GENESIS ENERGY LP
Form 10-Q
May 09, 2007

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 March 31, 2007

OR

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

Commission file number 1-12295

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

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

Securities registered pursuant to Section 12(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 _ü_ No ___

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

Large accelerated filer_____ Accelerated filer _ü_ Non-accelerated filer_____

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

Yes __ No _ü_

Indicate number of outstanding shares of each of the issuer's classes of common stock, as of the latest practicable date. Common units outstanding as of May 8, 2007: 13,784,441.

This report contains 37 pages

GENESIS ENERGY, L.P.

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PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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

	March 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,920	$ 2,318
Accounts receivable:		
Trade	86,935	88,006
Related Party	1,069	1,100
Inventories	8,759	5,172
Net investment in direct financing leases, net of unearned income - current portion - related party	578	568
Other	2,020	2,828
Total current assets	102,281	99,992
FIXED ASSETS, at cost	70,697	70,382
Less: Accumulated depreciation	(39,984)	(39,066)
Net fixed assets	30,713	31,316
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income - related party	5,225	5,373
CO_2 ASSETS, net of amortization	32,434	33,404
JOINT VENTURES AND OTHER INVESTMENTS	17,853	18,226
OTHER ASSETS, net of amortization	3,223	2,776
TOTAL ASSETS	$ 191,729	$ 191,087
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 86,747	$ 85,063
Related party	1,188	1,629
Accrued liabilities	7,800	9,220
Total current liabilities	95,735	95,912
LONG-TERM DEBT	10,200	8,000
OTHER LONG-TERM LIABILITIES	979	991
COMMITMENTS AND CONTINGENCIES (Note 11)		
MINORITY INTERESTS	522	522
PARTNERS' CAPITAL:		
Common unitholders, 13,784 units issued and outstanding	82,542	83,884
General partner	1,751	1,778
Total partners' capital	84,293	85,662

TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	191,729	$	191,087

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

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

	Three Months Ended March 31, 2007	2006
REVENUES:		
Crude oil gathering and marketing:		
Unrelated parties (including revenues from buy/sell arrangements of $69,772 in 2006)	$ 172,843	$ 252,261
Related parties	436	184
Pipeline transportation, including natural gas sales:		
Unrelated parties	5,447	6,590
Related parties	1,341	1,180
CO_2 marketing revenues:		
Unrelated parties	2,867	3,387
Related parties	630	-
Total revenues	183,564	263,602
COSTS AND EXPENSES:		
Crude oil costs:		
Unrelated parties (including costs from buy/sell arrangements of $68,899 in 2006)	167,711	245,912
Related parties	11	1,460
Field operating costs	3,958	3,345
Pipeline transportation costs:		
Pipeline operating costs	2,685	2,269
Natural gas purchases	1,235	2,699
CO_2 marketing costs:		
Transportation costs - related party	1,098	1,021
Other costs	46	52
General and administrative	3,328	2,660
Depreciation and amortization	1,928	1,864
Net gain on disposal of surplus assets	(16)	(50)
Total costs and expenses	181,984	261,232
OPERATING INCOME	1,580	2,370
OTHER INCOME (EXPENSE):		
Equity in earnings of joint ventures	261	313
Interest income	44	78
Interest expense	(270)	(200)
Income tax expense	(30)	-
Income before cmulative effect adjustment	1,585	2,561
Cumulative effect adjustment of adoption of new accounting principle	-	30
NET INCOME	$ 1,585	$ 2,591

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

	Three Months Ended March 31, 2007	2006
NET INCOME PER COMMON UNIT - BASIC AND DILUTED:		
Income before cumulative effect adjustment	$ 0.11	$ 0.18
Cumulative effect adjustment	-	-
NET INCOME	$ 0.11	$ 0.18
Weighted average number of common units outstanding	13,784	13,784

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

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

	Number of Common Units	Partners' Capital Common Unitholders	General Partner	Total
Partners' capital, January 1, 2007	13,784	$ 83,884	$ 1,778	$ 85,662
Net income	-	1,553	32	1,585
Cash distributions	-	(2,895)	(59)	(2,954)
Partners' capital, March 31, 2007	13,784	$ 82,542	$ 1,751	$ 84,293

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

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

	Three Months Ended March 31, 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 1,585	$ 2,591
Adjustments to reconcile net income to net cash provided by operating activities -		
Depreciation	958	909
Amortization of CO_2 contracts	970	955
Amortization of credit facility issuance costs	136	92
Amortization of unearned income on direct financing leases	(159)	(168)
Payments received under direct financing leases	297	297
Equity in earnings of investments in joint ventures	(261)	(313)
Distributions from joint ventures - return on investment	424	235
Gain on disposal of assets	(16)	(50)
Cumulative effect adjustment	-	(30)
Other non-cash charges	387	401
Changes in components of working capital -		
Accounts receivable	1,102	(4,334)
Inventories	(3,562)	(6,901)
Other current assets	808	354
Accounts payable	878	4,666
Accrued liabilities	(1,810)	(1,001)
Net cash provided by (used in) operating activities	1,737	(2,297)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to property and equipment	(365)	(163)
Distributions from joint ventures - return of investment	227	-
Proceeds from disposal of assets	16	67
Other, net	(90)	(32)
Net cash used in investing activities	(212)	(128)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings, net	2,200	2,600
Other, net	(169)	(501)
Distributions to common unitholders	(2,895)	(2,343)
Distributions to general partner	(59)	(48)
Net cash used in financing activities	(923)	(292)
Net increase (decrease) in cash and cash equivalents	602	(2,717)
Cash and cash equivalents at beginning of period	2,318	3,099
Cash and cash equivalents at end of period	$ 2,920	$ 382

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

1. Organization and Basis of Presentation

Organization

We are a publicly traded Delaware limited partnership formed in December 1996. Our operations are conducted through our operating subsidiary, Genesis Crude Oil, L.P., and its subsidiary partnerships. We are engaged in pipeline transportation of crude oil, and, to a lesser degree, natural gas and carbon dioxide (CO_2), crude oil gathering and marketing, and industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture. Our assets are located in the United States Gulf Coast area.

Our 2% general partner interest is held by Genesis Energy, Inc., a Delaware corporation and an indirect, wholly-owned subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner also owns 7.4% of our outstanding common units and all of our incentive distribution rights. See Note 5.

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 Consolidation and Presentation

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

In 2005, we acquired a 50% interest in T&P Syngas Supply Company. In 2006, we acquired a 50% interest in Sandhill Group, LLC. These investments are accounted for by the equity method, as we exercise significant influence over their operating and financial policies. See Note 3.

No provision for federal income taxes related to our operations is included in the accompanying consolidated financial statements; as such income will be taxable directly to the partners holding partnership interests. In May 2006, the State of Texas enacted a law which will require us to pay a tax of 0.5% on our "margin," as defined in the law, beginning in 2008 based on our 2007 results. The "margin" to which the tax rate will be applied generally will be calculated as our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax) purposes, in the State of Texas. See Note 13.

2. New and Recently Adopted Accounting Pronouncements

FASB Interpretation No. 48

In July 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109", or FIN 48, which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for us beginning January 1, 2007. The adoption of FIN 48 had no impact on our results of operations or financial position.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements", or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. SFAS 157 may impact our balance sheet and statement of operations in many areas including the fair value measurement and allocation of the purchase price in business combinations and the fair value measurements for derivative instruments, impairment of assets, and asset retirement obligations. We are currently assessing the impact of SFAS 157 on our consolidated financial statements.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities", or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

EITF 04-13

We enter into buy/sell arrangements that are accounted for on a gross basis in our statements of operations as revenues and costs of crude. These transactions are contractual arrangements that establish the terms of the purchase of a particular grade of crude oil at a specified location and the sale of a particular grade of crude oil at a different location at the same or at another specified date. These arrangements are detailed either jointly, in a single contract, or separately, in individual contracts that are entered into concurrently or in contemplation of one another with a single counterparty. Both transactions require physical delivery of the crude oil and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk. In accordance with the provision of Emerging Issues Task Force Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," we started reflecting these amounts of revenues and purchases as a net amount in our consolidated statements of operations beginning in the second quarter of 2006. Had this provision been in effect in the first quarter of 2006, our reported crude oil gathering and marketing revenues from unrelated parties for the three months ended March 31, 2006 would have been reduced by $70 million to $182 million. Our reported crude oil costs from unrelated parties for the three months ended March 31, 2006, would have been reduced by $69 million to $177 million. This change had no effect on operating income, net income or cash flows.

3. Joint Ventures and Other Investments

T&P Syngas Supply Company

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

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in T&P Syngas' net income, net of the amortization of the excess of our investment over our share of partners' capital of T&P Syngas. We paid $4.0 million more for our interest in T&P Syngas than our share of partners' capital on the balance sheet of T&P Syngas at the date of the acquisition. This excess amount of the purchase price over the equity in T&P Syngas is being amortized using the straight-line method over the remaining useful life of the assets of T&P Syngas of eleven years. Our consolidated statements of operations for the three months ended March 31, 2007 and 2006 included $409,000 and $401,000, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $88,000 and $88,000, respectively. We received distributions from T&P Syngas of $0.6 million during the three months ended March 31, 2007.

The tables below reflect summarized financial information for T&P Syngas (in thousands).

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Revenues	$ 1,254	$ 1,246
Operating expenses and depreciation	(432)	(447)
Other income (expense)	(4)	3
Net income	$ 818	$ 802

	March 31, 2007	December 31, 2006
Current assets	$ 1,356	$ 1,355
Non-current assets	15,128	15,387
Total assets	$ 16,484	$ 16,742
Current liabilities	$ 258	$ 156
Non-current liabilties	169	165
Partners' capital	16,057	16,421
Total liabilites and partners' capital	$ 16,484	$ 16,742

Sandhill Group, LLC

On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC. Magna Carta holds the other 50% interest in Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

We are accounting for our 50% ownership in Sandhill under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in Sandhill’s net income, net of the amortization of the excess of our investment over our share of partners’ capital of Sandhill that is not considered goodwill.

Our consolidated statements of operations for the three months ended March 31, 2007 included $9,000 as our share of the operating earnings of Sandhill for the period beginning April 1, 2006, reduced by amortization of the excess purchase price of $69,000. We received distributions from Sandhill of $60,000 during the three months ended March 31, 2007.

The tables below reflect summarized financial information for Sandhill (in thousands).

		Three Months Ended March 31, 2007
Revenues	$	2,448
Operating expenses and depreciation		(2,429)
Other income		1
Net income	$	20

		March 31, 2007		December 31, 2006
Current assets	$	1,365	$	1,606
Non-current assets		6,438		6,592
Total assets	$	7,803	$	8,198
Current liabilities	$	825	$	1,463
Non-current liabilties		4,483		4,140
Members' interests		2,495		2,595
Total liabilites and members' interests	$	7,803	$	8,198

The terms of the acquisition of Sandhill include earnout provisions such that we could pay up to an additional $2 million to Magna Carta for our interest in Sandhill, based on the distributable cash generated by Sandhill during the period 2006 through no later than 2012.

We effectively guaranty our proportionate share (50%) of Sandhill's outstanding bank debt, which was $4.5 million ($2.25 million net to us) at March 31, 2007. Sandhill makes principal payments totaling $0.6 million annually on that debt.

Other Projects

In 2006, we invested $1.0 million in a petroleum coke to ammonia project that is in the development stage. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained.

The funds we have invested will be used for project development activities, which include the negotiation of off-take agreements for the products and by-products of the plant to be constructed, securing permits and securing financing for the construction phase of the plant.

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

4. Debt

Our credit facility, with a maximum facility amount of $500 million, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The initial committed amount under our facility is $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at March 31, 2007 is approximately $79 million, and will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA (earnings before interest, taxes, depreciation and amortization), computed in accordance with the provisions of our credit facility. The commitment amount can be increased up to the maximum facility amount for acquisitions or internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of pro forma additional EBITDA attributable to acquisitions with approval of the lenders.

At March 31, 2007, we had $10.2 million borrowed under our credit facility. We had $3.6 million in letters of credit outstanding. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of November 15, 2011. The total amount available for borrowings at March 31, 2007 was $65.4 million under our credit facility.

The key terms of our credit facility are as follows:

- The interest rate on borrowings may be based on the prime rate or the LIBOR rate, at our option. The interest rate on prime rate loans can range from the prime rate plus 0.50% to the prime rate plus 1.875%. The interest rate for LIBOR-based loans can range from the LIBOR rate plus 1.50% to the LIBOR rate plus 2.875%. The rate is based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly.

- Letter of credit fees will range from 1.50% to 2.875% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At March 31, 2007, the rate was 1.50%.

- We pay a commitment fee on the unused portion of the $125 million commitment. The commitment fee will range from 0.30% to 0.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At March 31, 2007, the commitment fee rate was 0.30%.

- Collateral under the credit facility consists of substantially all our assets. Our general partner is jointly and severally liable for all of our obligations unless and except to the extent those obligations provide that they are non-recourse to our general partner. Our credit facility expressly provides that it is non-recourse to our general partner (except to the extent of its pledge of its general partner interest in certain of our subsidiaries) and Denbury and its other subsidiaries.

Our credit facility contains customary covenants (affirmative, negative and financial) that limit the manner in which we may conduct our business. Our credit facility contains three primary financial covenants - a debt service coverage ratio, leverage ratio and funded indebtedness to capitalization ratio - that require us to achieve specific minimum financial metrics as set forth in the table below. In general, the debt service coverage ratio calculation compares EBITDA (as adjusted in accordance with the credit facility), to interest expense. The leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with the credit facility) to EBITDA (as adjusted). The funded indebtedness ratio compares outstanding debt to the sum of our consolidated total funded debt plus our consolidated net worth.

Financial Covenant	Minimum Ratio	Actual Ratio as of March 31, 2007
Debt Service Coverage Ratio	3.0 to 1.0	21.5 to 1.0
Leverage Ratio	5.5 to 1.0	0.7 to 1.0
Funded Indebtedness Ratio	0.65 to 1.0	0.15 to 1.0

Our credit facility includes provisions for the temporary adjustment of the required ratios following acquisitions and with lender approval. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however the amount of such distributions may not exceed the sum of the distributable cash generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At March 31, 2007, the excess of distributable cash over distributions under this provision of the credit facility was $16.0 million. For a summary of our non-financial covenants, please refer to our Annual Report on Form 10-K for the year ended December 31, 2006.

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

5. Partners' Capital and Distributions

Partners' Capital

Partner's capital at March 31, 2007 consists of 13,784,441 common units, including 1,019,441 units owned by our general partner, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest), and a 2% general partner interest.

Our general partner owns all of our general partner interest, all of the 0.01% general partner interest in our operating partnership (which is reflected as a minority interest in the consolidated balance sheet at March 31, 2007) and operates our business.

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. As discussed in Note 4, our credit facility limits the amount of distributions we may pay in any quarter.

We paid or will pay the following distributions to the holders of our common units in 2006 and 2007:

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	Total Amount
			(in thousands)		
Fourth quarter 2005	February 2006	$ 0.17	$ 2,343	$ 48	$ 2,391
First quarter 2006	May 2006	$ 0.18	$ 2,481	$ 51	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,619	$ 53	$ 2,672
Third quarter 2006	November 2006	$ 0.20	$ 2,757	$ 56	$ 2,813
Fourth quarter 2006	February 2007	$ 0.21	$ 2,895	$ 59	$ 2,954
First quarter 2007	May 2007	$ 0.22	$ 3,032	$ 62	$ 3,094

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is entitled to receive 13.3% of any distributions to holders of our common units in excess of $0.25 per unit, 23.5% of any distributions to holders of our common units in excess of $0.28 per unit and 49% of any distributions to holders of our common units in excess of $0.33 per unit without duplication. We have not paid any incentive distributions from our inception through March 31, 2007.

Net Income per Common Unit

The following table sets forth the computation of basic and diluted net income per common unit (in thousands, except per unit amounts).

	Three Months Ended March 31, 2007		Three Months Ended March 31, 2006	
	(in thousands, except per unit amounts)			
Numerators for basic and diluted net income per common unit:				
Income from continuing operations	$	1,585	$	2,561
Less general partner 2% ownership		32		51
Income from continuing operations available for common unitholders	$	1,553	$	2,510
Income from cumulative effect adjustment	$	-	$	30
Less general partner 2% ownership		-		1
Income from cumulative effect adjustment available for common unitholders	$	-	$	29
Denominator for basic and diluted per common unit - weighted average number of common units outstanding		13,784		13,784
Basic and diluted net income per common unit:				
Income from continuing operations	$	0.11	$	0.18
Loss from cumulative effect adjustment		-		-
Net income	$	0.11	$	0.18

6. Business Segment Information

Our operations consist of three operating segments: (1) Pipeline Transportation - interstate and intrastate crude oil, natural gas and CO_2 pipeline transportation; (2) Industrial Gases - the sale of CO_2 acquired under volumetric production payments to industrial customers and our investment in a syngas processing facility, and (3) Crude Oil Gathering and Marketing - the purchase and sale of crude oil at various points along the distribution chain. The tables below reflect all periods presented as though the current segment designations had existed, and include only continuing operations data.

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

	Pipeline Transportation	Industrial Gases [a]	Crude Oil Gathering & Marketing	Total
		(in thousands)		
Three Months Ended March 31, 2007				
Segment margin excluding depreciation and amortization [b]	$ 2,868	$ 2,614	$ 1,599	$ 7,081
Capital expenditures	$ 293	$ -	$ 93	$ 386
Maintenance capital expenditures	$ 222	$ -	$ 93	$ 315
Net fixed and other long-term assets [c]	$ 31,478	$ 50,287	$ 7,683	$ 89,448
Revenues:				
External customers	$ 5,660	$ 3,497	$ 173,279	$ 182,436
Intersegment [d]	1,128	-	-	1,128
Total revenues of reportable segments	$ 6,788	$ 3,497	$ 173,279	$ 183,564
Three Months Ended March 31, 2006				
Segment margin excluding depreciation and amortization [b]	$ 2,802	$ 2,627	$ 1,728	$ 7,157
Capital expenditures	$ 166	$ -	$ 121	$ 287
Maintenance capital expenditures	$ 98	$ -	$ 121	$ 219
Net fixed and other long-term assets [c]	$ 33,957	$ 49,814	$ 5,839	$ 89,610
Revenues:				
External customers	$ 7,098	$ 3,387	$ 252,445	$ 262,930
Intersegment [d]	672	-	-	672
Total revenues of reportable segments	$ 7,770	$ 3,387	$ 252,445	$ 263,602

a) Industrial gases includes our CO_2 marketing operations and the income from our investments in T&P Syngas Supply Company and Sandhill Group, LLC.
b) Segment margin was calculated as revenues less cost of sales and operations expense. It includes our share of the operating income of equity joint ventures. A reconciliation of segment margin to income from continuing operations for the periods presented is as follows:

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Segment margin excluding depreciation and amortization	$ 7,081	$ 7,157
General and administrative expenses	(3,328)	(2,660)
Depreciation and amortization expense	(1,928)	(1,864)
Net gain on disposal of surplus assets	16	50
Interest expense, net	(226)	(122)
Income tax expense	(30)	-
Income before cumulative effect adjustment	$ 1,585	$ 2,561

c) Net fixed and other long-term assets are the measure used by management in evaluating the results of its operations on a segment basis. Current assets are not allocated to segments as the amounts are shared by the segments or are not meaningful in evaluating the success of the segment's operations.
d) Intersegment sales, in the opinion of management, were conducted on an arm's length basis.

7. Transactions with Related Parties

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

	Three Months Ended March 31, 2007		2006	
	(in thousands)			
Truck transportation services provided to Denbury	$	436	$	184
Pipeline transportation services provided to Denbury	$	1,224	$	993
Payments received under direct financing leases from Denbury	$	297	$	297
Pipeline transportation income portion of direct financing lease fees	$	158	$	167
Pipeline monitoring services provided to Denbury	$	30	$	15
Directors' fees paid to Denbury	$	30	$	30
CO_2 transportation services provided by Denbury	$	1,128	$	1,021
Crude oil purchases from Denbury	$	11	$	1,460
Operations, general and administrative services provided by our general partner	$	6,071	$	4,893
Distributions to our general partner on its limited partner units and general partner interest	$	273	$	221
Sales of CO_2 to Sandhill	$	630	$	-

Transportation Services

We provide truck transportation services to Denbury to move their crude oil from the wellhead to our Mississippi pipeline. Denbury pays us a fee for this trucking service that varies with the distance the crude oil is trucked. These fees are reflected in the statement of operations as gathering and marketing revenues.

Denbury is also a shipper on our Mississippi pipeline. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven CO_2 pipeline and recorded pipeline transportation income from these arrangements.

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

Directors’ Fees

We paid Denbury for the services of each of four of Denbury’s officers who serve as directors of our general partner, the same rate at which our independent directors were paid.

CO_2 Operations and Transportation

Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver CO_2 for us to our customers. In the first quarter of 2007, the inflation-adjusted transportation fee averaged $0.18 per Mcf.

Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions are provided by our general partner. We reimburse the general partner for all direct and indirect costs of these services.

Amounts due to and from Related Parties

At both March 31, 2007 and December 31, 2006, we owed Denbury \$0.8 million for purchases of crude oil and CO_2 transportation charges. Denbury owed us \$0.7 million and \$0.6 million for transportation services at March 31, 2007 and December 31, 2006, respectively. We owed our general partner \$0.4 million and \$0.9 million for administrative services at March 31, 2007 and December 31, 2006, respectively. At March 31, 2007 and December 31, 2006, Sandhill owed us \$0.4 million and \$0.5 million, respectively, for purchases of CO_2.

Financing

Our general partner is jointly and severally liable for all of our obligations unless and except to the extent those obligations provide that they are non-recourse to our general partner. Our credit facility expressly provides that it is non-recourse to our general partner (except to the extent of its pledge of its general partner interest in certain of our subsidiaries) and Denbury and its other subsidiaries.

We effectively guaranty our proportionate share (50%) of Sandhill’s outstanding bank debt, which was $4.5 million ($2.25 million net to us) at March 31, 2007. See Note 3.

8. Major Customers and Credit Risk

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

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

Shell Oil Company, Occidental Energy Marketing, Inc., and Calumet Specialty Products Partners, L.P. accounted for 23%, 20% and 12% of total revenues in the first quarter of 2007, respectively. Occidental Energy Marketing, Inc. and Shell Oil Company accounted for 23% and 16% of total revenues for the first quarter of 2006, respectively. The majority of the revenues from these three customers in both periods relate to our crude oil gathering and marketing operations.

9. Supplemental Cash Flow Information

We received interest payments of $27,000 and $101,000 for the three months ended March 31, 2007 and 2006, respectively. Payments of interest and commitment fees were $20,000 and $328,000 for the three months ended March 31, 2007 and 2006, respectively.

At March 31, 2007, we had incurred liabilities for fixed and other asset additions totaling $0.6 million that had not been paid at the end of the quarter, and, therefore, are not included in investing cash flows on the Consolidated Statements of Cash Flows.

10. Derivatives

Our market risk in the purchase and sale of crude oil contracts is the potential loss that can be caused by a change in the market value of the asset or commitment. In order to hedge our exposure to such market fluctuations, we may enter into various financial contracts, including futures, options and swaps. Historically, any contracts we have used to hedge market risk were less than one year in duration, although we have the flexibility to enter into arrangements with a longer term.

We may utilize crude oil futures contracts and other financial derivatives to reduce our exposure to unfavorable changes in crude oil prices. Every derivative instrument (including certain derivative instruments embedded in other contracts) must be recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative’s fair value must be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative’s gains and losses to offset related results on the hedged item in the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

We mark to fair value our derivative instruments at each period end, with changes in the fair value of derivatives that are not designated as hedges being recorded as unrealized gains or losses. Such unrealized gains or losses will change, based on prevailing market prices, at each balance sheet date prior to the period in which the transaction actually occurs. The effective portion of unrealized gains or losses on derivative transactions qualifying as cash flow hedges are reflected in other comprehensive income. Derivative transactions qualifying as fair value hedges are evaluated for hedge effectiveness and the resulting hedge ineffectiveness is recorded as a gain or loss in the consolidated statements of operations.

We review our contracts to determine if the contracts meet the definition of derivatives pursuant to SFAS 133. At March 31, 2007, we had futures contracts that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on March 31, 2007. We marked these contracts to fair value at March 31, 2007. During the three months ended March 31, 2007, we recorded losses of $62,000 related to derivative transactions, which are included in the consolidated statements of operations under the caption “Crude oil costs”.

At March 31, 2007, we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the three months ended March 31, 2007, we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $376,000. These gains are included in the caption “Crude oil costs” in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material.

The consolidated balance sheet at March 31, 2007 includes a decrease in other current assets of $508,000 as a result of these derivative transactions. The consolidated balance sheet at December 31, 2006 included an increase in other current assets of $165,000 as a result of derivative transactions.

At March 31, 2006, we had futures contracts on the NYMEX that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on the NYMEX on March 31, 2006. We marked these contracts to fair value at March 31, 2006. During the three months ended March 31, 2006, we recorded a loss of $87,000 related to derivative transactions, which are included in the consolidated statements of operations under the caption “Crude oil costs”.

At March 31, 2006, we had futures contracts on the NYMEX that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the three months ended March 31, 2006, we recognized losses, due to hedge ineffectiveness, on the fair value hedge of inventory of less than $1,000. These losses are included in the caption “Crude oil costs” in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material.

We determined that the remainder of our derivative contracts qualified for the normal purchase and sale exemption and were designated and documented as such at March 31, 2007 and December 31, 2006.

11. Contingencies

Guarantees

We have guaranteed the payments by our operating partnership to the banks under the terms of our credit facility related to borrowings and letters of credit. To the extent liabilities exist under the letters of credit, such liabilities are included in the consolidated balance sheet. Borrowings at March 31, 2007 were $10.2 million and are reflected in the consolidated balance sheet. We have also guaranteed the payments by our operating partnership under the terms of our operating leases of tractors and trailers.

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

We effectively guaranty our proportionate share (50%) of Sandhill’s bank debt, which was $4.5 million ($2.25 million, net to us) at March 31, 2007. Sandhill makes principal payments totaling $0.6 million annually on that debt.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot accurately be estimated at this time, we expect that our annual expenditures for integrity tests, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines to average between $1.0 million and $1.5 million.

Pennzoil Litigation

We were named a defendant in a complaint filed on January 11, 2001, in the 125th District Court of Harris County, Texas, Cause No. 2001-01176. Pennzoil-Quaker State Company, or PQS, was seeking from us property damages, loss of use and business interruption suffered as a result of a fire and explosion that occurred at the Pennzoil Quaker State refinery in Shreveport, Louisiana, on January 18, 2000. PQS claimed the fire and explosion were caused, in part, by crude oil we sold to PQS that was contaminated with organic chlorides. In December 2003, our insurance carriers settled this litigation for $12.8 million.

PQS is also a defendant in five consolidated class action/mass tort actions brought by neighbors living in the vicinity of the PQS Shreveport, Louisiana refinery in the First Judicial District Court, Caddo Parish, Louisiana, Cause Nos. 455,647-A, 455,658-B, 455,655-A, 456,574-A, and 458,379-C. PQS has brought third party claims against us for indemnity with respect to the fire and explosion of January 18, 2000. We believe that the demand against us is without merit and intend to vigorously defend ourselves in this matter. We currently believe that this matter will not have a material financial effect on our financial position, results of operations, or cash flows.

Environmental

In 1992, Howell Crude Oil Company entered into a sublease with Koch Industries, Inc., covering a one acre tract of land located in Santa Rosa County, Florida to operate a crude oil trucking station, known as Jay Station. The sublease provided that Howell would indemnify Koch for environmental contamination on the property under certain circumstances. Howell operated the Jay Station from 1992 until December of 1996 when this operation was sold to us by Howell. We operated the Jay Station as a crude oil trucking station until 2003. Koch has indicated that it has incurred certain investigative and/or other costs, for which Koch alleges some or all should be reimbursed by us, under the indemnification provisions of the sublease for environmental contamination on the site and surrounding areas. Koch has also alleged that we are responsible for future environmental obligations relating to the Jay Station.

Howell was acquired by Anadarko Petroleum Corporation in 2002. In 2005, we entered into a joint defense and cost allocation agreement with Anadarko. Under the terms of the joint allocation agreement, we agreed to reasonably cooperate with each other to address any liabilities or defense costs with respect to the Jay Station. Additionally under the joint allocation agreement, Anadarko will be responsible for sixty percent of the costs related to any liabilities or defense costs incurred with respect to contamination at the Jay Station.

We were formed in 1996 by the sale and contribution of assets from Howell and Basis Petroleum, Inc. Anadarko's liability with respect to the Jay Station is derived largely from contractual obligations entered into upon our formation. We believe that Basis has contractual obligations under the same formation agreements. We intend to seek recovery of Basis' share of potential liabilities and defense costs with respect to Jay Station.

We have developed a plan of remediation for affected soil and groundwater at Jay Station which has been approved by appropriate state regulatory agencies. We have accrued an estimate of our share of liability for this matter in the amount of $0.5 million. The time period over which our liability would be paid is uncertain and could be several years. This liability may decrease if indemnification and/or cost reimbursement is obtained by us for Basis' potential liabilities with respect to this matter. At this time, our estimate of potential obligations does not assume any specific amount contributed on behalf of the Basis obligations, although we believe that Basis is responsible for a significant part of these potential obligations.

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

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

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

12. Stock Appreciation Rights Plan

At December 31, 2005, we had a recorded liability of $0.8 million for our stock appreciation rights plan, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations. The adjustment of the liability to its fair value at March 31, 2006, resulted in expense of $0.2 million that is included in general and administrative expenses. The adjustment of the liability to its fair value at March 31, 2007, resulted in expense of $0.6 million, with $0.3 million, $0.2 million and $0.1 million included in general and administrative expenses, field operating costs and pipeline operating costs, respectively.

The following table reflects rights activity under our plan during the first quarter of 2007:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2007	659,010	$ 12.79		
Granted during 2007	15,987	$ 21.30		
Exercised during 2007	(38,335)	$ 9.35		
Forfeited or expired during 2007	(22,858)	$ 12.80		
Outstanding at March 31, 2007	613,804	$ 13.17	8.2	$ 3,034
Exercisable at March 31, 2007	198,072	$ 10.79	7.2	$ 2,123

The weighted-average fair value at March 31, 2007 of rights granted during the first quarter of 2007 was $4.00 per right. The total intrinsic value of rights exercised during the first quarter of 2007 was $389,000, which was paid in cash to the participants.

At March 31, 2007, there was $1.4 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. This amount was calculated as the fair value at March 31, 2007 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet until the rights are exercised, forfeited or expire. For the awards outstanding at March 31, 2007, the remaining cost will be recognized over a weighted average period of 0.8 years.

13. Income Taxes

In May 2006, the State of Texas enacted a law which will require us to pay a tax of 0.5% on our “margin,” as defined in the law, beginning in 2008 based on our 2007 results. The “margin” to which the tax rate will be applied generally will be calculated as our revenues (for federal income tax purposes) less the cost of the products sold (for federal income tax purposes), in the State of Texas.

Under FAS 109, taxes based on income like the Texas margin tax are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at the end of the period. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Temporary differences related to our inventory will affect the Texas margin tax, so we recorded a deferred tax asset in the amount of $11,000 upon enactment of the law in 2006. We believe that we will be able to utilize this deferred tax asset at March 31, 2007, and therefore have provided no valuation allowance against this deferred tax asset.

For the quarter ended March 31, 2007, we have provided current tax expense and liability in the amount of $30,000 as the estimate of the taxes that will be owed on our income for the period.

14. Subsequent Events

Davison Businesses Acquisition

On April 25, 2007, we entered into a contribution and sale agreement with several entities owned and controlled by the Davison family of Ruston, Louisiana to acquire (directly and through the acquisition of certain equity interests) the assets of businesses engaged in five energy-related services.

The total value of the transaction is expected to be approximately $560 million, subject to potential adjustments, primarily for working capital acquired. One-half of the total consideration will be in the form of common units while the remaining balance of the consideration will be in the form of cash. The transaction is expected to close early in the third quarter of 2007. See *“Pending Acquisitions”* in Item 2, Management’s Discussion and Analysis of Financial Condition and Results of Operations, below.

Distribution

On April 24, 2007, the Board of Directors of the general partner declared a cash distribution of $0.22 per unit for the quarter ended March 31, 2007. The distribution will be paid May 15, 2007 to our general partner and all common unitholders of record as of the close of business on May 7, 2007.

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:

- Pending Acquisitions
- Overview
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Other Matters
- New Accounting Pronouncements

Pending Acquisitions

On April 25, 2007, we entered into the Contribution Agreement with several entities owned and controlled by the Davison family of Ruston, Louisiana to acquire (directly and through the acquisition of certain equity interests) the assets of businesses engaged in five energy service segments. The Davison family has conducted energy related transportation businesses in Ruston since 1937. The businesses to be acquired from the Davison family include:

- Refinery services business - The refinery service business operates as a third-party contractor to provide the service of processing sour gas streams to remove sulfur at more than a dozen refining operations, located primarily in Louisiana, Texas and Arkansas.
- Petroleum products marketing business - The wholesale marketing of petroleum products business sells a variety of petroleum products to paper mills, utilities and other customers for use as fuels in their operations. This business has been operated under the name Davison Petroleum Products.
- Terminal business - The terminal business operates terminals for the storage and blending of refined petroleum products in north Louisiana and Mississippi. Each of the terminals is connected to multiple transportation modes. This business has been operated under the names Davison Terminal Services, Sunshine Oil and Red River Terminals.
- Trucking business - The trucking business operates a fleet of approximately 250 tractors and over 500 trailers under the name Davison Transport. The fleet, in addition to third-party carriage, supports the operations of the refinery services, petroleum products marketing and terminal businesses.
- Fuel procurement business - The fuel procurement business provides fuel procurement and delivery logistics management services to wholesale and retail customers in more than 35 states nationwide.

The total value of the transaction is expected to be approximately $560 million, subject to potential adjustments, primarily for working capital acquired. The Davisons will receive approximately 13.5 million common units and $280 million in cash. The transaction is expected to close early in the third quarter of 2007.

We are seeking lender approval to amend our credit facility to (i) increase the committed amount under our credit facility to an amount that would allow us to fund the cash portion of the purchase price, additional working capital requirements and a portion of certain of our other expansion requirements for 2007, (ii) increase our borrowing base to give pro forma effect to the Davison acquisition and (iii) otherwise accommodate the Davison acquisition. We are confident we will be able to raise the cash necessary to fund the cash portion of the purchase price.

The completion of the transaction is subject to the satisfaction of customary conditions to closing, including the performance of material covenants, accuracy of representations and warranties, obtaining material consents and approvals (including approval under the Hart-Scott-Rodino Antitrust Improvements Act) and approval by the AMEX to list the units to be issued as a portion of the purchase price. Additionally, we have the right to delay the closing until July 1, 2007, and until we have received audited financial statements covering the acquired businesses. Both the Davison companies and us have the right to terminate the Contribution Agreement under specified circumstances, including if the results of operations reflected in those audited financial statements are materially different in certain respects than the results of operations contained in the existing unaudited financial statements.

Upon consummation of the transaction, the Davison family will hold approximately 50% of our outstanding common units and, depending on their continued level of ownership in us, will have the right to appoint up to two directors. The Davison family also will have registration rights with respect to its common units, which will be subject to specified restrictions on sale and transfer. In addition, we will be granted a lien on forty percent of those common units for a specified period of time.

As Denbury has publicly stated, it is their intent to "drop-down" midstream assets to Genesis subject to the satisfaction of certain conditions. Those conditions include the negotiation of material terms, the execution of definitive agreements, the existence of adequate credit support and our acquisition (by construction or purchase) of assets that are not related to Denbury's operations in an amount at least equal to 150% of the amount of new acquisitions or financings we complete with Denbury. Based on the size of the transaction with the Davisons, we expect to initiate negotiations with respect to such "drop-down" transactions with Denbury up to an amount exceeding $350 million. Denbury currently has in full service some $200-$250 million worth of assets that we may acquire before the end of 2007, and Denbury is in the process of constructing approximately $100 million that should be completed and ready to "drop-down" over the next 12-18 months. We expect to fund the acquisitions with Denbury with borrowings under our credit facility as well as other sources such as a public or private offering of debt or equity.

Overview

In the discussions that follow, we will focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves. Our profitability depends to a significant extent upon our ability to maximize segment margin. Segment margin is calculated as revenues less cost of sales and operating expense, and does not include depreciation and amortization. Segment margin also includes our share of the equity in the operating income of our joint ventures. A reconciliation of segment margin to income from continuing operations is included in our segment disclosures in Note 6 to the consolidated financial statements. Available Cash before Reserves is a non-GAAP liquidity measure calculated as net income with several adjustments, the most significant of which are the elimination of gains and losses on asset sales, except those from the sale of surplus assets, the addition of non-cash expenses such as depreciation, the replacement with the amount recognized as our equity in the income of joint ventures with the available cash generated from those ventures, and the subtraction of maintenance capital expenditures, which are expenditures to sustain existing cash flows but not to provide new sources of revenues. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see "Liquidity and Capital Resources - Non-GAAP Financial Measure" below.

We conduct our business through three segments - pipeline transportation, industrial gases and crude oil gathering and marketing. We have a diverse portfolio of customers and assets, including pipeline transportation of primarily crude oil and, to a lesser extent, natural gas and CO_2 in the Gulf Coast region of the United States. In conjunction with our crude oil pipeline transportation operations, we operate a crude oil gathering and marketing business, which helps ensure a base supply of crude oil for our pipelines. We also participate in industrial gas activities, including a CO_2 supply business, which is associated with the CO_2 tertiary oil recovery process being used in Mississippi by an affiliate of our general partner. We generate revenues by selling crude oil and industrial gases, by charging fees for the transportation of crude oil, natural gas and CO_2 on our pipelines, and, through our joint venture in T&P Syngas Supply Company, by charging fees for services to produce syngas for our customer from the customer's raw materials. Our focus is on the margin we earn on these revenues, which is calculated by subtracting the costs of the crude oil and natural gas; the costs of transporting the crude oil, natural gas and CO_2 to the customer; and the costs of operating our assets. We also report our share of the earnings of our joint ventures, T&P Syngas, in which we acquired a 50% interest on April 1, 2005, and Sandhill Group, LLC, in which we acquired a 50% interest on April 1, 2006.

Our objective is to operate as a growth-oriented midstream MLP with a focus on increasing cash flow, earnings and return to holders of our common units by becoming one of the leading providers of pipeline transportation, crude oil gathering and marketing and industrial gas services in the regions in which we operate. As is evidenced by the discussion above under "*Pending Acquisitions*", we are pursuing acquisitions and projects involving transportation, gathering, terminalling or storage assets and related midstream businesses, some of which may be outside the scope of our historical operations. In addition to the Davison transaction, we are presently engaged in discussions with various parties regarding acquisitions of assets or businesses, but we can give no assurance that our efforts will be successful or that any acquisitions will be completed on terms favorable to us.

Increases in cash flow generally result in increases in Available Cash, which we distribute quarterly to holders of our common units and general partner. During the first quarter of 2007, we generated $3.9 million of Available Cash before Reserves, and distributed $3.1 million to holders of our common units and general partner. During the first quarter of 2007, cash provided by operations was $1.7 million.

In the first quarter of 2007, we generated net income of $1.6 million, or $0.11 per common unit. We increased our cash distribution by $0.01 to $0.21 per unit for the fourth quarter of 2006 (which was paid in February 2007) and increased our cash distribution again to $0.22 per unit for the first quarter of 2007. This distribution will be paid in May 2007. This distribution represented a 22% increase from our distribution of $0.18 per unit for the first quarter of 2006.

Results of Operations

The contribution of each of our segments to total segment margin in the first quarters of 2007 and 2006 was as follows:

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Pipeline transportation	$ 2,868	$ 2,802
Industrial gases	2,614	2,627
Crude oil gathering and marketing	1,599	1,728
Total segment margin	$ 7,081	$ 7,157

Pipeline Transportation Operations

We operate three crude oil common carrier pipeline systems in a four state area. We refer to these pipelines as our Mississippi System, Jay System and Texas System. Additionally, we operate a CO_2 pipeline in Mississippi to transport CO_2 from Denbury's main CO_2 pipeline to Brookhaven oil field. Denbury has the exclusive right to use this CO_2 pipeline. We also have several natural gas gathering systems.

Operating results for our pipeline transportation segment were as follows:

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 3,536	$ 3,333
Sales of crude oil pipeline loss allowance volumes	1,699	1,318
Revenues from direct financing leases of CO_2 pipelines	82	87
Tank rental reimbursements and other miscellaneous revenues	163	144
Total revenues from crude oil and CO_2 tariffs, including revenues from direct financing leases	5,480	4,882
Revenues from natural gas tariffs and sales	1,308	2,888
Natural gas purchases	(1,235)	(2,699)
Pipeline operating costs	(2,685)	(2,269)
Segment margin	$ 2,868	$ 2,802
Barrels per day on crude oil pipelines:		
Total	57,874	62,058
Mississippi System	19,355	16,409
Jay System	12,812	11,414
Texas System	25,707	34,235

Three Months Ended March 31, 2007 Compared with Three Months Ended March 31, 2006

Pipeline segment margin for the first quarter of 2007 was consistent with the first quarter of 2006. Revenues from crude oil tariffs and related sources and sales of pipeline loss allowance volumes increased a total of $0.6 million, which was offset by an increase in pipeline operating costs of $0.4 million and a decrease in net segment margin from natural gas pipeline activities.

Crude oil tariff and direct financing lease revenues increased $0.2 million despite a decrease of 4,184 barrels per day. Volumes increased on our Mississippi System by 2,946 barrels per day and on our Jay System by 1,398 barrels per day, both of which have much higher tariffs than on Texas System. The decline in volume on the Texas System of 8,528 barrels per day with a tariff of $0.22 per barrel had a $0.2 negative impact on revenues.

The volume increase on the Mississippi System was due to increased volumes shipped on our pipeline by Denbury for which we receive a tariff. Denbury is the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury's existing and prospective oil fields. As Denbury continues to acquire and develop old oil fields using CO_2 based tertiary recovery operations, we expect Denbury to add crude oil gathering and CO_2 supply infrastructure to those fields, which could create some opportunities for us.

The Jay System in Florida/Alabama ships crude oil from fields with relatively short remaining production lives. Recent changes in the ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development of these fields which may lead to increases in production. Additionally, new wells have been drilled in the area. This new production produces greater tariff revenue for us due to the greater distance that the crude oil is transported on the pipeline.

Our Texas System is dependent on the connecting carriers for supply, and on the two refineries for demand for our services. Volumes on the Texas System have declined as a result of changes in the supply available for the two refineries to acquire and ship on our pipeline. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets connected to TEPPCO's pipeline systems.

Sales of pipeline loss allowance volumes increased $0.4 million due to an increase in volumetric gain volumes of approximately 6,000 barrels. These volumes are sold at crude oil market prices.

Historically, the largest operating costs in our crude oil pipeline segment have consisted of personnel costs, power costs, maintenance costs and costs of compliance with regulations. Some of these costs are not predictable, such as failures of equipment or power cost increases. We perform regular maintenance on our assets in an effort to keep them in good operational condition and to minimize cost increases. Costs in the first quarter of 2007 were higher than in the first quarter of 2006 by a total of $0.4 million, primarily due to expenditures for integrity management testing and repairs on the Jay System totaling $0.2 million and costs of $0.1 million to tear down an out-of-service tank on the Texas System in order to replace it. Additionally, expense for our stock appreciation rights plan that relates to our pipeline operations personnel increased by $0.1 million.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO_2 sales to industrial customers and our share of the operating income of our 50% joint venture interests in T&P Syngas and Sandhill. Operating results from continuing operations for our industrial gases segment were as follows:

	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Revenues from CO_2 sales	$ 3,497	$ 3,387
CO_2 transportation and other costs	(1,144)	(1,073)
Equity in earnings of joint ventures	261	313
Segment margin	$ 2,614	$ 2,627
Volumes per day:		
CO_2 sales - Mcf	67,158	66,565

Three Months Ended March 31, 2007 Compared with Three Months Ended March 31, 2006

Segment margin from industrial gases activities was consistent between the two first quarter periods. This margin is derived from two sources - sales of CO_2 and our equity in the earnings of joint ventures.

CO_2 Sales

We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

Our industrial customers treat the CO_2 and transport it to their own customers. The primary industrial applications of CO_2 by these customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through 2007, we can expect some seasonality in our sales of CO_2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. Volumes sold in the first quarter of the calendar year are usually less than the volumes sold in any other quarter. Volumes sold each quarter in 2006 and in the first quarter of

2007 were as follows:

	Sales Mcf per Day
First Quarter 2006	66,565
Second Quarter 2006	73,980
Third Quarter 2006	82,244
Fourth Quarter 2006	68,452
First Quarter 2007	67,158

The CO_2 sales revenue increased by $0.1 million between the periods, due to a volume increase of an average of 593 Mcf per day combined with inflation adjustments in the contracts and variations in the volumes sold under each contract.

Similarly, the increased volumes and the inflation adjustment to the rate we pay Denbury to transport the CO_2 in its pipeline to our customers resulted in greater CO_2 transportation costs in the first quarter of 2007 when compared to the 2006 quarter.

Joint Ventures

We own a 50% interest in two joint ventures engaged in industrial gases activities, T&P Syngas and Sandhill. T&P Syngas owns a facility located in Texas City, Texas that manufactures syngas (a combination of carbon monoxide and hydrogen) and high-pressure steam. Under that processing agreement, Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility. T&P Syngas receives a processing fee for its services. Our share of the operating income of T&P Syngas for the three months of 2007 and 2006 was $409,000 and $401,000, respectively. We reduced the amount we recorded as our equity in T&P Syngas by $88,000 in each quarter as amortization of the excess purchase price of T&P Syngas. During the first quarters of 2007 and 2006, T&P Syngas paid us distributions totaling $0.6 million and $0.2 million, respectively, attributable to the fourth quarters of the prior years.

Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemicals and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury. We did not own our interest in Sandhill in the first quarter of 2006. Our share of the operating income of Sandhill for the first quarter of 2007 was $9,000, which we reduced by $69,000 for the amortization of excess purchase price. We received a distribution from Sandhill of $60,000 during the first quarter of 2007 that was attributable to the fourth quarter of 2006.

Additional discussion of our joint ventures is included in Note 3 of the Notes to the Unaudited Consolidated Financial Statements.

Crude Oil Gathering and Marketing Operations

Operating results from continuing operations for our crude oil gathering and marketing segment were as follows:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(in thousands)	
Revenues	$ 173,279	$ 252,445
Crude oil costs	(167,722)	(247,372)
Field operating costs	(3,958)	(3,345)
Segment margin	$ 1,599	$ 1,728
Volumes per day:		
Crude oil total - barrels	33,439 (1)	45,288
Crude oil truck transported only - barrels	4,970	2,767

(1) For purposes of comparison to the 2006 volume, barrels per day before netting of buy/sell volumes was 43,460.

Three Months Ended March 31, 2007 as Compared to Three Months Ended March 31, 2006

Gathering and marketing segment margins decreased $0.1 million for the three months ended March 31, 2007, as compared to the three months ended March 31, 2006. Revenues for this segment are derived from sales of crude oil and from the transportation by truck for a fee of crude oil volumes that we did not purchase, with costs for this segment relating to the purchase of the crude oil and the related aggregation and transportation costs.

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

The commodity prices (for purchases and sales) of crude oil do not necessarily bear a relationship to segment margin as those prices normally impact revenues and costs of sales by approximately equivalent amounts. Because period-to-period variations in revenues and costs of sales are not generally meaningful in analyzing the variation in segment margin for our gathering and marketing operations, these changes are not addressed in the following discussion.

Generally, as we purchase crude oil, we simultaneously establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases, on the one hand, and sales or future delivery obligations, on the other hand. We do not hold crude oil, futures contracts or other derivative products to speculate on crude oil price changes. When our positions become unbalanced such that we have inventory, we will use derivative instruments to hedge that inventory until such time as we can sell it into the market.

When the crude oil markets are in contango, (oil prices for future deliveries are higher than for current deliveries), we may store crude oil as inventory in our storage tanks that we have purchased at lower prices in the current month for delivery at higher prices in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period, either with a counterparty or in the crude oil futures market. The maximum storage available to us for use in this strategy is approximately 120,000 barrels, although maintenance activities on our pipelines impact the availability of this storage capacity. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 10 of the Notes to the Unaudited Consolidated Financial Statements.

Most of our contracts for the purchase and sale of crude oil have components in the pricing provisions such that the price paid or received is adjusted for changes in the market price for crude oil. The pricing in the majority of our purchase contracts contain the market price component, a bonus that is not fixed, but instead is based on another market factor and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts will sometimes also contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

Volumes, on a like-kind basis, declined by 1,828 barrels per day, primarily as a result of the elimination of a contract during the second quarter of 2006 that did not meet our targets for profitability. As a result, we have seen volumes decline, but an increase in the average difference between the sales price and the purchase price of crude oil resulted in the overall effect of the change in volumes affecting segment margin by only $0.1 million.

Volumes that we transported for a fee, but did not purchase, increased by 2,203 barrels per day. Most of this increase in volume was attributable to transportation of Denbury’s production from their wellheads to our pipeline. The increase in the fees for these services was $0.6 million between the two first quarter periods.

The increase in segment margin from transportation-only services was offset by an increase in field operating costs of $0.6 million when comparing the first quarter periods. Compensation costs to operate the trucks and manage our crude oil gathering operations increased $0.3 million, as a result of compensation increases and the use of contract personnel. Additionally, expense related to our stock appreciation rights plan increased by $0.2 million. Increased fuel costs to operate our fleet of trucks accounted for most of the remaining $0.1 increase in costs.

Other Costs and Interest

Three Months Ended March 31, 2007 Compared with Three Months Ended March 31, 2006

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

	Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Expenses excluding effect of stock appreciation rights plan and bonus plan	$ 2,539	$ 2,165
Bonus plan expense	446	343
Stock appreciation rights plan expense	343	152
Total general and administrative expenses	$ 3,328	$ 2,660

General and administrative expenses increased by $0.7 million, with $0.1 million attributable to bonus plan expense, $0.2 million to increased stock appreciation rights plan expense and the remaining $0.4 million to other costs. These other costs included employee compensation expenses and fees for legal and other consulting services.

The expense for our stock appreciation rights plan added $0.2 million to general and administrative costs, $0.1 million to pipeline operating costs and $0.2 million to crude oil gathering field costs, for a total impact to net income of $0.5 million when compared to the first quarter of 2006. Under the accounting method used to account for our stock appreciation rights, we determine the fair value of the rights at the end of each reporting period using a Black-Scholes valuation model and recognize the change in fair value as an expense. This fair value is affected by several assumptions as well as by the volatility of the market price for our common units. We believe that the significant increase in our unit price over the last year has been the more significant contributor to the increase in expense for this plan.

Since March 31, 2007, the market price for our common units has fluctuated significantly. If the unit price increases $10 per unit between March 31, 2007 and June 30, 2007, we estimate that the fair value of the outstanding rights under our stock appreciation rights plan would increase approximately $3.5 million to $4.5 million, affecting segment margin for our pipeline transportation and crude oil gathering and marketing segments and general and administrative expenses for the second quarter of 2007. This expense is a non-cash charge until the employees holding the rights choose to exercise them. See Note 12 of the Notes to Unaudited Consolidated Financial Statements for information on outstanding and exercisable rights.

Depreciation, amortization and impairment expense for the first quarter of 2007 was consistent with that of the first quarter of 2006, increasing less than $0.1 million. The slight increase is attributable to depreciation on property additions since the first quarter of 2006.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended March 31,			
	2007		2006	
	(in thousands)			
Interest expense, including commitment fees	$	209	$	115
Capitalized interest		(6)		-
Amortization of facility fees		67		85
Interest income		(44)		(78)
Net interest expense	$	226	$	122

During the first quarter of 2007, our average outstanding balance of debt was $3.8 million more than in the first quarter of 2006. Additionally, our average interest rate was 0.7% greater than in the 2006 period. For the first portion of the 2006 quarter we had no debt outstanding as funds from our equity offering in 2005 had been used to repay outstanding debt from acquisitions in prior periods. For part of the 2006 period we had excess funds which were invested resulting in higher interest income in the 2006 period when compared to the 2007 period.

In the fourth quarter of 2006, we replaced our credit facility, resulting in an increase in the amount we are amortizing each quarter for facility fees.

Liquidity and Capital Resources

Capital Resources/Sources of Cash

Historically, our primary sources of cash have been cash generated from our operating activities and a small revolving credit facility used for working capital. We also issued common units in an underwritten offering and issued common units to our general partner in December 2005, with net proceeds of $41 million.

In the last 12 months, we have adopted a growth strategy that, if effected, will dramatically increase our cash requirements. Consequently, we expect our capital resources to also include equity and debt offerings (public and private) and other financing transactions. 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. Our ability to satisfy future capital needs with respect to our growth strategy will depend on our ability to raise substantial amounts of additional capital, to amend our current credit facility and to implement our growth strategy successfully.

In November 2006, we entered into a credit facility with a maximum facility amount of $500 million (replacing our $100 million facility). The initial committed amount under our facility is $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at March 31, 2007 was approximately $79 million, and it will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit based on our EBITDA, computed in accordance with the provisions of our credit facility.

The terms of our credit facility also effectively limit the amount of distributions that we may pay to our general partner and holders of common units. Such distributions may not exceed the sum of the distributable cash generated for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. See Note 4 of the Notes to the Unaudited Consolidated Financial Statements.

We will finance the Davison acquisition (approximately $560 million) equally with common units issued to the sellers and cash, which we expect to fund under our credit facility. Other acquisitions may be initially funded primarily with debt or equity or any combination thereof.

Uses of Cash

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

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

Our accounts receivable settle monthly and collection delays generally relate only to discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered. Of the $88.0 million aggregate receivables on our consolidated balance sheet at March 31, 2007, approximately $86.7 million, or 98.5%, were less than 30 days past the invoice date.

Investing. We utilized cash flows to make limited capital expenditures, primarily for pipeline improvements. We received distributions from our T&P Syngas joint venture that exceeded our share of the earnings of T&P Syngas of $0.2 million during the first quarter of 2007.

Financing. Net cash of $1.0 million was utilized in financing activities. We paid distributions totaling $3.0 million to our limited partners and our general partner during the first quarter. We borrowed $2.2 million under our credit facility, and expended $0.2 million on other financing activities.

Capital Expenditures. A summary of our capital expenditures in the three months ended March 31, 2007 and 2006 is as follows:

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Maintenance capital expenditures:		
Mississippi pipeline systems	$ 62	$ 44
Jay pipeline system	72	39
Texas pipeline system	88	15
Crude oil gathering assets	91	72
Administrative and other assets	2	49
Total maintenance capital expenditures	315	219
Growth capital expenditures (including construction in progress and investments in joint ventures)		
Mississippi pipeline systems	71	68
Total growth capital expenditures	71	68
Total capital expenditures	$ 386	$ 287

We have no commitments to make capital expenditures; however, we anticipate that our maintenance capital expenditures relating to our existing assets for 2007 will be approximately $2.3 million. These expenditures are expected to relate primarily to the replacement of a tank on the Texas System and improvements on our Mississippi System. Based on the information available to us at this time, we do not anticipate that future capital expenditures for compliance with regulatory requirements will be material.

As discussed under "*Pending Acquisitions*" above, we expect to close on the transaction with the Davison family in the third quarter of 2007 and we are currently negotiating with Denbury regarding the possibility of acquiring certain CO_2 pipeline assets before the end of 2007.

Distributions

We are required by our partnership agreement to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last seven quarters, including the distribution to be paid for the first quarter of 2007, as shown in the table below.

Distribution For	Date Paid	Per Unit Amount	Limited Partner Interests Amount	General Partner Interest Amount	Total Amount
			(in thousands)		
Fourth quarter 2005	February 2006	$ 0.17	$ 2,343	$ 48	$ 2,391

First quarter 2006	May 2006	$ 0.18	$ 2,481	$ 51	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,619	$ 53	$ 2,672
Third quarter 2006	November 2006	$ 0.20	$ 2,757	$ 56	$ 2,813
Fourth quarter 2006	February 2007	$ 0.21	$ 2,895	$ 59	$ 2,954
First quarter 2007	May 2007	$ 0.22	$ 3,032	$ 62	$ 3,094

See Note 5 of the Notes to the Unaudited Consolidated Financial Statements.

Available Cash before Reserves for the three months ended March 31, 2007 is as follows (in thousands):

Net income	$	1,585
Depreciation and amortization		1,928
Cash received from direct financing leases not included in income		138
Effects of available cash generated by investments in joint ventures not included in income		299
Non-cash charges		299
Maintenance capital expenditures		(315)
Available Cash before reserves	$	3,934

We have reconciled Available Cash (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three months ended March 31, 2007 below. For the three months ended March 31, 2007, cash flows provided by operating activities were $1.7 million.

Non-GAAP Financial Measure

This quarterly report includes the financial measure of Available Cash, which measure often is referred to as 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. Our non-GAAP financial measure should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

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

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

The reconciliation of Available Cash (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three months ended March 31, 2007, is as follows (in thousands):

Cash flows from operating activities	$	1,737
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures		(315)
Proceeds from sales of certain assets		16
Amortization of credit facility issuance fees		(136)
Effects of available cash generated by investments in joint ventures not included in cash flows from operating activities		136
Cash effects of exercises under SAR Plan		(407)
Other items affecting Available Cash		319
Net effect of changes in operating accounts not included in calculation of Available Cash		2,584
Available Cash before reserves	$	3,934

Commitments and Off-Balance-Sheet Arrangements

Contractual Obligation and Commercial Commitments

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and crude oil purchase commitments. Neither the amounts nor the terms of these commitments or contingent obligations have changed significantly from the year-end 2006 amounts reflected in our Annual Report on Form 10-K. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations — "Commitments and Off-Balance Sheet Arrangements" contained in our 2006 Form 10-K for further information regarding our commitments and obligations

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under *Contractual Obligation and Commercial Commitments* above, nor do we have any debt or equity triggers based upon our unit or commodity prices.

New and Proposed Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2 of the Notes to Unaudited Consolidated Financial Statements.

Forward Looking Statements

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

these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

· demand for, the supply of, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs" in the United States, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;

· throughput levels and rates;

· changes in, or challenges to, our tariff rates;

· our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;

· service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;

· shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;

· changes in laws or regulations to which we are subject;

· our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of existing debt agreements that contain restrictive financial covenants;

· loss of key personnel;

· the effects of competition, in particular, by other pipeline systems;

· hazards and operating risks that may not be covered fully by insurance;

· the condition of the capital markets in the United States;

· loss of key customers;

· the political and economic stability of the oil producing nations of the world; and

· general economic conditions, including rates of inflation and interest rates.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006. 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

We are exposed to market risks primarily related to volatility in crude oil prices and interest rates.

Our primary price risk relates to the effect of crude oil price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. We utilize NYMEX commodity based futures contracts and forward contracts to hedge our exposure to these market price fluctuations as needed. At March 31, 2007, we had entered into NYMEX future contracts that will settle through June 2007. These contracts either do not qualify for hedge accounting or are fair value hedges, therefore the fair value of these derivatives have received mark-to-market treatment in current earnings. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" of our Consolidated Financial Statements in our Annual Report on Form 10-K.

	Sell (Short) Contracts	Buy (Long) Contracts
Futures Contracts		
Contract volumes (1,000 bbls)	164	33
Weighted average price per bbl	$ 62.57	$ 63.36
Contract value (in thousands)	$ 10,261	2,091
Mark-to-market change (in thousands)	591	83
Market settlement value (in thousands)	$ 10,852	$ 2,174

The table above presents notional amounts in barrels, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars. Fair values were determined by using the notional amount in barrels multiplied by the March 31, 2007 quoted market prices on the NYMEX.

We are also exposed to market risks due to the floating interest rates on our credit facility. Our debt bears interest at the LIBOR Rate or Prime Rate plus the applicable margin. We do not hedge our interest rates. At March 31, 2007, we had $10.2 million of debt outstanding under our credit facility.

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 adequate and effective in all material respects in providing to them on a timely basis material information relating to us (including our consolidated subsidiaries) required to be disclosed in this quarterly report.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I. Item 1. See Note 11 of the Notes to Unaudited Consolidated Financial Statements entitled “Contingencies”, which is incorporated herein by reference.

Item 1A. Risk Factors.

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006.

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

See Note 4 of the Notes to the Unaudited Consolidated Financial Statements.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

(a) Exhibits.

31.1	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
31.2	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
32.1	Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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, INC., as General Partner
Date: May 10, 2007	By:	/s/ Ross A. Benavides Ross A. Benavides Chief Financial Officer