GENESIS ENERGY LP
Form 10-K
March 16, 2011

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

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

Commission file number 1-12295

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

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of incorporation or organization) | 76-0513049<br>(I.R.S. Employer Identification No.) |
| 919 Milam, Suite 2100, Houston, TX<br>(Address of principal executive offices) | 77002<br>(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 o No x

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

Yes o No x

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

Yes x No o

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 o No o

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

x

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

| | | | |
|---|---|---|---|
| Large accelerated filer o | Accelerated filer x | Non-accelerated filer o | Smaller reporting company o |

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

Yes o No x

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.

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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,” “str “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 CO2, 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;

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

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

Pipeline Transportation—We transport crude oil and CO2 for others for a fee in the Gulf Coast region of the U.S. through approximately 930 miles of pipeline. Our Pipeline Transportation segment owns and operates three onshore crude oil common carrier pipelines and two CO2 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.

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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;

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- 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 CO2 producers; refinery owners; industrial and commercial enterprises that use NaHS and caustic soda; and businesses that use CO2 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.

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- 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.

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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:

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Prior

Before the IDR Restructuring on December 28, 2010:

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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 CO2 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.

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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<br>Webster, Texas to Texas City, Texas<br>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 CO2 injection and flooding.  Increased production from these fields could create increased demand for our crude oil transportation services because of the close proximity of our pipeline.  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.

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| | 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.

CO2 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 | CO2 | CO2 |
| 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 $CO_2$ 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.

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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.

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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.

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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.

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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 CO2 to industrial customers, (ii) process raw CO2 and sell that processed CO2, and (iii) manufacture and sell syngas, a combination of carbon monoxide and hydrogen.

CO2 – Industrial Customers

We supply CO2 to industrial customers currently under six long-term contracts, with an average remaining contract life of six years. Our compensation for supplying CO2 to our industrial customers, who treat the CO2 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 CO2 under each contract and the price at which we acquired our CO2 pursuant to our volumetric production payments (also known as VPPs), minus transportation costs. We expect some seasonality in our sales of CO2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. At December 31, 2010, we had 100.2 Bcf of CO2 remaining under the VPPs.

All of our CO2 supply is currently from our interests—our VPPs—in fields producing naturally occurring CO2. The agreements we executed when we acquired the VPPs provide that we may acquire additional CO2 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 CO2 supply if we choose to remain in the CO2 supply business.

CO2 – Processing

Our other joint venture is a 50% interest in Sandhill Group, LLC, or Sandhill, through which we process raw CO2 for sale to other customers for uses ranging from completing oil and natural gas producing wells to food processing. Reliant Processing Ltd. owns the remaining 50% of Sandhill. Sandhill's facility acquires CO2 from us under a long-term supply contract. This contract expires in 2023 and provides for a maximum daily contract quantity of 16,000 Mcf per day with a take-or-pay minimum quantity of 2,500,000 Mcf per year.

Syngas

We own a 50% 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 CO2 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 CO2 to affiliates of Reliant Processing Ltd., our partner in Sandhill, as discussed above. Sandhill has long-term relationships with those customers and has not experienced collection problems with them.

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Competition

Currently, all of our CO2 supply is from our interest—our VPPs—in fields producing naturally occurring sources. In the future, we may have to obtain our CO2 supply from manufactured processes. Naturally-occurring CO2, like that from the Jackson Dome area, occurs infrequently, and only in limited areas east of the Mississippi River. Our industrial CO2 customers have facilities that are connected to the NEJD Pipeline, which makes delivery easy and efficient. Once our existing VPPs expire, we will have to obtain additional CO2 should we choose to remain in the CO2 supply business, and the competition and pricing issues we will face at that time are uncertain. Due to the long-term contract and location of our syngas facility, as well as the costs involved in establishing facilities, we believe it is unlikely that competing facilities will be established for our syngas processing services. Sandhill has competition from the other industrial customers to whom we supply CO2. As discussed above, the limited amounts of naturally-occurring CO2 east of the Mississippi River makes it difficult for competitors of Sandhill to significantly increase their production or sales and, thereby, increase their market share.

Geographic Segments

All of our operations are in the United States.  Additionally, we transport and sell NaHS to customers in South America and Canada.  Revenues from customers in foreign countries totaled approximately $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

Pipeline Rate and Access Regulation

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

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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 CO2 pipelines are subject to regulation by the state agencies in the states in which they are located.

Marine Regulations

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

Jones Act. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. We are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. Jones Act requirements significantly increase operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Further, the USCG and American Bureau of Shipping ("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.

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## 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.

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Air Emissions

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

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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.

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## 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.

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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 CO2 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.

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

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

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

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

Fluctuations in demand for CO2 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 CO2.

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

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

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.

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Even if reserves exist or refined products are produced in the areas accessed by our facilities, we may not be chosen by the producers or refiners to gather, refine, market, transport, store or otherwise handle any of these 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.

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

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

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

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

If one or more of our refinery customers that, individually or in the aggregate, generate a material portion of our refinery services revenue experience financial difficulties or changes in their strategy for sulfur removal such that they do not need our services, our cash flows could be adversely affected. For example, in 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 CO2 operations are exposed to risks related to Denbury's operation of its CO2 fields, equipment and pipeline as well as any of our facilities that Denbury operates.

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

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

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

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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:

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- 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.

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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 CO2 pipeline and the operator of the fields that produce our CO2 reserves. We are also parties to agreements with Denbury, including the lease of the NEJD CO2 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.

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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.

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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.

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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.

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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.

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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.

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

In addition to federal income taxes, unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if unitholders do not live in any of those jurisdictions. Unitholders will likely be required to file foreign, state, and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in more than 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.

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. Business. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See "Commitments and Off-Balance Sheet Arrangements" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 19 of the Notes to 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 Distributions (1) |
|---|---|---|---|
| | High | Low | |
| 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."

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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.

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Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 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 |
| CO2 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 |
| CO2 pipeline (Mcf per day) (5) | 167,619 | 154,271 | 160,220 | - | - |
| CO2 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.

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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.

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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.

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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.

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

Segment Margin

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

| | Year Ended December 31, 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 |
| $CO_2$ tariffs and revenues from direct financing leases of $CO_2$ pipelines | 26,413 | 26,279 |
| Sales of crude oil pipeline loss allowance volumes | 5,519 | 4,462 |
| 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.

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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 CO2 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.

CO2 Volumes

Under the terms of a transportation services agreement extending through 2028, we deliver CO2 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 CO2 to its current and certain of its other tertiary operations in east Mississippi. Variations in Denbury's CO2 tertiary recovery activities create the fluctuations in the volumes transported on the Free State pipeline. The transportation services agreement provides for a $0.1 million per month minimum payment plus a tariff based on throughput. Denbury has two renewal options, each for five years on similar terms.

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

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

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.

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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.

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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.

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- 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.

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In our petroleum products marketing operations, we supply primarily fuel oil, asphalt, diesel and gasoline to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing "heavier" petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tend to be higher than the same percentage attributable to our recurring operations. We utilize our fleet of 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.

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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 CO2 marketing | $ 15,832 | $ 16,206 |
| CO2 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: | | |
| CO2 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 CO2 of $0.01 per Mcf, or 2%.

CO2 – Industrial Customers

We supply CO2 to industrial customers under six long-term CO2 sales contracts. The terms of our contracts with the industrial CO2 customers include minimum take-or-pay and maximum delivery volumes. The maximum daily contract quantity per year in the contracts totals 97,625 Mcf. Under the minimum take-or-pay volumes, the customers must purchase a total of 51,048 Mcf per day whether received or not. Any volume purchased under the take-or-pay provision in any year can then be recovered in a future year as long as the minimum requirement is met in that year. At December 31, 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 CO2 remained consistent as a percentage of revenues at approximately 36% to 37%. The transportation rate we pay Denbury is adjusted annually for inflation in a manner similar to the sales prices for the CO2.

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.

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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.

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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 CO2 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 CO2 volumetric payments is based on the units-of-production method. We acquired three volumetric production payments totaling 280 Mcf of CO2 from Denbury between 2003 and 2005. Amortization is based on volumes sold in relation to the volumes acquired. Amortization of CO2 volumetric payments fluctuate as a result of increases or decreases in the volume of CO2 sold..

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

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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.

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

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

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

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

Revenues for 2008 only included results from the NEJD and Free State $CO_2$ 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.

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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:

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| | 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.

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| | Year Ended December 31, 2009 | 2008 |
|---|---|---|
| | (in thousands) | |
| Revenues from CO2 marketing | $ 16,206 | $ 17,649 |
| CO2 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: | | |
| CO2 marketing - Mcf | 73,328 | 78,058 |

The decreased margins from the industrial gases segment between 2008 and 2009 were due to a decline in CO2 marketing volumes and a slight decrease in the average sales price of CO2 of $0.01 per Mcf, or 2%.

Transportation costs for the CO2 remained consistent as a percentage of revenues at approximately 36% to 37%. The transportation rate we pay Denbury is adjusted annually for inflation in a manner similar to the sales prices for the CO2. We also recorded a charge for approximately $0.3 million 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 CO2 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.

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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 CO2 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.

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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.

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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.

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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.

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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.

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

The reconciliation of Available Cash before Reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) 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.

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| Commercial Cash Obligations and Commitments | Payments Due by Period<br>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.)

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

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

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

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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.

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For phantom unit awards granted under our 2007 Long-Term Incentive Plan, the total compensation expense recognized over the service period 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.

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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.

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| | 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 | $ |