GENESIS ENERGY LP
Form 10-Q
November 03, 2010

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

Form 10-Q

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

For the quarterly period ended September 30, 2010

OR

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

Commission file number 001-12295

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

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

Securities registered pursuant to Section 12(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 þ No o

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

Yes o No o

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o

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

Yes o No þ

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 November 2, 2010: 39,585,692

GENESIS ENERGY, L.P.

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PART I. FINANCIAL INFORMATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,058	$ 4,148
Accounts receivable - trade, net of allowance for doubtful accounts of $1,303 and $1,372 at September 30, 2010 and December 31, 2009, respectively	169,370	127,248
Accounts receivable - related parties	315	2,617
Inventories	64,581	40,204
Investment in direct financing leases, net of unearned income -current portion	4,509	4,202
Other	8,904	10,825
Total current assets	250,737	189,244
FIXED ASSETS, at cost	373,636	373,927
Less: Accumulated depreciation	(103,834)	(89,040)
Net fixed assets	269,802	284,887
INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	169,626	173,027
CO2 ASSETS, net of accumulated amortization	16,869	20,105
EQUITY INVESTEES AND OTHER INVESTMENTS	14,255	15,128
INTANGIBLE ASSETS, net of accumulated amortization	123,315	136,330
GOODWILL	325,046	325,046
OTHER ASSETS, net of accumulated amortization	9,847	4,360
TOTAL ASSETS	$ 1,179,497	$ 1,148,127
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable - trade	$ 137,390	$ 114,428
Accounts payable - related parties	2,213	3,197
Accrued liabilities	25,733	23,803
Total current liabilities	165,336	141,428
LONG-TERM DEBT	426,000	366,900
DEFERRED TAX LIABILITIES	14,391	15,167
OTHER LONG-TERM LIABILITIES	5,523	5,699
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS' CAPITAL:		
Common unitholders, 39,586 and 39,488 units issued and outstanding,at September 30, 2010 and December 31, 2009, respectively	557,079	585,554
General partner	10,608	11,152

Accumulated other comprehensive loss		-		(829	)
Total Genesis Energy, L.P. partners' capital		567,687		595,877	
Noncontrolling interests		560		23,056	
Total partners' capital		568,247		618,933	
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	1,179,497	$	1,148,127	

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
REVENUES:				
Supply and logistics:				
Unrelated parties	$518,441	$355,604	$1,338,755	$833,658
Related parties	368	846	1,014	3,218
Refinery services	38,437	30,006	106,160	112,894
Pipeline transportation, including natural gas sales:				
Transportation services - unrelated parties	13,565	4,009	36,342	11,442
Transportation services - related parties	-	7,977	2,861	24,175
Natural gas sales revenues	522	435	1,967	1,667
CO2 marketing:				
Unrelated parties	3,886	3,712	9,881	9,821
Related parties	793	800	2,101	2,211
Total revenues	576,012	403,389	1,499,081	999,086
COSTS AND EXPENSES:				
Supply and logistics costs:				
Product costs - unrelated parties	490,358	324,162	1,251,777	751,524
Product costs - related parties	-	-	-	1,754
Operating costs	23,300	22,894	66,764	60,766
Operating costs - related parties	599	-	1,932	-
Refinery services operating costs	22,251	17,160	60,268	73,711
Pipeline transportation costs:				
Pipeline transportation operating costs	3,007	2,852	9,192	7,984
Natural gas purchases	490	395	1,847	1,519
CO2 marketing costs:				
Transportation costs	1,741	1,603	4,542	4,251
Other costs	16	16	47	47
General and administrative	10,583	10,128	23,678	27,188
Depreciation and amortization	13,477	15,806	40,489	47,358
Net loss (gain) on disposal of surplus assets	7	17	25	(141)
Total costs and expenses	565,829	395,033	1,460,561	975,961
OPERATING INCOME	10,183	8,356	38,520	23,125
Equity in earnings of joint ventures	377	(788)	922	1,382
Interest expense	(6,542)	(3,418)	(13,506)	(9,826)
Income before income taxes	4,018	4,150	25,936	14,681
Income tax expense	(155)	(253)	(1,827)	(1,661)
NET INCOME	3,863	3,897	24,109	13,020
Net loss attributable to noncontrolling interests	1,205	402	2,082	1,025
	$5,068	$4,299	$26,191	$14,045

NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net Income Attributable to Genesis Energy, L.P. Per Common Unit:				
Basic and Diluted	$0.12	$0.14	$0.48	$0.43

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income	$3,863	$3,897	$24,109	$13,020
Change in fair value of derivatives:				
Current period reclassification to earnings	1,553	224	2,112	514
Changes in derivative financial instruments - interest rate swaps	(224)	(315)	(424)	(400)
Comprehensive income	5,192	3,806	25,797	13,134
Comprehensive loss (income) attributable to noncontrolling interests	529	46	1,223	(60)
Comprehensive income attributable to Genesis Energy, L.P.	$5,721	$3,852	$27,020	$13,074

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

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GENESIS ENERGY, L.P.
UNAUDITED CONDENSED 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, 2010	39,488	$ 585,554	$ 11,152	$ (829)	$ 23,056	$ 618,933
Comprehensive income:						
Net income (loss)	-	20,052	6,139	-	(2,082)	24,109
Interest rate swap losses reclassified to interest expense	-	-	-	1,035	1,077	2,112
Interest rate swap loss	-	-	-	(206)	(218)	(424)
Cash contributions	-	-	37	-	-	37
Cash distributions	-	(43,644)	(7,909)	-	(5)	(51,558)
Contribution for executive compensation (See Note 9)	-	-	1,289	-	-	1,289
Unit based compensation expense	98	20	-	-	-	20
Acquisition of non-controlling interest in DG Marine (See Note 2)	-	(4,903)	(100)	-	(21,268)	(26,271)
Partners' capital, September 30, 2010	39,586	$ 557,079	$ 10,608	$ -	$ 560	$ 568,247

	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 (loss)	-	17,892	(3,847)	-	(1,025)	13,020
Interest rate swap loss reclassified to interest expense	-	-	-	251	263	514
Interest rate swap loss	-	-	-	(197)	(203)	(400)
Cash contributions	-	-	7	-	-	7
Cash distributions	-	(39,958)	(4,191)	-	(4)	(44,153)
Contribution for executive compensation (See Note 9)	-	-	7,587	-	-	7,587
Unit based compensation expense	26	793	-	-	-	793

Partners' capital, September 30, 2009	39,483	$ 595,698	$ 16,205	$ (908)	$ 23,835	$ 634,830

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

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

	Nine Months Ended September 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$24,109	$13,020
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation of fixed assets	17,241	19,378
Amortization of intangible and CO2 assets	23,248	27,980
Amortization and write-off of credit facility issuance costs	2,498	1,448
Amortization of unearned income and initial direct costs on direct financing leases	(13,275)	(13,606)
Payments received under direct financing leases	16,389	16,390
Equity in earnings of investments in joint ventures	(922)	(1,382)
Distributions from joint ventures - return on investment	1,494	800
Non-cash effect of unit-based compensation plans	1,941	2,758
Non-cash compensation charge	1,289	7,587
Deferred and other tax liabilities	649	1,084
Other non-cash items	2,423	(283)
Net changes in components of operating assets and liabilities (See Note 10)	(43,010)	(19,343)
Net cash provided by operating activities	34,074	55,831
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments to acquire fixed and intangible assets	(8,799)	(28,656)
Distributions from joint ventures - return of investment	308	-
Other, net	756	417
Net cash used in investing activities	(7,735)	(28,239)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings	561,429	174,300
Bank repayments	(502,329)	(165,200)
Credit facility issuance fees	(7,584)	-
General partner contributions	37	7
Noncontrolling interests distributions	(5)	(4)
Distributions to common unitholders	(43,644)	(39,958)
Distributions to general partner interest	(7,909)	(4,191)
Acquisition of non-controlling interests in DG Marine (See Note 2)	(26,271)	-
Other, net	(1,153)	(2,831)
Net cash used in financing activities	(27,429)	(37,877)
Net decrease in cash and cash equivalents	(1,090)	(10,285)
Cash and cash equivalents at beginning of period	4,148	18,985
Cash and cash equivalents at end of period	$3,058	$8,700

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

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GENESIS ENERGY, L.P.
NOTES TO UNAUDITED CONDENSED 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 crude oil and petroleum products by trucks and barges; 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. 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

Our 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 condensed 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, 2009.

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.

2. DG Marine

Today, DG Marine Transportation (“DG Marine”) is one of our wholly-owned consolidated subsidiaries, providing transportation services of petroleum products by barge that complements our other supply and logistics operations. Originally formed in 2008, DG Marine was a joint venture in which we owned (directly and indirectly) a 49% economic interest. The remaining 51% economic interest in DG Marine was owned by TD Marine, a related party. (See our Form 10-K for the year ended December 31, 2009 for a description of our related party relationships.)

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

As a result of this transaction, we reclassified the acquired noncontrolling interest in DG Marine of $21.3 million to Genesis Energy, L.P. partners' capital. Additionally, we reduced our partners' capital by $26.3 million for the costs related to the transaction ($25.5 million paid to TD Marine and $0.8 million in direct transaction costs associated with the acquisition). The net effect on Genesis Energy, L.P. partners' capital in our Consolidated Balance Sheet for September 30, 2010 was a decrease of $5.0 million.

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Until July 29, 2010, DG Marine was a variable interest entity as certain of our voting rights were not proportional to our 49% economic interest. Accounting provisions required us to consolidate DG Marine and reflect the interest of TD Marine as a noncontrolling interest.

3. Inventories

The major components of inventories were as follows:

	September 30, 2010	December 31, 2009
Crude oil	$ 18,385	$ 13,901
Petroleum products	36,421	22,150
Caustic soda	5,406	1,985
NaHS	4,350	2,154
Other	19	14
Total inventories	$ 64,581	$ 40,204

Inventories are valued at the lower of cost or market. The costs of inventories did not exceed market values at September 30, 2010 and December 31, 2009.

4. Intangible Assets and Goodwill

Intangible Assets

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

	September 30, 2010			December 31, 2009		
	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Customer relationships:						
Refinery services	$94,654	$ 50,217	$44,437	$94,654	$ 41,450	$53,204
Supply and logistics	35,430	18,859	16,571	35,430	15,493	19,937
Supplier relationships -						
Refinery services	36,469	30,745	5,724	36,469	28,551	7,918
Licensing Agreements -						
Refinery services	38,678	14,760	23,918	38,678	11,681	26,997
Trade names -						
Supply and logistics	18,888	7,009	11,879	18,888	5,444	13,444
Favorable lease -						
Supply and logistics	13,260	1,500	11,760	13,260	1,144	12,116
Other	10,129	1,103	9,026	3,823	1,109	2,714
Total	$247,508	$ 124,193	$123,315	$241,202	$ 104,872	$136,330

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Estimated amortization expense for each of the five subsequent fiscal years is expected to be as follows (amounts are exclusive of intangible assets not yet in service associated with our information technology systems upgrade project):

Year Ended December 31	Amortization Expense to be Recorded
Remainder of 2010	$ 7,042
2011	$ 21,918
2012	$ 18,261
2013	$ 14,264
2014	$ 11,790
2015	$ 9,856

Goodwill

The carrying amount of goodwill by business segment at both September 30, 2010 and December 31, 2009 was $301.9 million to refinery services and $23.1 million to supply and logistics.

5. Debt

Our obligations under credit facilities consisted of the following:

	September 30, 2010	December 31, 2009
Genesis Credit Facility, variable rate, due June 2015	$ 426,000	$ 320,000
DG Marine Credit Facility, variable rate	-	46,900
Total Long-Term Debt	$ 426,000	$ 366,900

On June 29, 2010, we restructured our senior secured credit agreement with a syndicate of banks led by BNP Paribas. Among other changes, our credit agreement:

- now matures on June 30, 2015;
- provides for a $525 million senior secured revolving credit facility, with the ability to increase the size of the facility up to $650 million, with approval of lenders;
- includes a $75 million hedged crude oil and petroleum products inventory loan sublimit based on 90% of the hedged value of the inventory; and
- no longer includes “borrowing base” limitations except with respect to inventory loans.

Our inventory borrowing base is recalculated monthly. At September 30, 2010, our inventory borrowing base was $50.4 million.

At September 30, 2010, we had $426 million borrowed under our credit agreement, with $50.4 million of that amount designated as a loan under the inventory sublimit. Additionally, we had $4.3 million in letters of credit outstanding.

The key terms for rates under our credit agreement are as follows:

- The interest rate on borrowings may be based on a eurodollar rate ("LIBOR") or an Alternate Base Rate ("ABR"), at our option. The interest rate on LIBOR borrowings is equal to the sum of (a) the LIBOR rate for the applicable interest period multiplied by the statutory reserve rate and (b) a margin that can range from 2.50% to 3.50%. The interest rate on ABR borrowings is equal to the sum of (a) the greatest of (i) the prime rate established by BNP Paribas, (ii) the federal funds effective rate plus ½ of 1% and (iii) the LIBOR rate for a one-month maturity plus 1%, and (b) a margin that can range from 1.50% to 2.50%. The applicable margin under either option is based on our leverage ratio as computed under our credit agreement. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At September 30, 2010, our borrowing rate margins were 2.75% and 1.75% for LIBOR and ABR borrowings, respectively.

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

- Letter of credit fees will range from 2.50% to 3.50% based on our leverage ratio as computed under our credit agreement. This rate can fluctuate quarterly. At September 30, 2010, our letter of credit rate was 2.75%.

- We pay a commitment fee on the unused portion of the $525 million facility amount. The commitment fee is 0.50%.

Collateral under the credit facility consists of substantially all of our assets, excluding our security interest in the NEJD pipeline and our ownership interest in the Free State pipeline. Our credit agreement is recourse to our general partner only with respect to its general partner interest in certain of our subsidiaries.

Our credit agreement contains customary covenants (affirmative, negative and financial) that limit the manner in which we may conduct our business. Our credit agreement contains three primary financial covenants – a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. In general, our leverage ratio calculations compare our consolidated funded debt (excluding the amounts borrowed under the inventory sublimit in our credit agreement) to EBITDA (as defined and adjusted in accordance with our credit agreement). Our interest coverage ratio compares EBITDA (as adjusted) to interest expense. Our credit agreement includes provisions for the temporary adjustment of the required ratios following material acquisitions and with lender approval. So long as we are in compliance with the terms of our credit agreement, we have no limitations on our ability to distribute all of our available cash (as defined in our partnership agreement).

We were in compliance with all applicable covenants of our credit agreement at September 30, 2010.

In connection with our purchase of TD Marine's interest in DG Marine on July 29, 2010, the outstanding balance on the DG Marine credit facility was repaid. See Note 2.

We believe the amounts included in our balance sheet for the debt outstanding under our revolving credit agreement approximate fair value due to the recent restructuring of our credit agreement.

6. Distributions and Net Income Per Common Unit

Distributions

We paid or will pay the following distributions in 2009 and 2010:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	General Partner Incentive Distribution Amount	Total Amount
Fourth quarter 2008	February 2009	$ 0.3300	$ 13,021	$ 266	$ 823	$ 14,110
First quarter 2009	May 2009	$ 0.3375	$ 13,317	$ 271	$ 1,125	$ 14,713
Second quarter 2009	August 2009	$ 0.3450	$ 13,621	$ 278	$ 1,427	$ 15,326

Third quarter 2009	November 2009	$	0.3525	$	13,918	$	284	$	1,729	$	15,931
Fourth quarter 2009	February 2010	$	0.3600	$	14,251	$	291	$	2,037	$	16,579
First quarter 2010	May 2010	$	0.3675	$	14,548	$	297	$	2,339	$	17,184
Second quarter 2010	August 2010	$	0.3750	$	14,845	$	303	$	2,642	$	17,790
Third quarter 2010	November 2010 (1)	$	0.3875	$	15,339	$	313	$	3,147	$	18,799

(1) This distribution will be paid on November 12, 2010 to our general partner and unitholders of record as of November 2, 2010.

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

Net Income Allocation to Partners

Net income is allocated to our partners in the Unaudited Condensed 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 9).
- 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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Numerators for basic and diluted net income per common unit:				
Income attributable to Genesis Energy, L.P.	$5,068	$4,299	$26,191	$14,045
Less: General partner's incentive distribution to be paid for the period	(3,147)	(1,729)	(8,128)	(4,281)
Add: Expense for Class B and Series B Awards (Note 9)	2,965	3,088	1,289	7,587
Subtotal	4,886	5,658	19,352	17,351
Less: General partner 2% ownership	(98)	(113)	(387)	(347)
Income available for common unitholders	$4,788	$5,545	$18,965	$17,004
Denominator for basic per common unit:				
Common Units	39,586	39,480	39,573	39,467
Denominator for diluted per common unit:				
Common Units	39,586	39,480	39,573	39,467
Phantom Units (1)	-	134	16	133
	39,586	39,614	39,589	39,600
Basic net income per common unit	$0.12	$0.14	$0.48	$0.43
Diluted net income per common unit	$0.12	$0.14	$0.48	$0.43

(1) See Note 9 for description of Phantom Units.

7. Business Segment Information

We define Segment Margin as revenues less product costs, 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.

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

	Pipeline Transportation	Refinery Services	Supply &Logistics	Industrial Gases	Total
Three Months Ended September 30, 2010					
Segment margin (a)	$ 11,920	$16,218	$7,740	$3,495	$39,373
Maintenance capital expenditures	$ 161	$354	$201	$-	$716
Revenues:					
External customers	$ 11,059	$40,246	$520,028	$4,679	$576,012
Intersegment (b)	3,028	(1,809)	(1,219)	-	-
Total revenues of reportable segments	$ 14,087	$38,437	$518,809	$4,679	$576,012
Three Months Ended September 30, 2009					
Segment margin (a)	$ 10,269	$12,694	$9,423	$2,893	$35,279
Maintenance capital expenditures	$ 451	$162	$723	$-	$1,336
Revenues:					
External customers	$ 10,729	$31,365	$356,783	$4,512	$403,389
Intersegment (b)	1,692	(1,359)	(333)	-	-
Total revenues of reportable segments	$ 12,421	$30,006	$356,450	$4,512	$403,389

	Pipeline Transportation	Refinery Services	Supply &Logistics	Industrial Gases	Total
Nine Months Ended September 30, 2010					
Segment margin (a)	$ 33,756	$45,668	$19,473	$8,990	$107,887
Maintenance capital expenditures	$ 295	$1,169	$795	$-	$2,259
Revenues:					
External customers	$ 33,969	$111,964	$1,341,166	$11,982	$1,499,081
Intersegment (b)	7,201	(5,804)	(1,397)	-	-
Total revenues of reportable segments	$ 41,170	$106,160	$1,339,769	$11,982	$1,499,081
Nine Months Ended September 30, 2009					
Segment margin (a)	$ 30,841	$38,643	$21,979	$8,785	$100,248
Maintenance capital expenditures	$ 1,201	$704	$1,853	$-	$3,758
Revenues:					
External customers	$ 32,927	$117,193	$836,934	$12,032	$999,086
Intersegment (b)	4,357	(4,299)	(58)	-	-
Total revenues of reportable segments	$ 37,284	$112,894	$836,876	$12,032	$999,086

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(a) A reconciliation of Segment Margin to income before income taxes for the periods presented is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Segment Margin	$39,373	$35,279	$107,887	$100,248
Corporate general and administrative expenses	(9,769)	(9,141)	(21,174)	(24,218)
Depreciation and amortization	(13,477)	(15,806)	(40,489)	(47,358)
Net (loss) gain on disposal of surplus assets	(7)	(17)	(25)	141
Interest expense, net	(6,542)	(3,418)	(13,506)	(9,826)
Non-cash expenses not included in segment margin	(4,301)	(1,008)	(2,966)	(1,850)
Other items excluded from income affecting segment margin	(1,259)	(1,739)	(3,791)	(2,456)
Income before income taxes	$4,018	$4,150	$25,936	$14,681

(b) Intersegment sales were conducted on similar terms as sales to third parties.

8. 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. An affiliate of Denbury Resources, Inc. sold its interest in our general partner on February 5, 2010. Transactions with Denbury through February 5, 2010 are included in the table below as related party transactions.

The transactions with related parties were as follows:

	Nine Months Ended September 30,	
	2010	2009
Operations, general and administrative services provided by our general partner	$ 34,827	$ 38,999
Marine operating costs provided by Quintana affiliate	$ 1,932	$ -
Sales of CO_2 to Sandhill	$ 2,101	$ 2,211
Petroleum products sales to Davison family businesses	$ 832	$ 602
Truck transportation services provided to Denbury (1)	$ 182	$ 2,616
Pipeline transportation services provided to Denbury (1)	$ 1,365	$ 10,481
Payments received under direct financing leases from Denbury (1)	$ 99	$ 16,390
Pipeline transportation income portion of direct financing lease fees from Denbury (1)	$ 1,502	$ 13,754
Pipeline monitoring services provided to Denbury (1)	$ 10	$ 90
CO_2 transportation services provided by Denbury (1)	$ 373	$ 4,029
Crude oil purchases from Denbury (1)	$ -	$ 1,754

(1) Amounts for 2010 only through February 5, 2010.

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Additionally, on July 29, 2010, we acquired the 51% interest of TD Marine in DG Marine. See Note 3.

Amounts due to and from Related Parties

At September 30, 2010 and December 31, 2009, we owed our general partner \$2.0 million and \$2.1 million for administrative services, respectively. We owed an affiliate of Quintana Capital Group II, L.P. \$0.2 million at September 30, 2010 for fuel and other expenses associated with our inland marine barge operations. Sandhill owed us \$0.3 million and \$0.7 million for purchases of CO2 at September 30, 2010 and December 31, 2009, respectively. Denbury owed us \$1.9 million for truck and pipeline transportation services, and we owed Denbury \$1.0 million for CO2 transportation charges at December 31, 2009.

9. Equity-Based Compensation

We recorded charges related to our equity-based compensation plans and awards for the three and nine months ended September 30, 2010 and 2009 as follows:

Expense Related to Equity-Based Compensation

	Three Months Ended September 30,		Nine Months Ended September 30,	
Statement of Operations	2010	2009	2010	2009
Pipeline operating costs	$ 200	$ 124	$ 307	$ 208
Refinery services operating costs	234	139	409	289
Supply and logistics operating costs	758	481	1,052	910
General and administrative expenses	3,829	3,710	2,819	9,041
Total	$ 5,021	$ 4,454	$ 4,587	$ 10,448

In connection with the sale of our general partner on February 5, 2010, our general partner redeemed all of its Class B Member Interests and replaced its Class A Member Interest with Series A units and Series B units.

Series B Units

Our general partner uses the Series B Units, which have no voting rights, as part of its long-term compensation structure for our management team. A total of 1,000 Series B Units may be issued by our general partner. Pursuant to restricted unit agreements entered into with Genesis Energy, LLC, our general partner, on February 5, 2010, certain members of our management team received an aggregate of 767 Series B units in our general partner. Provided the holder of the Series B Units is still employed on the seventh anniversary of the issuance date of the awards, the Series B Units will be converted into Series A Units (unless a conversion occurs at a prior date due to a public offering or a change in control of our general partner).

Subject to the rights of the holders of the Series A units in our general partner to receive distributions up to certain threshold amounts, holders of Series B units, upon vesting, have the right to receive a share of the distributions paid by us to our general partner. With regard to the right to receive a share of distributions, the Series B Units vest 25% per year on each of the next four anniversary dates of the award. The four-year vesting requirement would also be applicable to any conversion due to a public offering should that conversion occur in the first four years after issuance of the award.

Although the Series B units represent an equity interest in our general partner and our general partner will not seek reimbursement under our partnership agreement for the value of these compensation arrangements, we will record non-cash expense for the estimated fair value of the awards. The estimated fair value of the converted Series B units will be recomputed at each quarterly reporting date until conversion, and the expense to be recorded will be adjusted based on that fair value, with an offsetting entry to the capital account of our general partner.

Management's estimates of the fair value of these awards are based on a number of future events, including estimates of the distributions that would be received by our general partner in the future through the conversion date of February 5, 2017, the fair value of our general partner at February 5, 2017, and assumptions about an appropriate discount rate. Changes in our assumptions will change the amount of expense we record.

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At September 30, 2010, management estimates that the fair value of the Series B Units granted to our management team is approximately $36.4 million. This estimate of the fair value was determined using a discount rate of 14%. Due to the limited number of holders of Series B Units, we assumed a forfeiture rate of zero. For the three and nine months ended September 30, 2010, we recorded non-cash expense of $3.0 million and $3.5 million, respectively for these awards.

2007 Long Term Incentive Plan

As a result of the sale of our general partner on February 5, 2010, all outstanding phantom units issued pursuant to our 2007 Long Term Incentive Plan vested. As a result of this acceleration of the vesting period, we recorded non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested.

Class B Membership Interests

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

2010 Long Term Incentive Plan

In the second quarter of 2010, our general partner adopted the Genesis Energy, LLC 2010 Long-Term Incentive Plan (the “2010 Plan”). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to directors of our general partner, and employees and other representatives of our general partner and its affiliates who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights (“DERs”) are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on the phantom units had they been limited partner units issued by us. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the “GCBD Committee”) of the board of directors of our general partner.

The GCBD Committee (at its discretion) will designate participants in the 2010 Plan, determine the types of awards to grant to participants, determine the number of units to be covered by any award, and determine the conditions and terms of any award including vesting, settlement and forfeiture conditions. Awards under the 2010 Plan of 54,806 phantom units with tandem DERs were made in the first nine months of 2010. The phantom units will vest on the third anniversary of the date of issuance.

The compensation cost associated with the phantom units is re-measured each reporting period based on the fair value of the phantom units, and the liability recorded for the estimated amount to be paid to the participants will be adjusted. Management’s estimates of the fair value of these awards include assumptions about expectation of forfeitures prior to vesting. Due to the positions of the small group of employees and non-employee directors who received these awards, we have assumed that there will be no forfeitures of these phantom units in our fair value calculation as of September 30, 2010. At September 30, 2010, we estimate the fair value of these awards to be approximately $1.2 million, and we recorded $0.2 million of compensation expense for the three and nine months ended September 30, 2010.

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10. Supplemental Cash Flow Information

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Decrease (increase) in:		
Accounts receivable	$ (39,771)	$ (7,513)
Inventories	(25,571)	(15,048)
Other current assets	831	(523)
Increase (decrease) in:		
Accounts payable	22,503	4,071
Accrued liabilities	(1,002)	(330)
Net changes in components of operating assets and liabilities,net of working capital acquired	$ (43,010)	$ (19,343)

Cash received by us for interest for the nine months ended September 30, 2010 and 2009 was less than $0.1 million. Payments of interest and commitment fees were $10.8 million and $10.9 million for the nine months ended September 30, 2010 and 2009, respectively.

Cash paid for income taxes during the nine months ended September 30, 2010 and 2009 was $2.2 million and $1.0 million, respectively.

At September 30, 2010, we had incurred liabilities for fixed and intangible assets and other asset additions totaling $2.0 million that had not been paid at the end of the third quarter, and, therefore, are not included in the caption “Payments to acquire fixed and intangible assets” under investing activities on the Unaudited Condensed Consolidated Statements of Cash Flows. At September 30, 2009, we had incurred $0.3 million of such liabilities that had not been paid at that date and are not included in “Payments to acquire fixed and intangible assets” under investing activities.

11. Derivatives

Commodity Derivatives

At September 30, 2010, we had the following outstanding derivative commodity futures, forwards and options contracts that were entered into to hedge inventory or fixed price purchase commitments:

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	Sell (Short) Contracts	Buy (Long) Contracts
Designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	159	-
Weighted average contract price per bbl	$ 78.08	$ -
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	554	417
Weighted average contract price per bbl	$ 75.86	$ 75.78
Heating oil futures:		
Contract volumes (1,000 bbls)	115	15
Weighted average contract price per gal	$ 2.16	$ 2.32
RBOB gasoline futures:		
Contract volumes (1,000 bbls)	44	-
Weighted average contract price per gal	$ 1.93	$ -
#6 Fuel oil futures:		
Contract volumes (1,000 bbls)	325	215
Weighted average contract price per bbl	$ 66.92	$ 67.85
Crude oil written calls and puts:		
Contract volumes (1,000 bbls)	252	-
Weighted average premium received	$ 1.71	$ -

Interest Rate Derivatives

Until July 29, 2010, DG Marine utilized swap contracts with financial institutions to hedge interest payments for a portion of its outstanding debt. DG Marine expected these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates; therefore, we designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represented the change in fair value of the hedge that offset the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts was reported as a component of AOCL and was reclassified into future earnings contemporaneously as interest expense associated with the underlying debt under the DG Marine credit facility was recorded. In the third quarter of 2010, we settled the DG Marine interest rate swaps in connection with our acquisition of the 51% of DG Marine that we did not own. See Note 2.

Financial Statement Impacts

The following tables reflect the estimated fair value gain (loss) position of our hedge derivatives and related inventory impact for qualifying hedges at September 30, 2010 and December 31, 2009:

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Fair Value of Derivative Assets and Liabilities

	Asset Derivatives		
	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value September 30, 2010	Fair Value December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$768	$ 53
Undesignated hedges	Other Current Assets	1,516	307
Total asset derivatives		$2,284	$ 360

	Liability Derivatives		
	Unaudited Condensed Consolidated Balance Sheets Location	Fair Value September 30, 2010	Fair Value December 31, 2009
Commodity derivatives - futures and call options:			
Hedges designated under accounting guidance as fair value hedges	Other Current Assets	$ (1,250)(1)	$ (159)(1)
Undesignated hedges	Other Current Assets	(4,040)(1)	(2,118)(1)
Total commodity derivatives		(5,290)	(2,277)
Interest rate swaps designated as cash flow hedges under accounting rules:			
Portion expected to be reclassified into earnings within one year	Accrued Liabilities	-	(1,176)
Portion expected to be reclassified into earnings after one year	Other Long-term Liabilities	-	(512)
Total liability derivatives		$ (5,290)	$ (3,965)

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

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	Effect on Unaudited Condensed Consolidated Statements of Operations and Other Comprehensive Income Amount of Gain (Loss) Recognized in Income					
	Supply & Logistics Product Costs Three Months Ended September 30,		Interest Expense Reclassified from AOCL Three Months Ended September 30,		Other Comprehensive Income Effective Portion Three Months Ended September 30,	
	2010	2009	2010	2009	2010	2009
Commodity derivatives - futures and call options:						
Contracts designated as hedges under accounting guidance	$(354)	$758	$-	$-	$-	$-
Contracts not considered hedges under accounting guidance	(138)	1,288	-	-	-	-
Total commodity derivatives	(492)	2,046	-	-	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance	-	-	(1,553)	(224)	(224)	(315)
Total derivatives	$(492)	$2,046	$(1,553)	$(224)	$(224)	$(315)

	Effect on Unaudited Condensed Consolidated Statements of Operations and Other Comprehensive Income Amount of Gain (Loss) Recognized in Income					
	Supply & Logistics Product Costs Nine Months Ended September 30,		Interest Expense Reclassified from AOCL Nine Months Ended September 30,		Other Comprehensive Income Effective Portion Nine Months Ended September 30,	
	2010	2009	2010	2009	2010	2009
Commodity derivatives - futures and call options:						
Contracts designated as hedges under accounting guidance	$952 (1)	$(4,094)(1)	$-	$-	$-	$-
Contracts not considered hedges under accounting guidance	4,287	(1,075)	-	-	-	-
Total commodity derivatives	5,239	(5,169)	-	-	-	-
Interest rate swaps designated as cash flow hedges under accounting guidance	-	-	(2,112)	(514)	(424)	(400)
Total derivatives	$5,239	$(5,169)	$(2,112)	$(514)	$(424)	$(400)

(1) Represents the amount of gain (loss) recognized in income for derivatives related to the fair value hedge of inventory. The amount excludes the gain recorded on the hedged inventory under the fair value hedge of $0.5 million for the nine months ended September 30, 2010 and excludes the gain on the hedged inventory under the fair value hedge of $6.4 million for the nine months ended September 30, 2009.

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We have no derivative contracts with credit contingent features.

12. 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 September 30, 2010. As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value at September 30, 2010			Fair Value at December 31, 2009		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$2,284	$-	$-	$360	$-	$-
Liabilities	$(5,290)	$-	$-	$(2,277)	$-	$-
Interest rate swaps - Liabilities	$-	$-	$-	$-	$-	$(1,688)

Level 1

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

Level 2

At September 30, 2010, we had no Level 2 fair value measurements.

Level 3

At September 30, 2010, we had no Level 3 fair value measurements. Included within Level 3 of the fair value hierarchy at December 31, 2009, were our interest rate swaps. These swaps were closed out in July 2010 in connection with the acquisition of the 51% of DG Marine we did not own and the termination of DG Marine's credit facility.

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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Balance at beginning of period	(1,329)	(1,759)	(1,688)	(1,964)
Realized and unrealized gains (losses)-				
Reclassified into interest expense	1,553	224	2,112	514
Included in other comprehensive income	(224)	(315)	(424)	(400)

Balance at end of period	$-	$(1,850)	$-	$(1,850)
Total amount of losses for the nine months ended included in earnings attributable to the change in unrealized losses relating to contracts still held at September 30, 2010 and 2009, respectively			$-	$(9)

See Note 11 for additional information on our derivative instruments.

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

13. Contingencies

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

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.

14. Subsequent Event – Cameron Highway Oil Pipeline Company Acquisition

On October 22, 2010, we executed a definitive agreement to purchase Valero Energy Corporation’s ("Valero") 50% equity interest in Cameron Highway Oil Pipeline Company (“Cameron Highway”), a partnership, for $330 million in cash. Enterprise Products Partners, L.P. also owns a 50% interest in and operates Cameron Highway. The transaction is expected to close before year end, subject to usual and customary conditions, including receipt of all regulatory approvals. The purchase price is subject to customary adjustments, including for working capital.

We intend to permanently fund the acquisition with some combination of equity and debt. However, to protect against the possibility of a rapid deterioration in the capital markets, we entered into an agreement with a group of banks to provide up to $300 million of unsecured financing. This unsecured facility allows for borrowings through December 31, 2011.

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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

In the discussions that follow, we will focus on our revenues, expenses and net income, as well as two measures that we use to manage our business and to review our results of our operations. Those two measures are Segment Margin and Available Cash before Reserves. We define Segment Margin as revenues less product costs, 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 equity-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 before income taxes is included in our segment disclosures in Note 7 to our Unaudited Condensed 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 equity investees in lieu of our equity income attributable to such equity investees, the elimination of gains and losses on asset sales (except those from the sale of surplus assets), the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows, the elimination of earnings of DG Marine in excess of distributable cash until July 29, 2010 when DG Marine's credit facility was repaid, and the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see Liquidity and Capital Resources - Non-GAAP Reconciliation below.

Overview

In the third quarter of 2010, we reported net income attributable to the partnership of $5.1 million, or $0.12 per common unit. We generated $28.1 million of Available Cash before Reserves, and we will distribute $18.8 million to holders of our common units and general partner for the third quarter. During the third quarter of 2010, cash provided by operating activities was $23.4 million, which we believe is the most directly comparable GAAP financial measure to Available Cash before Reserves.

On October 13, 2010, we increased our quarterly distribution rate to our common unitholders for the twenty-first consecutive quarter. We will pay a distribution in November 2010 attributable to the third quarter of 2010 of $0.3875 per unit, which represents an approximate 9.9% increase from our distribution of $0.3525 per unit for the third quarter of 2009. We paid a distribution in August 2010 attributable to the second quarter of 2010 of $0.375 per unit.

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

On June 29, 2010, we restructured our senior secured credit facility. Our credit facility now provides for a $525 million senior secured revolving credit facility, includes an accordion feature whereby the total credit available can be increased up to $650 million under certain circumstances, and matures on June 30, 2015. Among other modifications, our credit facility now includes a $75 million sublimit tranche designed for more efficient financing of crude oil and petroleum products inventory. See additional discussion under Liquidity and Capital Resources – Capital Resources/Sources of Cash below and in Note 5 to our Unaudited Condensed Consolidated Financial Statements.

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On October 22, 2010, we entered into an agreement to acquire a 50% interest in Cameron Highway for approximately $330 million in cash. Cameron Highway, constructed in 2004, is a 380-mile 24-and 30-inch diameter pipeline, with capacity to deliver up to 500,000 barrels per day of crude oil from developments in the Gulf of Mexico to major refining markets along the Texas Gulf Coast located in Port Arthur and Texas City and includes approximately $50 million of linefill and $9 million in pumping equipment (in each case, net to Valero's interest). Valero's share of annualized distributions from the joint venture was approximately $27 million and $33 million at December 31, 2009 and June 30, 2010, respectively. During the twelve-month period ended June 30, 2010, Cameron Highway's owners received distributions totaling approximately $65 million. In the future, we expect the annualized distributions to be higher following resumed development of the fields (following the end to the moratorium on offshore drilling activities in the deepwater Gulf of Mexico as of October 12, 2010) currently dedicated to the pipeline as well as Cameron Highway's ability to provide services to future developments. We expect to fund this transaction with some combination of equity and debt. See additional discussion under Liquidity and Capital Resources – Capital Resources/Sources of Cash below.

We believe our current cash balances, 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 and the absence of any need to access the capital markets (other than opportunistically) may allow us to take advantage of other acquisition and/or growth opportunities that may develop.

Our ability to fund large new projects or make other large acquisitions in the near term may be limited by the current conditions in the credit and equity markets due to limitations in our ability to consummate future debt or equity financings. We also will consider other arrangements to fund large growth projects and acquisitions such as private equity and joint venture arrangements.

Available Cash before Reserves

Available Cash before Reserves was as follows:

	Three Months Ended September 30, 2010	2009
	(in thousands)	
Net income attributable to Genesis Energy, L.P.	$ 5,068	$ 4,299
Depreciation and amortization	13,477	15,806
Cash received from direct financing leases not included in income	1,063	951
Unrealized loss on inventory accounting hedges and derivative transactions	2,934	211
Effects of available cash generated by equity method investees not included in income	196	787
Cash effects of equity-based compensation plans	(165)	(77)
Non-cash tax expense	235	(3)
Loss (earnings) of DG Marine in excess of distributable cash	1,686	(1,108)
Non-cash equity-based compensation benefit	4,999	4,454
Other non-cash items, net	(651)	(269)
Maintenance capital expenditures	(716)	(1,336)
Available Cash before Reserves	$ 28,126	$ 23,715

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We have reconciled Available Cash before Reserves (a non-GAAP measure) to cash flow from operating activities (the most comparable GAAP measure) for the three months ended September 30, 2010 and 2009 in Liquidity and Capital Resources – Non-GAAP Reconciliation below. For the three months ended September 30, 2010 and 2009, cash flows provided by operating activities were $23.4 million and $36.8 million, respectively.

Results of Operations

Revenues, Costs and Expenses and Net Income

Our revenues for the three months ended September 30, 2010 increased $173 million, or 43% from the third quarter of 2009. Additionally, our costs and expenses increased $171 million, or 43% between the two periods. The majority of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products. The increase in our revenues and costs between the two third quarter periods is primarily attributable to fluctuations in the volumes of crude oil and petroleum products purchased and sold by our supply and logistics segment. Such volumes increased by 25,704 barrels per day, or 50%, as we increased our activities for petroleum products in response to additional opportunities to acquire volumes.

Net income (attributable to us) increased $0.8 million, or 18%, between the third quarter of 2009 and the same period in 2010. The significant factors affecting net income were improved operating results by most of our business segments as compared to the third quarter of 2009 and a net reduction in our non-cash general and administrative expenses for 2010 resulting from the sale of our general partner (comprised of a decrease in the amount of our non-cash executive compensation and equity-based compensation resulting from our general partner's redemption of certain equity interests, partially offset by other transaction related costs). A more detailed discussion of our segment results and other costs is included below.

Our revenues for the nine months ended September 30, 2010 increased $500 million, or 50% from the nine months ended September 30, 2009. Additionally, our costs and expenses increased $485 million, or 50% between the two periods. This increase in our revenues and costs between the two periods is primarily due to fluctuations in the market prices for crude oil and petroleum products, combined with an increase of 30% in the volumes of these products. In the first nine months of 2010, average closing prices for West Texas Intermediate crude oil on the New York Mercantile Exchange averaged $77.65 per barrel, as compared to $57.00 per barrel in the first nine months of 2009 – an increase of 36%. Net income (attributable to us) increased $12.1 million, or 86%, between the first nine months of 2009 and the same period in 2010, with the majority of this increase attributable to the improved segment results, decreased general and administrative expenses and a decrease in depreciation and amortization expense as discussed below.

Segment Margin

The contribution of each of our segments to total Segment Margin in the three and nine months ended September 30, 2010 and 2009 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Pipeline transportation	$11,920	$10,269	$33,756	$30,841
Refinery services	16,218	12,694	45,668	38,643
Supply and logistics	7,740	9,423	19,473	21,979
Industrial gases	3,495	2,893	8,990	8,785

Total Segment Margin	$39,373	$35,279	$107,887	$100,248

Pipeline Transportation Segment

Operating results for our pipeline transportation segment were as follows:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$5,473	$4,511	$14,885	$12,461
CO2 tariffs and revenues from direct financing leases of CO2 pipelines	6,519	6,361	19,470	19,481
Sales of crude oil pipeline loss allowance volumes	1,372	922	4,244	3,127
Non-income payments under direct financing leases	1,063	951	3,116	2,787
Other miscellaneous revenues	175	171	526	488
Revenues from natural gas tariffs and sales	547	456	2,044	1,727
Natural gas purchases	(490)	(395)	(1,847)	(1,519)
Pipeline operating costs, excluding non-cash charges for our equity-based compensation plans and other non-cash charges	(2,739)	(2,708)	(8,682)	(7,711)
Segment margin	$11,920	$10,269	$33,756	$30,841

Throughput Volumes: Pipeline System	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Mississippi-Bbls/day	23,672	22,643	23,750	24,046
Jay - Bbls/day	16,555	10,550	15,188	9,767
Texas - Bbls/day	31,549	24,593	26,280	26,477
Free State - Mcf/day	158,546	133,038	155,541	146,160

Three Months Ended September 30, 2010 Compared with Three Months Ended September 30, 2009

Pipeline Segment Margin for the third quarter of 2010 increased $1.7 million. The significant components of this change were as follows:

• Crude oil tariffs and revenues from direct financing leases increased $1.0 million. This increase in revenues was a function of volume increases on all three of our pipelines.

– Volumes transported on our Jay crude oil pipeline system increased 6,005 barrels per day. At the end of 2009, a producer connected to our Jay System restarted production from wells that were shut in during the majority of 2009 due to the decline in crude oil prices. Additionally, the Castleberry extension of our Jay System allowed us to access additional production in the area, increasing volumes on the Jay System between the periods.

– Volumes on the Texas System increased 6,956 barrels per day; however, approximately 80% of the volume on that system in the third quarter was shipped on a tariff of $0.31 per barrel.

– Volume fluctuations on the Mississippi System, where the incremental tariff rate is only $0.25 per barrel, are primarily a result of activities of crude oil producers. Volumes on this system increased by 1,029 barrels per day.

• CO2 tariffs and revenues from direct financing leases of CO2 pipelines increased $0.2 million primarily due to increased volumes on the Free State pipeline of 25.5 MMcf per day.

- An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $0.5 million. Pipeline allowance volumes increased 1,589 barrels. Higher market prices for crude oil increased the value of our pipeline loss allowance volumes and, accordingly, our loss allowance revenues. Average crude oil prices increased approximately $7.90, or 12%, between the two quarterly periods.

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Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

Pipeline Segment Margin increased $2.9 million between the nine month periods, with $2.4 million of the change due to increased crude oil tariff revenues. Sales of pipeline loss allowance volumes added to Segment Margin, but were largely offset by an increase in operating costs. The significant components of this change were as follows:

- Volumes on the Jay System increased 5,421 barrels per day due to restarted production from wells that had been shut in for most of 2009 as well as the addition of volumes we are able to access with the Castleberry extension to the Jay System. Volumes on the Texas and Mississippi Systems declined between the periods in large part to maintenance in the first quarter of 2010 on the Texas System.

- Tariff rate increases of approximately 7.6% on our Jay and Mississippi pipelines went into effect July 1, 2009. Tariff rate decreases of approximately 1.3% on our Jay and Mississippi pipelines went into effect July 1, 2010. Segment Margin increased by a net of approximately $0.5 million between the two periods as a result of these rate changes.

- An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $1.1 million related to the significant increase (an average of $21 per barrel) in crude oil prices which more than offset the decrease in pipeline loss allowance volumes of approximately 3,615 barrels.

- Pipeline operating costs increased $1.0 million largely due to an increase in pipeline integrity tests and other maintenance costs. In the first quarter of 2010 pipeline integrity tests on a segment of our Texas System cost approximately $0.6 million.

Refinery Services Segment

Operating results for our refinery services segment were as follows:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Volumes sold:				
NaHS volumes (Dry short tons "DST")	35,415	28,207	106,829	75,344
NaOH (caustic soda) volumes (DST)	21,442	26,898	66,778	63,561
Total	56,857	55,105	173,607	138,905
Revenues (in thousands):				
NaHS revenues	$30,498	$22,654	$85,270	$74,754
NaOH (caustic soda) revenues	7,586	6,455	19,198	33,534
Other revenues	2,162	2,256	7,496	8,905
Total external segment revenues	$40,246	$31,365	$111,964	$117,193
Segment margin	$16,218	$12,694	$45,668	$38,643
Average index price for caustic soda per DST (1)	$378	$198	$329	$493
Raw material and processing costs as % of segment revenues	38 %	33 %	34 %	47 %
Delivery costs as a % of segment revenues	14 %	14 %	16 %	11 %

(1) Source: Harriman Chemsult Ltd.

Three Months Ended September 30, 2010 Compared with Three Months Ended September 30, 2009

Refinery services Segment Margin for the third quarter of 2010 was $16.2 million, an increase of $3.5 million, or 28%, from the comparative period in 2009. The significant components of this fluctuation were as follows:

- An increase in NaHS sales volumes of 26%. As the world economies, particularly outside of the United States and European Union, are recovering from the depths of the greatest recession in the last 70 years, the demand for base metals such as copper and molybdenum has increased dramatically over the prior period. As a result, we have experienced a noticeable increase in the demand for NaHS from our mining customers in North and South America. Additionally, with the return of industrialization and urbanization in the world's more underdeveloped economies, the demand for paper products and packaging materials has increased dramatically. This trend has led to an increase in demand for NaHS from our pulp/paper customers primarily in North America. The pricing in the majority of our sales contracts for NaHS includes an adjustment for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments can be applied varies by geographic region and supply point.

- A decrease in caustic soda sales volumes of 20%. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. We are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively market caustic soda to third parties. Fluctuations in volumes sold are affected by the demand we have in our operations that consume caustic soda.

- Index prices for caustic soda averaged approximately $198 per DST in the third quarter of 2009. Market prices of caustic soda increased to an average of approximately $378 per DST during the third quarter of 2010. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, changes in caustic soda prices generally do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers. The increase in caustic soda prices did, however, increase our revenues from sales of caustic soda by 18% despite the decrease in caustic soda sales volumes.

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Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

Segment margin for our refinery services increased $7.0 million for similar reasons to the quarterly comparison.

- NaHS volumes increased 42% as a result of increased demand from mining companies and other industrial customers. As discussed above, increases in demand for base metals and paper products in the global economy have positively impacted demand for NaHS in North and South America. The average sales price of NaHS declined by 20% even though we experienced increases in some commodity components and contractual price inflators, which were more than offset by the declines in other costs. The related revenue increase was only 14% due to the effects of the pass-through of fluctuations in commodity benchmarks and transportation.

- Caustic soda sales volumes increased 5%, although revenues decreased 43% because the market prices for caustic soda decreased from an average of $493 per DST in the first nine months of 2009 to an average of $329 per DST in the first nine months of 2010.

- Delivery logistics costs were higher. Although our logistics costs per unit increased only modestly, our logistics costs expressed as a percentage of revenues increased by 5% (to 16%) primarily because our sales price per unit, along with our cost per unit, dropped precipitously. Quantities delivered to customers also increased. Freight demand and fuel prices increased modestly in the 2010 period as economic conditions improved, increasing demand for transportation services and the increase in crude oil prices increased the cost of fuel used in transporting these products.

Supply and Logistics Segment

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Supply and logistics revenue	$518,809	$356,450	$1,339,769	$836,876
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(490,358)	(323,951)	(1,251,777)	(753,217)
Operating and segment general and administrative costs, excluding non-cash charges for stock-based compensation and other non-cash expenses	(20,711)	(23,076)	(68,519)	(61,680)
Segment margin	$7,740	$9,423	$19,473	$21,979
Volumes of crude oil and petroleum products-average barrels per day	76,964	51,260	61,605	47,280

Three Months Ended September 30, 2010 Compared with Three Months Ended September 30, 2009

The average market prices of crude oil and petroleum products increased by approximately $8 per barrel, or 12%, between the two quarterly periods; however, that price variance had a limited impact on our supply and logistics Segment Margin. More significant factors for us are discussed below.

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The key factors affecting the two quarters were as follows:

- Fluctuations in the effects of quality differentials on pricing of petroleum products limited the contribution to Segment Margin while the effects on pricing of quality differentials for different grades of crude oil improved Segment Margin.

- We acquired, stored and sold-forward fewer barrels of crude oil as the effects of the contango market on crude oil prices narrowed in the third quarter of 2010 as compared to the prior year period.

- Increased opportunities to handle the heavy-end petroleum products due to increased access to transportation services (including DG Marine) and storage facilities partially offset the impact of fluctuations in differentials.

Our petroleum products activities involve handling volumes from the heavy end of the refined barrel. Despite increased volumes from our petroleum products activities, fluctuations in quality differentials resulted in a decrease of approximately $2.1 million in the contribution of petroleum products activities to Segment Margin.

Beginning late in 2008 and throughout most of 2009, the crude oil market was in wide contango. When crude oil markets are in contango, oil prices for future deliveries are higher than for current deliveries, providing an opportunity for us to purchase crude oil at current market prices, re-sell it through futures contracts at future prices, and store it as inventory until delivery. In the third quarter of 2009, we took advantage of contango conditions, holding an average of 220,000 barrels of crude oil in storage throughout the quarter. In 2010, contango market conditions had narrowed and we reduced the volumes of crude oil stored to take advantage of the contango conditions to an average of 170,000 barrels of crude oil throughout the quarter. Offsetting the reduced contribution from contango conditions was increased margins in our gathering activities. Fluctuations in price differentials between different grades of crude oil, which we refer to as quality differentials, increased margins on our gathering activities. As a result, margins from crude oil gathering and marketing activities increased approximately $0.5 million.

Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

For the nine month periods, the improvements in our heavy end petroleum products opportunities only partially offset the impacts of the narrowing in contango pricing and differentials in the crude oil markets. Segment Margin between the two periods declined $2.5 million. The key factors affecting the two nine-month periods were as follows:

- The effects on crude oil prices of quality differentials and the contango price market narrowed beginning late in the fourth quarter of 2009 and extended through most of the third quarter of 2010 decreasing the effects on contribution to Segment Margin of our crude oil activities by $2.2 million.

- Many of DG Marine’s inland marine tows were under term charter agreements during part of the first six months of 2009. As those agreements expired in the late spring and summer of 2009, tows have been operated under spot arrangements at lower average charter rates. Charter rates have improved in the first nine months of 2010; however, the differences as compared to the first nine months of 2009 resulted in a decline in Segment Margin of $0.5 million.

- Increased opportunities to handle the heavy end petroleum products due to increased access to transportation services (including those of DG Marine) and storage facilities in 2010 increased segment margin $0.2 million, partially offsetting the affects of the two factors above.

Industrial Gases Segment

Operating results from our industrial gases segment were as follows:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Revenues from CO2 marketing	$4,679	$4,512	$11,982	$12,032
CO2 transportation and other costs	(1,757)	(1,619)	(4,589)	(4,298)
Available cash generated by equity investees	573	-	1,597	1,051
Segment margin	$3,495	$2,893	$8,990	$8,785
Volumes per day:				
CO2 marketing - Mcf	86,534	80,520	74,341	73,697

Three Months Ended September 30, 2010 Compared with Three Months Ended September 30, 2009

Segment Margin from the industrial gases segment increased between the quarterly periods primarily due to an increase in volumes delivered to our customers. Volumes increased 7% between the two quarterly periods as customers increased purchases in response to improving economic conditions. The average sales price of CO2 per Mcf decreased $0.02, or 4% between the quarters.

Our industrial gases segment experienced increased costs due to inflationary adjustments to the rates we are charged to transport CO2 to our customers. Average transportation rates increased by 2.0% over the average rates in the 2009 third quarter.

Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

The increase in Segment Margin between the two nine-month periods was the result of increased available cash generated by equity investees offset by an increase in average CO2 transportation rates of 6%.

Other Costs, Interest, and Income Taxes
General and administrative expenses.

General and administrative expenses consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
General and administrative expenses not separately identified below	$5,355	$4,901	$15,391	$14,996
Expenses related to change in owner of our general partner	-	-	1,762	-
Bonus plan expense	1,400	1,517	3,706	3,151
Equity-based compensation plan expense	863	622	1,530	1,454
Non-cash compensation expense related to management team	2,965	3,088	1,289	7,587
Total general and administrative expenses	$10,583	$10,128	$23,678	$27,188

Comparing the three-month and nine-month periods, the primary factor driving the decrease in general and administrative expenses was the change in non-cash compensation expense related to our management team. On

December 31, 2008, our general partner and members of our management team entered into an equity-based compensation arrangement whereby our management team could earn an interest in distributions attributable to our incentive distribution rights owned by our general partner. While the former owner of our general partner was responsible for the cash cost of this compensation with our management team, we recorded the expense of those arrangements with an offsetting non-cash capital contribution by our general partner. On February 5, 2010, as a result of the sale of our general partner, that equity-based compensation arrangement was settled. In the first quarter of 2010, we recorded a credit of $2.0 million to general and administrative expense related to the difference in the ultimate settlement value of $14.9 million and the amounts that were previously charged to expense related to this arrangement. In the three and nine month periods of 2009, we recorded expenses of $3.1 million and $7.6 million, respectively, related to these non-cash compensation arrangements with our management team. See Note 9 to our Unaudited Condensed Consolidated Financial Statements.

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Partially offsetting the reduction from those compensation arrangements between the nine-month periods were $1.8 million of expenses we incurred related to the sale of our general partner, including costs related to a public offering of the common units initially retained by the former owner of our general partner and severance arrangements for an executive officer. Additionally, affecting Available Cash before Reserves, but not net income, was an increase of approximately $0.7 million in exercises of stock appreciation rights.

Depreciation and amortization expense. Depreciation and amortization expense decreased $2.3 million and $6.9 million between the three and nine month periods, respectively, as a result of the lower amortization expense recognized on intangible assets. We amortize our intangible assets over the period during which we expect them to contribute to our future cash flows. The amortization we record on those assets is greater in the initial years following their acquisition because the value of our intangible assets such as customer relationships and trade names are generally more valuable in the first years after an acquisition. Accordingly, the amount of amortization we have recorded has declined since we acquired those assets in 2007.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Interest expense, including commitment fees, excluding DG Marine	$3,563	$2,018	$7,561	$5,799
Amortization of facility fees, excluding DG Marine facility	435	167	763	495
Write-off of facility fees, excluding DG Marine	-	-	402	-
Interest expense and commitment fees-DG Marine	238	1,254	2,512	3,699
Interest rate swaps settlement - DG Marine	1,553	-	1,553	-
Write-off of facility fees - DG Marine	794	-	794	-
Capitalized interest	(30)	(3)	(39)	(112)
Interest income	(11)	(18)	(40)	(55)
Net interest expense	$6,542	$3,418	$13,506	$9,826

Our interest expense (excluding interest on DG Marine's stand-alone facility) increased as the average debt balance quarter to quarter increased $64.1 million and the average interest rate for borrowed funds increased approximately 1.2% over the same periods. For the nine-month periods, our average outstanding debt balance was $22.7 million higher in 2010 than 2009. The increase in the debt balance is attributable primarily to the acquisition of the 51% of DG Marine we did not own and the elimination of the DG Marine credit facility with borrowings under our credit facility.

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

Income tax expense. Income tax expense relates to corporate-level income tax accruals (accrued by the Partnership) and Texas Margin Tax on our operations in Texas. As the majority of our operations are not conducted by corporations, income tax expense is not expected to be significant.

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Liquidity and Capital Resources

Capital Resources/Sources of Cash

Recent market trends have indicated improvements in bank lending capacity and long-term interest rates from the situation in early 2009. 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 cash on hand, may allow us to take advantage of other attractive acquisition and/or growth opportunities that develop.

We continue to pursue a growth strategy that requires significant capital. As discussed above in the Overview, we have entered into an agreement to acquire a 50% interest in Cameron Highway for $330 million. We expect to fund this acquisition with some combination of equity and debt; however, to protect against the possibility of a rapid deterioration in the capital markets, we entered into an agreement with a group of banks to provide up to $300 million of unsecured financing. This unsecured facility allows for borrowings through December 31, 2011.

We expect our short-term and long-term capital resources to include equity and debt offerings (public and private), revolving and term credit facilities 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.

In 2010 alone, we have entered into two acquisition agreements (DG Marine and Cameron Highway), amended and extended our credit facility and completed a secondary equity offering of our common units for the former owner of our general partner and a significant unitholder.

On June 29, 2010, we restructured our credit facility – which we entered into in November 2006 and which was to mature in November 2011 – to reflect and better accommodate our larger and more diversified operations and resulting credit metrics. Our restructured credit facility is a $525 million senior secured revolving credit facility maturing on June 30, 2015. It includes an accordion feature whereby the total credit available can be increased up to $650 million for acquisitions or internal growth projects, with lender approval. Among other modifications, our credit facility also includes a $75 million inventory sublimit tranche. This inventory tranche is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Additionally, our restructured credit facility does not include a “borrowing base” limitation except with respect to our inventory loans. Eleven lenders participate in our credit facility, and we do not anticipate any of them being unable to satisfy their obligations under the credit facility. Additional information on our restructured credit facility is included in Note 5 to the Unaudited Condensed Consolidated Financial Statements.

While our new credit facility provides additional flexibility and committed borrowing capacity, our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital, to utilize our credit facility and to implement our growth strategy successfully. No assurance can be made that we will be able to raise the necessary funds on satisfactory terms. If we are unable to raise the necessary funds, we may be required to defer our growth plans until such time as funds become available.

We continue to monitor the credit markets and the economic outlook to determine the extent of the impact on our business environment. While we have experienced increases in demand for NaHS in 2010 resulting primarily from increased mining activities associated with increases in commodity prices for copper and molybdenum, we continue to experience lower demand for crude oil and petroleum products, primarily due to low utilization rates at refineries. We continue to adjust to the effects of these macroeconomic factors in our operating levels and financial decisions.

On July 29, 2010, in connection with our acquisition of the 51% interest of DG Marine that we did not own, we paid off DG Marine's stand-alone credit facility, which had an outstanding principal balance of $44.4 million, with proceeds from our credit agreement. See Note 2 to our Unaudited Condensed Consolidated Financial Statements and our Current Report on Form 8-K filed August 3, 2010.

Uses of Cash

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

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

Debt and Other Financing Activities. Our sources of cash are primarily from funds from operations and our credit facilities. Our net borrowings under our credit facility and the DG Marine credit facility totaled $59.1 million during the first nine months of 2010, which related partially to the acquisition of the 51% interest of DG Marine that we did not own. The remainder of these borrowings related primarily to increases in petroleum products inventory levels to take advantage of blending and storage opportunities, the investment in fixed and intangible assets, and the payment of liabilities accrued at the 2009 year end for such items as annual bonus payments and property tax obligations. We paid distributions totaling $51.6 million to our limited partners and our general partner during the first nine months of 2010. For a more detailed analysis of our recent distributions, see Note 6 to our Unaudited Condensed Consolidated Financial Statements.

Investing. We utilized cash flows for capital expenditures. The most significant investing activities in the first nine months of 2010 were expenditures related to our project to upgrade our information technology systems discussed below.

Capital Expenditures, and Business and Asset Acquisitions

A summary of our expenditures for fixed assets and other asset acquisitions for the nine months ended September 30, 2010 and 2009 is as follows:

	Nine Months Ended September 30,	
	2010	2009
	(in thousands)	
Capital expenditures for fixed and intangible assets:		
Maintenance capital expenditures:		
Pipeline transportation assets	295	1,201
Supply and logistics assets	766	1,269
Refinery services assets	1,169	704
Administrative and other assets	29	584
Total maintenance capital expenditures	2,259	3,758
Growth capital expenditures:		
Pipeline transportation assets	263	1,762
Supply and logistics assets	421	17,920
Refinery services assets	-	1,326
Information technology systems upgrade project	7,362	-
Total growth capital expenditures	8,046	21,008
Total	10,305	24,766
Capital expenditures for asset purchases:		
Acquisition of intangible assets	-	2,500
Total asset purchases	-	2,500
Capital expenditures attributable to unconsolidated affiliates	-	83

Total	-	83
Total capital expenditures	$10,305	$27,349

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During the remainder of 2010, we expect to expend approximately $0.5 million for maintenance capital projects in progress or planned. We also plan to spend approximately an additional $3.0 million in capital costs to integrate and upgrade our information technology systems to be positioned for further growth, which we will fund with borrowings under our credit facility.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital discussed above in Liquidity and Capital Resources – Capital Resources/Sources of Cash. As discussed above, we expect to close a transaction before the end of the year to acquire a 50% interest in Cameron Highway for $330 million.

Possible Partnership Simplification or IDR Restructuring Transaction

Our senior management has continuously evaluated strategic alternatives in an effort to enhance unitholder value. Among other things, senior management has focused on improving our competitive position and enhancing our long-term growth prospects by reducing our equity cost of capital, the impact of which it believes would benefit the holders of the Partnership's common units. Senior management believes that our cost of capital potentially has (and will continue to) become high in comparison to a number of publicly-traded limited partnerships, or MLPs, in our peer group. Our cost of issuing new units to facilitate the continuing growth of the Partnership includes not only the distributions payable to such new unitholders, but also the percent of our aggregate quarterly distributions we pay to our general partner in respect of our general partner interest (2%) and incentive distribution rights (currently, approximately 49%), or IDRs.

Senior management's focus on reducing our cost of equity capital became more acute after several other midstream MLPs, including Penn Virginia Resource Partners, L.P., Enterprise Product Partners, L.P., Inergy, L.P., Buckeye Partners, L.P., Sunoco Logistics Partners L.P., NuStar Energy L.P., Magellan Midstream Partners, L.P., Eagle Rock Energy Partners, L.P. and MarkWest Energy Partners, L.P., acted or proposed to reduce their cost of equity capital through restructuring their general partners and their attendant IDRs by, generally speaking, resetting, capping, repurchasing or eliminating them. Senior management believes, if we could economically restructure or eliminate our IDRs, we would be more competitive when pursuing acquisitions and able to finance organic growth projects less expensively, which would enhance our long-term distribution growth prospects to the holders of the Partnership's common units. Senior management also believes such a transaction would further align the interests of our general partner with those of our limited partners. Thus, senior management suggested to our general partner's Board that it should consider a partnership simplification or other restructuring transaction.

Our general partner's Board of Directors has authorized us to analyze alternative restructuring transactions, and it granted our Conflicts Committee the authority to analyze, negotiate, and consider for "Special Approval" (as defined in our partnership agreement) and recommendation to the Board such a restructuring. In September, we engaged a financial advisor to assist us, and in October our Conflicts Committee engaged legal and financial advisors to assist it in its Special Approval process.

Senior management believes that, under the right circumstances, the most desirable restructuring transaction would be to alleviate the burden to our equity cost of capital through the complete elimination (in one form or another) of our IDRs. It is impossible, at this time, to determine (i) whether or not we will consummate any form of a restructuring transaction, or (ii) if we were to consummate a restructuring transaction, when such transaction would be consummated and what terms such a transaction would include, such as (a) whether we would reset, cap, repurchase or eliminate our IDRs; (b) whether the consideration therefore would be in the form of common units, other equity, debt, cash, other consideration or any combination thereof; and (c) what other terms might be required.

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.

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Available Cash before Reserves, also referred to as distributable cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures, or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest costs 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 is the quantitative metric used by many in the investment community with respect to publicly-traded partnerships.

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

	Three Months Ended September 30,	
	2010	2009
	(in thousands)	
Cash flows from operating activities	$ 23,361	$ 36,765
Adjustments to reconcile operating cash flows to		
Available Cash:		
Maintenance capital expenditures	(716)	(1,336)
Amortization and write-off of credit facility issuance fees	(1,229)	(487)
Effects of available cash generated by equity method investees not included in cash flows from operating activities	201	-
Loss (earnings) of DG Marine in excess of distributable cash	1,686	(1,108)
Other items affecting available cash	264	(622)
Net effect of changes in operating accounts not included in calculation of Available Cash	4,559	(9,497)
Available Cash before Reserves	$ 28,126	$ 23,715

Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Commercial Commitments

The following table reflects our obligations and commitments at September 30, 2010:

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Commercial Cash Obligations and Commitments	Payments Due by Period Less than one year	1 - 3 years	3 - 5 Years	More than 5 years	Total
Contractual Obligations:					
Long-term debt (1)	$-	$-	$426,000	$-	$426,000
Estimated interest payable on long-term debt (2)	12,780	25,560	22,365	-	60,705
Operating lease obligations	8,014	11,503	6,623	23,791	49,931
Unconditional purchase obligations (3)	92,112	-	-	-	92,112
Other Cash Commitments:					
Asset retirement obligations (4)	-	-	-	13,777	13,777
Liabilities associated with unrecognized tax benefits and associated interest (5)	5,757	-	-	-	5,757
Total	$118,663	$37,063	$454,988	$37,568	$648,282

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of June 30, 2015.

(2) Interest on our long-term debt is at market-based rates. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at September 30, 2010 remained outstanding through the final maturity dates of June 30, 2015 and interest rates remained at the September 30, 2010 market levels through the final maturity dates.

(3) Unconditional purchase obligations include agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at September 30, 2010, were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.

(4) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $5.8 million.

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

We have guaranteed 50% of the $2.3 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under “Contractual Obligations and Commercial Commitments” in our Annual Report on Form 10-K for the year ended December 31, 2009, nor do we have any debt or equity triggers based upon our unit or commodity prices.

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,””goal”, “intend,” “may,” “could,” “plan,” “position,” “projection,” “strategy,” “sh negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include, among others:

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- demand for, the supply of, our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or “NGLs”, NaHS, caustic soda and $CO2$ all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and consummate strategic acquisitions on acceptable terms, develop or construct energy infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- our ability to make cash distributions on our units;
- service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;
- shut downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;
- risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;
- legislative or regulatory changes, such as changes in the Jones Act or changes in environmental regulation, environmental risks, regulations by FERC and liability under federal and state environmental laws and regulations;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result our credit agreement which contains various affirmative and negative covenants;
- loss of key personnel;
- the impact of new pipelines and other effects of competition from gatherers, transporters, marketers, brokers and other aggregators;
- cost and availability of insurance coverage;
- hazards and operating risks that may not be covered fully by insurance;
- our financial and commodity hedging arrangements;
- the volatility or disruption in the capital or financial markets in the United States;
- natural disasters, accidents or terrorism;
- loss, bankruptcy, credit risk or concentration 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 fluctuations in 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, 2009 and any other risk factors contained in our Current Reports on Form 8-K that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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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 2009 Annual Report on Form 10-K. There has been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures provided therein. Also, see Note 11 to our Unaudited Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

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.

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, 2009. 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, 2009. On August 3, 2010, we filed a Current Report on Form 8-K that covered several items, including our acquisition of the remaining interest in DG Marine. That Current Report on Form 8-K included some additional risk factors. There have been no material changes to the risk factors since the filing of such Form 10-K and/or that Current Report on Form 8-K.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. [Removed and Reserved]

Item 5. Other Information.

None.

Item 6. Exhibits

(a) Exhibits.

2.1		Contribution and Sale Agreement, dated July 28, 2010, by and between TD Marine, LLC and Genesis (incorporated by reference to Exhibit 2.1 to Form 8-K dated August 3, 2010, File No. 001-12295)
2.2	*	Purchase and Sale Agreement (the "Purchase Agreement") by and between Valero Energy Corporation, Valero Services, Inc., Valero Unit Investments, L.L.C., Genesis Energy, L.P., Genesis CHOPS I, LLC, and Genesis CHOPS II, LLC

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3.1		Certificate of Limited Partnership of Genesis Energy, L.P. ("Genesis") (incorporated by reference to Exhibit 3.1 to Amendment No. 2 to Registration Statement on Form S-1, 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, File No. 001-12295)
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, File No. 001-12295)
3.4		Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 10.2 to Form 8-K dated March 5, 2010, File No. 001-12295)
3.5		Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009, File No. 001-12295)
3.6		Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009, File No. 001-12295)
3.7		Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated February 5, 2010 (incorporated by reference to Exhibit 3.1 to Form 8-K dated February 11, 2010, File No. 001-12295)
3.8		Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated June 11, 2010 (incorporated by reference to Exhibit 3.10 to Form 10-Q for the quarterly period ended June 30, 2010, File No. 001-12295)
3.91		Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated July 28, 2010 (incorporated by reference to Exhibit 3.10 to Form 10-Q for the quarterly period ended June 30, 2010, File No. 001-12295)
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, File No. 001-12295)
10.1		Second Amended and Restated Credit Agreement, dated as of June 29, 2010, among Genesis as borrower, BNP Paribas as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 2, 2010, File No. 001-12295)
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
99.1	**	List of exhibits and schedules to the Purchase Agreement.

*Filed herewith

** A list of all exhibits and schedules are included under Exhibit 99.1. Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of such omitted exhibit or schedule to the SEC upon request.

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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: November 3, 2010	By:	/s/ Robert V. Deere Robert V. Deere Chief Financial Officer