GENESIS ENERGY LP
Form 10-Q
November 08, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2006

OR

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

Commission File Number 1-12295
GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0513049**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 Dallas, Suite 2500, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 860-2500
(Registrant s telephone number, including area code)

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 o No o

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 o Accelerated filer o Non-accelerated filer o

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

Yes o No o

Indicate number of outstanding shares of each of the issuer s classes of common stock, as of the latest practicable date. Limited Partner Units outstanding as of November 6, 2006: 13,784,441

This report contains 43 pages

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

	September 30, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 2,384	$ 3,099
Accounts receivable:		
Trade	90,698	82,119
Related party	1,004	515
Inventories	4,435	498
Net investment in direct financing leases, net of unearned income current portion	559	531
Insurance receivable	995	2,042
Other	2,218	1,645
Total current assets	102,293	90,449
FIXED ASSETS, at cost	70,202	69,708
Less: Accumulated depreciation	(38,399)	(35,939)
Net fixed assets	31,803	33,769
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	5,519	5,941
CO2 ASSETS, net of amortization	34,415	37,648
JOINT VENTURES AND OTHER INVESTMENTS	18,289	13,042
OTHER ASSETS, net of amortization	663	928
TOTAL ASSETS	$ 192,982	$ 181,777
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable:		
Trade	$ 87,967	$ 82,369
Related party	1,941	2,917
Accrued liabilities	7,719	7,325
Total current liabilities	97,627	92,611

LONG-TERM DEBT		6,000		
OTHER LONG-TERM LIABILITIES		1,009		955
COMMITMENTS AND CONTINGENCIES (Note 11)				
MINORITY INTERESTS		522		522
PARTNERS CAPITAL				
Common unitholders, 13,784 units issued and outstanding		86,003		85,870
General partner		1,821		1,819
Total partners capital		87,824		87,689
TOTAL LIABILITIES AND PARTNERS CAPITAL	$	192,982	$	181,777

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

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

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
REVENUES:				
Crude oil gathering and marketing:				
Unrelated parties (including revenues from buy/sell arrangements of $69,772 in the nine months of 2006 and $102,893 and $279,285 in the three and nine months of 2005, respectively)	$ 217,947	$ 290,887	$ 690,841	$ 785,161
Related parties	194	187	573	613
Pipeline transportation, including natural gas sales:				
Unrelated parties	5,880	5,849	19,874	17,776
Related parties	1,268	1,131	3,665	3,400
CO2 revenues:				
Unrelated parties	3,560	2,523	10,186	7,371
Related party	702		1,357	
Total revenues	229,551	300,577	726,496	814,321
COSTS AND EXPENSES:				
Crude oil costs:				
Unrelated parties (including crude oil costs from buy/sell arrangements of $68,899 in the nine months of 2006 and $102,304 and $278,703 in the three and nine months of 2005, respectively)	212,725	284,518	673,374	767,864
Related parties	12	1,421	1,496	3,422
Field operating	3,405	4,082	10,470	12,097
Pipeline transportation costs:				
Pipeline operating costs	2,349	2,917	7,095	7,450
Natural gas purchases	1,341	2,178	6,582	6,590
CO2 distribution costs:				
Transportation costs related party	1,324	806	3,498	2,296
Other costs	50	37	156	113
General and administrative	4,539	3,210	10,448	6,536
Depreciation and amortization	2,107	1,601	6,000	4,695
Net loss (gain) on disposal of surplus assets	11	(84)	(38)	(482)
OPERATING INCOME (LOSS)	1,688	(109)	7,415	3,740
OTHER INCOME (EXPENSE):				
Equity in earnings of joint ventures	267	8	919	260
Interest income	49	10	157	38
Interest expense	(309)	(550)	(802)	(1,439)

Income from continuing operations before income taxes		1,695		(641)		7,689		2,599
Income tax benefit						11		
INCOME (LOSS) FROM CONTINUING OPERATIONS		1,695		(641)		7,700		2,599
Income from operations of discontinued Texas System				45				318
Cumulative effect adjustment of adoption of new accounting principle						30		
NET INCOME (LOSS)	$	1,695	$	(596)	$	7,730	$	2,917
NET INCOME (LOSS) PER COMMON UNIT BASIC AND DILUTED:								
Income (loss) from continuing operations	$	0.12	$	(0.06)	$	0.55	$	0.28
Income from discontinued operations								0.03
Cumulative effect adjustment								
NET INCOME (LOSS)	$	0.12	$	(0.06)	$	0.55	$	0.31
DISTRIBUTIONS PAID PER COMMON UNIT	$	0.19	$	0.15	$	0.54	$	0.45
WEIGHTED AVERAGE NUMBER OF COMMON UNITS OUTSTANDING		13,784		9,314		13,784		9,314

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

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

	Nine months Ended September 30,	
	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 7,730	$ 2,917
Adjustments to reconcile net income to net cash (used in) provided by operating activities -		
Depreciation	2,767	2,678
Amortization of CO2 contracts	3,233	2,017
Amortization of credit facility issuance costs	279	279
Amortization of unearned income on direct financing leases	(495)	(521)
Payments received under direct financing leases	889	890
Equity in earnings of joint ventures	(919)	(260)
Distributions from joint ventures return on investment	1,151	260
Gain on asset disposals	(38)	(800)
Cumulative effect adjustment for new accounting principle	(30)	
Other non-cash charges (credits)	941	(1,078)
Changes in components of working capital -		
Accounts receivable	(9,068)	(26,099)
Inventories	(3,937)	(3,537)
Other current assets	474	(727)
Accounts payable	4,250	25,860
Accrued liabilities	(505)	2,364
Net cash provided by operating activities	6,722	4,243
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to property and equipment	(830)	(5,374)
Investment in T&P Syngas Supply Company		(13,418)
Distributions from joint ventures return of investment	352	53
Investment in Sandhill Group, LLC	(5,042)	
Investments, other	(707)	
Proceeds from sale of assets	67	1,581
Other, net	(54)	(209)
Net cash used in investing activities	(6,214)	(17,367)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Bank borrowings of debt, net	6,000	17,300
Other financing activities, net	372	172
Distributions to common unitholders	(7,442)	(4,191)
Distributions to General Partner	(153)	(86)

Net cash (used in) provided by financing activities	(1,223)	13,195
Net (decrease) increase in cash and cash equivalents	(715)	71
Cash and cash equivalents at beginning of year	3,099	2,078
Cash and cash equivalents at end of period	$ 2,384	$ 2,149

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

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(In thousands)
(Unaudited)

		Partners Capital		
	Number of Common Units	Common Unitholders	General Partner	Total
Partners capital at January 1, 2006	13,784	$ 85,870	$ 1,819	$ 87,689
Net income for the nine months ended September 30, 2006		7,575	155	7,730
Distributions to partners during the nine months ended September 30, 2006		(7,442)	(153)	(7,595)
Partners capital at September 30, 2006	13,784	$ 86,003	$ 1,821	$ 87,824

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

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

1. Organization and Basis of Presentation

Organization

We are a midstream partnership that was formed in 1996 as a master limited partnership, or MLP. We have a diverse portfolio of customers and assets, including pipeline transportation of primarily crude oil and, to a lesser extent, natural gas and carbon dioxide (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 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. During 2005, we also acquired a 50% interest in a joint venture that processes natural gas to produce syngas and high-pressure steam. During 2006, we acquired a 50% interest in a joint venture that processes CO_2 for use in the food, beverage, chemical and oil industries. Our operations are conducted through our operating subsidiary, Genesis Crude Oil, L.P., and its subsidiaries.

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 a 7.25% interest in us through limited partner interests.

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 September 30, 2006 and December 31, 2005 and our results of operations for the three and nine months ended September 30, 2006 and 2005, our cash flows for the nine months ended September 30, 2006 and 2005, and our changes in partners capital for the nine months ended September 30, 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. We account for these investments using the equity method, as we exercise significant influence over their operating and financial policies. See Note 3.

No provision for federal or state 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. The State of Texas enacted a margin tax in May 2006 that we will be required to pay beginning in 2008. The method of calculation for this margin tax is similar to an income tax, requiring us to recognize currently the impact of this new tax on the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. See Note 13.

The financial statements included herein have been prepared by us without audit pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, they reflect all adjustments (which consist solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the financial results for interim periods. Certain information and notes normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. However, we believe that the disclosures are adequate to make the information presented not misleading. These financial statements should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2005 filed with the Securities and Exchange Commission.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. New Accounting Pronouncements

Adoption of SFAS 123(R) on January 1, 2006

On January 1, 2006, we adopted the provisions of SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123 (revised December 2004), Share-Based Payments . The adoption of this statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates. See Note 12.

EITF 04-13

We enter into buy/sell transactions that 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 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 have reflected the amounts of revenues and purchases for these transactions as a net amount in our consolidated statements of operations beginning with April 2006. Transactions for periods prior to April 2006 are not reflected as a net amount, however the amounts are disclosed parenthetically on the consolidated statements of operations. This change had no effect on operating income, net income or cash flows, however it did reduce both crude oil gathering and marketing revenues and crude oil costs by $65.9 million and $132.2 million for the three and nine months ended September 30, 2006, respectively.

SFAS 154

In May 2005, the FASB issued Statement of Financial Standards No. 154, Accounting Changes and Error Corrections (SFAS 154). This statement established new standards on the accounting for and reporting of changes in accounting principles and error corrections. SFAS 154 requires retrospective application to the financial statements of prior periods for all such changes, unless it is impracticable to do so. SFAS 154 was effective for us in the first quarter of 2006.

SFAS 157

In September 2006, the FASB issued Statement of Financial Standards No. 157, Fair Value Measurements (SFAS 157). This statement established a new definition of fair value, a fair value hierarchy for classification of the source of information used in fair value measurements, and new disclosures for assets and liabilities measured at fair value based on their level in the hierarchy. SFAS 157 will be effective for us in the first quarter of 2008, with early adoption in 2007 allowed. 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 fair value measurements for derivative instruments, impairment of assets, and asset retirement obligations. The calculation of the impact of this statement cannot be measured at this time.

SFAS 158

In September 2006, the FASB issued Statement of Financial Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158). This statement requires public entities with defined benefit pension plans and other postretirement plans to fully recognize, as an asset or liability, the overfunded or underfunded status of its benefit plans in its 2006 balance sheet. We do not expect SFAS 158 to have an impact on us as we have no defined benefit pension or other postretirement plans.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. Joint Ventures and Other Investments

T&P Syngas Supply Company

On April 1, 2005, we acquired a 50% interest in T&P Syngas Supply Company, a Delaware general partnership, for $13.4 million in cash from a subsidiary of ChevronTexaco Corporation. Praxair Hydrogen Supply Inc. owns the remaining 50% partnership interest in T&P Syngas. We paid for our interest in T&P Syngas with proceeds from our credit facilities.

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. 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 and nine months ended September 30, 2006 included $374,000 and $1,185,000, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $88,000 and $264,000, respectively. We received distributions from T&P Syngas of $0.6 million and $1.4 million during the three and nine months ended September 30, 2006, respectively.

The table below reflects summarized financial information for T&P Syngas at September 30, 2006.

		Nine Months Ended September 30, 2006 *(in thousands)*
Revenues	$	3,702
Operating expenses and depreciation		(1,345)
Other income		13
Net income	$	2,370

		September 30, 2006 *(in thousands)*
Current assets	$	1,294
Non-current assets		15,792
Total assets	$	17,086
Current liabilities	$	294
Partners capital		16,792

Total liabilities and partners capital	$	17,086

Sandhill Group, LLC

On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC, for $5 million in cash, from Magna Carta 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 paid for our interest in Sandhill with cash on hand. The terms of the acquisition 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. Should the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

cumulative distributable cash of Sandhill in the period beginning with 2006 average at least $1.5 million per year, and distributions to the members average at least $1.2 million per year, we will owe Magna Carta $1.0 million at the end of the year when the target is exceeded. If the distributable cash averages $2.0 million per year and distributions average $1.6 million per year in the period beginning with 2006, we will owe Magna Carta an additional $1.0 million.

During 2003, Sandhill was authorized to issue a series of Issuer Floating Rate Option Notes in an amount not to exceed $15,000,000. In 2003, Sandhill issued notes in the amount of $5,900,000 which are backed by a letter of credit from a bank and have a maturity date of December 1, 2013. At September 30, 2006, the outstanding balance of these notes was $4.7 million. We provide a guarantee of 50% of the letter of credit to Sandhill s bank; therefore, our guaranty represents $2.35 million. Sandhill makes principal payments totaling $0.6 million annually. We have recorded the estimated fair value of this guarantee of $0.1 million as a long-term liability in our consolidated balance sheet, with a corresponding increase to our investment in Sandhill.

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. We paid $3.8 million more for our interest in Sandhill than our share of partners capital on the balance sheet of Sandhill at the date of the acquisition. This excess amount of the purchase price over the equity in Sandhill has been allocated to the property and equipment of Sandhill and certain intangible assets based on the fair value of those assets, with the remainder of the excess purchase price of $0.7 million allocated to goodwill. The amount allocated to property and equipment and intangible assets is being amortized using the straight-line method over the remaining useful lives of those assets. Our consolidated statements of operations for the three and nine months ended September 30, 2006 included $46,000 and $136,000, respectively, as our share of the operating earnings of Sandhill, reduced by amortization of the excess purchase price of $65,000 and $138,000, respectively. We received distributions from Sandhill of $0.1 million during the six month period that we have owned our interest.

The table below reflects summarized financial information for Sandhill at September 30, 2006, for the period since we acquired our interest in Sandhill.

		Three Months Ended September 30, 2006
		(in thousands)
Revenues	$	5,393
Operating expenses and depreciation		(5,121)
Other income		2
Net income	$	274

		September 30, 2006
		(in thousands)
Current assets	$	1,571
Non-current assets		6,742
Total assets	$	8,313

Current liabilities	$	957
Non-current liabilities		4,688
Members capital		2,668
Total liabilities and members capital	$	8,313

Other Projects

In 2006, we invested $0.7 million in a petroleum coke to ammonia project that is in the development stage. We have also committed to invest an additional $0.3 million. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

4. Debt

At September 30, 2006, we had a $100 million credit facility comprised of a $50 million revolving line of credit for acquisitions and a $50 million working capital revolving facility. At September 30, 2006, we had $6.0 million in loans and $9.2 million in letters of credit (primarily for crude oil purchases in September and October 2006) outstanding under the working capital portion and no balance outstanding under the acquisition portion of our credit facility. At September 30, 2006, the weighted average interest rate on the debt was 8.5%.

The aggregate amount that we may have outstanding at any time under the working capital portion of our credit facility is subject to a borrowing base calculation. The borrowing base is limited to $50 million and is calculated monthly. At September 30, 2006, the borrowing base was $49.5 million. The remaining amount available for borrowings at September 30, 2006 was $9.0 million under the working capital portion and $50.0 million under the acquisition portion of the credit facility.

Certain restrictive covenants in the credit facility limit our ability to make distributions to our unitholders and the general partner. The credit facility requires we maintain a cash flow coverage ratio of 1.1 to 1.0. In general, this calculation compares operating cash inflows (as adjusted in accordance with the credit facility), less maintenance capital expenditures, to the sum of interest expense and distributions. At September 30, 2006, the calculation resulted in a ratio of 1.7 to 1.0. The credit facility also requires that the level of operating cash inflows during the prior twelve months, as adjusted in accordance with the credit facility, be at least $8.5 million. At September 30, 2006, the result of this calculation was $21.4 million. Our credit facility also requires that we meet certain other financial ratios, such as a current ratio, leverage ratio and funded indebtedness to capitalization ratio. If we meet these covenants, we are otherwise not limited in making distributions.

We have recently received commitments from a syndicate of banks and are in the process of completing documentation to replace our existing facility with a new facility. We expect to complete the documentation of the new facility by the end of November 2006. This new facility, with a maximum facility amount of $500 million (subject to customary borrowing conditions), would have an initial commitment amount under the facility of $125 million. The commitment amount could be increased up to the maximum facility amount to allow us to make acquisitions.

5. Partners Capital and Distributions

Partners Capital

Partners capital at September 30, 2006 and December 31, 2005 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) 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. We paid distributions as follows in 2005 and 2006:

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

Distribution For	Date Paid or to be Paid	Per Unit Amount	Total Amount (000 s)
Fourth quarter 2004	February 2005	$ 0.15	$ 1,426
First quarter 2005	May 2005	$ 0.15	$ 1,426
Second quarter 2005	August 2005	$ 0.15	$ 1,426
Third quarter 2005	November 2005	$ 0.16	$ 1,521
Fourth quarter 2005	February 2006	$ 0.17	$ 2,391
First quarter 2006	May 2006	$ 0.18	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,672
Third quarter 2006	November 2006	$ 0.20	$ 2,813

The total amounts in the table above increased with the distribution for the fourth quarter of 2005 due to the issuance of 4,470,630 new common units in December 2005.

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 in excess of $0.25 per unit, 23.5% of any distributions in excess of $0.28 per unit and 49% of any distributions in excess of $0.33 per unit without duplication. We have not paid any incentive distributions through September 30, 2006.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net Income Per Common Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands, except per unit amounts)			
Numerators for basic and diluted net income per common unit:				
Income (loss) from continuing operations	$ 1,695	$ (641)	$ 7,700	$ 2,599
Less general partner 2% ownership	34	(13)	154	52
Income (loss) from continuing operations available for common unitholders	$ 1,661	$ (628)	$ 7,546	$ 2,547
Income from discontinued operations	$	$ 45	$	$ 318
Less general partner 2% ownership		1		6
Income from discontinued operations available for common unitholders	$	$ 44	$	$ 312
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	9,314	13,784	9,314
Basic and diluted net income per Common Unit:				
Income (loss) from continuing operations	$ 0.12	$ (0.06)	$ 0.55	$ 0.28
Income from discontinued operations				0.03
Income from cumulative effect adjustment				
Net income (loss)	$ 0.12	$ (0.06)	$ 0.55	$ 0.31

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 investments in joint ventures with a syngas processing facility and a CO_2 processing facility, and (3) Crude Oil Gathering and Marketing the purchase and sale of crude oil at various points along the distribution chain. In prior periods, our Industrial Gases segment was called CO_2 Marketing. 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.

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	Pipeline Transportation	Industrial Gases [(a)]	Crude Oil Gathering and Marketing	Total
		(in thousands)		
Three Months Ended September 30, 2006				
Segment margin excluding depreciation and amortization [(b)]	$ 3,458	$ 3,155	$ 1,999	$ 8,612
Capital expenditures	$ 216	$ 194	$ 34	$ 444
Maintenance capital expenditures	$ 146	$	$ 34	$ 180
Revenues:				
External Customers	$ 6,232	$ 4,262	$ 218,141	$ 228,635
Intersegment [(d)]	916			916
Total revenues of reportable segments	$ 7,148	$ 4,262	$ 218,141	$ 229,551
Three Months Ended September 30, 2005				
Segment margin excluding depreciation and amortization [(b)]	$ 1,885	$ 1,688	$ 1,053	$ 4,626
Capital expenditures	$ 555	$	$ 38	$ 593
Maintenance capital expenditures	$ 407	$	$ 7	$ 414
Revenues:				
External Customers	$ 5,989	$ 2,523	$ 291,074	$ 299,586
Intersegment [(d)]	991			991
Total revenues of reportable segments	$ 6,980	$ 2,523	$ 291,074	$ 300,577
Nine months Ended September 30, 2006				
Segment margin excluding depreciation and amortization [(b)]	$ 9,862	$ 8,808	$ 6,074	$ 24,744
Capital expenditures	$ 639	$ 5,744	$ 190	$ 6,573
Maintenance capital expenditures	$ 370	$	$ 190	$ 560
Net fixed and other long-term assets [(c)]	$ 32,516	$ 52,704	$ 5,469	$ 90,689
Revenues:				
External Customers	$ 20,158	$ 11,543	$ 691,414	$ 723,115
Intersegment [(d)]	3,381			3,381
Total revenues of reportable segments	$ 23,539	$ 11,543	$ 691,414	$ 726,496
Nine months Ended September 30, 2005				
Segment margin excluding depreciation and amortization [(b)]	$ 7,136	$ 5,222	$ 2,391	$ 14,749
Capital expenditures	$ 5,157	$ 13,418	$ 315	$ 18,890

Maintenance capital expenditures	$ 1,070	$	$ 55	$ 1,125
Net fixed and other long-term assets [c]	$ 35,284	$ 37,739	$ 6,140	$ 79,163
Revenues:				
External Customers	$ 18,579	$ 7,371	$ 785,774	$ 811,724
Intersegment [d]	2,597			2,597
Total revenues of reportable segments	$ 21,176	$ 7,371	$ 785,774	$ 814,321

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a) Industrial gases segment margin 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 September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Segment margin excluding depreciation and amortization	$ 8,612	$ 4,626	$ 24,744	$ 14,749
General and administrative expenses	(4,539)	(3,210)	(10,448)	(6,536)
Depreciation, amortization and impairment	(2,107)	(1,601)	(6,000)	(4,695)
Net (loss) gain on disposal of surplus assets	(11)	84	38	482
Interest expense, net	(260)	(540)	(645)	(1,401)
Income tax credit			11	

Income (loss) from continuing operations	$ 1,695	$ (641)	$ 7,700	$ 2,599

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 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.

	Nine months Ended September 30,	
	2006	2005
	(in thousands)	
Transactions with Denbury, our General Partner and Sandhill		
Crude oil purchases from Denbury	$ 1,496	$ 3,422
Crude oil sales to Denbury	$	$ 22
Truck transportation services provided to Denbury	$ 573	$ 591
Pipeline transportation services provided to Denbury	$ 3,110	$ 2,858
Payments received under direct financing leases from Denbury	$ 889	$ 890
Pipeline transportation income portion of direct financing lease fees	$ 495	$ 521
Pipeline monitoring services provided to Denbury	$ 45	$ 22
Directors fees paid to Denbury	$ 90	$ 90
CO_2 transportation services provided by Denbury	$ 3,498	$ 2,296
Operations, general and administrative services provided by our general partner	$ 13,330	$ 11,487
Distributions to our general partner on its limited partner units and general partner interest	$ 703	$ 396

Sales of CO_2 to Sandhill (for the period since Sandhill became a related party) See Note 3	$	1,352	$	

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.

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Denbury is 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 pay Denbury for the services of four Denbury officers who serve as directors of our general partner at the same rate at which our independent directors are paid.

CO_2 Operations and Transportation

We acquired contracts, along with volumetric production payments, from Denbury in 2005 and prior years. Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver the CO_2 for us to our customers.

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 September 30, 2006 and December 31, 2005, we owed Denbury $0.9 million and $1.9 million, respectively, for purchases of crude oil and CO_2 transportation charges. Denbury owed us $.05 million and $0.5 million for transportation services at September 30, 2006 and December 31, 2005, respectively. We owed our general partner $1.0 million and $1.1 million at September 30, 2006 and December 31, 2005, respectively, for administrative services.

At September 30, 2006, Sandhill owed us $0.5 million for purchases of CO_2.

Financing

Our general partner, a wholly owned subsidiary of Denbury, guarantees our obligations under our credit facility. Our general partner s principal assets are its general and limited partnership interests in us. Those obligations are not guaranteed by Denbury or any of its other subsidiaries.

We guarantee 50% of the obligation of Sandhill to a bank. At September 30, 2006, the total amount of Sandhill s obligation to the bank was $4.7 million; therefore, our guarantee was for $2.35 million. 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.

Occidental Energy Marketing, Inc., Shell Oil Company and Calumet Specialty Products Partners, L.P. accounted for 21%, 18% and 11% of total revenues in the first nine months of 2006, respectively. Occidental Energy Marketing, Inc. and Shell Oil Company accounted for 27% and 12% of total revenues for the first nine months of 2005, respectively. The majority of the revenues from these three customers in both periods relate to our gathering and marketing operations.

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9. Supplemental Cash Flow Information

We received interest payments of $164,000 and $38,000 for the nine months ended September 30, 2006 and 2005, respectively. Payments of interest and commitment fees were $768,000 and $931,000 for the nine months ended September 30, 2006 and 2005, respectively.

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 September 30, 2006, 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 September 30, 2006. We marked these contracts to fair value at September 30, 2006. During the nine months ended September 30, 2006, we recorded gains of $97,000 related to derivative transactions, which is included in the consolidated statements of operations under the caption Crude Oil Costs .

At September 30, 2006, we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During the nine months ended September 30, 2006, we recognized losses, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $53,000. 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.

The consolidated balance sheet at September 30, 2006 includes an increase in other current assets of $260,000 as a result of these derivative transactions. The consolidated balance sheet at December 31, 2005 included an increase in other current assets of $6,000 as a result of derivative transactions.

At September 30, 2005, 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 September 30, 2005. We marked these contracts to fair value at September 30, 2005. During the three months ended September 30, 2005, we recorded a loss of $8,000 related to derivative transactions, which are included in the consolidated statements of operations under the caption Crude Oil Costs . For the nine month period in 2005, these derivative transactions had no effect on earnings.

At September 30, 2005, 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 and nine months ended September 30, 2005, we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory totaling

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$155,000 and $147,000, respectively. 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.

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 September 30, 2006 and December 31, 2005.

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 September 30, 2006 were $6.0 million and are reflected in the consolidated balance sheet.

We guaranty 50% of the obligations of Sandhill under a credit facility with a bank. At September 30, 2006, Sandhill owed $4.7 million; therefore our guarantee was $2.35 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot be accurately estimated at this time, we anticipate that we will expend a total of approximately $0.7 million in 2006 and 2007 for testing, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines. After 2007 we expect that our annual expenditures for integrity testing, repairs and improvements to average from $1.0 million to $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 (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 and others 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.

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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, and the appropriate state regulatory agencies have approved, a plan of remediation for certain affected soils and affected groundwater at Jay Station. 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

We have taken additional security measures since the terrorist attacks of September 11, 2001 in accordance with guidance provided by the Department of Transportation and other government agencies. We cannot assure you that these security measures would protect our facilities from a terrorist attack. Any future attacks on us or our customers or competitors could have a material effect on our business, whether insured or not. We believe we are adequately insured for public liability and property damage to others and that our coverage is comparable 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 would consider reasonable.

As discussed in Note 3, we have committed to invest an additional $0.3 million in a potential investment project.

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

Under the terms of our stock appreciation rights plan, all regular, full-time active employees (with the exception of the new senior management team) and the members of the Board are eligible to participate in the plan. The plan is administered by the Compensation Committee of the Board, who shall determine, in its full discretion, the number of rights to award, the grant date of the units and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit.

The rights have a term of 10 years from the date of grant. The initial award to a participant will vest one-fourth each year beginning with the first anniversary of the grant date of the award. Subsequent awards to participants will vest on the fourth anniversary of the grant date. If the right has not been exercised at the end of the ten year term and the participant has not terminated his employment with us, the right will be deemed exercised as of the date of the right s expiration and a cash payment will be made as described below.

Upon vesting, the participant may exercise his rights and receive a cash payment calculated as the difference between the averages of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. The cash payment to the participant will be net of any applicable withholding taxes required by law. If the Committee determines, in its full discretion, that it would cause significant financial harm to the Partnership to make cash payments to participants who have exercised rights under the plan, then the Committee may authorize deferral of the cash payments until a later date.

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Termination for any reason other than death, disability or normal retirement (as these terms are defined in the plan) will result in the forfeiture of any non-vested rights. Upon death, disability or normal retirement, all rights will become fully vested. If a participant is terminated for any reason within one year after the effective date of a change in control (as defined in the plan) all rights will become fully vested.

Prior to January 1, 2006, we had accounted for this plan under the provisions of FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans , which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. On January 1, 2006, we adopted SFAS No. 123 (revised December 2004), Share-Based Payments . The adoption of this statement required that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we include the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount at each balance sheet date with the adjustment reflected in the statement of operations.

The estimates that we made upon the adoption of this standard included the following:

In determining the expected life of the rights, we used the simplified method allowed by the Securities and Exchange Commission. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee exercise patterns. The simplified method produces an initial expected life of 6.25 years for those rights we issued that vest 25% per year for four years, and an initial expected life of 7 years for those rights we issued that fully vest at the end of a four-year period.

The expected volatility of our units was computed using the historical period we believe is representative of future expectations. We determined what period to use in the historical period by considering whether we were paying distributions to our unitholders, and at what rate. The expected volatility used in the fair value calculations was approximately 33% and 32% at January 1, 2006 and September 30, 2006, respectively.

The risk-free interest rate was determined from current yields for U.S. Treasury zero-coupon bonds with a term similar to the remaining expected life of the rights. At January 1, 2006, the risk-free interest rate ranged from 4.39% to 4.41%. At September 30, 2006, the risk-free interest rate ranged from 4.67% to 4.69%.

In determining our expected future distribution yield, we considered our history of distribution payments, our expectations for future payments, and the distribution yields of entities similar to us. At January 1, 2006 and September 30, 2006, we used an expected future distribution yield of 6%.

The final estimate we were required to make is the expected forfeitures of non-vested rights and expirations of vested rights. We have very limited experience with employee forfeiture and expiration patterns, as our plan was not initiated until December 31, 2003. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also used different estimates for different groups of employees.

At December 31, 2005, we had a recorded liability of $0.8 million, 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

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from the cumulative effect of the adoption of a new accounting principle on our statement of operations. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material. The adjustment of the liability to its fair value of $1.5 million at September 30, 2006, resulted in general and administrative expense of $0.4 million and $0.9 million for the three and nine month periods ended September 30, 2006, respectively.

The following table reflects rights activity under our plan as of December 31, 2005, and changes during the nine months ended September 30, 2006:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Yrs)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006	596,128	$ 10.39		
Granted	66,153	$ 15.65		
Exercised	(45,581)	$ 9.44		
Forfeited or expired	(78,756)	$ 10.57		
Outstanding at September 30, 2006	537,944	$ 11.03	8.2	$ 1,666
Exercisable at September 30, 2006	151,842	$ 9.96	7.5	$ 888

The weighted-average fair value at September 30, 2006 of rights granted during the nine months of 2006 was $3.11 per right. The total intrinsic value of rights exercised during the first three quarters of 2006 was $270,000, which was paid in cash to the participants.

At September 30, 2006, there was $0.7 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 September 30, 2006 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet date until the rights are exercised, forfeited or expire. For the awards outstanding at September 30, 2006, the remaining cost will be recognized over a weighted average period of 1 year.

13. Income Taxes

In May 2006, the State of Texas enacted a margin tax that will become effective in 2008. This margin tax 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 the provisions of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes , we are required to record the effects on deferred taxes for a change in tax rates or tax law in the period that includes the enactment date.

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 have recorded a deferred tax asset in the amount of $11,000. We believe that we will be able to utilize this deferred tax asset at September 30, 2006, and therefore have provided no valuation allowance against this deferred tax asset.

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14. Subsequent Events

Distribution

On October 23, 2006, the Board of Directors of the general partner declared a cash distribution of $0.20 per unit for the quarter ended September 30, 2006. The distribution will be paid November 14, 2006 to our general partner and all common unitholders of record as of the close of business on November 2, 2006.

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

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

Overview

New Management Team and New Credit Facility

Acquisitions in 2006

Results of Operations

Liquidity and Capital Resources

Commitments and Off-Balance Sheet Arrangements

Other Matters

New Accounting Pronouncements

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

Overview

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 Sates. 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 our unitholders 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. With the new credit agreement discussed in *New Management Team and New Credit Facility* below, we will be positioned to make accretive acquisitions and develop internal growth projects. 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. 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.

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Increases in cash flow generally result in increases in Available Cash, which we distribute quarterly to our unitholders and general partner. During the third quarter of 2006, we generated $4.1 million of Available Cash before Reserves, and distributed $2.8 million to our unitholders and general partner. During the third quarter of 2006, cash provided by operations was $8.3 million.

In the third quarter of 2006, we generated net income of $1.7 million, or $0.12 per common unit. For the nine month period ended September 30, 2006, net income totaled $7.7 million, or $0.55 per common unit. The results for 2006 include increased segment margin from our pipeline transportation and crude oil gathering and marketing segments and significant contributions from asset acquisitions in the industrial gases segment. We also adopted a new accounting pronouncement affecting the manner in which we value and account for our stock appreciation rights plan. We recorded a charge of $1.3 million in the third quarter of 2006 related to transition costs for the change in our senior management team that reduced our net income and Available Cash for both the third quarter and the nine-month period.

We increased our cash distribution by $0.01 per unit for the each of the first and second quarters of 2006 (which were paid in May and August 2006) and increased our cash distribution by $0.01 per unit again to $0.20 per unit for the third quarter of 2006. This distribution will be paid in November 2006. This distribution represented a 25% increase from our distribution of $0.16 per unit for the third quarter of 2005.

New Management Team and New Credit Facility

On August 8, 2006, we hired three senior executive officers: Grant E. Sims, former CEO of Leviathan Gas Pipeline Partners, L.P. was appointed as the new Chief Executive Officer and a member of the Board of Directors; Joseph A. Blount, Jr., former President and Chief Operating Officer of Unocal Midstream & Trade, was appointed as President and Chief Operating Officer; and Brad N. Graves, former Vice President of Enterprise Products Partners, L.P., was appointed as Executive Vice President of Business Development. This management team will be responsible for designing and implementing a growth-oriented strategy that will include acquisitions from third parties, development projects and, ultimately, acquisitions from (or lease arrangements with) Denbury. A company owned by Messrs. Sims, Blount and Graves will have the opportunity to earn up to 20% of the equity interest in our general partner (currently owned 100% by Denbury), subject to meeting certain performance criteria.

Given the performance of our existing business segments, we have the flexibility to now focus to a greater extent on increasing the long-term value of our partnership units. To further that strategy, we have recently received commitments from a syndicate of banks and are in the process of completing documentation to replace our existing credit facility with a new facility. This facility, with up to $500 million of ultimate availability, would position us to execute our plan to make significant accretive investments to grow the partnership

Acquisitions in 2006

Sandhill Investment

On April 1, 2006, we acquired a 50% partnership interest in Sandhill Group, LLC for $5 million from Magna Carta 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.

The acquisition was financed with cash on hand. The terms of the acquisition include earnout provisions such that additional payments of up to $2.0 million would be paid by us to Magna Carta if Sandhill achieves targeted performance levels during the seven years between 2006 and 2012 inclusive. We have also guaranteed to Sandhill s lender 50% of the outstanding debt of $4.7 million, or $2.35 million.

Sandhill is managed by a management committee consisting of two representatives each from Magna Carta and us. Our equity in the earnings of Sandhill is included in our industrial gases segment. Additional discussion of the earnout provisions and guaranty of Sandhill s debt is included in Note 3 to the financial statements and in Commitments and Off-Balance Sheet Arrangements below.

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Results of Operations

Pipeline Transportation Operations

We operate three crude oil common carrier pipeline systems in a four state area. We refer to these pipelines as our Texas System, Mississippi System and Jay System. Volumes shipped on these systems are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(barrels per day)			
Mississippi	17,078	14,924	16,828	15,568
Jay	14,785	11,704	13,321	13,909
Texas	30,747	33,536	32,335	32,213

The Mississippi System begins in Soso, Mississippi and extends to Liberty, Mississippi. At Liberty, shippers can transfer the crude oil to Capline, a pipeline system that moves crude oil from the Gulf Coast to refineries in the Midwest. During recent years, we have improved the system to handle the increased volumes produced by Denbury and transported on the pipeline. In order to handle future increases in production volumes in the areas that are expected, we have made capital expenditures for tank, station and pipeline improvements and we intend to make further improvements. See *Capital Expenditures* under Liquidity and Capital Resources below.

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, additional crude oil gathering and CO_2 supply infrastructure will be needed, although we can provide no assurance that we will be involved in any such projects.

The Jay pipeline system in Florida/Alabama ships crude oil from fields with relatively short remaining production lives. While new production in the area surrounding the Jay System has offset some of the declining production curves of the older producing fields in the area, we do not know if this new production will be sufficient to continue to offset declining production from existing wells in the area. The new production produces greater tariff revenue for us due to the greater distance that the crude oil travels on the pipeline. This increased revenue, increases in tariff rates each year on the remaining segments of the pipeline, sales of pipeline loss allowance volumes, and operating efficiencies that have decreased operating costs have contributed to sustain our cash flows from the Jay System at a level that has offset the effects of the decline in volumes. Therefore we do not anticipate that the declines in volumes will affect the recoverability of our remaining net investment in the Jay System.

Should the production surrounding the Jay System decline such that it becomes uneconomical to continue to operate the pipeline in crude oil service, we believe that the best use of the Jay System may be to convert it to natural gas service. We have reviewed opportunities to effect such a conversion and would do so again if performance of the Jay System suggested it would be prudent to do so. Part of the process will involve finding alternative methods for us to continue to provide crude oil transportation services in the area. While we believe this initiative has long-term potential, it is not expected to have a substantial impact on us during 2006 or 2007.

Volumes on our Texas System averaged 32,335 barrels per day during the first nine months of 2006. The crude oil that enters our system comes to us at West Columbia where we have a connection to TEPPCO s South Texas System and at Webster where we have connections to two other pipelines. One of these connections at Webster is with ExxonMobil Pipeline and is used to receive volumes that originate from TEPPCO s pipelines. We have a joint tariff with TEPPCO under which we earn approximately $0.22 per barrel on the majority of the barrels we deliver to the shipper s facilities. Substantially all of the volumes being shipped on our Texas System go to two refineries on the Texas Gulf Coast.

Our Texas System is dependent on connecting carriers for supply, and on the two refineries for demand for our services. Volumes on the Texas System fluctuate as a result of changes in the supply available for the two

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refineries to acquire and ship on our pipeline. We lease tankage in Webster on the Texas System of approximately 165,000 barrels. We have a tank rental reimbursement agreement with the primary shipper on our Texas System to reimburse us for leasing that storage capacity. 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.

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. This arrangement has been accounted for as a direct financing lease.

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 equipment failure or power cost increases. We perform regular maintenance on our assets to keep them in good operational condition and to minimize cost increases.

Operating results from continuing operations for our pipeline transportation segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 3,792	$ 3,314	$ 10,659	$ 10,096
Sales of crude oil pipeline loss allowance volumes	1,669	1,158	5,064	3,456
Revenues from direct financing leases of CO_2 pipelines	84	88	257	271
Tank rental reimbursements and other miscellaneous revenues	144	134	452	432
Revenues from crude oil and CO_2 tariffs and related sources	5,689	4,694	$ 16,432	$ 14,255
Revenues from natural gas tariffs and sales	1,459	2,286	7,107	6,921
Natural gas purchases	(1,341)	(2,178)	(6,582)	(6,590)
Pipeline operating costs	(2,349)	(2,917)	(7,095)	(7,450)
Segment margin	$ 3,458	$ 1,885	$ 9,862	$ 7,136
Crude oil pipeline volumes per day barrels	62,610	60,164	62,484	61,690

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

Pipeline segment margin increased $1.6 million or 83% to $3.5 million for the three months ended September 30, 2006, as compared to $1.9 million for the three months ended September 30, 2005. Revenues from crude oil and CO_2 tariffs and related sources added the majority of the increase for the period. Higher market prices for crude oil added $0.5 million to pipeline loss allowance revenues. Volumes on the pipelines increased, combining with increased tariffs to add $0.5 million to crude oil tariff revenues.

Also contributing to the improved quarterly results was a reduction of $0.6 million in the costs of operating our pipelines. We substantially completed the first cycle of our required testing and repairs under our integrity management program during 2005, with a substantial portion of those costs occurring in the third quarter of 2005. Similar costs were not required in the third quarter of 2006.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Pipeline segment margin increased $2.7 million or 38% to $9.9 million for the nine months ended September 30, 2006, as compared to the nine months ended September 30, 2005. Revenues from crude oil and CO_2 tariffs and related sources increased by $2.2 million with the majority of that increase resulting from the effects of higher crude oil market prices on pipeline loss allowance revenues.

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Segment margin from our natural gas pipelines also increased by $0.2 million, primarily as a result of improved volumes.

As discussed in the third quarter comparison, we substantially completed our first cycle of IMP requirements in 2005. Although costs related to electricity, insurance and right-of way maintenance increased, the reduction in IMP activities in 2006 resulted in an overall decline in pipeline operating costs of $0.4 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% interests in T&P Syngas and Sandhill.

CO_2

We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. We acquired those contracts, as well as the CO_2 necessary to satisfy our expected obligations under those contracts, in three separate transactions with Denbury. We sell our CO_2 to customers who treat the CO_2 and sell it to end users for use for beverage carbonation and food chilling and freezing and other applications. Our compensation for supplying CO_2 to our industrial customers is the difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our volumetric production payments (VPPs), minus transportation costs. We expect our CO_2 contracts to provide stable cash flows until they expire, at which time we will attempt to extend or replace those contracts, including acquiring the necessary CO_2 supply. At September 30, 2006, we have 216.8 Bcf of CO_2 remaining under the VPPs.

The terms of our contracts with the industrial CO_2 customers include minimum take-or-pay and maximum delivery volumes. The maximum daily contract quantity per year in the contracts totals 98,000 Mcf. Under the minimum take-or-pay volumes, the customers must purchase a total of 51,000 Mcf per day whether received or not. Any volume purchased under the take-or-pay provision in any year can then be recovered in a future year as long as the minimum requirement is met in that year. In the three years ended December 31, 2005, all of our customers purchased more than their minimum take-or-pay quantities.

Our seven industrial contracts expire at various dates beginning in 2010 and extending through 2023. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price. One of the seven contracts is with Sandhill in which we hold a 50% ownership interest. The contract with Sandhill expires in 2023.

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 2006, 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. The table below depicts these seasonal fluctuations. The average daily sales (in Mcfs) of CO_2 for each quarter in 2006, 2005 and 2004 under these contracts (including volumes sold by Denbury on the contracts we acquired in the third quarter of 2004 and fourth quarter of 2005) were as follows:

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Quarter	2006	2005	2004
First	66,565	67,434	63,953
Second	73,495	73,307	73,734
Third	82,072	77,264	78,097
Fourth		77,089	70,696

Syngas

On April 1, 2005, we acquired from TCHI Inc., a wholly owned subsidiary of ChevronTexaco Global Energy Inc., a 50% partnership interest in T&P Syngas for $13.4 million in cash, which we funded with proceeds from our credit facility. T&P Syngas is a partnership which 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. Praxair has the exclusive right to use the facility through at least 2016 (term extendable at Praxair s option for two additional five year terms). Praxair also is our partner in the joint venture and owns the remaining 50% interest. We recognize our share of the earnings of T&P Syngas in each period. We are amortizing the excess of the price we paid for our interest in T&P Syngas over our share of the equity of T&P Syngas over the remaining useful life of the assets of T&P Syngas. This excess of $4.0 million is being amortized over eleven years. We receive cash distributions from T&P Syngas quarterly.

Sandhill

On April 1, 2006, we acquired from Magna Carta Group, LLC a 50% partnership interest in Sandhill for $5.0 million in cash, which we funded with cash on hand. Magna Carta owns the remaining 50% of 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, chemicals and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury. This contract expires in 2023, and provides for a daily contract quantity of 16,000 Mcf per day with a take-or-pay minimum quantity of 2,500,000 Mcf.

We recognize our share of the earnings of Sandhill in each period. We paid $3.8 million more for our interest in Sandhill than our share of the equity on the balance sheet of Sandhill at the date of acquisition. This excess of the purchase price over our share of the equity of Sandhill has been allocated to the property and equipment and intangible assets based on the fair value of those assets, with the remaining $0.7 million allocated to goodwill. We are amortizing the amount allocated to property, equipment and intangibles over the remaining useful lives of those assets. The amount allocated to goodwill will be reviewed for impairment periodically.

Segment margin

Operating results from operations for our industrial gases segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands, except volumes per day)			
Revenues from CO_2	$ 4,262	$ 2,523	$ 11,543	$ 7,371
CO_2 transportation and other costs	(1,374)	(843)	(3,654)	(2,409)
Equity in earnings of joint ventures	267	8	919	260
Segment margin	$ 3,155	$ 1,688	$ 8,808	$ 5,222

Volumes per day from continuing operations:				
CO_2 Sales Mcf	82,072	51,386	74,321	50,094

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Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

The increasing margins from the industrial gases segment between the third quarters of 2005 and 2006 are primarily attributable to the acquisition we made in the fourth quarter of 2005 in this segment. The average revenue per Mcf sold increased 6% between the periods, due to inflation adjustments in the contracts and variations in the volumes sold under each contract.

Transportation costs for the CO_2 on Denbury s pipeline have increased due to the increased volume and the effect of the annual inflation factor in the rate paid to Denbury. The rate per Mcf in 2006 increased 4% over the 2005 third quarter rate.

Our share of the operating income of T&P Syngas for the third quarter of 2006 was $374,000. We reduced the amount we recorded as our equity in T&P Syngas by $88,000 as amortization of the excess purchase price of T&P Syngas. During the third quarter of 2006, T&P Syngas paid us a distribution of $608,000 attributable to the second quarter of 2006.

Our share of the operating income of Sandhill for the third quarter of 2006 was $46,000. We reduced the amount we recorded as our equity in Sandhill by $65,000 for amortization of the excess purchase price of Sandhill. We received a distribution of $65,000 during the third quarter attributable to the second quarter.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

The nine month period in 2006 includes the margins from CO2 sales under industrial contracts acquired in 2005, providing approximately $2.7 million of the $3.6 million improvement in segment margin. Variations in the volumes sold under each of the existing group of contracts, combined with inflation adjustments in the contracts, added additional revenues. The effect of the annual inflation factor in the rate paid to Denbury increased transportation costs.

T&P Syngas provided $921,000 of the equity from joint ventures for the nine-month period. Our share of T&P Syngas earnings was $1,185,000, and we recorded $264,000 for amortization of the excess purchase price. In 2006, T&P has paid $1,438,000 in cumulative distributions to us.

For the six months in 2006 that we have owned our interest in Sandhill, we recorded $136,000 as our equity in the earnings of Sandhill, and we recorded $138,000 of amortization of the excess purchase price.

Crude Oil Gathering and Marketing Operations

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 price (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

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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 to the 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.

Field operating costs consist of the costs to operate our fleet of leased trucks used to transport crude oil, and the costs to maintain the trucks and assets used in the crude oil gathering operation. More than 60% of these costs are variable and increase or decrease with volumetric changes. These costs include payroll and benefits (as drivers are paid on a commission basis based on volumes), maintenance costs for the trucks (as we lease the trucks under full service maintenance contracts under which we pay a maintenance fee per mile driven), and fuel costs. Fuel costs also fluctuate based on changes in the market price of diesel fuel. Fixed costs include the base lease payment for the vehicle, insurance costs and costs for environmental and safety related operations.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands, except volumes per day)			
Revenues[1]	$ 218,141	$ 291,074	$ 691,414	$ 785,774
Crude oil costs[1]	212,737	285,939	674,870	771,286
Field operating costs	3,405	4,082	10,470	12,097
Segment margin	$ 1,999	$ 1,053	$ 6,074	$ 2,391
Volumes per day from continuing operations:				
Crude oil wellhead barrels[1]	31,626	37,213	34,009	39,818
Crude oil total barrels[1]	34,190	51,639	38,243	55,211
Crude oil transported only barrels	3,060	2,212	3,363	3,335

(1)

Excludes buy/sell volumes and amounts beginning April 1, 2006.

Three Months Ended September 30, 2006 as Compared to Three Months Ended September 30, 2005

Gathering and marketing segment margins increased $0.9 million to $2.0 million for the three months ended September 30, 2006, as compared to $1.1 million for the three months ended September 30, 2005. The primary reasons for this increase in segment margin were a decrease in field costs of $0.7 million and a $0.3 million

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improvement in marketing margins. Adding to the improved segment margin was a $0.1 million increase in revenues from volumes that we transported for a fee but did not purchase.

The $0.7 million decrease in field costs in 2006 is attributable to a reduction in the size of our fleet. When we leased new trucks late in 2005, we reduced the size of the fleet to better match the volumes being purchased. This reduction in fleet size reduced personnel and truck lease costs. Higher fuel costs offset part of the reduction. Fuel costs during the 2006 quarter increased more than $0.29 per gallon over the 2005 quarter.

Marketing margins have improved between the periods as we have focused on eliminating volumes providing insufficient contribution to our segment margin. New business with higher profit margins has replaced some of these volumes.

Nine Months Ended September 30, 2006 as Compared to Nine Months Ended September 30, 2005

For the nine month periods, gathering and marketing segment margins increased $3.7 million, to more than twice the result for the 2005 period. Reduced field operating costs added $1.6 million to margin. Most of the remaining increase of $2.1 million resulted again from a focus on eliminating less profitable volumes, and increasing profitability on the volumes retained. Additionally, while we have been in a contango crude oil price market for most of 2005 and 2006, the contribution to segment margin from our inventory hedges has been greater in the 2006 period.

The majority of the decrease in field operating costs of $1.6 million is attributable to a reduction in the size of our trucking fleet, combined with a reserve we recorded in 2005 of $0.4 million for 40% of the expected costs to remediate Jay Station. The fleet size reduction reduced personnel and lease costs for the tractor/trailers by a total of $0.5 million. Insurance costs were also reduced by $0.3 million due to the decreased activity level. These reductions were partially offset by increased fuel costs, which added $0.2 million to field costs despite the smaller fleet size. Prices for diesel fuel for the 2006 period were approximately $0.44 per gallon greater than in the 2005 period.

Other Costs and Interest

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Expenses excluding effects of stock appreciation rights plan and transition costs	$ 2,804	$ 2,465	$ 8,240	$ 7,077
Transition costs related to new management team	1,293		1,293	
Stock appreciation rights plan expense (credit)	442	745	915	(541)
Total general and administrative expenses	$ 4,539	$ 3,210	$ 10,448	$ 6,536

Three Months Ended September 30, 2006 Compared with Three Months Ended September 30, 2005

General and administrative expenses increased by $1.3 million. Transition costs related to our new management team added $1.3 million to expenses. A $0.3 million decrease attributable to our employee stock appreciation rights plan was offset by increases totaling $0.3 million in other general and administrative costs.

In August 2006, we added a new management team as discussed in our *Overview* above. Severance costs and other costs related to the transition totaled $1.3 million.

Our stock appreciation rights plan is a long-term incentive plan whereby rights are granted for the grantee to receive cash equal to the difference between the grant price and common unit price at date of exercise. The rights vest over several years. In 2005 we accounted for these rights under the provisions of FASB Interpretation No. 28, which provided that we calculate the difference between the current market price for our common units and the strike price of the rights. On January 1, 2006, we adopted the provisions of a new accounting pronouncement for accounting for stock-based compensation. Under this pronouncement, we determine the fair value of the rights at each balance sheet date, and record the change in fair value over the service period required from our employees

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before the rights vest. See additional discussion below under Cumulative Effect Adjustment of Adoption of New Accounting Principle and in Note 12 to the financial statements.

The remaining increase in general and administrative expenses is attributable to employee costs. As a result of our improved results, the accrual for bonus compensation for our employees is $0.3 million greater than for the 2005 three-month period.

Nine Months Ended September 30, 2006 Compared with Nine Months Ended September 30, 2005

Between the two nine-month periods, general and administrative expenses were $3.9 million greater. $1.3 million was related to the transition and severance costs discussed above. $1.4 million of the increase is attributable to the accounting for the stock appreciation rights plan. The remaining $1.2 million increase in general and administrative expenses was attributable primarily to increases in employee costs, including benefits and bonus accruals.

Depreciation, amortization and impairment expense increased $0.5 million between 2005 and 2006 third quarters, and $1.3 million between the nine-month periods. The majority of these increases related to amortization of our CO_2 assets. Amortization of the CO_2 assets increased due to the additional CO_2 volumes sold in the 2006 periods as compared to 2005. These additional sales related primarily to the CO_2 contracts acquired in the fourth quarter of 2005.

Interest expense, net.

Interest expense, net was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Interest expense, including commitment fees	$ 220	$ 461	$ 547	$ 1,174
Amortization of facility fees	89	89	255	265
Interest income	(49)	(10)	(157)	(38)
Net interest expense	$ 260	$ 540	$ 645	$ 1,401

In the 2006 third quarter, our net interest expense decreased by $0.3 million compared to the 2005 period. In the 2006 period, our average outstanding balance of bank debt was $16.1 million lower than in the 2005 third quarter and our average interest rate was 1.5% greater than in the 2005 period. For the nine-month periods, interest expense was $0.6 million lower due to average outstanding bank debt that was $13.7 million lower and an interest rate that was 1.2% greater. Our equity offering in December 2005 was used to repay outstanding debt from acquisitions in 2005 and prior years, resulting in the lower average debt balance in 2006.

As a result of the termination of our existing credit facility to enter into a new facility (see Note 4 to the Consolidated Financial Statements), we will write-off $0.5 million of deferred facility fees related to the existing credit facility in the fourth quarter of 2006.

Gain on disposal of surplus assets. In the 2006 third quarter and first nine months, we disposed of a minimal amount of surplus assets. In the 2005 first nine months, we sold the Liberty to Maryland segment of our Mississippi pipeline and two idle segments of pipeline in Texas. The Mississippi segment had been out-of-service since February 2002. The Texas segments were idle as a result of our sale of part of our Texas System to TEPPCO in 2003. Additionally we sold an idle site in Houma, Louisiana. We received $1.3 million from the sales of these assets and realized gains totaling $0.5 million, of which $0.3 million was recorded as discontinued operations.

Cumulative Effect Adjustment Adoption of New Accounting Principle

On January 1, 2006, we adopted the provisions of SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123 (revised December 2004), Share-Based Payments . The adoption of this statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the

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adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), the liability will be calculated using a fair value method that will take into consideration the expected future value of the rights at their expected exercise dates.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we consider the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount with the adjustment reflected in the statement of operations.

The estimates that we made upon the adoption of this standard at January 1, 2006 included the following:

In determining the expected life of the rights, we used the simplified method allowed by the Securities and Exchange Commission. We have very limited experience with employee exercise patterns, as our plan was initiated on December 31, 2003. The simplified method produces an initial expected life of 6.25 years for those rights we issued that vest 25% per year for four years, and an initial expected life of 7 years for those rights we issued that fully vest at the end of a four-year period.

The expected volatility of our units was computed using the historical period we believe is representative of future expectations. We determined what period to use in the historical period by considering whether we were paying distributions to our unitholders, and at what rate. The expected volatility used in the fair value calculations was approximately 33% at January 1, 2006 and 32% at September 30, 2006.

The risk-free interest rate was determined from current yields for U.S. Treasury zero-coupon bonds with a term similar to the remaining expected life of the rights.

In determining our expected future distribution yield, we considered our history of distribution payments, our expectations for future payments, and the distribution yields of entities similar to us.

The final estimate we were required to make is the expected forfeitures of non-vested rights and expirations of vested rights. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee forfeiture and expiration patterns. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also decided to use different estimates for different groups of employees.

At December 31, 2005, we had a recorded liability of $0.8 million, 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. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material. The adjustment of the liability to its fair value at September 30, 2006, resulted in the expense of $0.9 million that is included in general and administrative expenses for the nine months ended September 30, 2006.

Liquidity and Capital Resources

Capital Resources

At September 30, 2006 we had a $100 million credit facility comprised of a $50 million revolving line of credit for acquisitions and a $50 million working capital revolving facility. At September 30, 2006, we had $9.2 million in letters of credit and $6.0 million of debt outstanding under the working capital portion.

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Interest on amounts borrowed under the credit facility is equal to (x) either the applicable Eurodollar settlement rate or the higher of the Federal funds rate plus $^1/2$ of 1% or Bank of America s prime rate for the relevant period, at our option, plus (y) the applicable margin rate. We are required to pay our credit facility lenders a fee based upon amounts available but not borrowed under each of the acquisition and working capital facilities, as well as certain other fees.

The aggregate amount that we may have outstanding at any time in loans and letters of credit under the working capital portion of our credit facility is subject to a borrowing base calculation. The borrowing base is limited to $50 million and is calculated monthly. At September 30, 2006, the borrowing base was $49.5 million. The total amount available for borrowings at September 30, 2006 was $9.0 million under the working capital portion and $50.0 million under the acquisition portion of our credit facility.

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

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- extend credit;
- acquire or be acquired by other companies;
- enter into or amend certain existing agreements to the detriment of the lenders under the credit facility; and
- to maintain physical petroleum inventory for which there is not an off-setting sale or hedging agreement, subject to specified exceptions.

Our credit facility covenants also require us to achieve specified minimum financial metrics. For example, before we may make distributions to our partners, we must maintain a cash flow coverage ratio of at least 1.1 to 1.0. In general, this calculation compares operating cash inflows, as adjusted in accordance with the credit facility, less maintenance capital expenditures, to the sum of interest expense and distributions. At September 30 2006, the calculation resulted in a ratio of 1.7 to 1.0. The credit facility also requires that the level of operating cash inflows during the prior twelve months, as adjusted in accordance with the credit facility, be at least $8.5 million. At September 30, 2006, the result of this calculation was $21.4 million. Our credit facility also requires that we meet or exceed certain other financial ratios, such as a current ratio, leverage ratio and funded indebtedness to capitalization ratio. If we meet these covenants and are not otherwise in default under our credit facility, we are otherwise not limited by our credit facility in making distributions to our partners.

The covenants described above could prevent us from engaging in certain transactions which might otherwise be considered beneficial to us. For example, they could:

- increase our vulnerability to generally adverse economic and industry conditions;
- limit our ability to make distributions to unitholders; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions, construction or development activities; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any

- restrictive terms of our indebtedness; and

- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate.

Our credit facility contains customary events of default, including for non-payment of principal and interest, and failure to comply with any covenant.

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Our average daily outstanding balance under our credit facility during the first nine months of 2006 was less than $4 million. The interest rate we paid during this same period was 8.35%.

Our credit facility is secured by liens on substantially all of our assets.

We have recently received commitments from a syndicate of 15 banks and are in the process of completing documentation to replace our existing facility with a new facility. We expect to complete the documentation of the new facility by the end of November 2006. This new facility, with a maximum facility amount of $500 million (subject to customary borrowing conditions), would have an initial commitment amount under the facility of $125 million. The commitment amount could be increased up to the maximum facility amount to allow us to make acquisitions.

Capital Expenditures

A summary of our capital expenditures in the nine months ended September 30, 2006 and 2005 is as follows:

	Nine months Ended September 30, 2006	2005
	(in thousands)	
Maintenance capital expenditures:		
Texas pipeline system	$ 118	$ 101
Mississippi pipeline system	163	961
Jay pipeline system	89	7
Crude oil gathering assets	92	10
Administrative assets	98	46
Total maintenance capital expenditures	560	1,125
Growth capital expenditures:		
Mississippi pipeline system	269	976
Natural gas gathering assets		3,110
T&P Syngas Company investment		13,418
Sandhill Group, LLC investment	5,042	
Other investment projects	702	
Crude oil gathering assets		260
Total growth capital expenditures	6,013	17,764
Total capital expenditures	$ 6,573	$ 18,889

We have no commitments to make capital expenditures; however, we anticipate that our maintenance capital expenditures for 2006 will total to approximately $1.0 million. The remainder to be spent in 2006 is expected to relate to improvements on all of our crude oil pipeline systems. Maintenance capital expenditures for 2007 are expected to total to approximately $1.7 million. 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.

With the new credit agreement discussed in *Capital Resources* above, we will be positioned to make accretive acquisitions and develop internal growth projects. We are pursuing accretive 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. 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.

Denbury has been and may continue to be a significant source of growth acquisitions for us. Denbury has disclosed its intent to enter into long-term financing or sales transactions with us with respect to its existing or planned CO_2 pipelines. These transactions would be conditioned on our achievement of certain goals, primarily the acquisition of other economic projects that are not related to Denbury, based upon acquisition by us of $1.50 of non-

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Denbury acquisitions for every $1.00 of financings or sales with Denbury, subject to reaching mutually agreeable terms.

Sources of Future Capital

Our new credit facility provides us with a bank group to support our current operations and our plans for growth. As discussed above, this syndicate of banks will be making an initial commitment to us of $125 million with an approval process in place to increase that amount to $500 million. We expect to use cash flows from operating activities to fund cash distributions and maintenance capital expenditures needed to sustain existing operations. Future acquisitions or capital projects for our expansion will require funding through borrowings under our new credit facility or from proceeds from equity offerings, or a combination of the two sources of funds.

Cash Flows

Our primary sources of cash flows are operations, credit facilities, and in 2005, proceeds from the sale of idle assets. Our primary uses of cash flows are capital expenditures and distributions. A summary of our cash flows is as follows:

	Nine months Ended September 30,	
	2006	2005
	(in thousands)	
Cash provided by (used in):		
Operating activities	$ 6,722	$ 4,243
Investing activities	$ (6,214)	$ (17,367)
Financing activities	$ (1,223)	$ 13,195

Our operating cash flows are affected significantly by changes in items of working capital. The cash settlement from the purchase and sale of crude oil typically occurs within 25 days after the end of the month. We have had situations, however, 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. Decisions to acquire inventory in a contango crude oil pricing market also affect the cash flows from operating activities between periods. The timing of operating 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 $92 million aggregate receivables on our consolidated balance sheet at September 30, 2006, approximately $90.5 million, or 98.7%, were less than 30 days past the invoice date.

Investing. In 2006, we utilized cash flows to make an investment in a joint venture and other investments and to make capital expenditures, primarily related to equipment we installed on our newly leased trucks used in our gathering operations, and for pipeline improvements.

Financing. In the first nine months of 2006, we borrowed $6.0 million under our credit facility. We also paid distributions to our unitholders and our general partner totaling $7.6 million. In the prior year period, we increased our borrowings by $17.3 million and paid distributions totaling $4.3 million.

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 three quarters, including the distribution to be paid for the second quarter of 2006, as shown in the table below.

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Distribution For	Date Paid or to be Paid	Per Unit Amount	Total Amount (000 s)
Fourth quarter 2004	February 2005	$0.15	$1,426
First quarter 2005	May 2005	$0.15	$1,426
Second quarter 2005	August 2005	$0.15	$1,426
Third quarter 2005	November 2005	$0.16	$1,521
Fourth quarter 2005	February 2006	$0.17	$2,391
First quarter 2006	May 2006	$0.18	$2,532
Second quarter 2006	August 2006	$0.19	$2,672
Third quarter 2006	November 2006	$0.20	$2,813

The total amounts in the table above increased with the distribution for the fourth quarter of 2005 due to the issuance of 4,470,630 new common units in December 2005.

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, our general partner is entitled to receive 13.3% of any distributions in excess of $0.25 per unit, 23.5% of any distributions in excess of $0.28 per unit, and 49% of any distributions in excess of $0.33 per unit, without duplication. The likelihood and timing of the payment of any incentive distributions will depend on our ability to increase the cash flow from our existing operations and to make cash flow accretive acquisitions. In addition, our partnership agreement authorizes us to issue additional equity interests in our partnership with such rights, powers and preferences (which may be senior to our common units) as our general partner may determine in its sole discretion, including with respect to the right to share in distributions and profits and losses of the partnership. We have not paid any incentive distributions and do not expect to make incentive distributions during 2006.

Available Cash before Reserves for the three and nine months ended September 30, 2006 is as follows (in thousands):

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
	(in thousands)	
AVAILABLE CASH BEFORE RESERVES:		
Net income	$ 1,695	$ 7,730
Depreciation and amortization	2,107	6,000
Cash received from direct financing leases not included in income	133	394
Cash effects from certain asset sales		67
Effects of available cash generated by investments in joint ventures not included in net income	288	988
Net non-cash (credits) charges	12	538
Maintenance capital expenditures	(180)	(560)
Available Cash before reserves	$ 4,055	$ 15,157

We have reconciled Available Cash (a non-GAAP liquidity measure) to cash flow from operating activities (the GAAP measure) for the three and nine months ended September 30, 2006 below. For the three and nine months ended September 30, 2006, cash flows provided by operating activities were $8.3 million and $6.7 million respectively.

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

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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 and nine months ended September 30, 2006, is as follows (in thousands):

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
	(in thousands)	
Cash flows from operating activities	$ 8,266	$ 6,722
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures	(180)	(560)
Proceeds from sales of certain assets		67
Amortization of credit facility issuance fees	(93)	(279)
Cash effects of stock appreciation rights plan	(242)	(271)
Effects of available cash generated by joint ventures not included in cash flows from operating activities	81	756
Unrealized gains on fair value hedges	(588)	(64)
Net effect of changes in working capital accounts not included in calculation of Available Cash	(3,189)	8,786
Available Cash before reserves	$ 4,055	$ 15,157

Commitments and Off-Balance-Sheet Arrangements

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 below, nor do we have any debt or equity triggers based upon our unit or commodity prices.

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Contractual Obligations and Commercial Commitments

In addition to the credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil. The table below summarizes our obligations and commitments at September 30, 2006.

	Payments Due by Period				
Contractual Cash Obligations	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
	(in thousands)				
Long-term Debt	$	$ 6,000	$	$	$ 6,000
Interest Payments [1]	510	341			851
Other investment projects [2]	306				306
Operating Lease Obligations	2,617	3,806	1,769	159	8,351
Unconditional Purchase Obligations [3]	116,334				116,334
Total Contractual Cash Obligations	$ 119,767	$ 10,147	$ 1,769	$ 159	$ 131,842

(1) Interest on our long-term debt is at market-based rates. Amount shown for interest payments represents interest that would be paid if the debt outstanding at September 30, 2006 remained outstanding through the maturity date of our credit facility and market interest rates remained at the September 30, 2006 market levels through that date. Actual

obligations may differ from the amounts included above.

(2) We invested \$0.7 million in a potential investment project through September 30, 2006, and have made a commitment to invest an additional \$0.3 million within the next year. See additional discussion in the Other Projects section of Note 3 to the consolidated financial statements.

(3) The unconditional purchase obligations included above are contracts to purchase crude oil, generally at market-based prices. For purposes of this table, market prices at September 30, 2006, were used to value the obligations. Actual obligations may differ from the amounts included above.

In additional to the contractual cash obligations included above, we also have a contingent obligation related to our acquisition of a 50% interest in Sandhill, which could require us to pay an additional $2 million for our interest.

See additional discussion in the section on Sandhill in Note 3 to the consolidated financial statements.

We have guaranteed 50% of the $4.7 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation. See additional discussion in the section on Sandhill in Note 3 to the consolidated financial statements.

New and Proposed Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2, New Accounting Pronouncements in the accompanying consolidated financial statements.

Forward Looking Statements

The statements in this Quarterly Report on Form 10-Q that are not historical information may be forward looking statements within the meaning of the various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions and other such references are forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as anticipate, believe, continue, estimate, expect, forecast, intend, may, plan, position, projection, strategy or will or the negative of those terms or other variations of them or by comparable

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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, 2005. 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 September 30, 2006, we had entered into NYMEX futures contracts that will settle through December 2006. 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)	102	35
Weighted average price per bbl	$ 66.05	$ 63.69
Contract value (in thousands)	$ 6,737	$ 2,229
Mark-to-market change (in thousands)	(287)	(27)
Market settlement value (in thousands)	$ 6,450	$ 2,202

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 September 30, 2006 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 or prime rate plus the applicable margin. We do not hedge our interest rates. The average interest rate presented below is based upon rates in effect at September 30, 2006. The carrying value of our debt in our credit facility approximates fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

	Expected Year Of Maturity 2008 *(in thousands)*
Long-term debt variable rate	6,000
Average interest rate	8.5%

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.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I. Item 1. Note 11 to the 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, 2005.

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

None.

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.

Exhibit 10.1 Letter dated August 3, 2006 to Grant E. Sims regarding Offer to Enter into Employment Agreements

Exhibit 31.1 Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

Exhibit 31.2 Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

Exhibit 32.1 Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.2 Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURES

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

		GENESIS ENERGY, L.P. (A Delaware Limited Partnership)
	By:	GENESIS ENERGY, INC., as General Partner
Date: November 8, 2006	By:	/s/ Ross A. Benavides
		Ross A. Benavides Chief Financial Officer

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Index to Exhibits.

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Exhibit 32.2 Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.