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

FORM 10-Q

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

For the quarterly period ended June 30, 2006

OR

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

For the transition period from _________ to _________

Commission File No.: 1-16335

Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**73-1599053**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

One Williams Center, P.O. Box 22186, Tulsa, Oklahoma 74121-2186
(Address of principal executive offices and zip code)

(918) 574-7000
(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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12-b-2 of the Exchange Act). Yes ☐ No ☒

As of August 4, 2006, there were outstanding 66,360,624 common units.

TABLE OF CONTENTS

PART I

FINANCIAL INFORMATION

PART II

OTHER INFORMATION

PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
Transportation and terminals revenues	$ 125,933	$ 138,555	$ 238,625	$ 268,746
Product sales revenues	129,486	172,806	274,960	321,702
Affiliate management fee revenue	167	172	334	345
Total revenues	255,586	311,533	513,919	590,793
Costs and expenses:				
Operating expense	51,800	54,578	96,055	105,691
Environmental	1,772	467	2,972	2,739
Product purchases	122,348	154,857	253,659	288,452
Depreciation and amortization	13,931	15,356	26,901	30,557
Affiliate general and administrative	15,134	15,737	30,260	30,764
Total costs and expenses	204,985	240,995	409,847	458,203
Equity earnings	804	946	1,322	1,665
Operating profit	51,405	71,484	105,394	134,255
Interest expense	12,864	14,037	25,282	28,125
Interest income	(1,157)	(601)	(2,142)	(1,247)
Debt placement fee amortization	731	678	1,463	1,355
Other income	(1)	—	(300)	339
Net income	$ 38,968	$ 57,370	$ 81,091	$ 105,683
Allocation of net income for purposes of calculating earnings per limited partner unit:				
Limited partners' interest	$ 32,037	$ 41,143	$ 68,014	$ 77,828
General partner's interest	6,931	16,227	13,077	27,855
Net income	$ 38,968	$ 57,370	$ 81,091	$ 105,683
Basic net income per limited partner unit	$ 0.48	$ 0.62	$ 1.02	$ 1.17
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	66,361	66,361	66,361	66,361
Diluted net income per limited partner unit	$ 0.48	$ 0.62	$ 1.02	$ 1.17
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	66,604	66,482	66,536	66,482

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2005	June 30, 2006
		(Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 36,489	$ 402
Restricted cash	5,537	5,551
Accounts receivable (less allowance for doubtful accounts of $133 and $41 at December 31, 2005 and June 30, 2006, respectively)	49,373	55,116
Other accounts receivables	5,566	9,394
Affiliate accounts receivable	5,535	6,021
Inventory	78,155	87,066
Other current assets	5,034	9,863
Total current assets	185,689	173,413
Property, plant and equipment	2,116,143	2,174,368
Less: accumulated depreciation	506,626	533,134
Net property, plant and equipment	1,609,517	1,641,234
Equity investment	24,888	24,528
Long-term receivables	7,327	7,129
Long-term affiliate receivables	1,245	—
Goodwill	24,430	24,033
Other intangibles (less accumulated amortization of $3,607 and $4,405 at December 31, 2005 and June 30, 2006, respectively)	11,652	10,854
Debt placement costs (less accumulated amortization of $6,911 and $8,266 at December 31, 2005 and June 30, 2006, respectively)	8,084	7,112
Other noncurrent assets	3,686	3,532
Total assets	$ 1,876,518	$ 1,891,835
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 25,508	$ 35,161
Affiliate accounts payable	5,821	8,431
Affiliate payroll and benefits	17,028	12,701
Accrued interest payable	9,628	9,439
Accrued taxes other than income	17,307	18,079
Environmental liabilities	30,840	31,227
Deferred revenue	17,522	18,333
Accrued product purchases	34,772	16,557
Current portion of long-term debt	14,345	14,345
Other current liabilities	13,124	22,508
Total current liabilities	185,895	186,781
Long-term debt	782,639	787,182
Long-term affiliate payable	10,091	5,444
Long-term affiliate pension and benefits	9,766	10,096
Other deferred liabilities	52,773	62,352
Environmental liabilities	27,364	22,648
Commitments and contingencies		
Partners' capital:		
Partners' capital	810,045	820,268
Accumulated other comprehensive loss	(2,055)	(2,936)
Total partners' capital	807,990	817,332
Total liabilities and partners' capital	$ 1,876,518	$ 1,891,835

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30,	
	2005	**2006**
Operating Activities:		
Net income	$ 81,091	$ 105,683
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	26,901	30,557
Debt placement fee amortization	1,463	1,355
Loss on sale and retirement of assets	2,101	4,674
Equity earnings	(1,322)	(1,665)
Distributions from equity investments	1,300	2,025
Changes in components of operating assets and liabilities:		
Accounts receivable and other receivables	(9,394)	(9,571)
Affiliate accounts receivable	346	(486)
Inventory	(13,222)	(8,911)
Accounts payable	12,344	9,653
Affiliate accounts payable	4,687	2,610
Accrued interest payable	(202)	(189)
Accrued taxes other than income	(526)	772
Affiliate payroll and benefits	(7,659)	(4,327)
Accrued product purchases	2,291	(18,215)
Accrued product shortages	(7,507)	—
Current and noncurrent environmental liabilities	(3,270)	(4,329)
Other current and noncurrent assets and liabilities	(656)	499
Net cash provided by operating activities	88,766	110,135
Investing Activities:		
Purchases of marketable securities	(50,500)	—
Sales of marketable securities	138,302	—
Additions to property, plant and equipment	(34,507)	(67,119)
Proceeds from sale of assets	64	540
Prepaid construction costs from related party	—	4,000
Net cash provided (used) by investing activities	53,359	(62,579)
Financing Activities:		
Distributions paid	(74,109)	(100,665)
Borrowings under revolver	—	138,800
Payments on revolver	—	(126,600)
Debt placement costs	—	(383)
Capital contributions by affiliate	1,043	5,189
Other	48	16
Net cash used by financing activities	(73,018)	(83,643)
Change in cash and cash equivalents	69,107	(36,087)
Cash and cash equivalents at beginning of period	29,833	36,489
Cash and cash equivalents at end of period	$ 98,940	$ 402

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Basis of Presentation

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with our subsidiaries. We are a Delaware limited partnership. Magellan GP, LLC, a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. Magellan GP, LLC is a wholly-owned subsidiary of Magellan Midstream Holdings, L.P. (“MGG”), a publicly traded Delaware limited partnership. We and Magellan GP, LLC have contracted with Magellan Midstream Holdings GP, LLC (“MGG GP”), MGG’s general partner, to provide all general and administrative services (“G&A”) and operating functions required for our operations.

We operate and report in three business segments: the petroleum products pipeline system, the petroleum products terminals and the ammonia pipeline system. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

In the opinion of management, our accompanying consolidated financial statements, which are unaudited except for the consolidated balance sheet as of December 31, 2005, which is derived from audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2006, and the results of operations for the three and six months ended June 30, 2005 and 2006 and cash flows for the six months ended June 30, 2005 and 2006. The results of operations for the three and six months ended June 30, 2006 are not necessarily indicative of the results to be expected for the full year ending December 31, 2006. Certain amounts in the financial statements for 2005 have been reclassified to conform to the current period’s presentation.

Pursuant to the rules and regulations of the Securities and Exchange Commission, the financial statements do not include all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States. These financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2005.

2. Allocation of Net Income

The allocation of net income between our general partner and limited partners is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
Net income	$ 38,968	$ 57,370	$ 81,091	$ 105,683
Direct charges to the general partner:				
Reimbursable G&A costs	601	553	1,644	965
Previously indemnified environmental charges	171	(542)	637	58
Total direct charges to general partner	772	11	2,281	1,023
Income before direct charges to general partner	39,740	57,381	83,372	106,706
General partner's share of distributions (a)	19.39%	28.30%	18.42%	27.06%
General partner's allocated share of net income before direct charges	7,703	16,238	15,358	28,878
Direct charges to general partner	(772)	(11)	(2,281)	(1,023)
Net income allocated to general partner	$ 6,931	$ 16,227	$ 13,077	$ 27,855
Net income	$ 38,968	$ 57,370	$ 81,091	$ 105,683
Less: net income allocated to general partner	6,931	16,227	13,077	27,855
Net income allocated to limited partners	$ 32,037	$ 41,143	$ 68,014	$ 77,828

(a) On July 20, 2006, our general partner's board of directors declared a distribution of $0.5775 per unit associated with earnings for the three months ended June 30, 2006 (see Note 14—Distributions). Our general partner's share of these cash distributions was 26.40%. However, under the "two class" method of computing earnings per share, as prescribed by Statement of Financial Accounting Standards No. 128, "Earnings Per Share", earnings are to be allocated to participating securities as if all of the earnings for the period had been distributed. A theoretical cash distribution of $0.61178 per unit would result in a distribution of $57.4 million, which is equal to net income for the three months ended June 30, 2006. At this distribution level, our general partner's share of distributions would be 28.30%. For purposes of calculating earnings per limited partner unit, our general partner's share of distributions for the six months ended June 30, 2006 is derived from its share of actual first quarter 2006 distributions plus its share of theoretical distributions for second quarter 2006.

Reimbursable G&A costs represent G&A expenses charged against our income during each respective period for which we either have been or will be reimbursed by our general partner under the terms of the new omnibus agreement. Consequently, these amounts have been charged directly against our general partner's allocation of net income. We record these reimbursements by our general partner as a capital contribution. During 2004, we and our general partner entered into an agreement with a former affiliate to settle its indemnification obligations to us (see Note 12—Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs have been charged directly to our general partner. We believe we will collect the full amount of the indemnification settlement and accordingly will continue to allocate amounts associated with previously indemnified costs to our general partner.

3. Comprehensive Income

A reconciliation of net income to comprehensive income is provided in the table below (in thousands). For information on our derivative instruments, see Note 11 – Derivative Financial Instruments.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
Net income	$ 38,968	$ 57,370	$ 81,091	$105,683
Change in fair value of product hedges	—	(1,041)	—	(986)
Amortization of net loss on cash flow hedges	50	52	103	105
Other comprehensive income	50	(989)	103	(881)
Comprehensive income	$ 39,018	$ 56,381	$ 81,194	$104,802

4. Asset Impairment

In June 2006, we recorded a $3.0 million charge against the earnings of our petroleum products pipeline system segment associated with an impairment of our Menard, Illinois terminal, which we may close in 2007. The impairment charge is included in operating expenses on our consolidated statements of income and the tables included in our segment disclosures note below. An impairment review was initiated during our review of second quarter results, which included management's reassessment of the system integrity costs that we would be required to incur on this terminal and the various probabilities involving continuing to operate or closing the facility. The carrying value of the Menard, Illinois terminal prior to the impairment was $3.6 million. The fair value of the terminal was determined using probability-weighted discounted cash flow techniques.

5. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different marketing strategies and business knowledge.

The non-generally accepted accounting principles measure of operating margin (in the aggregate and by segment) is presented in the following tables. The components of operating margin are computed by using amounts that are determined in accordance with generally accepted accounting principles ("GAAP"). A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Management believes that investors benefit from having access to the same financial measures management uses to evaluate performance. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and G&A costs, that management does not consider when evaluating the core profitability of an operation.

	Three Months Ended June 30, 2005 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 97,828	$ 25,506	$ 3,506	$ (907)	$ 125,933
Product sales revenues	126,155	3,741	—	(410)	129,486
Affiliate management fee revenue	167	—	—	—	167
Total revenues	224,150	29,247	3,506	(1,317)	255,586
Operating expenses	41,745	9,639	2,012	(1,596)	51,800
Environmental	1,688	52	32	—	1,772
Product purchases	121,522	1,364	—	(538)	122,348
Equity earnings	(804)	—	—	—	(804)
Operating margin	59,999	18,192	1,462	817	80,470
Depreciation and amortization	9,074	3,858	182	817	13,931
Affiliate G&A expenses	10,850	3,755	529	—	15,134
Segment profit	$ 40,075	$ 10,579	$ 751	$ —	$ 51,405

	Three Months Ended June 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 105,825	$ 30,267	$ 3,428	$ (965)	$ 138,555
Product sales revenues	168,670	4,136	—	—	172,806
Affiliate management fee revenue	172	—	—	—	172
Total revenues	274,667	34,403	3,428	(965)	311,533
Operating expenses	40,940	12,837	2,530	(1,729)	54,578
Environmental	6	5	456	—	467
Product purchases	152,553	2,434	—	(130)	154,857
Equity earnings	(946)	—	—	—	(946)
Operating margin	82,114	19,127	442	894	102,577
Depreciation and amortization	9,605	4,667	190	894	15,356
Affiliate G&A expenses	11,153	4,026	558	—	15,737
Segment profit	$ 61,356	$ 10,434	$ (306)	$ —	$ 71,484

	Six Months Ended June 30, 2005 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 183,099	$ 51,016	$ 6,207	$ (1,697)	$ 238,625
Product sales revenues	268,959	6,411	—	(410)	274,960
Affiliate management fee revenue	334	—	—	—	334
Total revenues	452,392	57,427	6,207	(2,107)	513,919
Operating expenses	76,874	18,821	3,414	(3,054)	96,055
Environmental	2,530	90	352	—	2,972
Product purchases	251,647	2,675	—	(663)	253,659
Equity earnings	(1,322)	—	—	—	(1,322)
Operating margin	122,663	35,841	2,441	1,610	162,555
Depreciation and amortization	17,468	7,459	364	1,610	26,901
Affiliate G&A expenses	21,909	7,277	1,074	—	30,260
Segment profit	$ 83,286	$ 21,105	$ 1,003	$ —	$ 105,394

	Six Months Ended June 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 196,574	$ 65,742	$ 8,149	$ (1,719)	$ 268,746
Product sales revenues	312,389	9,313	—	—	321,702
Affiliate management fee revenue	345	—	—	—	345
Total revenues	509,308	75,055	8,149	(1,719)	590,793
Operating expenses	79,718	24,674	4,534	(3,235)	105,691
Environmental	1,914	126	699	—	2,739
Product purchases	283,016	5,693	—	(257)	288,452
Equity earnings	(1,665)	—	—	—	(1,665)
Operating margin	146,325	44,562	2,916	1,773	195,576
Depreciation and amortization	19,167	9,237	380	1,773	30,557
Affiliate G&A expenses	21,971	7,702	1,091	—	30,764
Segment profit	$ 105,187	$ 27,623	$ 1,445	$ —	$ 134,255

6. Related Party Transactions

Affiliate Entity Transactions

In March 2004, we acquired a 50% ownership interest in Osage Pipe Line Company, LLC (“Osage Pipeline”). We are paid a management fee for operating the Osage pipeline. Management fees from operating the Osage pipeline were $0.2 million for both the three months ended June 30, 2005 and 2006 and $0.3 million for both the six months ended June 30, 2005 and 2006, which we reported as affiliate management fee revenues.

The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
MGG—allocated operating expenses	$ 16,432	$ —	$ 32,251	$ —
MGG—allocated G&A expenses	15,134	—	30,260	—
MGG GP—allocated operating expenses	—	18,095	—	36,082
MGG GP—allocated G&A expenses	—	15,737	—	30,764

In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. We reimbursed MGG for all payroll and benefit costs it incurred from January 1, 2005 through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG GP, the services agreement with MGG was terminated and a new services agreement with MGG GP was executed. Consequently, we now reimburse MGG GP for costs of employees necessary to conduct our operations. The affiliate payroll and benefits accrual associated with this agreement at December 31, 2005 and June 30, 2006 was $17.0 million and $12.7 million, respectively. The long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2005 and June 30, 2006 were $9.8 million and $10.1 million, respectively. We settle our affiliate payroll and payroll-related expenses and post-retirement benefit costs with MGG GP on a monthly basis and we settle our long-term pension liabilities through annual contributions to MGG GP's pension funds.

In June 2003, we and our general partner entered into an agreement with MGG whereby MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. The amount of G&A costs that either has been or will be reimbursed by MGG to us was $0.6 million and $1.6 million for the three and six months ended June 30, 2005, respectively, and $0.6 million and $1.0 million for the three and six months ended June 30, 2006, respectively.

During 2004, we settled environmental indemnifications owed to us by a former affiliate. In addition, when MGG purchased our general partner interest in June 2003, it agreed to assume certain indemnified obligations to us. See Note 12—Commitments and Contingencies for additional information relative to these matters.

Other Related Party Transactions

MGG, which owns our general partner, is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). Two of the members of our general partner's eight-member board of directors are nominees of CRF. On January 25, 2005, affiliates of CRF acquired general and limited partner interests in SemGroup, L.P. ("SemGroup"). CRF's combined general and limited partner interests in SemGroup are approximately 30%. One of the members of the seven-member board of directors of SemGroup's general partner is a nominee of CRF, with three votes on that board. We are a party to a number of transactions with SemGroup and its affiliates. A summary of these transactions is provided in the following table (in millions):

	Three Months Ended June 30,		Period From January 25, 2005 Through June 30, 2005	Six Months Ended June 30, 2006
	2005	2006		
Product sales revenues	$ 25.1	$ 32.9	$ 50.9	$ 61.1
Product purchases	13.7	9.8	33.5	20.8
Terminalling and other services revenues	1.5	1.4	2.7	3.0
Storage tank lease revenues	0.8	0.9	1.2	1.7
Storage tank lease expense	0.3	0.3	0.5	0.5

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2005 and June 30, 2006, we had recognized a receivable of $6.2 million and $2.4 million, respectively, from and a payable of $6.1 million and $3.1 million, respectively, to SemGroup and its affiliates. The receivable is included with the accounts receivable amounts and the payable is included with the accounts payable amounts on our consolidated balance sheets.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup's affiliate and to lease these tanks back for a 10-year period. Through June 30, 2006, we have received $4.0 million associated with this transaction from SemGroup's affiliate, which we reported as prepaid construction costs from related party on our consolidated statements of cash flows.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). During the three months and six months ended June 30, 2005, our operating expenses included $0.0 million and $0.3 million, respectively, of costs we incurred with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye. We have incurred no operating expenses with Buckeye or its subsidiaries during 2006.

The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedure. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to competing companies in which CRF owns an interest. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on the boards of directors of competing companies in which CRF owns an interest.

During May 2005, John P. DesBarres was appointed as an independent director on our general partner's board of directors. Mr. DesBarres also serves as a board member for American Electric Power Company, Inc. ("AEPC") of Columbus, Ohio. During May and June 2005, our operating expenses included $0.4 million of costs that we incurred with Public Service Company of Oklahoma ("PSO"), a subsidiary of AEPC. During the three and six months ended June 30, 2006, our operating expenses included $0.8 million and $1.5 million, respectively, of costs we incurred with PSO.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives 50% of any incremental cash distributions per limited partner unit. Our executive officers collectively own approximately 6.0% of MGG Midstream Holdings, L.P., the partial owner of MGG, which owns 100% of our general partner; consequently, our executive officers also indirectly benefit from these distributions. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.5775 per unit, our general partner would receive distributions of approximately $58.0 million on its combined 2% general partner interest and incentive distribution rights.

During February 2006, MGG sold 35% of its MGG common units in an initial public offering. We did not receive any of the proceeds from MGG's initial public offering and do not expect our ownership structure or operations to be materially impacted by this transaction. In connection with the closing of this offering, we amended our partnership agreement to remove the requirements for our general partner to maintain its current 2% general partner interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive cash distributions paid to our general partner by $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to $4.2 million, which represented the present value of the remaining reductions in our general partner's incentive cash distributions.

7. Inventory

Inventory at December 31, 2005 and June 30, 2006 was as follows (in thousands):

	December 31, 2005	June 30, 2006
Refined petroleum products	$ 56,680	$ 43,723
Natural gas liquids	9,693	28,625
Transmix	9,589	12,618
Additives	1,805	1,729
Other	388	371
Total inventory	$ 78,155	$ 87,066

8. Equity Investment

We use the equity method to account for our 50% ownership interest in Osage Pipeline. The remaining 50% interest is owned by National Cooperative Refining Association ("NCRA"). Our agreement with NCRA calls for equal sharing of Osage Pipeline's net income. Summarized financial information for Osage Pipeline for the three and six months ended June 30, 2005 and 2006 is presented below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
Revenues	$ 2,993	$ 3,866	$ 5,335	$ 7,154
Net income	$ 1,940	$ 2,225	$ 3,308	$ 3,995

Condensed balance sheets for Osage Pipeline as of December 31, 2005 and June 30, 2006 are presented below (in thousands):

	December 31, 2005	June 30, 2006
Current assets	$ 4,767	$ 4,718
Noncurrent assets	$ 4,535	$ 4,554
Current liabilities	$ 431	$ 457
Members' equity	$ 8,871	$ 8,815

A summary of our equity investment in Osage Pipeline is as follows (in thousands):

	Six Months Ended June 30,	
	2005	2006
Investment at beginning of period	$ 25,084	$ 24,888
Earnings in equity investment:		
Proportionate share of Osage earnings	1,654	1,997
Amortization of excess investment	(332)	(332)
Net earnings in equity investment	1,322	1,665
Cash distributions	(1,300)	(2,025)
Equity investment at end of period	$ 25,106	$ 24,528

Our initial investment in Osage Pipeline included an excess net investment amount of $21.7 million, which is being amortized over the average asset lives of Osage Pipeline. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at December 31, 2005 and June 30, 2006, was $20.5 million and $20.1 million, respectively.

9. Employee Benefit Plans

MGG GP sponsors a pension plan for union employees, a pension plan for non-union employees and a post-retirement benefit plan for selected employees. The following tables present our consolidated net periodic benefit costs related to these plans during the three and six months ended June 30, 2005 and 2006 (in thousands):

	Three Months Ended June 30, 2005		Six Months Ended June 30, 2005	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,272	$ 86	$ 2,543	$ 172
Interest cost	497	186	995	372
Expected return on plan assets	(451)	—	(902)	—
Amortization of prior service cost	169	449	338	899
Net periodic benefit cost	$ 1,487	$ 721	$ 2,974	$ 1,443

	Three Months Ended June 30, 2006		Six Months Ended June 30, 2006	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,565	$ 140	$ 2,794	$ 280
Interest cost	562	270	1,103	540
Expected return on plan assets	(395)	—	(953)	—
Amortization of prior service cost	170	449	339	899
Amortization of actuarial loss	17	116	269	231
Net periodic benefit cost	$ 1,919	$ 975	$ 3,552	$ 1,950

10. Debt

Debt at December 31, 2005 and June 30, 2006 was as follows (in thousands):

	December 31, 2005	June 30, 2006
Magellan Pipeline notes:		
Current portion	$ 14,345	$ 14,345
Long-term portion	270,074	268,372
Total Magellan Pipeline notes	284,419	282,717
Revolving credit facility	13,000	25,200
6.45% Notes due 2014	249,546	249,568
5.65% Notes due 2016	250,019	244,042
Total debt	$ 796,984	$ 801,527

*Magellan Pipeline Notes***.** During October 2002, Magellan Pipeline Company, L.P. ("Magellan Pipeline") entered into a private placement debt agreement with a group of financial institutions for $302.0 million of fixed-rate notes. The maturity date of the notes is October 7, 2007; however, we repaid $15.1 million of the notes on October 7, 2005, which represented 5.0% of the outstanding balance on that date, and we will be required to repay an additional 5.0% of the principal amount outstanding on October 7, 2006. The outstanding principal amount of the notes at December 31, 2005 and June 30, 2006 was decreased by $2.5 million and $4.2 million, respectively, for the change in the fair value of the associated hedge (see Note 11–Derivative Financial Instruments). The interest rate of the notes is fixed at 7.7%. However, including the impact of the associated fair value hedge, which effectively swaps $250.0 million of the fixed-rate notes to floating-rate debt, the weighted-average interest rate for the notes at June 30, 2005 and June 30, 2006 was 7.4% and 8.9%, respectively. We make deposits in an escrow account in anticipation of semi-annual interest payments on these notes and the cash deposits are secured; however, the notes themselves are unsecured. These deposits of $5.5 million at December 31, 2005 and $5.6 million at June 30, 2006 were reflected as restricted cash on our consolidated balance sheets.

Revolving Credit Facility. In May 2006, we amended and restated our revolving credit facility to increase the borrowing capacity from $175.0 million to $400.0 million. In addition, the maturity date of the revolving credit facility was extended from May 25, 2009 to May 25, 2011, and the interest rate was reduced from LIBOR plus a spread ranging from 0.6% to 1.5% based on our credit ratings to LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Borrowings under this revolving credit facility remain unsecured. There was $25.2 million outstanding on the revolver at June 30, 2006. The net proceeds from the revolving credit facility were used for general corporate purposes, including capital expenditures. At both December 31, 2005 and June 30, 2006, $1.1 million of the facility was obligated for letters of credit, which is not reflected as debt on our consolidated balance sheets. The weighted-average interest rate on the revolver at December 31, 2005 and June 30, 2006 was 5.1% and 5.7%, respectively. Interest is assessed on the unused portion of the credit facility at a rate from 0.05% to 0.125% depending on our credit rating.

6.45% Notes due 2014. On May 25, 2004, we sold $250.0 million aggregate principal of 6.45% notes due June 1, 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million, and the discount is being accreted over the life of the notes. Including the impact of the amortization of the realized gains on the interest hedges associated with these notes (see Note 11–Derivative Financial Instruments), the effective interest rate of these notes is 6.3%. Interest is payable semi-annually in arrears on June 1 and December 1 of each year.

5.65% Notes due 2016. On October 15, 2004, we issued $250.0 million aggregate principal of 5.65% notes due 2016. The notes were issued for the discounted price of 99.9%, or $249.7 million, and the discount is being accreted over the life of the notes. Including the impact of hedges associated with these notes (see Note 11–Derivative Financial Instruments), the weighted-average interest rate of these notes at June 30, 2005 and 2006 was 5.4% and 6.1%, respectively. Interest is payable semi-annually in arrears on April 15 and October 15 of each year. The outstanding principal amount of the notes at December 31, 2005 and June 30, 2006 was increased by $0.3 million and decreased by $5.7 million, respectively, for the change in the fair value of the associated hedge (see Note 11–Derivative Financial Instruments).

11. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes hedges we have settled associated with various debt offerings (dollars in millions):

Hedge	Date	Gain/(Loss)	Amortization Period
Interest rate hedge	October 2002	$ (1.0)	5-year life of Magellan Pipeline notes
Interest rate swaps and treasury lock	May 2004	5.1	10-year life of 6.45% notes
Interest rate swaps	October 2004	(6.3)	12-year life of 5.65% notes

In addition to the above, we have entered into the following interest rate swap agreements:

- During May 2004, we entered into certain interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline senior notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the interest rate swap agreements, we receive 7.7% (the weighted-average interest rate of the outstanding Magellan Pipeline senior notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007, the maturity date of the Magellan Pipeline senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period, we record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense associated with this hedge of $0.6 million. The fair value of the instruments associated with this hedge at December 31, 2005 and June 30, 2006 was $(2.5) million and $(4.2) million, respectively, which was recorded to other noncurrent liabilities and long-term debt.

- In October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016 which were issued in October 2004. The notional amount of this agreement is $100.0 million and effectively converts $100.0 million of our 5.65% fixed-rate senior notes issued in October 2004 to floating-rate debt. Under the terms of the agreement, we receive the 5.65% fixed rate of the notes and pay LIBOR plus 0.6%. The agreement began on October 15, 2004 and terminates on October 15, 2016, which is the maturity date of these senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we will record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense of $0.3 million associated with this hedge. The fair value of this hedge at December 31, 2005 and June 30, 2006, was $0.3 million and $(5.7) million, respectively, which was recorded to other noncurrent assets and long-term debt at December 31, 2005 and noncurrent liabilities and long-term debt at June 30, 2006.

In February 2006, we entered into a forward sales contract for 0.1 million barrels of gasoline related to our petroleum products blending activities. These barrels will be sold at the Platts average price during September 2006. Concurrent with that transaction, we entered into three derivative swap contracts to hedge against price changes associated with the sale of that product, in which we agreed to buy 0.1 million barrels of gasoline at the Platts average price in September 2006 and to sell 0.1 million barrels of gasoline at the fixed price of $77.28 per barrel. Our objective in entering into this derivative was to lock in a gross margin on the expected sale of 0.1 million barrels of gasoline in September 2006. The fair value of these hedging instruments at June 30, 2006 was $(1.0) million, which was recorded to other current liabilities and other comprehensive income.

12. Commitments and Contingencies

Estimated liabilities for environmental costs were $58.2 million and $53.9 million at December 31, 2005 and June 30, 2006, respectively. These estimates are provided on an undiscounted basis and have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years. Our environmental liabilities, among other items, include accruals associated with the *Environmental Protection Agency ("EPA") Issue, Kansas City, Kansas Release and Independence, Kansas Release*, which are discussed as follows:

EPA Issue. In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. This matter was included in our May 2004 indemnification settlement (see *Environmental Indemnification Settlement* discussion below). We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

Kansas City, Kansas Release. During the second quarter of 2005, we experienced a line break and release of approximately 2,900 barrels of product on our petroleum products pipeline near our Kansas City, Kansas terminal. As of June 30, 2006, we have estimated remediation costs associated with this release of approximately $2.7 million. Through June 30, 2006, we have spent $1.8 million on remediation associated with this release and, as of June 30, 2006, have recorded associated environmental liabilities of $0.9 million and a receivable of $1.1 million from our insurance carrier. The EPA has included this release with the 32 other releases discussed in *EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Independence, Kansas Release. During the first quarter of 2006, we experienced a line break and release of approximately 3,200 barrels of product on our petroleum products pipeline near Independence, Kansas. As of June 30, 2006, we have estimated remediation costs associated with this release of approximately $3.0 million. Through June 30, 2006, we have spent $2.6 million on remediation associated with this release and, as of June 30, 2006, have recorded associated environmental liabilities of $0.4 million and a receivable of $1.4 million from our insurance carrier. The EPA has included this release with the 32 other releases discussed in *EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Environmental Indemnification Settlement. Prior to May 2004, The Williams Companies, Inc. ("Williams") had agreed to indemnify us against certain environmental losses, among other things, associated with assets contributed to us at the time of our initial public offering or which we subsequently acquired from Williams. In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from these indemnifications. We received $35.0 million, $27.5 million and $20.0 million on July 1, 2004, 2005 and 2006, respectively, pursuant to this agreement and we expect to receive a final installment payment of $35.0 million on July 1, 2007. While the settlement agreement releases Williams from its environmental and certain indemnifications, other indemnifications remain in effect. These remaining indemnifications cover issues involving employee benefits matters, rights of way, easements and real property, including asset titles, and unlimited losses and damages related to tax liabilities.

As of December 31, 2005 and June 30, 2006, known liabilities that would have been covered by Williams' previous indemnity agreements were $43.1 million and $39.9 million, respectively. Through June 30, 2006, we have spent $23.6 million of the $117.5 million indemnification settlement amount for indemnified matters, including $8.3 million of capital costs. The cash we have received from the indemnity settlement is not reserved and has been used for our various other cash needs, including expansion capital spending.

MGG Indemnification Obligation. Concurrent with its acquisition of limited and general partner interests in us, MGG assumed obligations for $21.9 million of our known environmental liabilities. To the extent the environmental and indemnity claims against MGG pursuant to this agreement are less than $21.9 million, MGG will pay Williams the remaining difference between $21.9 million and the indemnity claims paid by MGG. Recorded liabilities associated with this indemnification were $5.5 million and $3.7 million at December 31, 2005 and June 30, 2006, respectively.

Environmental Receivables. Concurrent with MGG's assumption of environmental obligations to us, as discussed in *MGG Indemnification Obligation* above, we recorded a receivable from MGG of $21.9 million. Our receivable balance with MGG at December 31, 2005 and June 30, 2006 was $6.7 million and $4.7 million, respectively. Environmental receivables from insurance carriers for remediation were $1.5 million and $3.0 million at December 31, 2005 and June 30, 2006, respectively.

Unrecognized product gains. Our operations generate product overage and shortages. When we experience net product losses, we recognize expense for those losses in the period in which they occur. When we experience product gains we have product on hand for which we have no cost basis. Therefore, these overages are not recognized in our financial statements until the associated barrels are either sold or are used to offset product losses. The combined net product overages for our operations had a market value of approximately $8.8 million as of June 30, 2006. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

Other. We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our future financial position, results of operations or cash flows.

13. Long-Term Incentive Plan

We have a long-term incentive plan for certain employees who perform services for us and directors of our general partner. The long-term incentive plan primarily consists of two components: phantom units and unit options. To date, there have been no unit options granted. The long-term incentive plan permits the grant of awards covering an aggregate of 1.4 million of our common units. The compensation committee of our general partner's board of directors administers the long-term incentive plan.

We adopted Statement of Financial Accounting Standard ("SFAS") No. 123(R) on January 1, 2006 using the modified prospective application method, which required us to account for our equity-based incentive awards granted prior to January 1, 2006 using the fair value method as defined in SFAS No. 123 instead of our previous methodology of using the intrinsic value method as defined in Accounting Principles Bulletin ("APB") No. 25. Due to the structure of our award grants prior to January 1, 2006, we recognized compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123; therefore, the impact of the change from accounting for the award grants under APB No. 25 to SFAS No. 123 was insignificant to our results of operations, financial position and cash flows.

The long-term incentive awards, discussed below, that have been granted by our general partner's board of directors are subject to forfeiture if employment is terminated for any reason other than for retirement, death or disability prior to the vesting date. If an award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's grant will be prorated based upon the completed months of employment during the vesting period and the award will be paid at the end of the vesting period. The award grants do not have an early vesting feature except when there is a change in control of our general partner. There was no impact on our cash from operating or financing activities during the three and six months ended June 30, 2006 associated with these awards.

In February 2004, our general partner issued approximately 159,000 unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant are based on the attainment of short-term and long-term performance metrics. The number of phantom units that could ultimately be issued under this award ranges from zero up to a total of 304,000, as adjusted for estimated forfeitures and retirements; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 40%. The units will vest at the end of 2006. We have estimated the number of units that will be awarded under this grant to be approximately 300,000, the value of which on June 30, 2006 was $10.2 million. Unrecognized estimated compensation expense associated with these awards as of June 30, 2006 was $1.8 million.

In February 2005, our general partner issued approximately 161,000 unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant are based on the attainment of long-term performance metrics. The number of phantom units that could ultimately be issued under this award ranges from zero units up to a total of 308,000 as adjusted for estimated forfeitures and retirements; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 20%. The units will vest at the end of 2007. We have estimated the number of units that will be awarded under this grant to be approximately 278,000, the value of which on June 30, 2006 was $9.4 million. Unrecognized estimated compensation expense associated with these awards as of June 30, 2006 was $4.7 million.

During the six months ended June 30, 2006, our general partner issued approximately 175,000 unit award grants pursuant to the long-term incentive plan. These awards are being accounted for as follows:

- Of the unit awards discussed above, approximately 137,000 are based on the attainment of long-term performance metrics. These units vest on December 31, 2008. The number of units that could ultimately vest under this component of the award range from zero to approximately 263,000 as adjusted for expected forfeitures and retirements. Upon vesting, these award grants must be paid out to the employees in units; therefore, we have accounted for these awards using the equity method. The weighted-average fair value of the awards on the grant date was $24.53 per unit; which was based on our unit price on the grant date less the present value of the estimated cash distributions on those units during the vesting period. We have accrued for these awards based on the probability of a standard payout. The unrecognized compensation expense associated with these awards as of June 30, 2006 was $2.8 million, which will be recognized over the next 30 months.

- Of the unit awards discussed above, approximately 34,000 are based on personal performance at the discretion of the compensation committee. These units vest December 31, 2008. The number of units that could ultimately vest under this component of the award range from zero to approximately 66,000 as adjusted for expected forfeitures and retirements. Because vesting criteria for these awards are partially based on conditions other than service, performance or market conditions, we have accounted for these awards using the liability method, as such; the compensation expense we recognize is based on the period-end closing price of our units and the percentage of the service period completed at each period end. We have accrued for these awards based on the probability of a standard payout. The value of these awards at June 30, 2006 was $1.1 million and the unrecognized estimated compensation cost on that date was $1.0 million.

- Of the unit awards discussed above, an additional 4,000 units have been issued with various vesting dates. We are using the equity method to account for most of these awards. The unrecognized compensation expense associated with these awards is less than $0.1 million.

Our equity-based incentive compensation expense for the three and six months ended June 30, 2005 and 2006 is summarized as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2006	2005	2006
2003 awards	$ 822	$ —	$ 1,505	$ (86)
October 2003 awards	3	—	6	(3)
January 2004 awards	43	—	87	(4)
2004 awards	1,083	1,046	1,960	1,728
2005 awards	476	835	890	1,586
2006 awards	—	374	—	563
Total	$ 2,427	$ 2,255	$ 4,448	$ 3,784

14. Distributions

We paid the following distributions during 2005 and 2006 (in thousands, except per unit amounts):

Cash Distribution Payment Date	Per Unit Cash Distribution Amount	Cash Distributions Paid: Common Units	Subordinated Units	General Partner	Total
02/14/05	$ 0.45625	$ 26,390	$ 3,887	$ 5,201	$ 35,478
05/13/05	0.48000	29,127	2,726	6,778	38,631
08/12/05	0.49750	30,189	2,825	7,939	40,953
11/14/05	0.53125	32,236	3,018	10,178	45,432
Total	$ 1.96500	$ 117,942	$ 12,456	$ 30,096	$ 160,494
02/14/06	$ 0.55250	$ 33,526	$ 3,138	$ 12,839	$ 49,503
05/13/06	0.56500	37,494	—	13,668	51,162
08/14/06 (a)	0.57750	38,323	—	14,498	52,821
Total	$ 1.69500	$ 109,343	$ 3,138	$ 41,005	$ 153,486

(a) Our general partner declared this cash distribution on July 20, 2006 to be paid on August 14, 2006 to unitholders of record at the close of business on August 4, 2006.

In February 2006, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

15. Net Income Per Unit

The following table provides details of the basic and diluted net income per unit computations (in thousands, except per unit amounts):

	Three Months Ended June 30, 2005			Six Months Ended June 30, 2005		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 32,037	66,361	$ 0.48	$ 68,014	66,361	$ 1.02
Effect of dilutive restricted unit grants	—	243	—	—	175	—
Diluted net income per limited partner unit	$ 32,037	66,604	$ 0.48	$ 68,014	66,536	$ 1.02

	Three Months Ended June 30, 2006			Six Months Ended June 30, 2006		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 41,143	66,361	$ 0.62	$ 77,828	66,361	$ 1.17
Effect of dilutive restricted unit grants	—	121	—	—	121	—
Diluted net income per limited partner unit	$ 41,143	66,482	$ 0.62	$ 77,828	66,482	$ 1.17

Units reported as dilutive securities are related to phantom unit grants (see Note 13 – Long-Term Incentive Plan).

16. Subsequent Events

On July 20, 2006, our general partner's board of directors declared a distribution of $0.5775 per limited partner unit to be paid on August 14, 2006 to unitholders of record as of August 4, 2006.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of June 30, 2006, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 45 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 29 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our company. The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2005.

Recent Developments

Distribution. On July 20, 2006, the board of directors of our general partner declared a quarterly cash distribution of $0.5775 per unit for the period of April 1 through June 30, 2006, representing our twenty-first consecutive quarterly distribution increase since our initial public offering in February 2001. We intend to pay the quarterly distribution on August 14, 2006 to unitholders of record on August 4, 2006.

Results of Operations

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure used by management to evaluate the economic performance of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the table below. Operating profit includes expense items, such as depreciation and amortization and general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of an operation.

Three Months Ended June 30, 2005 Compared to Three Months Ended June 30, 2006

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2006
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenues:		
Petroleum products pipeline system	$ 97.8	$ 105.8
Petroleum products terminals	25.5	30.3
Ammonia pipeline system	3.5	3.4
Intersegment eliminations	(0.9)	(1.0)
Total transportation and terminals revenues	125.9	138.5
Product sales	129.5	172.8
Affiliate management fees	0.2	0.2
Total revenues	255.6	311.5
Operating and environmental expenses:		
Petroleum products pipeline system	43.4	40.9
Petroleum products terminals	9.7	12.8
Ammonia pipeline system	2.0	3.0
Intersegment eliminations	(1.5)	(1.7)
Total operating and environmental expenses	53.6	55.0
Product purchases	122.3	154.9
Equity earnings	(0.8)	(0.9)
Operating margin	80.5	102.5
Depreciation and amortization expense	14.0	15.3
Affiliate G&A expenses	15.1	15.7
Operating profit	$ 51.4	$ 71.5
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped	$1.029	$1.078
Transportation barrels shipped (million barrels)	76.9	77.9
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (million barrels)	16.7	18.8
Throughput (million barrels)	13.5	12.1
Inland terminals:		
Throughput (million barrels)	28.9	30.3
Ammonia pipeline system:		
Volume shipped (thousand tons)	186	162

Transportation and terminals revenues for the three months ended June 30, 2006 were $138.5 million compared to $125.9 million for the three months ended June 30, 2005, an increase of $12.6 million, or 10%. This increase primarily resulted from:

- an increase in petroleum products pipeline system revenues of $8.0 million, or 8%, primarily related to additional gasoline volume shipments, principally reflecting increased demand from our customers, and an increase in the average transportation rate per barrel shipped. Additional ancillary fees for additive services further benefited the current quarter; and

- an increase in petroleum products terminals revenues of $4.8 million, or 19%. Revenues increased at our marine terminals due to operating results from our Wilmington, Delaware marine terminal, which we acquired in September 2005, and expansion projects completed over the past year at our other marine terminals. Our inland terminal revenues also increased due to record throughput volumes and higher additive fees.

Operating and environmental expenses combined were $55.0 million for the three months ended June 30, 2006 compared to $53.6 million for the three months ended June 30, 2005, an increase of $1.4 million, or 3%. By business segment, this variance was principally the result of:

- a decrease in petroleum products pipeline system expenses of $2.5 million, or 6%, primarily attributable to higher product overages and lower environmental expense. Product overages, which reduce operating expenses, were higher in the 2006 quarter due to the sale of accumulated system overages and high commodity prices. Current quarter environmental expenses were lower due to a pipeline release during the 2005 period. These favorable variances were partially offset by expenses related to a $3.0 million non-cash impairment charge recognized in the current quarter related to one of our pipeline system terminals that we may close in 2007, increased property taxes and higher integrity spending;

- an increase in petroleum products terminals expenses of $3.1 million, or 32%. This increase was primarily related to expenses associated with our Wilmington marine terminal, which we acquired in September 2005, and higher power and maintenance expenses at our other terminals. The 2006 period also was impacted by the retirement of a storage tank that we plan to replace at one of our marine terminals; and

- an increase in ammonia pipeline system expenses of $1.0 million, or 50%, primarily attributable to increased environmental expense accruals in the current quarter associated with an October 2004 release and higher system integrity costs. We expect the amount of system integrity spending to be significantly higher during 2006 due to the timing of high consequence area testing mandated by federal regulations.

Product sales revenues primarily result from a third-party product supply agreement, our petroleum products blending operations and fractionating transmix. Revenues from product sales were $172.8 million for the three months ended June 30, 2006, while product purchases were $154.9 million, resulting in gross margin from these transactions of $17.9 million. The gross margin resulting from product sales and purchases for the 2006 period increased $10.7 million compared to gross margin for the 2005 period of $7.2 million, reflecting product sales for the three months ended June 30, 2005 of $129.5 million and product purchases of $122.3 million. The 2006 period benefited from higher petroleum products blending, product supply and fractionation margins per barrel as a result of high gasoline prices and increased volumes for our petroleum products blending and fractionation operations. We believe the gross margin we realize on these activities could be substantially lower in future periods when refined petroleum product prices decrease or stabilize.

Operating margin increased $22.0 million, or 27%, primarily due increased commodity margin principally attributable to high petroleum product prices, the results of expansion projects put in place over the past year and improved utilization of our assets.

Depreciation and amortization expense was $15.3 million for the three months ended June 30, 2006 compared to $14.0 million for the three months ended June 30, 2005, an increase of $1.3 million, or 9%. This increase is primarily related to asset acquisitions and capital improvements over the past year and the acceleration of depreciation for our terminal automation systems that we are in the process of upgrading.

Affiliate G&A expenses were $15.7 million for the three months ended June 30, 2006 compared to $15.1 million for the three months ended June 30, 2005, an increase of $0.6 million, or 4%. This increase is primarily related to higher bonus accruals and additional headcount as a result of expansion projects. Excluding long-term incentive compensation expense, the amount of cash we spend for G&A costs is determined by an agreement we have with Magellan Midstream Holdings, L.P. ("MGG"), the owner of our general partner. For the three months ended June 30, 2006 and 2005, we were responsible for paying G&A costs of $13.3 million and $12.5 million, respectively. MGG reimburses us for our actual G&A costs, excluding incentive compensation expense, that exceed these amounts. The amount of G&A reimbursed to us was $0.6 million for both periods.

Interest expense, net of interest income, for the three months ended June 30, 2006 was $13.4 million compared to $11.7 million for the three months ended June 30, 2005, an increase of $1.7 million, or 15%. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, decreased to $797.1 million during second-quarter 2006 from $802.0 million during second-quarter 2005 primarily due to a $15.1 million scheduled prepayment on our Magellan Pipeline notes during October 2005, partially offset by borrowings under our revolving credit facility to fund our capital spending and working capital needs. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.2% for the 2006 period from 6.4% for the 2005 period primarily due to rising interest rates.

Net income for the three months ended June 30, 2006 was $57.4 million compared to $39.0 million for the three months ended June 30, 2005, an increase of $18.4 million, or 47%.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2006

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2006
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenues:		
Petroleum products pipeline system	$ 183.1	$ 196.6
Petroleum products terminals	51.0	65.7
Ammonia pipeline system	6.2	8.2
Intersegment eliminations	(1.7)	(1.7)
Total transportation and terminals revenues	238.6	268.8
Product sales	275.0	321.7
Affiliate management fees	0.3	0.3
Total revenues	513.9	590.8
Operating and environmental expenses:		
Petroleum products pipeline system	79.4	81.6
Petroleum products terminals	18.9	24.8
Ammonia pipeline system	3.8	5.2
Intersegment eliminations	(3.1)	(3.2)
Total operating and environmental expenses	99.0	108.4
Product purchases	253.6	288.5
Equity earnings	(1.3)	(1.7)
Operating margin	162.6	195.6
Depreciation and amortization	26.9	30.5
Affiliate G&A expenses	30.3	30.8
Operating profit	$ 105.4	$ 134.3
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped	$1.025	$1.054
Transportation barrels shipped (million barrels)	142.6	146.9
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (million barrels)	16.6	18.9
Throughput (million barrels)	25.9	23.0
Inland terminals:		
Throughput (million barrels)	55.0	58.0
Ammonia pipeline system:		
Volume shipped (thousand tons)	338	378

Transportation and terminals revenues for the six months ended June 30, 2006 were $268.8 million compared to $238.6 million for the six months ended June 30, 2005, an increase of $30.2 million, or 13%. This increase was a result of:

- an increase in petroleum products pipeline system revenues of $13.5 million, or 7%, primarily related to increased diesel fuel and gasoline shipments during the current period, principally reflecting increased demand from our customers, and an increase in the average transportation rate per barrel shipped. We also earned more ancillary revenues related to additive and terminal services during 2006;

- an increase in petroleum products terminals revenues of $14.7 million, or 29%, primarily due to results from our Wilmington, Delaware marine terminal, which we acquired in September 2005, and the recognition of revenue during first-quarter 2006 related to a variable-rate terminalling agreement. Under this variable-rate terminalling agreement, we provided storage rental and throughput fees based on discounted rates plus a variable fee, which was based on a percentage of the net profits from certain trading activities conducted by our customer. During 2006, we recognized revenues of $6.4 million from the variable fee portion of the agreement once our customer's trading profits were determinable at the end of the contract term, which expired January 31, 2006. Upon expiration of this agreement, we negotiated a similar agreement pursuant to which we will receive a share of any net trading profits above a specified amount, but we will not share in any net trading losses. We cannot predict what revenues, if any, we may realize from this variable-rate agreement.

  Revenues also increased at our inland terminals due to higher additive fees and throughput volumes and at our marine terminals primarily due to expansion projects completed over the past year; and

- an increase in ammonia pipeline system revenues of $2.0 million, or 32%, due to higher tariffs associated with our new transportation agreements, which became effective July 1, 2005, and increased volumes. Transportation volumes were primarily higher because 2005 volumes were negatively affected by planned maintenance work at a customer's ammonia facilities and additional production in the 2006 period. Because natural gas prices were high in late 2005, our customers' ammonia production was curtailed. In early 2006, natural gas prices moderated on a relative basis, and our customers increased production to make up some of their production shortfalls from the latter half of 2005.

Operating and environmental expenses combined were $108.4 million for the six months ended June 30, 2006 compared to $99.0 million for the six months ended June 30, 2005, an increase of $9.4 million, or 9%. By business segment, this increase was principally the result of:

- an increase in petroleum products pipeline system expenses of $2.2 million, or 3%, primarily attributable to higher power costs, increased property taxes and expenses related to a $3.0 million non-cash impairment charge recognized in the current period related to one of our pipeline system terminals that we may close in 2007. These increases were partially offset by more favorable product overages due to high commodity prices and sales of accumulated system overages, which reduce operating expenses;

- an increase in petroleum products terminals expenses of $5.9 million, or 31%. This increase was primarily related to expenses associated with our Wilmington marine terminal, which we acquired in September 2005, and higher power, personnel and maintenance expenses at our other terminals. The 2006 period also was impacted by the retirement of a storage tank that we plan to replace at one of our marine terminals; and

- an increase in ammonia pipeline system expenses of $1.4 million, or 37%, primarily attributable to higher power costs resulting from additional shipments, increased environmental expenses and additional system integrity costs. We expect the amount of system integrity spending to be significantly higher during 2006 due to the timing of high consequence area testing mandated by federal regulations.

Product sales revenues primarily result from a third-party product supply agreement, our petroleum products blending operations and fractionating transmix. Revenues from product sales were $321.7 million for the six months ended June 30, 2006, while product purchases were $288.5 million, resulting in gross margin from these transactions of $33.2 million. The gross margin resulting from product sales and purchases for the 2006 period increased $11.8 million compared to gross margin for the 2005 period of $21.4 million, reflecting product sales for the six months ended June 30, 2005 of $275.0 million and product purchases of $253.6 million. The gross margin increase in 2006 primarily resulted from the impact of high gasoline prices on our petroleum products blending, fractionation and product supply operations. We believe the gross margin on these activities could be substantially lower in future periods when refined petroleum product prices decrease or stabilize.

Operating margin increased $33.0 million, or 20%, primarily due to revenues from a variable-rate terminalling agreement, increased commodity margin due to high petroleum prices, incremental operating results from our recently-acquired Wilmington marine facility and improved utilization of our assets.

Depreciation and amortization expense was $30.5 million for the six months ended June 30, 2006 compared to $26.9 million for the six months ended June 30, 2005, an increase of $3.6 million, or 13%. This increase is primarily related to asset acquisitions and capital improvements over the past year and the acceleration of depreciation for our terminal automation systems that we are in the process of upgrading.

Affiliate G&A expenses were $30.8 million for the six months ended June 30, 2006 compared to $30.3 million for the six months ended June 30, 2005, an increase of $0.5 million, or 2%. This increase is primarily related to higher bonus accruals and additional headcount as a result of expansion projects. Excluding long-term incentive compensation expense, the amount of cash we spend for G&A costs is determined by an agreement we have with MGG. For the six months ended June 30, 2006 and 2005, we were responsible for paying G&A costs of $26.7 million and $24.9 million, respectively. MGG reimburses us for our actual G&A costs, excluding incentive compensation expense, that exceed these amounts. The amount of G&A reimbursed to us for the six months ended June 30, 2006 and 2005 was $1.0 million and $1.6 million, respectively.

Interest expense, net of interest income, for the six months ended June 30, 2006 was $26.9 million compared to $23.1 million for the six months ended June 30, 2005, an increase of $3.8 million, or 16%. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $807.0 million during the six-month period ended June 30, 2006 from $802.0 million during the six-month period ended June 30, 2005, primarily due to borrowings under our revolving credit facility to fund our capital spending and working capital needs. Further, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.0% for the 2006 period from 6.3% for the 2005 period, primarily due to rising interest rates. Also, during the six months ended June 30, 2006, we earned $0.9 million less interest income as compared to the six months ended June 30, 2005, due to lower cash balances on hand and lower marketable securities on hand.

Net income for the six months ended June 30, 2006 was $105.7 million compared to $81.1 million for the six months ended June 30, 2005, an increase of $24.6 million, or 30%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $110.1 million and $88.8 million for the six months ended June 30, 2006 and 2005, respectively. The $21.3 million increase from 2005 to 2006 was primarily attributable to:

- increased operating margin of $33.0 million;

- changes in inventory values between 2005 and 2006 which resulted in an increase in cash from operating activities of $4.3 million. Inventories consumed $13.2 million of cash in the 2005 period compared to $8.9 million in the 2006 period. The increase in inventories in the 2005 period principally reflects higher levels of inventory to service our third-party supply agreement and higher product prices in 2005. The increase in inventories in the 2006 period was primarily due to even higher product prices during the period; and

- a decrease in accrued product shortages of $7.5 million. At the end of 2004, we were in a product shortage position which had a value of $7.5 million. During 2005, we experienced product overages, which eliminated that shortage, resulting in a use of cash for the 2005 period of $7.5 million. During 2006, we have continued to be in a product overage position.

These increases were partially offset by a decrease in accrued product purchases of $18.2 million in 2006 compared to an increase in 2005 of $2.3 million, which resulted in a $20.5 million decrease in cash from operating activities between the periods. The decrease is primarily due to the timing of invoices received from our suppliers.

Net cash provided (used) by investing activities for the six months ended June 30, 2006 and 2005 was $(62.6) million and $53.4 million, respectively. During 2006, we spent $67.1 million versus $34.5 million in 2005 for capital expenditures. Of these amounts, total maintenance capital spending before indemnifications and reimbursements was $12.2 million and $9.3 million during the six months ended June 30, 2006 and 2005, respectively. In 2005, our sales of marketable securities, net of purchases, generated $87.8 million of cash. Please see Capital Requirements below for further discussion of capital expenditures as well as maintenance capital amounts net of indemnifications.

Net cash used by financing activities for the six months ended June 30, 2006 and 2005 was $83.6 million and $73.0 million, respectively, and primarily consisted of cash distributions paid to our unitholders. During 2006, net borrowings on our revolving credit facility of $12.2 million and capital contributions from our owner of $5.2 million partially offset distributions paid. The capital contributions received in the 2006 period included $4.2 million received from MGG as part of our agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition.

During second-quarter 2006, we paid $51.2 million in cash distributions to our unitholders and general partner. Based on the declared quarterly distribution of $0.5775 per unit associated with the second quarter of 2006, we intend to pay $52.8 million in distributions during third quarter 2006. If we continue to pay cash distributions at this current level and the number of outstanding units remains the same, we will pay total cash distributions of $211.3 million on an annual basis. Of this amount, $58.0 million, or 27%, is related to our general partner's 2% ownership interest and incentive distribution rights.

Capital Requirements

Our businesses require continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending for our businesses consists primarily of:

- maintenance capital expenditures, such as those required to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire additional complementary assets to grow our business and to expand or upgrade our existing facilities, referred to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During second-quarter 2006, we spent maintenance capital of $7.8 million, excluding $0.8 million of spending on environmental projects that would have been covered by indemnifications settled in May 2004. For the six months ended June 30, 2006, we have spent maintenance capital of $10.7 million, excluding $1.5 million of spending on environmental projects that would have been covered by the May 2004 indemnification settlement. Including the $20.0 million payment we received from Williams on July 1, 2006, we have received $82.5 million to date under this settlement agreement. Please see Environmental below for additional discussion of this indemnification settlement.

For 2006, we expect to incur maintenance capital expenditures for our existing businesses of approximately $30.0 million, excluding the following:

- $7.0 million for environmental projects that would have been covered by the indemnifications discussed above; and

- $2.0 million for which we expect to be reimbursed from insurance proceeds for the replacement of docks at our Marrero, Louisiana marine terminal. These docks remain operational but were damaged by Hurricane Katrina in third-quarter 2005, and we are in the process of replacing them.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. For the three and six months ended June 30, 2006, we spent cash of $34.0 million and $54.9 million, respectively, for organic growth projects. Based on projects currently underway or in advanced stages of development, we currently plan to spend approximately $175.0 million on organic growth capital during 2006, excluding future acquisitions and approximately $80.0 million during 2007 to complete these projects.

Liquidity

As of June 30, 2006, total debt reported on our consolidated balance sheet was $801.5 million, as described below. The difference between this amount and the $812.1 million face value of our outstanding debt is due to adjustments associated with fair value hedges.

Magellan Pipeline Notes. In connection with the long-term financing of our acquisition of Magellan Pipeline Company, L.P. ("Magellan Pipeline"), we and Magellan Pipeline entered into a note purchase agreement on October 1, 2002. As of June 30, 2006, $286.9 million of senior notes were outstanding pursuant to this agreement The maturity date of these notes is October 7, 2007, with a scheduled prepayment equal to 5% of the outstanding balance on October 7, 2006. We guarantee payment of interest and principal by Magellan Pipeline. The notes are unsecured except for cash deposited monthly by Magellan Pipeline into a cash escrow account in anticipation of semi-annual interest payments. The weighted-average interest rate for the senior notes, including the impact of the swap of $250.0 million of the notes from fixed-rate to floating-rate debt, was 8.9% at June 30, 2006.

Revolving Credit Facility. In May 2006, we amended and restated our revolving credit facility to increase the borrowing capacity of the facility from $175.0 million to $400.0 million. In addition, the maturity of the facility was extended to May 2011, and the interest rate on borrowings under the facility was reduced from LIBOR plus a spread ranging from 0.6% to 1.5% based on our credit ratings to LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Borrowings under this credit facility remain unsecured. As of June 30, 2006, $25.2 million was outstanding under this facility, and $1.1 million of the facility was obligated for letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets. As of June 30, 2006, the weighted-average interest rate on borrowings outstanding under this facility was 5.7%.

6.45% Senior Notes due 2014. On May 25, 2004, we sold $250.0 million of 6.45% senior notes due 2014 in an underwritten public offering at 99.8% of par. We received proceeds after underwriters' fees and expenses of approximately $246.9 million. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at June 30, 2006 was 6.3%.

5.65% Senior Notes due 2016. On October 15, 2004, we sold $250.0 million of 5.65% senior notes due 2016 in an underwritten public offering as part of the long-term financing of the pipeline system assets we acquired in October 2004. The notes were issued at 99.9% of par, and we received proceeds after underwriters' fees and expenses of approximately $247.6 million. Including the impact of pre-issuance hedges associated with these notes and the swap of $100.0 million of the notes from fixed-rate to floating-rate, the weighted-average interest rate on the notes at June 30, 2006 was 6.1%.

The debt instruments described above include various covenants. In addition to certain financial ratio covenants, these covenants limit our ability to, among other things, incur indebtedness secured by certain liens, encumber our assets, make certain investments, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We are in compliance with these covenants.

Interest Rate Derivatives. We utilize interest rate derivatives to manage interest rate risk. In conjunction with our existing debt instruments, we were engaged in the following derivative transactions as of June 30, 2006:

- In October 2004, we entered into a $100.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of our 5.65% senior notes due 2016. This agreement effectively changes the interest rate on $100.0 million of those notes to a floating rate of six-month LIBOR plus 0.6%, with LIBOR set in arrears. This swap agreement expires on October 15, 2016, the maturity date of the 5.65% senior notes; and

- In May 2004, we entered into $250.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline senior notes. These agreements effectively change the interest rate on $250.0 million of the senior notes from a fixed rate of 7.7% to a floating rate of six-month LIBOR plus 3.4%, with LIBOR set in arrears. These swap agreements expire on October 7, 2007, the maturity date of the Magellan Pipeline senior notes.

Credit Ratings. Our current credit ratings are BBB by Standard and Poor's and Baa3 by Moody's Investor Services.

Environmental

Various governmental authorities in the jurisdictions in which we conduct our operations subject us to environmental laws and regulations. We have accrued liabilities for estimated site restoration costs to be incurred in the future at our facilities and properties, including liabilities for environmental remediation obligations at various sites where we have been identified as a possible responsible party. Under our accounting policies, we record liabilities when site restoration and environmental remediation obligations are either known or considered probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involve significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Prior to May 2004, The Williams Companies, Inc. ("Williams") provided indemnifications to us for assets we had acquired from it. In May 2004, we entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release it from those indemnification obligations. Including the $20.0 million payment we received from Williams on July 1, 2006, we have received $82.5 million pursuant to this agreement and expect to receive the remaining balance of $35.0 million on July 1, 2007. As of June 30, 2006, known liabilities that would have been covered by these indemnifications were $39.9 million. In addition, we have spent $23.6 million through June 30, 2006 that would have been covered by these indemnifications, including $8.3 million of capital costs.

When MGG purchased our general partner interest in June 2003, MGG assumed obligations to indemnify us for $21.9 million of known environmental liabilities. Through June 30, 2006, we have incurred $18.2 million of costs associated with this indemnification obligation, leaving a remaining liability of $3.7 million. Our receivable balance with MGG on June 30, 2006 was $4.7 million.

In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired in April 2002. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those spills may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount that is less than $22.0 million associated with this matter. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations or cash flows.

Other Items

Pipeline tariff increase. The Federal Energy Regulatory Commission ("FERC") regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted. The FERC reviews this approved methodology on a periodic basis. Until recently, the annual adjustment was equal to the annual change in the producer price index for finished goods ("PPI-FG"). During March 2006, the FERC approved the methodology of PPI-FG plus 1.3% for the annual adjustment related to the next five year period, commencing July 1, 2006. Based on an actual annual change in PPI-FG of approximately 4.8%, the July 1, 2006 adjustment would result in a tariff increase of approximately 6.1% on that date. We increased virtually all of our published tariffs by the allowed adjustment of approximately 6.1% effective July 1, 2006.

Galena Park marine terminal expansion. During late 2005 and early 2006, we executed a series of long-term terminalling agreements with several customers pursuant to which we will construct 30 new storage tanks at our Galena Park, Texas marine terminal. Tank construction has begun and we expect the new tanks to be placed into service during 2006 and 2007. We believe these new agreements will significantly contribute to our results of operations and cash flows once construction is complete and the 30 new tanks have been placed into service.

Unrecognized product gains. Our operations generate product overages and shortages. When we experience net product shortages, we recognize expense for those losses in the period in which they occur. When we experience product overages, we have product on hand for which we have no cost basis. Therefore, these overages are not recognized in our financial statements until the associated barrels are either sold or are used to offset product losses. The net product overages for our operations had a market value of approximately $8.8 million as of June 30, 2006. However, the actual amounts we will recognize in future periods will depend on product prices at the time associated barrels are either sold or used to offset future product losses.

State tax issues. Texas legislators recently passed a law that, without amendment, will impose a partnership-level tax beginning in 2007 based on the financial results of our assets operating within the state of Texas. While we currently expect our tax obligation to be less than $3.0 million per year, this tax will impact the amount of cash available for us to pay as distributions to our unitholders. If other states create a similar tax, the impact could be material to our results of operations or cash flows.

Approval of board members. On April 26, 2006, we held our fourth annual unitholder meeting. Proxy statements were mailed in advance to unitholders of record on February 28, 2006. Our unitholders approved the appointment of N. John Lancaster, Jr., George A. O'Brien, Jr. and Thomas S. Souleles to continue serving in their capacity as members of our general partner's board of directors until our 2009 annual meeting. No other matters requiring a unitholder vote were discussed.

Affiliate transactions. In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. We reimbursed MGG for all payroll and benefit costs it incurred from January 1, 2005 through December 24, 2005. On December 24, 2005, the employees necessary to conduct our business operations were transferred to MGG's general partner, and the services agreement with MGG was terminated and a new services agreement with MGG's general partner was executed. Consequently, we now reimburse MGG's general partner for costs of employees necessary to conduct our operations. Also in June 2003, we and our general partner entered into an agreement with MGG whereby MGG agreed to reimburse us for G&A expenses in excess of a defined G&A cap.

For the three and six month periods ended June 30, 2006, we were allocated operating expenses from MGG and its general partner of $18.1 million and $36.1 million, respectively, and G&A expenses of $15.7 million and $30.8 million, respectively. For the three and six month periods ended June 30, 2005, we were allocated operating expenses from MGG and its general partner of $16.4 million and $32.3 million, respectively, and G&A expenses of $15.1 million and $30.3 million, respectively. MGG reimbursed us G&A costs of $0.6 million and $1.0 million for the three and six months ended June 30, 2006, respectively, and $0.6 million and $1.6 million for the three and six months ended June 30, 2005, respectively.

In March 2004, we acquired a 50% ownership interest in a crude oil pipeline company. We earn a fee to operate this pipeline which was $0.3 million for both the six months ended June 30, 2006 and 2005. We report these fees as affiliate management fee revenue.

Related party transactions. MGG is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). Two members of our general partner's eight-member board of directors are nominees of CRF. On January 25, 2005, affiliates of CRF acquired general and limited partner interests in SemGroup, L.P. ("SemGroup"). CRF's total combined interest in SemGroup is approximately 30%. One of the members of the seven-member board of directors of SemGroup's general partner is a nominee of CRF, with three votes on that board.

We are a party to a number of transactions with SemGroup and its affiliates. For the three and six months ended June 30, 2006, we recognized revenues from SemGroup related to the sale of petroleum products of $32.9 million and $61.1 million, respectively; terminalling and other services of $1.4 million and $3.0 million, respectively; and leased storage tanks of $0.9 million and $1.7 million, respectively. For the three months ended June 30, 2005 and the period from January 25, 2005 through June 30, 2005, we recognized revenues from SemGroup related to the sale of petroleum products of $25.1 million and $50.9 million, respectively; terminalling and other services of $1.5 million and $2.7 million, respectively; and leased storage tanks of $0.8 million and $1.2 million, respectively. We also provide common carrier transportation services to SemGroup.

Additionally, during the three and six months ended June 30, 2006, we recognized product purchases from SemGroup of $9.8 million and $20.8 million, respectively, and expenses for leased storage tanks of $0.3 million and $0.5 million, respectively. During the three months ended June 30, 2005 and the period from January 25, 2005 through June 30, 2005, we recognized product purchases from SemGroup of $13.7 million and $33.5 million, respectively, and expenses for leased storage tanks of $0.3 million and $0.5 million, respectively.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup's affiliate and to lease these tanks back for a 10-year period. Through June 30, 2006, we have received $4.0 million associated with this transaction from SemGroup's affiliate, which we reported as prepaid construction costs from related party on our consolidated statements of cash flows. In conjunction with this agreement, we received a three-year throughput commitment from SemGroup.

As of June 30, 2006, we had recognized a receivable of $2.4 million from and a payable of $3.1 million to SemGroup and its affiliates.

During the second quarter of 2006, an affiliate of CRF announced that it, along with a group of other investors, made an offer to acquire Kinder Morgan, Inc. Among other assets, Kinder Morgan, Inc. owns the general partner interest of Kinder Morgan Energy Partners, L.P., a publicly traded partnership engaged in the transportation and distribution of petroleum products and natural gas that is a customer of ours and competes with us in various markets that we serve. Once this acquisition is complete, all transactions between us and Kinder Morgan, Inc. and its affiliates will become related party transactions.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). We do not have a significant relationship with Buckeye and do not have extensive operations in the geographic areas primarily served by Buckeye.

The board of directors of our general partner has adopted a policy to address board of director conflicts of interests. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to competing companies in which CRF owns an interest. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on the boards of directors of competing companies in which CRF owns an interest.

Because our distributions have exceeded target levels as specified in our partnership agreement, MGG indirectly receives 50% of any incremental cash distributions per limited partner unit. The executive officers of our general partner collectively own approximately 6.0% of MGG Midstream Holdings, L.P., which owns 65% of MGG and therefore also indirectly benefits from these distributions. Assuming MMP has sufficient available cash to continue to pay distributions on all of its outstanding units for four quarters at its current quarterly distribution level of $0.5775 per unit, MGG would receive distributions of approximately $58.0 million in 2006 on its combined 2% general partner interest and incentive distribution rights.

NEW ACCOUNTING PRONOUNCEMENTS

There were no new accounting pronouncements during the three months ended June 30, 2006.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may be exposed to market risk through changes in commodity prices and interest rates. We have established policies to monitor and control these market risks. We also enter into derivative agreements to help manage our exposure to commodity price and interest rate risks.

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risk to which we are exposed is interest rate risk. As of June 30, 2006, we had $25.2 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of certain interest rate swap agreements discussed below, we are exposed to interest rate market risk on an additional $350.0 million of our debt. Considering these interest rate swap agreements and the amount outstanding on our revolving credit facility as of June 30, 2006, our annual interest expense would change by $0.9 million if LIBOR were to change by 0.25%.

During May 2004, we entered into four separate interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the agreements, we receive 7.7% (the interest rate on the Magellan Pipeline notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007. Payments settle in April and October of each year with LIBOR set in arrears.

During October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016. We have accounted for this interest rate hedge as a fair value hedge. The notional amount of the interest rate swap agreement is $100.0 million. Under the terms of the agreement, we receive 5.65% (the interest rate of the $250.0 million senior notes) and pay LIBOR plus 0.6%. This hedge effectively converts $100.0 million of our 5.65% fixed-rate debt to floating-rate debt. The interest rate swap agreement began on October 15, 2004 and expires on October 15, 2016. Payments settle in April and October of each year with LIBOR set in arrears.

As of June 30, 2006, we had entered into futures contracts, qualifying as normal purchases, for the purchase of approximately 0.2 million barrels of petroleum products. The notional value of these agreements, with maturities from September 2006 through November 2006, was approximately $17.8 million.

As of June 30, 2006, we had entered into futures contracts, qualifying as normal sales, for the sale of approximately 0.7 million barrels of petroleum products. The notional value of these agreements, with maturities from July 2006 through December 2006, was approximately $60.5 million.

In February 2006, we entered into a forward sales contract for 0.1 million barrels of gasoline related to activities from our petroleum products blending operations. These barrels will be sold at the Platts average price during September 2006. Concurrently, we entered into three derivative swap contracts to hedge against price changes associated with the sale of that product, in which we agreed to buy 0.1 million barrels of gasoline at the Platts average price in September 2006 and sell 0.1 million barrels of gasoline at the fixed price of $77.28 per barrel. Our objective in entering into this derivative was to lock in a gross margin on the expected sale of 0.1 million barrels of gasoline in September 2006. The fair value of these hedging instruments at June 30, 2006 was $(1.0) million, which was recorded to other current liabilities and other comprehensive income.

ITEM 4. CONTROLS AND PROCEDURES

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner’s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner’s Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report.

Our management, including our general partner’s Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting (“internal controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant. There have been no substantial changes in our internal controls since December 31, 2005.

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements that discuss our expected future results based on current and pending business operations.

Forward-looking statements can be identified by words such as “anticipates,” “believes,” “expects,” “estimates,” “forecasts,” “projects” and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to numerous assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document.

The following are among the important factors that could cause future results to differ materially from actual results or from any projected, forecasted, estimated or budgeted amounts which we have discussed in this report:

- price fluctuations for natural gas liquids and refined petroleum products;
- overall demand for natural gas liquids, refined petroleum products, natural gas, oil and ammonia in the United States;
- weather patterns materially different than historical trends;
- development of alternative energy sources;
- changes in demand for storage in our petroleum products terminals;
- changes in supply patterns for our marine terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- our ability to satisfy our product purchase obligations at historical purchase terms;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the United States Surface Transportation Board and state regulatory agencies;
- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our petroleum products terminals or petroleum products pipeline system;
- loss of one or more of our three customers on our ammonia pipeline system;
- an increase in the competition our operations encounter;
- the occurrence of an operational hazard or unforeseen interruption for which we are not adequately insured;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in general economic conditions in the United States;
- changes in laws or regulations to which we are subject, including tax withholding issues, safety, environmental and employment laws and regulations;

- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or could have other adverse consequences;
- a change of control of our general partner could, under certain circumstances, result in our debt or the debt of our subsidiaries becoming due and payable;
- the condition of the capital markets in the United States;
- the effect of changes in accounting policies;
- the potential that internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price;
- the ability of third parties to pay the amounts owed to us under indemnification agreements;
- conflicts of interests between us, our general partner, MGG, MGG's general partner and related parties of MGG and its general partner;
- the ability of our general partner, its affiliates or related parties to enter into certain agreements which could negatively impact our financial position, results of operations and cash flows;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2001, the EPA, pursuant to Section 308 of the Act served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

During the second quarter of 2005, we experienced a product release involving approximately 2,900 barrels of gasoline from our petroleum products pipeline near our Kansas City, Kansas terminal. In regards to this release, we responded on a timely basis to an EPA request for information pursuant to Section 308 of the Act. We can provide no assurances that we will not be assessed civil or other statutory penalties of $100,000 or more by the EPA or other regulatory agencies associated with this release.

During the first quarter of 2006, we experienced a product release involving approximately 3,200 barrels of gasoline from our petroleum products pipeline near Independence, Kansas. We can provide no assurances that we will not be assessed civil or other statutory penalties of $100,000 or more by the EPA or other regulatory agencies associated with this release.

We are a party to various legal actions that have arisen in the ordinary course of our business. We do not believe that the resolution of these matters will have a material adverse effect on our financial condition or results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Other risk factors to consider are as follows:

Tax Risks to Common Unitholders

If the Internal Revenue Service contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

The Internal Revenue Service ("IRS") has made no determination as to our status as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that result from that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to our unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. Tax exempt entities or foreign persons should consult their tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in 22 states, most of which impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to our unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

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

The annual meeting of our limited partners was held on April 26, 2006. At this meeting, three individuals were elected as Class I directors of our general partner's board of directors. A tabulation of the voting on this issue follows:

Name	For	Withheld	Abstain	Broker Non-Votes
N. John Lancaster, Jr.	56,641,127	6,175,448	—	—
George A. O'Brien, Jr...............	62,244,370	572,205	—	—
Thomas S. Souleles..................	56,609,393	6,207,182	—	—

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit 12.1 – Ratio of earnings to fixed charges.
Exhibit 31.1 – Rule 13a-14(a)/15d-14(a) Certification of Don R. Wellendorf, principal executive officer.
Exhibit 31.2 – Rule 13a-14(a)/15d-14(a) Certification of John D. Chandler, principal financial and accounting officer.
Exhibit 32.1 – Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
Exhibit 32.2 – Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 99.1 – Magellan GP, LLC balance sheets as of December 31, 2005 and June 30, 2006 and notes thereto.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma, on August 7, 2006.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its General Partner

/s/ John D. Chandler
John D. Chandler
Chief Financial Officer
and Treasurer (Principal Accounting and Financial Officer)

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
12.1	Ratio of earnings to fixed charges.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Don R. Wellendorf, principal executive officer.
31.2	Rule 13a-14(a)/15d-14(a) Certification of John D. Chandler, principal financial and accounting officer.
32.1	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
32.2	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
99.1	Magellan GP, LLC balance sheets as of December 31, 2005 and June 30, 2006 and notes thereto.

Exhibit 12.1

MAGELLAN MIDSTREAM PARTNERS, L.P.
RATIO OF EARNINGS TO FIXED CHARGES
(In thousands)

	Year Ended December 31,					Six Months Ended June 30,
	2001	2002	2003	2004	2005	2006
EARNINGS:						
Income from continuing operations before income taxes, extraordinary gain (loss) and cumulative effect of change in accounting principle *	$ 97,613	$ 107,495	$ 88,169	$ 108,601	$ 156,379	$ 104,018
Fixed charges	15,755	33,344	39,779	41,657	56,656	30,332
Amortization of capitalized interest	465	471	462	463	465	356
Distributed income of equity investees	—	—	—	—	3,300	2,025
Capitalized interest	(764)	(231)	(102)	(426)	(817)	(633)
Total earnings	$ 113,069	$ 141,079	$ 128,308	$ 150,295	$ 215,983	$ 136,098
FIXED CHARGES:						
Interest expense	$ 14,606	$ 22,907	$ 36,597	$ 37,893	$ 52,554	$ 28,125
Capitalized interest	764	231	102	426	817	633
Debt expense amortization	253	9,950	2,830	3,056	2,871	1,355
Rent expense representative of interest factor	132	256	250	282	414	219
Total fixed charges	$ 15,755	$ 33,344	$ 39,779	$ 41,657	$ 56,656	$ 30,332
Ratio of earnings to fixed charges	7.2	4.2	3.2	3.6	3.8	4.5

* Excludes income from equity investments and minority interest expense.