GENESIS ENERGY LP
Form 10-Q
May 08, 2009

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

Form 10-Q

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

For the quarterly period ended March 31, 2009

OR

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

Commission file number 1-12295

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

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

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

NONE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes R No £

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

Yes £ No £

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

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

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

Yes £ No R

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date. Common Units outstanding as of May 6, 2009: 39,456,774

GENESIS ENERGY, L.P.

Form 10-Q

INDEX

PART I. FINANCIAL INFORMATION

Index

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

	March 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$15,392	$ 18,985
Accounts receivable - trade, net of allowance for doubtful accounts of $1,519 and $1,132 at March 31, 2009 and December 31, 2008,respectively	107,224	112,229
Accounts receivable - related party	2,365	2,875
Inventories	25,390	21,544
Net investment in direct financing leases, net of unearned income -current portion - related party	3,865	3,758
Other	11,463	8,736
Total current assets	165,699	168,127
FIXED ASSETS, at cost	364,305	349,212
Less: Accumulated depreciation	(72,860)	(67,107)
Net fixed assets	291,445	282,105
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	176,195	177,203
CO2 ASSETS, net of amortization	23,380	24,379
EQUITY INVESTEES AND OTHER INVESTMENTS	20,997	19,468
INTANGIBLE ASSETS, net of amortization	158,781	166,933
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	15,994	15,413
TOTAL ASSETS	$1,177,537	$ 1,178,674
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$85,090	$ 96,454
Accounts payable - related party	3,484	3,105
Accrued liabilities	19,442	26,713
Total current liabilities	108,016	126,272
LONG-TERM DEBT	398,800	375,300
DEFERRED TAX LIABILITIES	16,833	16,806
OTHER LONG-TERM LIABILITIES	2,818	2,834
COMMITMENTS AND CONTINGENCIES (Note 17)		
PARTNERS' CAPITAL:		
Common unitholders, 39,457 units issued and outstanding	610,699	616,971
General partner	16,515	16,649
Accumulated other comprehensive loss	(961)	(962)

Total Genesis Energy, L.P. partners' capital	626,253	632,658
Non-controlling interests	24,817	24,804
Total partners' capital	651,070	657,462
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,177,537	$ 1,178,674

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

Index

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
REVENUES:		
Supply and logistics:		
Unrelated parties	$187,818	$429,393
Related parties	1,244	725
Refinery services	48,294	43,912
Pipeline transportation, including natural gas sales:		
Transportation services - unrelated parties	3,401	5,909
Transportation services - related parties	8,294	1,052
Natural gas sales revenues	713	1,324
CO2 marketing:		
Unrelated parties	3,052	3,163
Related parties	677	707
Total revenues	253,493	486,185
COSTS AND EXPENSES:		
Supply and logistics costs:		
Product costs - unrelated parties	163,731	407,275
Product costs - related parties	1,713	-
Operating costs	17,269	16,582
Refinery services operating costs	35,333	30,324
Pipeline transportation costs:		
Pipeline transportation operating costs	2,494	2,356
Natural gas purchases	654	1,286
CO2 marketing costs:		
Transportation costs - related party	1,307	1,257
Other costs	16	15
General and administrative	8,754	8,524
Depreciation and amortization	15,419	16,789
Net (gain) loss on disposal of surplus assets	(218)	18
Total costs and expenses	246,472	484,426
OPERATING INCOME	7,021	1,759
Equity in earnings of joint ventures	1,906	178
Interest income	21	117
Interest expense	(3,056)	(1,786)
Income before income taxes	5,892	268
Income tax (expense) benefit	(591)	1,377
NET INCOME	5,301	1,645
Non-controlling interests	(11)	-
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$5,290	$1,645

Index

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

	Three Months Ended March 31, 2009	2008
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:		
BASIC	$0.16	$0.03
DILUTED	$0.16	$0.03
OUTSTANDING COMMON UNITS:		
BASIC	39,457	38,253
DILUTED	39,566	38,297

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

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

	Three Months Ended March 31, 2009	2008
Net income	$5,301	$1,645
Change in fair value of derivatives:		
Current period reclassification to earnings	132	-
Changes in derivative financial instruments - interest rate swaps	(128)	-
Comprehensive income	5,305	1,645
Comprehensive income attributable to non-controlling interests	(3)	-
Comprehensive income attributable to Genesis Energy, L.P.	$5,302	$1,645

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

Index

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

	Partners' Capital					
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2009	39,457	$ 616,971	$ 16,649	$ (962)	$ 24,804	$ 657,462
Comprehensive income:						
Net income		6,481	(1,191)		11	5,301
Interest rate swap losses reclassified to interest expense				64	68	132
Interest rate swap loss				(63)	(65)	(128)
Cash distributions		(13,021)	(1,089)		(1)	(14,111)
Contribution for executive compensation (See Note 12)			2,146			2,146
Unit based compensation expense		268				268
Partners' capital, March 31, 2009	39,457	$ 610,699	$ 16,515	$ (961)	$ 24,817	$ 651,070

	Partners' Capital					
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-Controlling Interests	Total Capital
Partners' capital, January 1, 2008	38,253	$ 615,265	$ 16,539	$ -	$ 570	$ 632,374
Comprehensive income:						
Net income		1,612	33			1,645
Cash distributions		(10,903)	(467)		(1)	(11,371)
Partners' capital, March 31, 2008	38,253	$ 605,974	$ 16,105	$ -	$ 569	$ 622,648

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

Index

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 5,301	$ 1,645
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation and amortization	15,419	16,789
Amortization of credit facility issuance costs	480	268
Amortization of unearned income and initial direct costs on direct financing leases	(4,555)	(148)
Payments received under direct financing leases	5,462	295
Equity in earnings of investments in joint ventures	(1,906)	(178)
Distributions from joint ventures - return on investment	400	517
Non-cash effect of unit-based compensation plans	2,825	(912)
Deferred and other tax liabilities	459	(1,626)
Other non-cash items	(517)	(148)
Net changes in components of operating assets and liabilities (See Note 13)	(20,211)	881
Net cash provided by operating activities	3,157	17,383
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed assets	(17,076)	(6,439)
Distributions from joint ventures - return of investment	-	161
Investments in joint ventures and other investments	(21)	(2,210)
Other, net	529	(218)
Net cash used in investing activities	(16,568)	(8,706)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	77,600	71,700
Bank repayments	(54,100)	(69,700)
Distributions to non-controlling interests	(1)	(1)
Distributions to common unitholders	(13,021)	(10,903)
Distributions to general partner interest	(1,089)	(467)
Other, net	429	274
Net cash provided by (used in) financing activities	9,818	(9,097)
Net decrease in cash and cash equivalents	(3,593)	(420)
Cash and cash equivalents at beginning of period	18,985	11,851
Cash and cash equivalents at end of period	$ 15,392	$ 11,431

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

Index

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

1. Organization and Basis of Presentation and Consolidation

Organization

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

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

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

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

Basis of Presentation and Consolidation

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. The consolidated financial statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. However, we believe that the disclosures are adequate to make the information presented not misleading when read in conjunction with the information contained in the periodic reports we file with the SEC pursuant to the Securities Exchange Act of 1934, including the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2008.

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

The accompanying unaudited consolidated financial statements and related notes present our consolidated financial position as of March 31, 2009 and December 31, 2008 and our results of operations, changes in comprehensive income and cash flows for the three months ended March 31, 2009 and 2008 and changes in capital for the three months ended March 31, 2009. Intercompany transactions have been eliminated. The accompanying unaudited consolidated financial statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries.

We participate in three joint ventures: DG Marine Transportation, LLC (DG Marine), T&P Syngas Supply Company (T&P Syngas) and Sandhill Group, LLC (Sandhill). We acquired our interest in DG Marine in July 2008, and, since then DG Marine has been consolidated in our financial statements. We account for our 50% investments in T&P Syngas and Sandhill by the equity method of accounting.

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

Index

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

2. Recent Accounting Developments

Implemented

SFAS 141(R)

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 141(R) "Business Combinations" (SFAS 141(R)). SFAS 141(R) replaces FASB Statement No. 141, "Business Combinations." This statement retains the purchase method of accounting used in business combinations but replaces SFAS 141 by establishing principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction costs and restructuring costs be charged to expense as incurred. In addition, the statement requires disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) will apply to acquisitions we make after December 31, 2008. The impact to us will be dependent on the nature of the business combination.

SFAS 160

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

SFAS 161

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133" (SFAS 161). This Statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS No. 161 on January 1, 2009, and have included the enhanced disclosures in Note 15.

EITF 07-4

In March 2008, the FASB ratified the consensus reached by the Emerging Issues Task Force (or EITF) of the FASB in issue EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." Under this consensus, the computation of earnings per unit will be affected by the incentive distribution rights ("IDRs") we are contractually obligated to distribute at the end of the current reporting period. In periods when earnings are in excess of cash distributions, we will reduce net income or loss for the current reporting period (for purposes of calculating earnings or loss per unit) by the amount of available cash that will be distributed to our limited partners and general partner for its general partner interest and incentive distribution rights for the reporting period, and the remainder will be allocated to the limited partner and general partner in accordance with their ownership interests. When cash distributions exceed current-period earnings, net income or loss (for purposes of calculating earnings or loss per unit) will be reduced (or increased) by cash distributions, and the resulting excess of distributions over earnings will be allocated to the general partner and limited partner based on their respective sharing of losses. EITF 07-4 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted EITF 07-4 on January 1, 2009 and have reflected the calculation of earnings per unit for the three months ended March 31, 2009 and 2008 in accordance with its provisions. See Note 9.

Index

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

FASB Staff Position No. 142-3

In April 2008, the FASB issued FASB Staff Position No. 142-3, "Determination of the Useful Life of Intangible Assets" (FSP 142-3). This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset under Statement of Financial Accounting Standards No. 142, "Goodwill and other Intangible Assets." The purpose of this FSP is to develop consistency between the useful life assigned to intangible assets and the cash flows from those assets. FSP 142-3 is effective for fiscal years beginning after December 31, 2008. We adopted FSP 142-3 on January 1, 2009 and adoption had no effect on our consolidated financial statements.

SFAS 157

We adopted Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements" (SFAS 157), on January 1, 2008. On February 12, 2008 the Financial Accounting Standards Board (FASB) issued Staff Position No. 157-2, "Effective Date of FASB Statement No. 157" (FSP 157-2) which amends SFAS 157 to delay the effective date for all non-financial assets and non-financial liabilities, except for those that are recognized at fair value in the financial statements on a recurring basis, to January 1, 2009. Non-recurring non-financial assets and non-financial liabilities for which we did not apply the provisions of SFAS 157 included those measured at fair value in goodwill impairment testing and asset retirement obligations initially measured at fair value. We adopted the deferred provisions as of January 1, 2009. SFAS 157 does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements. The adoption of FSP 157-2 as described above had no material impact on us. See Note 17 for further information regarding fair-value measurements.

3. Consolidated Joint Venture – DG Marine

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

We have entered into a subordinated loan agreement with DG Marine whereby we may (at our sole discretion) lend up to $25 million to DG Marine. The loan agreement provides for DG Marine to pay us interest on any loans at a rate to be determined which is expected to be the prime rate plus 4%. Those loans will mature on January 31, 2012. Under that subordinated loan agreement, DG Marine is required to make monthly payments to us of principal and interest to the extent DG Marine has any available cash that otherwise would have been distributed to the owners of DG Marine in respect of their equity interest. DG Marine also has a revolving credit facility with a syndicate of financial institutions that includes restrictions on DG Marine's ability to make specified payments under our subordinated loan agreement and distributions in respect of our equity interest. At March 31, 2009 and December 31, 2008, there were no amounts outstanding under the subordinated loan agreement. We have, however, provided a $7.5 million guaranty to the lenders under DG Marine's credit facility. That guaranty will be terminated on May 31, 2009, if DG Marine maintains a leverage ratio under its credit facility of less than 4.50 to 1.00 for the month ending May 31, 2009.

Index

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

At March 31, 2009 and December 31, 2008, our unaudited consolidated balance sheets included the following amounts related to DG Marine:

	March 31, 2009	December 31, 2008
Cash	$ 282	$ 623
Accounts receivable - trade	2,117	2,812
Other current assets	504	859
Fixed assets, at cost	121,643	110,214
Accumulated depreciation	(4,868)	(3,084)
Intangible assets, net	2,102	2,208
Other assets	1,964	2,178
Total assets	$ 123,744	$ 115,810
Accounts payable	$ 941	$ 1,072
Accrued liabilities	8,948	9,258
Long-term debt	63,800	55,300
Other long-term liabilities	1,323	1,393
Total liabilities	$ 75,012	$ 67,023

4. Inventories

Inventories are valued at the lower of cost or market. The costs of inventories did not exceed market values at March 31, 2009. The costs of inventories at December 31, 2008 exceeded market values by approximately $1.2 million, and are reflected below at those market values. The major components of inventories were as follows:

	March 31, 2009	December 31, 2008
Crude oil	10,220	1,878
Petroleum products	5,312	5,589
Caustic soda	5,305	7,139
NaHS	4,534	6,923
Other	19	15
Total inventories	$25,390	$ 21,544

5. Fixed Assets and Asset Retirement Obligations

Fixed assets consisted of the following:

	March 31, 2009	December 31, 2008
Land, buildings and improvements	$13,549	$13,549
Pipelines and related assets	139,791	139,184
Machinery and equipment	22,963	22,899
Transportation equipment	32,774	32,833
Barges and push boats	116,304	96,865

Office equipment, furniture and fixtures	4,513	4,401
Construction in progress	23,032	27,906
Other	11,379	11,575
Subtotal	364,305	349,212
Accumulated depreciation and impairment	(72,860)	(67,107)
Total	$291,445	$282,105

Index

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

Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the three months ended March 31, 2009.

Asset retirement obligations as of December 31, 2008	$1,430
Liabilities settled in the period	(55)
Accretion expense	25
Asset retirement obligations as of March 31, 2009	1,400
Less current portion included in accrued liabilities	(150)
Long-term asset retirement obligations as of March 31, 2009	$1,250

Certain of our unconsolidated affiliates have asset retirement obligations recorded at March 31, 2009 and December 31, 2008 relating to contractual agreements. These amounts are immaterial to our financial statements.

6. Intangible Assets and Goodwill

Intangible Assets

The following table reflects the components of intangible assets being amortized at the dates indicated:

		March 31, 2009			December 31, 2008		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Customer relationships:							
Refinery services	5	$94,654	$ 29,875	$64,779	$94,654	$ 26,017	$68,637
Supply and logistics	5	35,430	11,341	24,089	35,430	9,957	25,473
Supplier relationships -							
Refinery services	2	36,469	25,500	10,969	36,469	24,483	11,986
Licensing Agreements -							
Refinery services	6	38,678	8,302	30,376	38,678	7,176	31,502
Trade names -							
Supply and logistics	7	18,888	3,693	15,195	18,888	3,118	15,770
Favorable lease -							
Supply and logistics	15	13,260	789	12,471	13,260	671	12,589
Other	5	1,322	420	902	1,322	346	976
Total	5	$238,701	$ 79,920	$158,781	$238,701	$ 71,768	$166,933

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The favorable lease and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $8.2 million and $11.7 million for the three months ended March 31, 2009 and 2008, respectively.

Goodwill

The carrying amount of goodwill by business segment at March 31, 2009 and December 31, 2008 was $302.0 million to refinery services and $23.1 million to supply and logistics.

Index

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

7. Equity Investees and Other Investments

T&P Syngas Supply Company

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting. We received distributions from T&P Syngas of $0.4 million and $0.6 million during the three months ended March 31, 2009 and 2008, respectively. During the first quarter of 2009, "Equity in earnings of joint ventures" included $1.7 million of non-cash items related to T&P Syngas that increased earnings.

The tables below reflect summarized information for T&P Syngas:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Revenues	$ 1,165	$ 1,209
Operating expenses and depreciation	(574)	(367)
Other income (expense)	8	(7)
Net income	$ 599	$ 835

	March 31, 2009	December 31, 2008
Current assets	$ 3,539	$ 3,131
Non-current assets	18,595	18,906
Total assets	$ 22,134	$ 22,037
Current liabilities	$ 836	$ 543
Non-current liabilities	203	198
Partners' capital	21,095	21,296
Total liabilities and partners' capital	$ 22,134	$ 22,037

Sandhill Group, LLC

We are accounting for our 50% ownership in Sandhill under the equity method of accounting. We received a distribution from Sandhill of $124,000 during the three months ended March 31, 2008.

Other Projects

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

No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair value of our investment at March 31, 2009; therefore, our investment is included in our Unaudited Consolidated Balance Sheets at cost.

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

8. Debt

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

	March 31, 2009	December 31, 2008
Genesis Credit Facility	$ 335,000	$ 320,000
DG Marine Credit Facility	63,800	55,300
Total Long-Term Debt	$ 398,800	$ 375,300

Genesis Credit Facility

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

The borrowing base may be increased to the extent of pro forma additional EBITDA, (as defined in the credit agreement), attributable to acquisitions or internal growth projects with approval of the lenders. Our borrowing base as of March 31, 2009 exceeds $500 million. At March 31, 2009, we had $335.0 million borrowed under our credit facility and we had $3.4 million in letters of credit outstanding. The total amount available for borrowings at March 31, 2009 was $161.6 million under our credit facility. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of November 15, 2011.

DG Marine Credit Facility

DG Marine has a $90 million revolving credit facility with a syndicate of banks led by SunTrust Bank and BMO Capital Markets Financing, Inc. That facility, which matures on July 18, 2011, is secured by all of the equity interests issued by DG Marine and substantially all of DG Marine’s assets. Other than the pledge of our equity interest in DG Marine, that facility is non-recourse to us and TD Marine. At March 31, 2009, our Unaudited Consolidated Balance Sheet included $123.7 million of DG Marine’s assets in our total assets.

At March 31, 2009, DG Marine had $63.8 million outstanding under its credit facility. The total amount available for borrowings at March 31, 2009 was $26.2 million under this credit facility. Due to the revolving nature of loans under the DG Marine credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date.

In August 2008, DG Marine entered into a series of interest rate swap agreements to effectively fix the underlying LIBOR rate on $32.9 million of its borrowings under its credit facility through July 18, 2011. The fixed interest rates in the swap agreements range from the three-month interest rate of 3.23% in effect at March 31, 2009 to 4.68% at July 18, 2011.

9. Partners’ Capital and Distributions

Partners' Capital

Partner's capital at March 31, 2009 consists of 39,456,774 common units, including 4,028,096 units owned by our general partner and its affiliates, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest), and a 2% general partner interest.

Our general partner owns all of our general partner interest, our incentive distribution rights, and all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which is reflected as a non-controlling interest in our Unaudited Consolidated Balance Sheets) and operates our business.

Without obtaining unitholder approval, we may issue an unlimited number of additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

Index

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

Distributions

We will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves.

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

	Unitholders	General Partner
Quarterly Cash Distribution per Common Unit:		
Up to and including $0.25 per Unit	98.00%	2.00%
First Target - $0.251 per Unit up to and including $0.28 per Unit	84.74%	15.26%
Second Target - $0.281 per Unit up to and including $0.33 per Unit	74.53%	25.47%
Over Second Target - Cash distributions greater than $.033 per Unit	49.02%	50.98%

We paid or will pay the following distributions in 2008 and 2009:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2007	February 2008	$ 0.2850	$ 10,902	$ 222	$ 245	$ 11,369
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009 (1)	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713

(1) This distribution will be paid on May 15, 2009 to our general partner and unitholders of record as of May 4, 2009.

Net Income Allocation to Partners

Net income is allocated to our partners in the Consolidated Statements of Partners' Capital as follows:

- To our general partner – income in the amount of the incentive distributions paid in the period.

- To our general partner – expense in the amount of the executive compensation expense to be borne by our general partner (See Note 12.).

- To our limited partners and general partner – the remainder of net income in the ratio of 98% to the limited partners and 2% to our general partner.

Net Income Per Common Unit

Our net income is first allocated to our general partner based on the amount of incentive distributions to be paid for the quarter. The adoption of EITF 07-4 effective January 1, 2009 resulted in a change in the calculation of net income per common unit by changing the amount of the incentive distributions to be considered in the calculation from the distributions paid during the quarter to the distributions to be paid with respect to the quarter. As required by EITF 07-4, we have retrospectively applied the provisions of EITF 07-4 to the calculation of net income per common unit for the first quarter of 2008 in the table below. As a result, basic and diluted net income per common unit both decreased by $0.01 from amounts previously reported for the three months ended March 31, 2008.

Index

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

We then allocate to our general partner the expense related to the Class B Membership Awards to our executive officers, as our general partner will bear the cash cost of those awards. The remainder of our net income is then allocated 98% to our limited partners and 2% to our general partner. Basic net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period. Diluted net income per common unit is calculated in the same manner, but also considers the impact to common units for the potential dilution from phantom units outstanding. (See Note 12 for discussion of phantom units.)

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

	Three Months Ended March 31,	
	2009	2008
Numerators for basic and diluted net income per common unit:		
Net income attributable to Genesis Energy, L.P.	$ 5,290	$ 1,645
Less: General partner's incentive distribution to to be paid for the period	(1,125)	(429)
Add: Expense for Class B Membership Awards (Note 12)	2,146	-
Subtotal	6,311	1,216
Less: General partner 2% ownership	(126)	(24)
Income available for common unitholders	$ 6,185	$ 1,192
Denominator for basic per common unit:		
Common Units	39,457	38,253
Denominator for diluted per common unit:		
Common Units	39,457	38,253
Phantom Units	109	44
	39,566	38,297
Basic net income per common unit	$ 0.16	$ 0.03
Diluted net income per common unit	$ 0.16	$ 0.03

10. Business Segment Information

Our operations consist of four operating segments: (1) Pipeline Transportation – interstate and intrastate crude oil and CO_2; (2) Refinery Services – processing high sulfur (or “sour”) gas streams as part of refining operations to remove the sulfur and selling the related by-product; (3) Supply and Logistics – terminaling, blending, storing, marketing, gathering and transporting by truck and barge crude oil and petroleum products, and (4) Industrial Gases – the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility. All of our revenues are derived from, and all of our assets are located in the United States.

Index

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

During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with the business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by the business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Segment information for the three months ended March 31, 2008 has been retrospectively revised to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. Our segment margin definition also excludes the non-cash effects of our stock-based compensation plans, and includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant and maintenance capital investment.

	Pipeline Transportation	Refinery Services	Supply &Logistics	Industrial Gases (a)	Total
Three Months Ended March 31, 2009					
Segment margin excluding depreciation and amortization (b)	$ 10,225	$12,759	$5,956	$3,023	$31,963
Capital expenditures (c)	$ 2,090	$1,800	$11,638	$21	$15,549
Maintenance capital expenditures	$ 274	$493	$181	$-	$948
Revenues:					
External customers	$ 11,315	$49,905	$188,544	$3,729	$253,493
Intersegment (d)	1,093	(1,611)	518	-	-
Total revenues of reportable segments	$ 12,408	$48,294	$189,062	$3,729	$253,493
Three Months Ended March 31, 2008					
Segment margin excluding depreciation and amortization (b)	$ 4,661	$12,430	$4,061	$3,199	$24,351
Capital expenditures (c)	$ 1,278	$1,151	$4,603	$2,210	$9,242
Maintenance capital expenditures	$ 165	$281	$330	$-	$776
Revenues:					
External customers	$ 6,788	$43,912	$431,615	$3,870	$486,185
Intersegment (d)	1,497	-	(1,497)	-	-
Total revenues of reportable segments	$ 8,285	$43,912	$430,118	$3,870	$486,185

Index

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

a) Industrial gases includes our CO2 marketing operations and our equity income from our investments in T&P Syngas and Sandhill.
b) A reconciliation of segment margin to income before income taxes and non-controlling interests for the periods presented is as follows:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Segment margin excluding depreciation and amortization	$ 31,963	$ 24,351
Corporate general and administrative expenses	(7,501)	(5,229)
Depreciation and amortization	(15,419)	(16,789)
Net gain (loss) on disposal of surplus assets	218	(18)
Interest expense, net	(3,035)	(1,669)
Non-cash expenses not included in segment margin	(716)	192
Other non-cash items affecting segment margin	382	(570)
Income before income taxes	$ 5,892	$ 268

c) Capital expenditures includes fixed asset additions and acquisitions of businesses.
d) Intersegment sales were conducted on an arm's length basis.

11. Transactions with Related Parties

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Truck transportation services provided to Denbury	$ 1,048	$ 458
Pipeline transportation services provided to Denbury	$ 3,714	$ 1,295
Payments received under direct financing leases from Denbury	$ 5,462	$ 295
Pipeline transportation income portion of direct financing lease fees	$ 4,606	$ 162
Pipeline monitoring services provided to Denbury	$ 30	$ 30
Directors' fees paid to Denbury	$ 51	$ 30
CO2 transportation services provided by Denbury	$ 1,240	$ 1,257
Crude oil purchases from Denbury	$ 1,713	$ -

Operations, general and administrative services provided by our general partner	$	16,380	$	14,328
Distributions to our general partner on its limited partner units and general partner interest, including incentive distributions	$	2,022	$	1,274
Sales of CO2 to Sandhill	$	677	$	707
Petroleum products sales to Davison family businesses	$	196	$	266

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

Transportation Services

We provide truck transportation services to Denbury to move its crude oil from the wellhead to our Mississippi pipeline. Denbury pays us a fee for that trucking service which varies with the distance we haul its crude oil. Those fees are reflected in the Unaudited Consolidated Statements of Operations as supply and logistics revenues.

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

We also provide pipeline monitoring services to Denbury. That revenue is included in pipeline revenues in our Unaudited Consolidated Statements of Operations.

Directors' Fees

We paid Denbury for the services of each of four of Denbury's officers who serve as directors of our general partner. The annual rate and rate for attendance at meetings are the same as the rates at which our other directors were paid.

CO2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO2 for us to our customers. In the first three months of 2009, the inflation-adjusted transportation fee averaged $0.1978 per Mcf.

Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions and personnel are provided by our general partner. We reimburse our general partner for all direct and indirect costs of those services, excluding any payments to our management team pursuant to their Class B Membership Interests. See Note 12.

Amounts due to and from Related Parties

At March 31, 2009 and December 31, 2008, we owed Denbury $2.6 million and $1.0 million, respectively, for CO2 transportation charges and purchases of crude oil. Denbury owed us $1.6 million and $2.0 million for transportation services at March 31, 2009 and December 31, 2008, respectively. We owed our general partner $0.8 million and $2.1 million for administrative services at March 31, 2009 and December 31, 2008, respectively. At both March 31, 2009 and December 31, 2008, Sandhill owed us $0.7 million for purchases of CO2.

DG Marine Joint Venture

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

Financing

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

We guarantee 50% of the obligation of Sandhill to a bank. At March 31, 2009, the total amount of Sandhill's obligation to the bank was $3.0 million; therefore, our guarantee was for $1.5 million.

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

Index

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

As discussed in Note 12, we recorded a non-cash capital contribution from our general partner of $2.1 million for the three months ended March 31, 2009 related to the Class B Membership Awards for our executive management team.

12. Equity-Based Compensation

We recorded charges and credits related to our equity-based compensation plans and awards for three months ended March 31, 2009 and 2008 as follows:

Expense (Credits to Expense) Related to Equity-Based Compensation

	Three Months Ended	
Statement of Operations	2009	2008
Pipeline operating costs	$ 33	$ (140)
Refinery services operating costs	77	18
Supply and logistics operating costs	209	(127)
General and administrative expenses	2,510	(505)
Total	$ 2,829	$ (754)

Stock Appreciation Rights Plan

The following table reflects rights activity under our plan during the three months ended March 31, 2009:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at January 1, 2009	1,017,985	$18.09		
Granted during 2009	228,215	$13.00		
Exercised during 2009	(2,157)	$11.10		
Forfeited or expired during 2009	(27,579)	$-		
Outstanding at March 31, 2009	1,216,464	$16.65	6.3	$89
Exercisable at March 31, 2009	455,290	$15.91	6.4	$87

The weighted-average fair value at March 31, 2009 of rights granted during the first three months of 2009 was $2.04 per right, determined using the following assumptions:

Assumptions Used for Fair Value of Rights
Granted in First Quarter 2009

Expected life of rights (in years)	6.25
Risk-free interest rate	2.20 %
Expected unit price volatility	44.7 %
Expected future distribution yield	6.00 %

The total intrinsic value of rights exercised during the first three months of 2009 was less than $0.1 million, which was paid in cash to the participants.

At March 31, 2009, there was $0.6 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. For the awards outstanding at March 31, 2009, the remaining cost will be recognized over a weighted average period of one year.

Index

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

2007 Long Term Incentive Plan

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

Non-vested Phantom Unit Grants	Number of Units	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2009	78,388	$ 19.32
Granted	82,501	$ 8.14
Non-vested at March 31, 2009	160,889	$ 13.59

The weighted-average fair value of Phantom Units granted during the first quarter of 2009 was determined using the following assumptions:

Grant Date Price	$10.19
Expected Distribution Rate	$0.33
Risk Free Rate	0.73% - 1.50 %

The aggregate grant date fair value of Phantom Unit awards granted during the three months ended March 31, 2009 was $0.7 million. As of March 31, 2009, there was $1.3 million of unrecognized compensation expense related to these units. This unrecognized compensation cost is expected to be recognized over a weighted-average period of one year.

Class B Membership Interests

As part of finalizing the compensation arrangements for our Senior Executives on December 31, 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. Those Class B Membership Interests compensate the holders thereof by providing rewards based on increased shares of the cash distributions attributable to our incentive distribution rights (or IDRs) (See Note 9) to the extent we increase Cash Available Before Reserves, or CABR (defined below) (from which we pay distributions on our common units) above specified targets. CABR generally means Available Cash before Reserves, less Available Cash before Reserves generated from specific transactions with our general partner and its affiliates (including Denbury Resources Inc.) The Class B Membership Interests do not provide any Senior Executive with a direct interest in any assets (including our IDRs) owned by our general partner.

Our general partner has agreed that it will not seek reimbursement (on behalf of itself or its affiliates) under our partnership agreement for the costs of these Senior Executive compensation arrangements to the extent relating to their ownership of Class B Membership Interests (including current cash distributions made by the general partner out of its IDRs and payment of redemption amounts for those IDRs) and the deferred compensation amounts. Although our general partner will not seek reimbursement for the costs of the Class B Membership Interests and deferred compensation plan arrangements, we will record non-cash compensation expense. The Class B Membership Interests awarded to our senior executives are accounted for as liability awards under the provisions of SFAS 123(R). As such, the fair value of the compensation cost we record for these awards is recomputed at each measurement date and the expense to be recorded is adjusted based on that fair value. Management's estimates of the fair value of these awards are based on assumptions regarding a number of future events, including estimates of the Available Cash before Reserves we will generate each quarter through the final vesting date of December 31, 2012, estimates of the future amount of incentive distributions we will pay to our general partner, and assumptions about appropriate discount rates. Additionally the determination of fair value is affected by the distribution yield of ten publicly-traded entities that are the general partners in publicly-traded master limited partnerships, a factor over which we have no control. Included within the assumptions used to prepare these estimates are projections of available cash and distributions to our common unitholders and general partner, including an assumed level of growth and the effects of future new growth projects during the four-year vesting period. These assumptions were used to estimate the total amount that would be paid under the Class B Membership awards through the final vesting date and do not represent the contractual amounts payable under these awards at the reporting date.

Index

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

At March 31, 2009, we computed the fair value of the awards utilizing a discount rate of 15%, representing the risks inherent in the assumptions we used and the time until final vesting. Due to the limited number of participants in the Class B Membership awards, we assumed a forfeiture rate of zero. At March 31, 2009, management estimates that the fair value of the Class B Membership Awards and the related deferred compensation awards granted to our Senior Executives on that date is approximately $19.9 million. Management's estimates of fair value are made in order to record non-cash compensation expense over the vesting period, and do not necessarily represent the contractual amounts payable under these awards at March 31, 2009.

The fair value of these incentive awards will be recomputed each quarter through the final settlement of the awards. The fair value to be recorded by us as compensation expense in each quarterly period will be the excess of the recomputed estimated fair value over the previously recorded amounts, and will consider the vesting conditions for the awards. This expense will be recorded on an accelerated basis to align with the requisite service period of the award. Changes in our assumptions will change the amount of compensation cost we record. For the three months ended March 31, 2009, we recorded expense of $2.1 million.

13. Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2009	2008
Decrease (increase) in:		
Accounts receivable	$ 3,971	$ (21,194)
Inventories	(2,851)	(1,928)
Other current assets	(2,373)	(371)
Increase (decrease) in:		
Accounts payable	(10,099)	26,699
Accrued liabilities	(8,859)	(2,325)
Net changes in components of operating assets and liabilities, net of working capital acquired	$ (20,211)	$ 881

Cash received by us for interest for the three months ended March 31, 2009 and 2008 was $3,000 and $78,000, respectively. Payments of interest and commitment fees were $3,860,000 and $2,398,000 for the three months ended March 31, 2009 and 2008, respectively.

Cash paid for income taxes during the three months ended March 31, 2009 and 2008 were $917,000 and $62,000, respectively.

At March 31, 2009, we had incurred liabilities for fixed asset and other asset additions totaling $0.6 million that had not been paid at the end of the first quarter, and, therefore, are not included in the caption "Payments to acquire fixed assets" and "Other, net" under investing activities on the Unaudited Consolidated Statements of Cash Flows. At March 31, 2008, we had incurred $1.3 million of liabilities that had not been paid at that date and are not included in "Payments to acquire fixed assets" under investing activities.

14. Major Customers and Credit Risk

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

Index

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

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

Shell Oil Company accounted for 13% and 18% of total revenues in the three months ended March 31, 2009 and 2008, respectively. The majority of the revenues from this customer in both periods relate to our crude oil supply and logistics operations.

15. Derivatives

On January 1, 2009, we adopted SFAS 161 which requires enhanced disclosures about (1) how and why we use derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), and (3) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows.

Commodity Derivatives

We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (primarily futures and options contracts traded on the NYMEX) to hedge our exposure to commodity prices, primarily crude oil, fuel oil and petroleum products; however only a portion of these instruments are designated as hedges under the provisions of SFAS 133. Our decision as to whether to designate derivative instruments as fair value hedges under SFAS 133 relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under SFAS 133 in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil, that we supply cannot be hedged with a high degree of effectiveness with derivative contracts available on the NYMEX, therefore we do not designate derivative contracts utilized to limit our price risk related to these products as hedges for accounting purposes. Typically we utilize crude oil and natural gas futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges under SFAS 133 can occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged, therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.

We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the provisions of SFAS 133. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss in the consolidated statements of operations.

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

Index

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

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

	Sell (Short) Contracts	Buy (Long) Contracts
Designated under SFAS 133:		
Crude oil futures:		
Contract volumes (1,000 bbls)	312	124
Weighted average contract price per bbl	$ 51.89	$ 50.12
Not qualifying or not designated under SFAS 133:		
Crude oil futures:		
Contract volumes (1,000 bbls)	147	42
Weighted average contract price per bbl	$ 49.40	$ 50.73
Crude oil forwards:		
Contract volumes (1,000 bbls)	90	18
Weighted average contract price per bbl	$ 45.70	$ 48.65
Heating oil futures:		
Contract volumes (1,000 bbls)	8	
Weighted average contract price per gal	$ 1.48	
Natural gas futures:		
Contract volumes (10,000 mmBtus)		5
Weighted average contract price per mmbtu		$ 4.02
Crude oil written/purchased call options:		
Contract volumes (1,000 bbls)	45	40

Weighted average premium received/paid	$ 2.76	$ 3.66

Interest Rate Derivatives

DG Marine utilizes swap contracts with financial institutions to hedge interest rates for $32.9 million of its outstanding debt through July 2011. The weighted average interest rate of these swap contracts is 4.04%. Because DG Marine expects these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates, we have designated these swap contracts as cash flow hedges under the provisions of SFAS 133. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in fair value of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts is reported as a component of Accumulated Other Comprehensive Income (Loss) (AOCI) and reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility is recorded. To the extent that the change in the fair value of the interest rate swaps do not perfectly offset the change in the fair value of our exposure to interest rates, the ineffective portion of the hedge will be immediately recognized in interest expense in our Unaudited Consolidated Statements of Operations.

Index

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

Financial Statement Impacts

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

		Impact of Unrealized Gains and Losses	
Derivative Instrument	Hedged Risk	Unaudited Consolidated Balance Sheets	Unaudited Consolidated Statements of Operations
Designated under SFAS 133:			
Crude oil futures contracts(fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in Other Current Assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventory	Excess, if any, over effective portion of hedge is recorded in Supply and Logistics - Cost of Sales. Effective portion is offset in Cost of Sales against change in value of inventory being hedged
Interest rate swaps(cash flow hedge)	Changes in interest rates	Entire hedge is recorded in Accrued Liabilities or Other Liabilities depending on duration	Expect hedge to fully offset hedged risk; no ineffectiveness recorded. Effective portion is recorded in interest expense.
Not qualifying or not designated under SFAS 133:			
Commodity hedges consisting of crude oil, heating oil and natural gas futures and forward contracts and call options	Volatility in crude oil and petroleum products prices - effect on market value of inventory or purchase commitments.	Derivative is recorded in Other Current Assets (offset against margin deposits) or Accrued Liabilities	Entire amount of change in fair value of hedge is recorded in Supply and Logistics - Cost of Sales

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

Index

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

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

	Fair Value of Derivative Assets and Liabilities					
	Derivative Assets		Unaudited Consolidated Balance Sheets Location	Derivative Liabilities		Unaudited Consolidated Balance Sheets Location
Commodity derivatives - futures and call options:						
Hedges designated under SFAS 133as fair value hedges	$640		Other Current Assets	$(497)	(1)	Other Current Assets
Undesignated hedges	281		Other Current Assets	(559)	(1)	Other Current Assets
Undesignated hedges	18	(2)	Accrued Liabilities	(355)		Accrued Liabilities
Total commodity derivatives	939			(1,411)		
Interest rate swaps designated as cash flow hedges:						
Portion expected to be reclassified into earnings within one year				(766)		Accrued Liabilities
Portion expected to be reclassified into after one year				(1,194)		Other Liabilities
Total derivatives	$939			$(3,371)		

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

(2) These derivative assets are subject to netting agreements and are presented on a net basis in our Unaudited Consolidated Balance Sheet in Accrued Liabilities.

	Effect on Unaudited Consolidated Statements of Operations and Other Comprehensive Income (Loss) Amount of Gain (Loss) Recognized in Income			
	Supply & Logistics - Product Costs		Interest Expense Reclassifed from AOCI	Other Comprehensive Income Effective Portion
Commodity derivatives - futures and call options:				
Hedges designated under SFAS 133	$(529)	(1)	$-	$ -
Undesignated hedges	182			
Total commodity derivatives	(347)		-	-

Interest rate swaps designated as cash flow hedges		(132)	(128)
Total derivatives	$(347)	$(132)	$ (128)

(1) Represents the amount of loss recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain on the hedged inventory under the fair value hedge of $1.0 million.

Index

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

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

We expect to reclassify $0.8 million in unrealized losses from AOCI into interest expense during the next 12 months. Because a portion of these losses are based on market prices at the current period end, actual amounts to be reclassified to earnings will differ and could vary materially as a result of changes in market conditions. We have no derivative contracts with credit contingent features.

16. Fair-Value Measurements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value at March 31, 2009		
Recurring Fair Value Measures	Level 1	Level 2	Level 3
Commodity derivatives, net	$ (135)	$ (337)	$ -
Interest rate swaps	$ -	$ -	$ (1,960)

Level 1

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

Level 2

Included within Level 2 of the fair value hierarchy are physical commodity contracts that meet the definition of a derivative but are not excluded from SFAS 133 under the normal purchase and normal sale scope exception. The fair value of the commodity contracts are measured with Level 1 inputs for similar but not identical instruments and therefore must be included in Level 2 of the hierarchy.

Level 3

Included within Level 3 of the fair value hierarchy are our interest rate swaps. The fair value of our interest rate swaps is based on indicative broker price quotations. These derivatives are included in Level 3 of the fair value hierarchy because broker price quotations used to measure fair value are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these Level 3 derivatives is not based upon significant management assumptions or subjective inputs.

-27-

Index

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

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as Level 3 in the fair value hierarchy:

	Three Months Ended March 31, 2009
Balance as of January 1, 2009	$ (1,964)
Realized and unrealized gains (losses)-	
Reclassified into interest expense for settled contracts	132
Included in other comprehensive income	(128)
Balance as of March 31, 2009	$ (1,960)
Total amount of losses for the three months ended March 31, 2009, included in earnings attributable to the change in unrealized losses relating to liabilities still held at March 31, 2009	$ (11)

See Note 15 for additional information on our derivative instruments.

We generally apply fair value techniques on a non-recurring basis associated with (1) valuing the potential impairment loss related to goodwill pursuant to SFAS 142, (2) valuing asset retirement obligations pursuant, and (3) valuing potential impairment loss related to long-lived assets accounted for pursuant to SFAS 144.

17. Contingencies

Guarantees

We guaranteed $1.2 million of residual value related to the leases of trailers from a lessor. We believe the likelihood that we would be required to perform or otherwise incur any significant losses associated with this guarantee is remote.

We guaranteed 50% of the obligations of Sandhill under a credit facility with a bank. At March 31, 2009, Sandhill owed $3.0 million; therefore our guaranty was $1.5 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year.

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities; however, no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. Such hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations.

We are subject to lawsuits in the normal course of business, as well as examinations by tax and other regulatory authorities. We do not expect such matters presently pending to have a material adverse effect on our financial position, results of operations, or cash flows.

Index

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

- Overview
- Available Cash before Reserves
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- New Accounting Pronouncements

In the discussions that follow, we will focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves. During the fourth quarter of 2008, we revised the manner in which we internally evaluate our segment performance. As a result, we changed our definition of segment margin to include within segment margin all costs that are directly associated with a business segment. Segment margin now includes costs such as general and administrative expenses that are directly incurred by a business segment. Segment margin also includes all payments received under direct financing leases. In order to improve comparability between periods, we exclude from segment margin the non-cash effects of our stock-based compensation plans which are impacted by changes in the market price for our common units. Previous periods have been retrospectively revised to conform to this segment presentation. We now define segment margin as revenues less cost of sales, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our joint ventures. In addition, our segment margin definition excludes the non-cash effects of our stock-based compensation plans, and includes the non-income portion of payments received under direct financing leases. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment margin, segment volumes where relevant, and maintenance capital investment. A reconciliation of segment margin to income from before income taxes is included in our segment disclosures in Note 10 to the consolidated financial statements.

Available Cash before Reserves (a non-GAAP measure) is net income as adjusted for specific items, the most significant of which are the addition of non-cash expenses (such as depreciation), the substitution of cash generated by our joint ventures in lieu of our equity income attributable to such joint ventures, the elimination of gains and losses on asset sales (except those from the sale of surplus assets) and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see "Liquidity and Capital Resources - Non-GAAP Reconciliation" below.

Overview

In the first quarter of 2009, we reported net income of $5.3 million, or $0.16 per common unit. Non-cash expense related to our senior executive compensation arrangements totaling $2.1 million reduced net income during the first quarter. See additional discussion of our senior executive compensation expense in "Results of Operations – Other Costs, Interest and Income Taxes" below.

During the first quarter of 2009, we generated $21.3 million of Available Cash before Reserves, and we will distribute $14.7 million to holders of our common units and general partner for the first quarter. During the first quarter of 2009, cash provided by operating activities was $3.2 million.

Segment margin for most of our segments increased in the first quarter 2009 as compared to the first quarter of 2008. A significant portion of the increase was attributable to acquisitions during 2008, specifically the two drop down transactions with Denbury in May 2008 and the acquisition of our interest in DG Marine in July 2008.

On April 7, 2009, we announced that our distribution to our common unitholders relative to the first quarter of 2009 will be $0.3375 per unit (to be paid in May 2009). This distribution amount represents a 12.5% increase from our distribution of $0.30 per unit for the first quarter of 2008. During the first quarter of 2009, we paid a distribution of $0.33 per unit related to the fourth quarter of 2008.

Index

The current economic crisis has restricted the availability of credit and access to capital in our business environment. Despite efforts by U.S. Treasury and banking regulators to provide liquidity to the financial sector, capital markets continue to remain constrained. While we anticipate that the challenging economic environment will continue for the foreseeable future, we believe that our current cash balances, future internally-generated funds and funds available under our credit facility will provide sufficient resources to meet our current working capital needs. The financial performance of our existing businesses, $177.0 million in cash and existing debt commitments and no need, other than opportunistically, to access the capital markets, may allow us to take advantage of acquisition and/or growth opportunities that may develop.

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

Available Cash before Reserves

Available Cash before Reserves was as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Net income attributable to Genesis Energy, L.P.	$ 5,290	$ 1,645
Depreciation and amortization	15,419	16,789
Cash received from direct financing leases not included in income	907	147
Cash effects of sales of certain assets	405	245
Effects of available cash generated by equity method investees not included in income	(1,289)	423
Cash effects of stock appreciation rights plan	(4)	(158)
Non-cash tax expense	460	(1,626)
Earnings of DG Marine in excess of distributable cash	(1,970)	-
Other non-cash items, net	3,072	(902)
Maintenance capital expenditures	(948)	(776)
Available Cash before Reserves	$ 21,342	$ 15,787

We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the three months ended March 31, 2009 in "Liquidity and Capital Resources – Non-GAAP Reconciliation" below. For the three months ended March 31, 2009 and 2008, cash flows provided by operating activities were $3.2 million and 17.4 million, respectively.

Index

Results of Operations

The contribution of each of our segments to total segment margin in the first quarters of 2009 and 2008 was as follows:

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Pipeline transportation	$ 10,225	$ 4,661
Refinery services	12,759	12,430
Supply and logistics	5,956	4,061
Industrial gases	3,023	3,199
Total segment margin	$ 31,963	$ 24,351

Pipeline Transportation Segment

Operating results for our pipeline transportation segment were as follows:

	Three Months Ended March 31	
Pipeline System	2009	2008
Mississippi-Bbls/day	25,364	22,854
Jay - Bbls/day	9,433	14,616
Texas - Bbls/day	29,827	28,562
Free State - Mcf/day	171,293	-

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 3,954	$ 4,126
Non-income payments under direct financing leases	907	147
Sales of crude oil pipeline loss allowance volumes	799	2,459
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	6,744	78
Tank rental reimbursements and other miscellaneous revenues	178	267
Revenues from natural gas tariffs and sales	733	1,355
Natural gas purchases	(654)	(1,286)
	(2,436)	(2,485)

Pipeline operating costs, excluding non-cash charges for our equity-based compensation plans and other non-cash charges		
Segment margin	$ 10,225	$ 4,661

Three Months Ended March 31, 2009 Compared with Three Months Ended March 31, 2008

Pipeline segment margin for the first quarter of 2009 increased $5.6 million as compared to the first quarter of 2008. The significant component of this change is an increase in revenues from CO2 financing leases and tariffs of $6.7 million and a related increase in non-income payments from the same financing leases of $0.8 million. Reducing the impact of this increase were decreases in revenues from sales of pipeline loss allowance volumes of $1.7 million and revenues from crude oil tariffs and related sources of $0.2 million.

Tariff and direct financing lease revenues from our crude oil pipelines decreased $0.2 million primarily due to volume decreases on our Jay pipeline system totaling 5,183 barrels per day as compared to the first quarter of 2008. The decreased volumes were principally due to a producer connected to our Jay System shutting in production in the first quarter of 2009. Volumes on the Mississippi and Texas systems increased in the 2009 first quarter slightly offsetting the impact on tariff revenue of the Jay System decline.

Index

The decline in market prices for crude oil reduced pipeline loss allowance revenues. Average crude oil market prices decreased approximately $54 per barrel between the two quarters. Additionally, pipeline loss allowance volumes combined with net volumetric measurement gains were 10,700 barrels greater in the first quarter of 2008 than the first quarter of 2009. The combination of these two declines resulted in a decrease of $1.7 million in pipeline loss allowance revenues.

Revenues and payments related to CO2 pipelines increased by a total of $7.5 million between the two quarters, with $5.2 million attributable to the NEJD pipeline and $2.3 million to the Free State pipeline. The average volume transported on the Free State pipeline for the first quarter of 2009 was 171 MMcf per day, with the transportation fees and the minimum payments totaling $2.0 million and $0.3 million, respectively.

Refinery Services Segment

Segment margin from our refinery services for the first quarter of 2009 was $12.8 million. Segment margin from our refinery services for the same period in 2008 was $12.4 million. The increase in segment margin is primarily related to the decline in sales volumes of NaHS being substantially offset by increased sales of caustic soda and by cost management and logistics optimization. The current macroeconomic conditions have negatively impacted the short-term demand for NaHS, primarily in mining and industrial activities. To help mitigate the financial effects of the decline in NaHS sales, we have been successful in selling caustic soda not needed in our operations and using our existing logistical assets to support such marketing to third parties. The key cost components of the provision of the refinery sulfur removal service continued to be volatile in the first quarter of 2009. Market prices for caustic soda, as published by the Chemical Market Associates, Inc. (CMAI) ranged from $400 to $500 per dry short ton (DST) during the first quarter of 2008 compared to a range of $580 to $750 per DST in the first quarter of 2009. Our freight costs during the first quarter periods fluctuated with freight demand and fuel prices, both of which were significantly higher in the 2008 period. We believe that we were successful in mitigating some of the impact on segment margin of the volatility of these costs through our management of caustic acquisition and freight costs and by indexing our sales prices for NaHS to caustic market prices.

The table below reflects information about NaHS sales for first quarters of 2009 and 2008 volumes and sales prices.

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
NaHS Sales		
Dry Short Tons (DST)	26,229	41,742
Average sales price per DST, net of delivery costs	$ 1,069	$ 660

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

In the first quarter of 2009, the contribution to segment margin of the other activities of our refinery services segment was $2.1 million more than in the first quarter of 2008, primarily resulting from selling caustic soda not needed in our operations.

Index

Supply and Logistics Segment

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

	Three Months Ended March 31, 2009	2008
	(in thousands)	
Supply and logistics revenue	$ 189,062	$ 430,118
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(165,317)	(407,275)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(17,789)	(18,782)
Segment margin	$ 5,956	$ 4,061
Volumes of crude oil and petroleum products - average barrels per day	41,489	46,939

Three Months Ended March 31, 2009 as Compared to Three Months Ended March 31, 2008

Fluctuations in the market price of crude oil and petroleum products have limited impact on our segment margin. Therefore, although our supply and logistics revenues and crude oil and product costs fluctuated significantly between the first quarters of 2009 and 2008 due to an almost $50 per barrel market price variance, we will focus our discussion of our operating results on segment margin.

Segment margin increased $2.0 million comparatively between the first quarters of 2009 and 2008. The key factors affecting this comparison are as follows:

– Acquisition of inland marine transportation operations of Grifco in third quarter of 2008 (increased segment margin);

– Reduction in opportunities for us to take advantage of purchasing and blending of products (reduced segment margin); and

– Crude oil contango market conditions (increased segment margin).

The inland marine transportation operations of Grifco Transportation, acquired by DG Marine in the third quarter of 2008, added $3.1 million to segment margin in the first quarter of 2009. These operations provided us with an additional capability to provide transportation services of petroleum products by barge.

In the first quarter of 2008, the high demand for gasoline by consumers led refiners to operate at increased production levels. Refineries are willing to sell the “heavy” end of the refined barrel, in the form of fuel oil or asphalt, at more attractive pricing (to us) in order to free up capacity to meet the gasoline demand. Due to our logistics equipment, we were able to take advantage of these opportunities and acquire product at attractive prices for our petroleum products marketing and blending.. In the first quarter of 2009, demand for gasoline declined significantly. With refiners reducing their production rates volumes available to us to purchase were limited, resulting in a decrease in our petroleum products volumes of 16% and segment margin of $2.0 million.

During the first quarter of 2009, crude oil markets were in contango (oil prices for future deliveries are higher than for current deliveries), providing an opportunity for us to purchase and store crude oil as inventory for delivery in future months. The crude oil markets were not in contango in the first quarter of 2008. During the first quarter of 2009, we placed 188,000 barrels of crude oil in our storage tanks and hedged this volume with futures contracts on the NYMEX. We are accounting for the effects of this inventory position and related derivative contracts as a fair value hedge under SFAS 133. The effect on segment margin for the amount excluded from effectiveness testing related to this fair value hedge was a $0.5 million gain in the first quarter of 2009.

Index

Industrial Gases Segment

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

CO2 - Industrial Customers - We supply CO2 to industrial customers under seven long-term CO2 sales contracts. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

Our industrial customers treat the CO2 and transport it to their customers. The primary industrial applications of CO2 by those customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through the first quarter of 2009, we can 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.

Operating Results - Operating results from our industrial gases segment were as follows:

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Revenues from CO2 marketing	$ 3,729	$ 3,870
CO2 transportation and other costs	(1,323)	(1,272)
Available cash generated by equity investees	617	601
Segment margin	$ 3,023	$ 3,199
Volumes per day:		
CO2 marketing - Mcf	69,833	73,062

Three Months Ended March 31, 2009 Compared with Three Months Ended March 31, 2008

The decrease in margin from the industrial gases segment between the two quarterly periods was the result of a decrease in volumes sold, slightly offset by an increase in the average sales price of CO2 to our customers. During the first quarter of 2009, volumes declined 4% as compared to the 2008 first quarter as customers reduced volumes while performing maintenance activities at their facilities. Variations in the volumes sold among contracts with different pricing terms resulted in the average sales price of the CO2 increasing $0.01 per Mcf, or 2%.

The inflation adjustment to the rate we pay Denbury to transport the CO2 to our customers resulted in greater CO2 transportation costs in the first quarter of 2009 when compared to the 2008 quarter. The transportation rate increase between the two quarters was 4.4%.

Our share of the available cash before reserves generated by our equity investments in each quarterly period primarily resulted from our investment in T&P Syngas.

Other Costs, Interest, and Income Taxes

General and administrative expenses. General and administrative expenses consisted of the following:

Three Months Ended March 31,

	2009	2008
	(in thousands)	
General and administrative expenses not separately identified below	$ 5,389	$ 7,866
Bonus plan expense	855	1,163
Equity-based compensation plans expense (credit)	364	(505)
Compensation expense related to management team	2,146	-
Total general and administrative expenses	$ 8,754	$ 8,524

Index

Between the first quarter periods, general and administrative expenses increased by $0.2 million. Several factors contributed to this increase. These factors are:

- Expense recorded for the compensation arrangement between our senior executive team and our general partner added $2.1 million in the first quarter of 2009. This cash cost of these arrangements will be borne by our general partner.

- The increase in our common unit price since December 31, 2008 and the issuance of additional stock appreciation rights and phantom units resulted in equity-based compensation expense for the first quarter of 2009 of $0.4 million related to personnel included in general and administrative expenses. As compared to the first quarter of 2008, this was an increase in expense of $0.9 million.

- Reductions in travel costs, audit and tax professional services and bonus expense totaling $1.8 million offset some of the increased amounts.

On December 31, 2008, our general partner and our senior executive management team entered into a compensation arrangement whereby our executive team may earn an interest in our incentive distribution rights owned by our general partner. While our general partner will bear the cash cost of the arrangement with our senior executives, we record the expense of the arrangements with an offsetting non-cash capital contribution by our general partner. As discussed in Note 12 under Class B Membership Interests, we estimate the fair value of the awards to our senior executives at each reporting date and adjust the expense we have recorded based on that fair value. Based on the fair value estimate at March 31, 2009 of $19.9 million, we recorded expense for the first quarter of 2009 of $2.1 million. The fair value of the awards is being recorded on an accelerated basis due to the vesting conditions contained in the awards, so as to match the expense recorded to the service period required for vesting.

Depreciation and amortization expense. Depreciation and amortization expense decreased in the first quarter of 2009 as compared to the same quarter in 2008 primarily as a result of the amortization expense recognized on intangible assets. Depreciation and amortization totaled $15.4 million and $16.8 million for the quarters ended March 31, 2009 and 2008, respectively.

We are amortizing our intangible assets over the period during which the intangible asset is expected to contribute to our future cash flows. As intangible assets such as customer relationships and trade names are generally more valuable in the first years after an acquisition, the amortization we record on these assets is greater in the initial years after the acquisition. As such the amount of amortization we have recorded has declined since the intangible assets were acquired in 2007.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Interest expense, including commitment fees, excluding DG Marine	$ 1,616	$ 1,674
Amortization of facility fees, excluding DG Marine facility	163	165
Interest expense and commitment fees - DG Marine	1,363	-
Capitalized interest	(86)	(53)
Interest income	(21)	(117)
Net interest expense	$ 3,035	$ 1,669

On May 30, 2008, we increased our debt to fund the drop-down transactions from Denbury. As a result, our average outstanding debt balance under our credit facility increased by $248.2 million over the average outstanding debt balance in the first quarter of 2008. Our average interest rate, however, was 4.1% lower during the 2009 quarter, resulting in a decrease for the quarter of $0.1 million. DG Marine incurred interest expense in the first quarter of $1.4 million under its credit facility.

Index

Income tax expense. Income tax expense is based on non-qualified income generated in the period. In the first quarter of 2009, non-qualified income increased in relation to the tax deductions attributable to that income, resulting in an increase in income tax expense. As the majority of our operations are not taxable to us, income tax expense is not expected to be significant.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

Credit and access to capital continues to be negatively impacted by current economic conditions in our business environment. We believe that the challenging economic environment will continue for the foreseeable future, however, we anticipate that our short-term working capital needs will be met through our current cash balances, future internally-generated funds and funds available under our credit facility. Existing capacity in our credit facility and $15.4 million of cash on hand, as well as the absence of any need to access the capital markets may allow us to take advantage of acquisition and/or growth opportunities that may develop.

Long-term, we continue to pursue a growth strategy that requires significant capital. We expect our long-term capital resources to include equity and debt offerings (public and private) and other financing transactions, in addition to cash generated from our operations. Accordingly, we expect to access the capital markets (equity and debt) from time to time to partially refinance our capital structure and to fund other needs including acquisitions and ongoing working capital needs. Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, to utilize our current credit facility and to implement our growth strategy successfully. No assurance can be made that we will be able to raise the necessary funds on satisfactory terms. If we are unable to raise the necessary funds, we may be required to defer our growth plans until such time as funds become available.

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

At March 31, 2009, we had $335 million of loans and $3.4 million in letters of credit outstanding under our $500 million credit facility, resulting in $161.6 million of remaining credit, all of which was available under our borrowing base. DG Marine had $63.8 million of loans outstanding under its $90 million credit facility. As of March 31, 2009, DG Marine had one remaining barge under construction and one push boat remaining to be purchased with an estimated total remaining cost of $4.1 million, which transactions were subsequently completed in April 2009 and funded under DG Marine's credit facility.

Uses of Cash

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

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

Debt and Other Financing Activities. Our sources of cash are primarily from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $23.5 million. These borrowings related primarily to the investment in fixed assets and the payment of liabilities accrued at year end such as annual bonus payments and property tax obligations. We paid distributions totaling $14.1 million to our limited partners and our general partner during the first quarter of 2009. See the details of distributions paid in "Distributions" below.

Index

Investing. We utilized cash flows for capital expenditures. The most significant investing activities in the first quarter of 2009 were expenditures by DG Marine of $11.4 million for additional barges and related costs as well as other capital expenditures as shown in the table below.

Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets and other asset acquisitions in the first quarters of 2009 and 2008 is as follows:

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Capital expenditures for property, plant and equipment:		
Maintenance capital expenditures:		
Pipeline transportation assets	274	165
Supply and logistics assets	121	304
Refinery services assets	493	281
Administrative and other assets	60	26
Total maintenance capital expenditures	948	776
Growth capital expenditures:		
Pipeline transportation assets	1,816	1,113
Supply and logistics assets	11,457	4,273
Refinery services assets	1,307	870
Total growth capital expenditures	14,580	6,256
Total	15,528	7,032
Capital expenditures attributable to unconsolidated affiliates:		
Faustina project	21	2,210
Total	21	2,210
Total capital expenditures	$ 15,549	$ 9,242

During the remainder of 2009, we expect to expend approximately $7.6 million for maintenance capital projects in progress or planned. Those expenditures are expected to include approximately $0.9 million of improvements in our refinery services business, $1.5 million in our crude oil pipeline operations, including $0.8 million for rehabilitation of a segment of the Mississippi System as a result of integrity management plan, or IMP testing, $3.5 million related to integration and upgrades of our information technology systems, and the remainder on projects related to our truck transportation operations, including $1.7 for replacement vehicles. In future years we expect to spend $4 million to $5 million per year on vehicle replacements as the average age of our fleet increases.

We will also complete construction of an expansion of our existing Jay System that will extend the pipeline to producers operating in southern Alabama. That expansion will consist of approximately 33 miles of pipeline and gathering connections to approximately 35 wells and will include storage capacity of 20,000 barrels. We expect to spend a total of approximately $2.2 million in the second quarter of 2009 to complete this project, including the acquisitions of crude oil linefill.

DG Marine expended approximately $4.1 million in April of 2009 for the last barge that was under construction and one additional push boat. As of April 30, 2009, DG Marine had twenty barges and ten push boats. DG Marine's capital expenditures are funded through its credit facility.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital discussed above in "Capital Resources -- Sources of Cash." We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows.

Index

Distributions

We are required by our partnership agreement to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last six quarters, including the distribution to be paid for the first quarter of 2009, as shown in the table below (in thousands, except per unit amounts).

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2007	February 2008	$ 0.2850	$ 10,902	$ 222	$ 245	$ 11,369
First quarter 2008	May 2008	$ 0.3000	$ 11,476	$ 234	$ 429	$ 12,139
Second quarter 2008	August 2008	$ 0.3150	$ 12,427	$ 254	$ 633	$ 13,314
Third quarter 2008	November 2008	$ 0.3225	$ 12,723	$ 260	$ 728	$ 13,711
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009 (1)	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713

(1) This distribution will be paid on May 15, 2009 to our general partner and unitholders of record as of May 4, 2009.

See Note 9 of the Notes to the Unaudited Consolidated Financial Statements.

Non-GAAP Reconciliation

This quarterly 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 discretionary 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 Quarterly Report on Form 10-Q may not be comparable to similarly titled measures of other companies. The GAAP measure most directly comparable to Available Cash before Reserves is net cash provided by operating activities.

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

Index

The reconciliation of Available Cash before Reserves (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three months ended March 31, 2009 and 2008 is as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Cash flows from operating activities	$3,157	$17,383
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures	(948)	(776)
Proceeds from sales of certain assets	405	245
Amortization of credit facility issuance fees	(480)	(268)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	217	84
Earnings of DG Marine in excess of distributable cash	(1,970)	-
Other items affecting available cash		
Net effect of changes in operating accounts not included in	750	-
calculation of Available Cash	20,211	(881)
Available Cash before Reserves	$21,342	$15,787

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligations and Commercial Commitments

There have been no material changes to the commitments and obligations reflected in our Annual Report on Form 10-K for the year ended December 31, 2008.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under “Contractual Obligations and Commercial Commitments” in our Annual Report on Form 10-K for the year ended December 31, 2008, nor do we have any debt or equity triggers based upon our unit or commodity prices.

New and Proposed Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2, “Recent Accounting Developments” in the accompanying unaudited consolidated financial statements.

Forward Looking Statements

The statements in this Quarterly Report on Form 10-Q that are not historical information may be “forward looking statements” within the meaning of the various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions, and other such references are forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “continue,” “estimate,” “expect,” “forecast,” “intend,” “may,” “plan,” “position,” “projection,” “strategy” or “will,” or the nega terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

Index

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

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2008. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2008 Annual Report on Form 10-K. There have been no material changes in that information other than as described below. Also, see Note 15 to our Unaudited consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Index

		Sell (Short) Contracts		Buy (Long) Contracts
Futures Contracts:				
Crude Oil:				
Contract volumes (1,000 bbls)		459		166
Weighted average price per bbl	$	51.09	$	50.28
Contract value (in thousands)	$	23,451		8,346
Mark-to-market change (in thousands)		(33)		(102)
Market settlement value (in thousands)	$	23,418	$	8,244
Heating Oil:				
Contract volumes (1,000 bbls)		8		-
Weighted average price per gal	$	1.48	$	-
Contract value (in thousands)	$	496		-
Mark-to-market change (in thousands)		(36)		-
Market settlement value (in thousands)	$	460	$	-
Natural Gas:				
Contract volumes (10,000 mmBtus)				5
Weighted average price per mmBtu	$	-	$	4.02
Contract value (in thousands)	$	-		201
Mark-to-market change (in thousands)		-		(12)
Market settlement value (in thousands)	$	-	$	189
Forward Contracts - Crude Oil:				
Contract volumes (1,000 bbls)		90		18
Weighted average price per bbl	$	45.70	$	48.65
Contract value (in thousands)	$	4,113		876
Mark-to-market change (in thousands)		356		18
Market settlement value (in thousands)	$	4,469	$	894
NYMEX Option Contracts:				
Crude Oil- Written/Purchased Calls				
Contract volumes (1,000 bbls)		45		40
Weighted average premium received/paid	$	2.76	$	3.66
Contract value (in thousands)	$	124	$	146
Mark-to-market change (in thousands)		29		(82)
Market settlement value (in thousands)	$	153	$	64

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Item 4. Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosures.

Index

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Information with respect to this item has been incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2008. There have been no material developments in legal proceedings since the filing of such Form 10-K.

Item 1A. Risk Factors.

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2008. There have been no material changes to the risk factors since the filing of such Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Our credit facility provides that we may make quarterly distributions to our unitholders if we meet the financial metrics and are not otherwise in default under our credit facility. The amount of such distributions may not exceed the sum of the distributable cash generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At March 31, 2009, the excess of distributable cash over distributions under this provision of the credit facility was $54.3 million.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits

(a) Exhibits.

3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (“Genesis”) (incorporated by reference to Exhibit 3.1 to Registration Statement, File No. 333-11545)
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 4.1 to Form 8-K dated June 15, 2005)
3.3	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to

	Exhibit 3.3 to Form 10-K for the year ended December 31, 2007.)
3.4	Certificate of Limited Partnership of Genesis Crude Oil, L.P. ("the Operating Partnership") (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 1996)
3.5	Fourth Amended and Restated Agreement of Limited Partnership of the Operating Partnership (incorporated by reference to Exhibit 4.2 to Form 8-K dated June 15, 2005)
3.6	Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009.)

Index

3.7		Certificate of Formation of Genesis Energy, LLC (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009.)
3.8		Limited Liability Company Agreement of Genesis Energy, LLC dated December 29, 2008 (incorporated by reference to Exhibit 3.3 to Form 8-K dated January 7, 2009.)
3.9		First Amendment to Limited Liability Company Agreement of Genesis Energy, LLC dated December 31, 2008 (incorporated by reference to Exhibit 3.4 to Form 8-K dated January 7, 2009.)
4.1		Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2007.)
31.1	*	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2	*	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934.
32	*	Certification by Chief Executive Officer and Chief Financial Officer Pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934.

*Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)
By: GENESIS ENERGY, LLC, as General Partner

Date: May 8, 2009

By: /s/ Robert V. Deere
Robert V. Deere
Chief Financial Officer

-43-