Total income tax expense (benefit)	$ 2,588	$ 3,080	$ (362)

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

	December 31, 2010	2009
Deferred tax assets:		
Current:		
Other current assets	$ 445	$ 279
Other	8	8
Total current deferred tax asset	453	287
Net operating loss carryforwards	862	308
Total long-term deferred tax asset	862	308
Valuation allowances	(416)	(308)
Total deferred tax assets	899	287
Deferred tax liabilities:		
Current:		
Other	(213)	(198)
Long-term:		
Fixed assets	(7,807)	(8,481)
Intangible assets	(7,386)	(6,686)
Total long-term liability	(15,193)	(15,167)
Total deferred tax liabilities	(15,406)	(15,365)
Total net deferred tax liability	$ (14,507)	$ (15,078)

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

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

	Year Ended December 31, 2010		2009		2008	
(Loss) income before income taxes	$	(47,953)	$	9,258	$	25,463
Partnership loss (income) not subject to tax		47,357		(7,822)		(30,902)
(Loss) income subject to income taxes		(596)		1,436		(5,439)
Tax (benefit) expense at federal statutory rate	$	(209)	$	503	$	(1,904)
State income taxes, net of federal benefit		583		991		357
Effects of unrecognized tax positions, federal and state		1,909		1,733		1,431
Return to provision, federal and state		257		(224)		(258)
Other		48		77		12
Income tax expense (benefit)	$	2,588	$	3,080	$	(362)
Effective tax rate on (loss) income before income taxes		(1)		33%		-1%

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

The company adopted the provisions in accounting guidance related to uncertain tax positions on January 1, 2007. A reconciliation of the beginning and ending amount of our unrecognized tax positions, which is recorded in Other current liabilities on our Consolidated Balance Sheets was as follows:

Balance at January 1, 2008	$	864
Additions based on tax positions related to current year		1,735
Balance at December 31, 2008		2,599
Additions based on tax positions related to current year		1,733
Balance at December 31, 2009		4,332
Additions based on tax positions related to current year		1,909
Balance at December 31, 2010	$	6,241

If the unrecognized tax positions at December 31, 2010 were recognized, $6.2 million would affect our effective income tax rate. There are no uncertain tax positions as of December 31, 2010 for which it is reasonably possible that the amount of unrecognized tax positions would significantly decrease during 2011.

21. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2010 and 2009.

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

	2009 Quarters				Total
	First	Second	Third	Fourth [2]	Year
Revenues	$ 253,493	$ 342,204	$ 403,389	$ 436,274	$ 1,435,360
Operating income (loss)	$ 7,021	$ 7,748	$ 8,356	$ (1,754)	$ 21,371
Net income (loss)	$ 5,301	$ 3,822	$ 3,897	$ (6,842)	$ 6,178
Net income (loss) attributable to Genesis Energy, L.P.	$ 5,290	$ 4,456	$ 4,299	$ (5,982)	$ 8,063
Net income per common unit - basic and diluted	$ 0.16	$ 0.13	$ 0.14	$ 0.08	$ 0.51
Cash distributions per common unit [1]	$ 0.3300	$ 0.3375	$ 0.3450	$ 0.3525	$ 1.3650

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

(2) Includes executive compensation expense related to Series B and Class B awards borne entirely by our general partner in the amounts of $75.6 million for 2010 and $6.5 million for 2009. See Note 15.

Financial Statements of Significant Equity Investee – Cameron Highway Oil Pipeline Company

INDEPENDENT AUDITORS' REPORT

To the Management Committee of
Cameron Highway Oil Pipeline Company
Houston, Texas

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

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

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 4, 2011

CAMERON HIGHWAY OIL PIPELINE COMPANY
BALANCE SHEET
December 31, 2010
(Dollars in thousands)

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

See Notes to Financial Statements

CAMERON HIGHWAY OIL PIPELINE COMPANY
STATEMENT OF OPERATIONS
Period from November 23, 2010 through December 31, 2010
(Dollars in thousands)

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

See Notes to Financial Statements

CAMERON HIGHWAY OIL PIPELINE COMPANY
STATEMENT OF CASH FLOWS
Period from November 23, 2010 through December 31, 2010
(Dollars in thousands)

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

See Notes to Financial Statements

CAMERON HIGHWAY OIL PIPELINE COMPANY
STATEMENT OF PARTNERS' EQUITY
Period from November 23, 2010 through December 31, 2010
(Dollars in thousands)

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

See Notes to Financial Statements

CAMERON HIGHWAY OIL PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Partnership Organization

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

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

2. Summary of Significant Accounting Policies

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

Business Segment

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

Cash and Cash Equivalents

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

Contingencies

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

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

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

Crude Oil Imbalances

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

Environmental Costs

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

Estimates

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

Financial Instruments

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

Impairment Testing For Long-Lived Assets

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

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

Income Taxes

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

Partnership Equity

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

Property, Plant and Equipment

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

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

Recently Issued Accounting Standards

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

Revenue Recognition

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

Subsequent Events

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

3. Property, Plant and Equipment

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

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

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

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

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

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

4. Related Party Transactions

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

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

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

5. Commitments and Contingencies

Operating Leases

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

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

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

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

Other Matters

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

6. Significant Risks

Nature of Operations

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

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

Weather-Related Risks

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

Officers*

Grant E. Sims
Chief Executive Officer

Robert V. Deere
Chief Financial Officer

Steven R. Nathanson
President and Chief Operating Officer

Stephen M. Smith
Vice President

Karen N. Pape
Senior Vice President and Controller

Unitholder Information

Partnership Offices
Genesis Energy, L.P.
5919 Milam, Suite 2100
Houston, TX 77002
(713) 860-2500

Partnership Website
www.genesisenergy.com

Exchange Listing
NYSE
Ticker Symbol: GEL

Principal Transfer Agent, Registrar and Cash Distribution Paying Agent
American Stock Transfer & Trust Company
40 Wall Street
New York, NY 10005
(800) 937-5449

Additional Information:

- For information regarding your K-1 tax report, call (888) 236-1148
- Unitholder questions regarding transfers, lost certificates, distribution checks and address changes should be directed to the Transfer Agent or your stockbroker.

The Partnership's Annual Report on Form 10-K is available to Unitholders upon request. It is also available on the Internet at http://www.genesisenergy.com

Directors*

James E. Davison [1]
Private investor; former chairman of Davison Transport, Inc.

James E. Davison, Jr. [1]
Private investor; executive of Davison family businesses

Donald L. Evans [1]
President of Don Evans Group, Ltd.; former Secretary of U.S. Dept of Commerce

Sharilyn S. Gasaway[1] [2]
Private investor; former Executive Vice President and Chief Financial Officer of Alltel Corporation

Kenneth M. Jastrow, II [1]
Non-Executive Chairman of Forestar Group, Inc.; former Chairman and Chief Executive Officer of Temple-Inland, Inc.

S. James Nelson [1][2]
Private investor; former Chief Financial Officer, Vice Chairman and director of Cal Dive International, Inc.

Corbin J. Robertson III [1]
Private investor; Managing Director, Coal and Downstream for Quintana Capital Group, L.P.

William K. Robertson [1]
Private investor; Managing Director, Midstream and Power for Quintana Capital Group, L.P.

Grant E. Sims [1]
Chief Executive Officer, Genesis Energy, LLC

Robert C. Sturdivant [1]
Chairman of the Board, Genesis Energy, LLC; Vice President-Finance and Managing Director–Risk Management of certain Quintana Capital Group, L.P. affiliates

Carl A. Thomason[1][2]
Private investor; marketing consultant to Yessup Oil Corp.

(1) Governance, Compensation and Business Development Committee Member
(2) Audit Committee Member

*Genesis Energy, L.P., does not have officers or directors. Listed above are the officers and directors of the General Partner, Genesis Energy, LLC