MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
May 07, 2007
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2007

OR

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

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 x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.

Large accelerated filer x 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 x

As of May 4, 2007, there were outstanding 66,546,297 common units.

Table of Contents

PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS		
CONSOLIDATED STATEMENTS OF INCOME		2
CONSOLIDATED BALANCE SHEETS		3
CONSOLIDATED STATEMENTS OF CASH FLOWS		4
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS		
1.	Organization and Basis of Presentation and Other	5
2.	Allocation of Net Income	5
3.	Comprehensive Income	6
4.	Segment Disclosures	7
5.	Related Party Disclosures	8
6.	Inventory	10
7.	Equity Investment	10
8.	Employee Benefit Plans	11
9.	Debt	11
10.	Derivative Financial Instruments	12
11.	Commitments and Contingencies	13
12.	Long-Term Incentive Plan	15
13.	Distributions	17
14.	Net Income Per Unit	17
15.	Fair Value Measurements	17
16.	Subsequent Events	18
ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS		
Introduction		19
Recent Developments		19
Results of Operations		20
Liquidity and Capital Resources		22
Environmental		24
Other Items		25
Impact of Inflation		25
New Accounting Pronouncements		25
ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK		26
ITEM 4. CONTROLS AND PROCEDURES		26
Forward-Looking Statements		26

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS	29
ITEM 1A. RISK FACTORS	29
ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS	31
ITEM 3. DEFAULTS UPON SENIOR SECURITIES	31
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	31
ITEM 5. OTHER INFORMATION	32
ITEM 6. EXHIBITS	32

Table of Contents

MAGELLAN MIDSTREAM PARTNERS, L.P.

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 March 31,	
	2006	**2007**
Transportation and terminals revenues	$ 130,191	$ 143,151
Product sales revenues	148,896	148,663
Affiliate management fee revenue	173	173
Total revenues	279,260	291,987
Costs and expenses:		
Operating	53,385	60,975
Product purchases	133,595	133,980
Depreciation and amortization	15,201	15,440
Affiliate general and administrative	15,027	17,685
Total costs and expenses	217,208	228,080
Equity earnings	719	763
Operating profit	62,771	64,670
Interest expense	14,292	14,867
Interest income	(646)	(371)
Interest capitalized	(204)	(897)
Debt placement fee amortization	677	645
Other expense	339	
Income before income taxes	48,313	50,426
Provision for income taxes		724
Net income	$ 48,313	$ 49,702
Allocation of net income:		
Limited partners interest	$ 36,685	$ 36,851
General partner s interest	11,628	12,851
Net income	$ 48,313	$ 49,702

Basic net income per limited partner unit	$	0.55	$	0.55
Weighted average number of limited partner units outstanding used for basic net income per unit calculation		66,361		66,538
Diluted net income per limited partner unit	$	0.55	$	0.55
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation		66,482		66,546

See notes to consolidated financial statements.

Table of Contents

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands)

ASSETS	December 31, 2006	March 31, 2007 (Unaudited)
Current assets:		
Cash and cash equivalents	$ 6,390	$ 65
Restricted cash	5,283	10,620
Accounts receivable (less allowance for doubtful accounts of $51 at December 31, 2006 and March 31, 2007)	51,730	60,517
Other accounts receivable	13,288	13,086
Affiliate accounts receivable	483	747
Inventory	91,550	79,607
Other current assets	8,294	12,765
Total current assets	177,018	177,407
Property, plant and equipment	2,260,608	2,298,573
Less: accumulated depreciation	557,869	572,594
Net property, plant and equipment	1,702,739	1,725,979
Equity investments	24,087	23,750
Long-term receivables	6,920	6,811
Goodwill	23,945	23,945
Other intangibles (less accumulated amortization of $5,196 and $5,583 at December 31, 2006 and March 31, 2007, respectively)	8,633	8,246
Debt placement costs (less accumulated amortization of $9,592 and $10,237 at December 31, 2006 and March 31, 2007, respectively)	5,829	5,184
Other noncurrent assets	3,478	3,331
Total assets	$ 1,952,649	$ 1,974,653
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 55,549	$ 28,024
Affiliate accounts payable	11,008	9,516
Affiliate payroll and benefits	18,676	7,364
Accrued interest payable	9,266	22,178
Accrued taxes other than income	17,460	17,583
Environmental liabilities	34,952	34,943
Deferred revenue	22,901	22,658
Accrued product purchases	63,098	45,791
Current portion of long-term debt	270,839	
Other current liabilities	14,640	12,842
Total current liabilities	518,389	200,899
Long-term debt	518,609	856,831
Long-term affiliate payable	8,133	984
Long-term affiliate pension and benefits	29,278	31,401
Other deferred liabilities	48,945	46,446

Environmental liabilities	22,813	26,174
Commitments and contingencies		
Partners capital:		
Partners capital	825,333	827,389
Accumulated other comprehensive loss	(18,851)	(15,471)
Total partners capital	806,482	811,918
Total liabilities and partners capital	$ 1,952,649	$ 1,974,653

See notes to consolidated financial statements.

Table of Contents

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2007
Operating Activities:		
Net income	$ 48,313	$ 49,702
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	15,201	15,440
Debt placement fee amortization	677	645
Loss on sale and retirement of assets	394	862
Equity earnings	(719)	(763)
Distributions from equity investment	1,075	1,100
Equity method incentive compensation expense		537
Amortization of prior service cost and net actuarial loss		384
Changes in operating assets and liabilities:		
Accounts receivable and other accounts receivable	(13,351)	(8,585)
Affiliate accounts receivable	(250)	(264)
Inventory	15,387	11,943
Accounts payable	(225)	(16,764)
Affiliate accounts payable	1,565	(1,492)
Affiliate payroll and benefits	(7,383)	(11,312)
Accrued interest payable	12,999	12,912
Accrued taxes other than income	(39)	123
Accrued product purchases	(11,045)	(17,307)
Restricted cash	(5,580)	(5,337)
Current and noncurrent environmental liabilities	(1,413)	3,352
Other current and noncurrent assets and liabilities	(5,101)	(2,795)
Net cash provided by operating activities	50,505	32,381
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(24,479)	(39,356)
Proceeds from sale of assets	466	202
Changes in accounts payable		(10,761)
Prepaid construction costs from related party	2,500	
Net cash used in investing activities	(21,513)	(49,915)
Financing Activities:		
Distributions paid	(49,503)	(56,291)
Net borrowings under revolver	15,000	66,800
Capital contributions by affiliate	4,777	700
Other	16	
Net cash provided by (used in) financing activities	(29,710)	11,209
Change in cash and cash equivalents	(718)	(6,325)
Cash and cash equivalents at beginning of period	36,489	6,390

Cash and cash equivalents at end of period	$ 35,771	$ 65
Supplemental non-cash investing and financing transactions:		
Issuance of common units in settlement of 2004 long-term incentive plan awards	$	$ 7,406

See notes to consolidated financial statements.

4

Table of Contents

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Presentation and Other

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 an approximate 2% general partner interest in us as well as all of our incentive distribution rights. 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 (G&A) services 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, 2006, which is derived from audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of March 31, 2007, and the results of operations and cash flows for the three months ended March 31, 2006 and 2007. The results of operations for the three months ended March 31, 2007 are not necessarily indicative of the results to be expected for the full year ending December 31, 2007.

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, 2006.

Other

Beginning in 2007, the state of Texas implemented a partnership-level tax based on a percentage of the financial results of our assets apportioned to the state of Texas. We have reported our estimate of this tax as provision for income taxes on our consolidated statements of income.

2. Allocation of Net Income

For purposes of calculating earnings per unit and determining the capital balances of the general partner and the limited partners, the allocation of net income between our general partner and limited partners was as follows (in thousands):

Table of Contents

	Three Months Ended March 31, 2006	2007
Allocation of net income to general partner:		
Net income	$ 48,313	$ 49,702
Direct charges to general partner:		
Reimbursable G&A costs	412	276
Previously indemnified environmental charges	600	2,250
Total direct charges to general partner	1,012	2,526
Income before direct charges to general partner	49,325	52,228
General partner s share of income (a)	25.63%	29.44%
General partner s allocated share of net income before direct charges	12,640	15,377
Direct charges to general partner	(1,012)	(2,526)
Net income allocated to general partner	$ 11,628	$ 12,851
Net income	$ 48,313	$ 49,702
Less: net income allocated to general partner	11,628	12,851
Net income allocated to limited partners	$ 36,685	$ 36,851

(a) For those periods when the distributions we pay exceed our net income, the general partner s percentage share of income is its proportion of cash distributions paid for the period. The cash distributions we have paid or will pay for the three months ended March 31, 2006 and 2007 exceeded our net income for each respective period.

The reimbursable G&A costs above represent G&A expenses charged against our income during the periods presented that were required to be reimbursed to us by MGG under the terms of an omnibus agreement to which MGG is a party. Because the limited partners do not share in these costs, we have allocated these G&A expense amounts directly to our general partner. We record these reimbursements by our general partner as capital contributions. We and our general partner have entered into an agreement with a former affiliate to settle certain of our former affiliate s indemnification obligations to us (see Note 11 Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs have been allocated directly to our general partner. We have received $82.5 million of the $117.5 million settlement from the former affiliate, and the final $35.0 million installment is due in July 2007.

3. Comprehensive Income

A reconciliation of net income to comprehensive income follows below (in thousands). For information on all of our derivative instruments, see Note 10 Derivative Financial Instruments.

	Three Months Ended March 31, 2006	2007
Net income	$ 48,313	$ 49,702
Change in fair value of product hedges	55	
Change in fair value of cash flow hedges		2,943
Amortization of net loss on cash flow hedges	53	53
Amortization of prior service cost and net actuarial loss		384

Other comprehensive income	108	3,380
Comprehensive income	$ 48,421	$ 53,082

Table of Contents

4. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenues from affiliates and external customers, operating expenses, product purchases and equity earnings. Transactions between our business segments are conducted and recorded on the same basis as transactions with third-party entities.

We believe that investors benefit from having access to the same financial measures being used by management. Operating margin, which is presented in the tables below, is an important measure used by management to evaluate 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 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 tables below. Operating profit includes expense items, such as depreciation and amortization and G&A expenses, that management does not consider when evaluating the core profitability of our operations.

Beginning in 2007, commercial and operating responsibilities for our Dallas and Southlake, Texas inland terminals were transferred from the petroleum products terminals segment to the petroleum products pipeline system segment. As a result, historical financial results for our segments have been adjusted to conform to the current period s presentation.

	Three Months Ended March 31, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 91,853	$ 34,371	$ 4,721	$ (754)	$ 130,191
Product sales revenues	145,464	3,432			148,896
Affiliate management fee revenue	173				173
Total revenues	237,490	37,803	4,721	(754)	279,260
Operating expenses	41,029	11,615	2,247	(1,506)	53,385
Product purchases	131,575	2,147		(127)	133,595
Equity earnings	(719)				(719)
Operating margin	65,605	24,041	2,474	879	92,999
Depreciation and amortization	9,725	4,407	190	879	15,201
Affiliate G&A expenses	10,819	3,675	533		15,027
Segment profit	$ 45,061	$ 15,959	$ 1,751	$	$ 62,771

Table of Contents

	Three Months Ended March 31, 2007 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 107,311	$ 31,749	$ 4,915	$ (824)	$ 143,151
Product sales revenues	144,265	4,398			148,663
Affiliate management fee revenue	173				173
Total revenues	251,749	36,147	4,915	(824)	291,987
Operating expenses	42,942	13,961	5,539	(1,467)	60,975
Product purchases	131,426	2,682		(128)	133,980
Equity earnings	(763)				(763)
Operating margin	78,144	19,504	(624)	771	97,795
Depreciation and amortization	9,630	4,843	196	771	15,440
Affiliate G&A expenses	12,530	4,527	628		17,685
Segment profit	$ 55,984	$ 10,134	$ (1,448)	$	$ 64,670

5. Related Party Disclosures

Affiliate Entity Transactions

We have a 50% ownership interest in Osage Pipe Line Company, LLC (Osage Pipeline) and are paid a management fee for its operation. During both the three months ended March 31, 2006 and 2007, we received operating fees from Osage Pipeline of $0.2 million, which we reported as affiliate management fee revenues.

Transactions between us and our affiliates are accounted for as affiliate transactions. The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Three Months Ended March 31,	
	2006	2007
MGG GP - allocated operating expenses	$ 17,712	$ 19,203
MGG GP - allocated G&A expenses	$ 10,037	$ 10,351

Under our services agreement with MGG GP, we reimburse MGG GP for costs of employees necessary to conduct our operations. The affiliate payroll and benefits accruals associated with this agreement at December 31, 2006 and March 31, 2007 were $18.7 million and $7.4 million, respectively, and the long-term affiliate pension and benefits accrual associated with this agreement at December 31, 2006 and March 31, 2007 was $29.3 million and $31.4 million, respectively. We settle our affiliate payroll, payroll-related expenses and non-pension postretirement benefit costs with MGG GP on a monthly basis. We settle our long-term affiliate pension liabilities through payments to MGG when MGG makes contributions to MGG GP s pension funds.

MGG has 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. We do not expect to receive reimbursements under this agreement beyond 2008. The amount of G&A costs required to be reimbursed by MGG to us was $0.4 million and $0.3 million for the three months ended March 31, 2006 and 2007, respectively.

Other Related Party Transactions

MGG, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF). During 2006 and through January 30, 2007, one or more of the members of our general partner s eight-member board of directors were representatives of CRF. The board of directors of our general partner 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, CRF agreed that none of its representatives would serve on our general partners board of directors and on the boards of directors of competing companies in which CRF owns an interest. CRF is part of an investment group that has agreed to purchase Kinder Morgan, Inc. To alleviate competitive concerns the Federal Trade Commission

(FTC) raised regarding the transaction, CRF agreed with the FTC to remove their representatives from our general partner s board of directors upon the closing of the purchase of Kinder Morgan, Inc. This agreement was announced on January 25, 2007. Effective January 30, 2007, all of the representatives of CRF voluntarily resigned from the board of directors of our general partner.

CRF has total combined general and limited partner interests in SemGroup, L.P. (SemGroup) of approximately 30%. One of the members of the seven-member board of directors of SemGroup s general partner is a representative of CRF, with three votes on that board. Through our affiliates, we are a party to a number of arms-length transactions with SemGroup and its affiliates, and we disclosed these transactions as related party transactions. As a result of the voluntary resignation of the CRF representatives from our general partner s board of directors as of January 30, 2007, we no longer classify SemGroup as a related party for accounting purposes. A summary of our transactions with SemGroup during the first quarter of 2006 and during the period of the current quarter in which SemGroup was classified as a related party is provided in the following table (in millions):

	Three Months Ended March 31, 2006	January 1, 2007 Through January 30, 2007
Product sales revenues	$28.2	$20.5
Product purchases	11.0	14.5
Terminalling and other services revenues	1.6	0.3
Storage tank lease revenues	0.8	0.4
Storage tank lease expense	0.2	0.1

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2006, we had recognized a receivable of $4.0 million from and a payable of $18.8 million to SemGroup and its affiliates. The receivable was included with the trade accounts receivable amount and the payable was included with the accounts payable amount on our December 31, 2006 consolidated balance sheet.

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 under a 10-year operating lease. Through March 31, 2006, we received $2.5 million associated with this transaction from SemGroup s affiliate, which we reported as prepaid construction costs from related party on our consolidated statement of cash flows. We received no funds associated with this transaction during the period of the current quarter in which SemGroup was classified as a related party.

Our general partner s board of directors appointed John P. DesBarres as an independent board member. Mr. DesBarres currently serves as a board member for American Electric Power Company, Inc. of Columbus, Ohio. During the three months ended March 31, 2006 and 2007, our operating expenses included $0.7 million and $0.6 million, respectively, of power costs incurred with Public Service Company of Oklahoma, which is a subsidiary of American Electric Power Company, Inc. We had no amounts payable to or receivable from Public Service Company of Oklahoma or American Electric Power Company, Inc. at either December 31, 2006 or March 31, 2007.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives approximately 50% of any incremental cash distributed per limited partner unit. As of March 31, 2007, our executive officers collectively own approximately 5% of MGG Midstream Holdings, L.P., which currently owns approximately 28% of MGG, the owner of our general partner; therefore, our executive officers also benefit from distributions to our general partner. 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 $0.61625 per unit, our general partner would receive annual distributions of approximately $68.4 million on its combined general partner interest and incentive distribution rights.

Table of Contents

6. Inventory

Inventory at December 31, 2006 and March 31, 2007 was as follows (in thousands):

	December 31, 2006	March 31, 2007
Refined petroleum products	$ 45,839	$ 33,138
Natural gas liquids	28,848	30,457
Transmix	14,449	12,509
Additives	2,026	3,115
Other	388	388
Total inventory	$ 91,550	$ 79,607

7. 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 in McPherson, Kansas (NCRA). The 135-mile Osage pipeline transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to the NCRA refinery and the Frontier refinery in El Dorado, Kansas. Our agreement with NCRA calls for equal sharing of Osage Pipeline s net income. Income from our equity investment in Osage Pipeline is included with our petroleum products pipeline system. Summarized financial information for Osage Pipeline for the three months ended March 31, 2006 and 2007 is presented below (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2007
Revenues	$ 3,288	$ 3,520
Net income	$ 1,770	$ 1,858

Condensed balance sheets for Osage Pipeline as of December 31, 2006 and March 31, 2007 are presented below (in thousands):

	December 31, 2006	March 31, 2007
Current assets	$ 5,015	$ 4,759
Noncurrent assets	$ 4,278	$ 4,227
Current liabilities	$ 697	$ 731
Members equity	$ 8,596	$ 8,255

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

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2007
Investment at beginning of period	$ 24,888	$ 24,087
Earnings in equity investment:		

Proportionate share of earnings	885	929
Amortization of excess investment	(166)	(166)
Net earnings in equity investment	719	763
Cash distributions	(1,075)	(1,100)
Equity investment at end of period	$ 24,532	$ 23,750

Our initial investment in Osage Pipeline included an excess net investment amount of $21.7 million, which is being amortized over the average lives of Osage Pipeline s assets. 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, 2006 and March 31, 2007 was $19.8 million and $19.6 million, respectively, and represents additional value of the underlying identifiable assets.

8. Employee Benefit Plans

MGG GP sponsors a pension plan for union employees, a pension plan for non-union employees and a postretirement benefit plan for selected employees. The following table presents our consolidated net periodic benefit costs related to these plans during the three months ended March 31, 2006 and 2007 (in thousands):

	Three Months Ended March 31, 2006		Three Months Ended March 31, 2007	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,229	$ 140	$ 1,474	$ 124
Interest cost	541	270	634	225
Expected return on plan assets	(558)		(573)	
Amortization of prior service cost	169	450	169	45
Amortization of actuarial loss	252	115	59	111
Net periodic benefit cost	$ 1,633	$ 975	$ 1,763	$ 505

9. Debt

Our debt at December 31, 2006 and March 31, 2007 was as follows (in thousands):

	December 31, 2006	March 31, 2007
Magellan Pipeline notes	$ 270,839	$ 271,469
Revolving credit facility	20,500	87,300
6.45% Notes due 2014	249,589	249,599
5.65% Notes due 2016	248,520	248,463
Total debt	$ 789,448	$ 856,831

Our debt and the debt of our consolidated subsidiaries is non-recourse to our general partner.

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 March 31, 2007, $272.6 million of senior notes were outstanding pursuant to this agreement. The original maturity date of the notes was October 7, 2007; however, we repaid these notes on May 3, 2007, primarily with net proceeds from a $250.0 million public offering of 30-year senior notes (see Note 16 Subsequent Events). The outstanding principal amount of the notes at December 31, 2006 and March 31, 2007 was decreased by $1.8 million and $1.1 million, respectively, for the fair value of associated hedges (see Note 10 Derivative Financial Instruments). The carrying amount of these notes was included in long-term debt on our March 31, 2007 consolidated balance sheet since these notes have been refinanced with debt having maturities of longer than twelve months. The interest rate of the notes was fixed at 7.7%. However, including the impact of the associated fair value hedges, which effectively swapped $250.0 million of the fixed-rate notes to floating-rate debt, the weighted-average interest rate for the notes was 8.5% and 8.7% at March 31, 2006 and 2007, respectively. We made deposits in an escrow account in anticipation of semi-annual interest payments on these notes. These deposits of $5.3 million at December 31, 2006 and $10.6 million at March 31, 2007 were reflected as restricted cash on our consolidated balance sheet.

Revolving Credit Facility. The borrowing capacity under our revolving credit facility is $400.0 million, which matures in May 2011. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. As of March 31, 2007, $87.3 million was outstanding under this facility, and $1.1 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets. The weighted-average interest rate on the revolver at March 31, 2006 and 2007 was 5.5% and 5.8%, respectively.

Table of Contents

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 10 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 of senior 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 10 Derivative Financial Instruments), the weighted-average interest rate of these notes at March 31, 2006 and March 31, 2007 was 5.9% 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 was decreased by $1.2 million and $1.3 million at December 31, 2006 and March 31, 2007, respectively, for the fair value of the associated hedge.

10. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes hedges we had settled as of March 31, 2007 associated with various debt offerings (dollars in millions):

Hedge	Date	Gain/(Loss)	Amortization Period
Interest rate hedge	October 2002	$ (1.0)	Remaining 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 agreements 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%. The fair value of the instrument associated with this hedge at December 31, 2006 was $(1.8) million, which was recorded to other current liabilities and current portion of long-term debt. The fair value of the instrument associated with this hedge at March 31, 2007 was $(1.1) million, which was recorded to other current liabilities and long-term debt. We unwound these agreements on May 3, 2007 in conjunction with the repayment of Magellan Pipeline notes (see Note 16 Subsequent Events).

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. We have accounted for this agreement as a fair value hedge. 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 the related notes. Payments settle in April and October each year with LIBOR set in arrears. During each 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 results 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, 2006 and March 31, 2007, respectively, was $(1.2) million and $(1.3) million, which was recorded to other deferred liabilities and long-term debt.

In September and November 2006, we entered into forward starting interest rate swap agreements to hedge against the variability of future interest payments on $250.0 million of debt we expected to issue in 2007. These interest rate swap agreements were unwound and settled in April 2007, in conjunction with our public debt offering of $250.0 million of senior notes (see Note 16 Subsequent Events for further discussion of this matter). We accounted for these agreements as cash flow hedges. The fair value of these agreements at December 31, 2006 and March 31, 2007 was $0.2 million and $3.2 million, respectively, which was recorded to other current assets and other comprehensive income. These agreements had no impact on our cash flows for the quarter ending March 31, 2007.

Table of Contents

We also use derivatives to help us manage product purchases and sales. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of March 31, 2007, we had commitments under future contracts for product purchases that will be accounted for as normal purchases totaling approximately $10.3 million. Additionally, we had commitments under future contracts for product sales that will be accounted for as normal sales totaling approximately $51.3 million.

11. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $57.8 million and $61.1 million at December 31, 2006 and March 31, 2007, respectively. Environmental liabilities have been classified as current or noncurrent based on management s estimates regarding the timing of actual payments for all other environmental liabilities. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years.

During the third quarter of 2006, we entered into an agreement with a contractor pursuant to which the contractor assumed the responsibility for the remediation of certain of our environmental sites in exchange for $14.0 million to be paid over the next 10 years. Further, the agreement required the contractor to purchase a cost cap insurance policy, under which we are an additional named insured. The cost of this policy was $2.2 million, which we were required to pay. At the time we entered into this agreement, we adjusted our environmental liabilities associated with these sites to $11.9 million, which represented the discounted amount of the cash payments to be made to this contractor. We discounted this liability as we believed the amount and timing of cash payments to be made under this agreement were reliably determinable as defined in Statement of Position 96-1. Due to a number of factors, during first-quarter 2007 we determined that the exact timing of the payments to be made under this agreement were no longer reliably determinable. As a result, we increased the liability to its undiscounted amount and recognized expense of $1.7 million.

Our environmental liabilities include, among other items, accruals for the items discussed below:

EPA Issue. 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. 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. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* discussion below). 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. We are in ongoing negotiations with the EPA; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA 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 March 31, 2007, we have estimated remediation costs associated with this release of approximately $2.8 million. Through March 31, 2007, we have spent $1.9 million on remediation associated with this release and, as of March 31, 2007, have recorded associated environmental liabilities of $0.9 million. We have recognized a receivable of $1.2 million from our insurance carrier for this matter. We will include 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 March 31, 2007, we have estimated remediation costs associated with this release of approximately $5.1 million. Through March 31, 2007, we have spent $3.0 million on remediation associated with this release and, as of March 31, 2007, have recorded associated environmental liabilities of $2.1 million and a receivable of $3.6 million from our insurance carrier. We will include this release with the 32 other releases discussed in *EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Polychlorinated Biphenyls (PCB) Impacts. We have identified PCB impacts at one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term, after our delineation process is complete, the PCB contamination levels could require corrective actions. We are unable at this time to determine what these corrective actions and associated costs might be. These items would have been considered covered by the indemnity agreement settled in May 2004 (see *Indemnification Settlement* below), however, the costs of these corrective actions could be material to our results of operations and cash flows.

Blair, Nebraska and Kingman, Kansas Ammonia Releases. In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third party operator constituted violations of federal criminal statutes. We do not believe we have an obligation to indemnify or defend the third party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and third party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter.

Indemnification Settlement. Prior to May 2004, The Williams Companies, Inc. (Williams), the former owner of our general partner, had agreed to indemnify us against, among other things, certain environmental losses associated with assets contributed to us at the time of our initial public offering or which we subsequently acquired from it. In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release it from these indemnifications. Pursuant to this agreement, we received $35.0 million, $27.5 million and $20.0 million on July 1, 2004, 2005 and 2006, respectively, and we expect to receive a final payment of $35.0 million in July 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. We have reflected $45.1 million of the amounts received under this indemnification settlement as a reduction in our affiliate accounts receivables and $37.4 million as a capital contribution from our general partner.

As of December 31, 2006 and March 31, 2007, known liabilities that would have been covered by this indemnity agreement were $45.7 million and $46.9 million, respectively. Through March 31, 2007, we have spent $33.6 million of the $117.5 million indemnification settlement amount for indemnified matters, including $14.2 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.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $5.9 million and $6.1 million at December 31, 2006 and March 31, 2007, respectively.

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 net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The combined net unrecognized product overages for our operations had a market value of approximately $15.6 million as of March 31, 2007. 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.

12. 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 phantom units. The long-term incentive plan permits the grant of awards covering an aggregate of 1.4 million limited partner units (see Note 16 Subsequent Events for further discussion of this matter). The compensation committee of our general partner s board of directors (the Compensation Committee) administers the long-term incentive plan.

The long-term incentive awards discussed below that have been granted by the Compensation Committee 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 award 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 under certain circumstances following a change in control of our general partner.

In February 2004, the Compensation Committee approved approximately 159,000 unit award grants pursuant to the long-term incentive plan. These units vested on December 31, 2006, and, because we exceeded certain performance metrics, the actual number of units awarded with this grant totaled approximately 285,000. The value of these units on December 31, 2006 was $11.0 million. We settled these award grants in January 2007 by issuing 184,905 common limited partner units and distributing those units to the participants. The difference between the units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. We paid associated tax withholdings and employer taxes of $3.9 million and $0.5 million, respectively, in January 2007, which we intend to finance with funds from our next equity offering.

In February 2005, the Compensation Committee approved approximately 160,600 unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant is based on the attainment of long-term performance metrics. The number of units that could ultimately be issued under this award ranges from zero units up to a total of 297,200 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 on December 31, 2007. As of March 31, 2007, approximately 11,300 award grants have been forfeited and we estimate an additional 700 will be forfeited prior to the vesting date. We have estimated the number of units that will be awarded under this grant to be approximately 282,300, the fair value of which was $12.7 million on March 31, 2007. Unrecognized estimated compensation expense associated with these award grants as of March 31, 2007 was $3.2 million, which will be recognized over the next 9 months. There was no impact on our cash flows associated with these award grants during the first quarter of 2006 and 2007.

During 2006, the Compensation Committee approved approximately 178,500 unit award grants pursuant to the long-term incentive plan. There was no impact on our cash flows associated with these award grants during the first quarter of 2006 and 2007. These award grants are being accounted for as follows:

- Approximately 139,700 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 ranges from zero to approximately 258,500 as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the equity method. The weighted-average fair value of the awards on the grant date was $24.67 per unit, which was based on our unit price on the grant date less the present value of the per-unit estimated cash distributions during the vesting period. As of March 31, 2007, approximately 8,500 award grants have been forfeited and we expect an additional 2,000 will be forfeited prior to the vesting date. We increased our estimate of the number of payout units under this grant to approximately 232,700 because we believe we will achieve above-standard results compared to the established performance metrics. The value of these award grants was $5.7 million on March 31, 2007, and the unrecognized compensation cost on that date was $3.5 million, which will be recognized over the next 21 months.

- Approximately 34,900 are based on personal performance and payouts will be determined by the Compensation Committee. These units vest December 31, 2008. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 64,600 as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the liability method; consequently, the compensation expense we recognize is based on the fair value of the unit awards and the percentage of the service period completed at each period end. As of March 31, 2007, approximately 2,100 award grants have been forfeited and we expect an additional 500 will be forfeited prior to the vesting date. We increased our estimate of the number of payout units under this grant to approximately 58,200 because we believe the Compensation Committee will approve above-standard discretionary payouts as they have

historically done when above-standard financial results are achieved. The fair value of these award grants was $2.5 million on March 31, 2007, and the unrecognized estimated compensation cost on that date was $1.5 million, which will be recognized over the next 21 months.

An additional 3,800 award grants were approved with various vesting dates. As of March 31, 2007, approximately 2,600 award grants have been forfeited. We are using the equity method to account for most of these award grants. The value of these award grants was $0.1 million on March 31, 2007, and the unrecognized estimated compensation cost on that date was less than $0.1 million, which will be recognized over the next 9 months.

In January 2007, the Compensation Committee approved approximately 147,900 unit award grants pursuant to the long-term incentive plan. There was no impact on our cash flows from the award grants during the current quarter. These award grants have a three-year vesting period which will end on December 31, 2009; however, the grants are broken equally into three specific tranches. Under the first tranche, 80% of the payouts are based on performance metrics set for the 2007 fiscal year. Under the second and third tranches, 80% of the payouts will be based on performance metrics that will be established in the first quarter of each respective year. Under all three tranches, 20% of the payouts are based on personal performance and payouts will be determined by the Compensation Committee. These awards are being accounted for as follows:

Approximately 39,500 of the unit awards are based on attainment of 2007 performance metrics. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 75,300 units as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the equity method. The fair value of the awards on the grant date was $32.31 per unit, which was based on our closing unit price on January 29, 2007, less the present value of the per-unit estimated cash distributions during the vesting period. Management currently estimates that we will achieve a standard payout; therefore, our current compensation expense accruals assumed that 37,700 units will vest under this award grant, the fair value of which on March 31, 2007 was $1.2 million. The unrecognized compensation cost on that date was $1.1 million, which will be recognized over the next 33 months.

Approximately 9,800 of the unit awards are based on personal performance. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 18,800 units as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the liability method; therefore, the compensation expense we recognize is based on the fair value of unit awards and the percentage of the service period completed at each period end. The fair value of the unit awards at March 31, 2007 was $39.86 per unit. Management currently estimates that we will achieve a standard payout; therefore, our current compensation expense accruals assumed that 9,400 units will vest under this award grant. The fair value of these unit awards on March 31, 2007 was $0.4 million of which less than $0.1 million has been recognized as compensation expense. The estimated unrecognized compensation expense will be recognized over the next 33 months.

Our equity-based incentive compensation expense for the three months ended March 31, 2006 and 2007 is summarized as follows (in thousands):

	Three Months Ended March 31,	
	2006	**2007**
2003 awards	$ (86)	$
October 2003 awards	(3)	
January 2004 awards	(4)	
2004 awards	682	519
2005 awards	751	2,290
2006 awards	189	743
2007 awards		98
Total	$ 1,529	$ 3,650

Table of Contents

13. Distributions

We paid the following distributions during 2006 and 2007 (in thousands, except per unit amounts):

Date Cash Distribution Paid	Per Unit Cash Distribution Amount	Common Units	Subordinated Units	General Partner	Total Cash Distribution
02/14/06	$ 0.55250	$ 33,526	$ 3,138	$ 12,839	$ 49,503
05/15/06	0.56500	37,494		13,668	51,162
08/14/06	0.57750	38,323		14,498	52,821
11/14/06	0.59000	39,153		15,327	54,480
Total	$ 2.28500	$ 148,496	$ 3,138	$ 56,332	$ 207,966
02/14/07	$ 0.60250	$ 40,094	$	$ 16,197	$ 56,291
05/15/07(a)	0.61625	41,009		17,112	58,121
Total	$ 1.21875	$ 81,103	$	$ 33,309	$ 114,412

(a) Our general partner declared this cash distribution on April 25, 2007 to be paid on May 15, 2007 to unitholders of record at the close of business on May 8, 2007.

14. 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):

	For The Three Months Ended March 31, 2006		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 36,685	66,361	$ 0.55
Effect of dilutive restricted unit grants		121	
Diluted net income per limited partner unit	$ 36,685	66,482	$ 0.55

	For The Three Months Ended March 31, 2007		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 36,851	66,538	$ 0.55
Effect of dilutive restricted unit grants		8	
Diluted net income per limited partner unit	$ 36,851	66,546	$ 0.55

Units reported as dilutive securities are related to phantom unit grants (see Note 12 Long-Term Incentive Plan).

15. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) adopted Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years; however, earlier application was encouraged. We have elected to adopt SFAS No. 157 effective January 1, 2007. Our fair value measurements as of March 31, 2007 using significant other observable inputs for interest rate swap derivatives and forward starting interest rate swap derivatives were $(3.7) million and $3.2 million, respectively.

Table of Contents

16. Subsequent Events

On April 19, 2007, we issued $250.0 million of 6.4% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million, and the $1.1 million discount will be accreted over the life of the notes. Net proceeds from the offering, after underwriter discounts of $2.2 million and estimated offering costs of $0.5 million, were $246.2 million. The proceeds were used to prepay our Magellan Pipeline notes, as discussed below. In connection with the offering of the notes, we unwound $250.0 million of forward starting interest rate swap agreements that we executed in September and November 2006 to hedge against the variability of future interest payments on the new notes. We received $5.5 million from the settlement of these agreements, of which $5.3 million was recorded to other comprehensive income and will be amortized against interest expense over the life of the notes, and $0.2 million was considered ineffective and recognized as a gain. Including the impact of the amortization of the realized gain on these hedges, the effective interest rate of the new notes is 6.3%.

On May 3, 2007, we repaid the $272.6 million outstanding balance of our Magellan Pipeline notes, together with a make-whole payment of $2.0 million and accrued interest of $1.5 million. In connection with that repayment, we also unwound $250.0 million of associated fair value hedges, resulting in payments totaling $1.1 million to the hedge counterparties. These payments were funded using the $246.2 million net proceeds of our notes offering described above, together with borrowings on our revolver.

On April 25, 2007, our general partner declared a quarterly distribution of $0.61625 per unit to be paid on May 15, 2007 to unitholders of record at the close of business on May 8, 2007. Total distributions to be paid under this declaration are approximately $58.1 million.

On January 25, 2007, our general partner s board of directors approved an amendment to the long-term incentive plan, subject to unitholder approval, that would increase the total number of common units authorized to be issued under the plan from 1.4 million to 3.2 million common units. This proposal was approved by our unitholders at our annual meeting of limited partners held April 25, 2007. Also, at our annual meeting, our unitholders elected John P. DesBarres, Patrick C. Eilers and Thomas T. Macejko, Jr. to serve as members of our general partner s board of directors until our 2010 annual meeting.

Table of Contents

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 March 31, 2007, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 47 terminals;

- petroleum products terminals, which principally includes our seven marine terminal facilities and 27 inland terminals; and

- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

Beginning in 2007, commercial and operating responsibilities for the partnership s Dallas and Southlake, Texas inland terminals moved to the petroleum products pipeline system. As a result, historical financial results and operating statistics have been adjusted to conform to the current period s presentation.

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 partnership. 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, 2006.

Recent Developments

Distribution. On April 25, 2007 the board of directors of our general partner declared a quarterly cash distribution of $0.61625 per unit for the period of January 1 through March 31, 2007, representing 24 consecutive distribution increases since our initial public offering in February 2001. The new quarterly distribution will be paid on May 15, 2007 to unitholders of record on May 8, 2007.

Unitholder vote results. On April 25, 2007, we held our annual unitholder meeting. Proxy statements were mailed in advance to unitholders of record on February 23, 2007. Our unitholders elected John P. DesBarres, Patrick C. Eilers and Thomas T. Macejko, Jr. to serve as members of our general partner s board of directors until our 2010 annual meeting. In addition, our unitholders approved an amendment to increase the number of common units authorized to be issued under our long-term incentive compensation plan. No other matters requiring a unitholder vote were presented.

Debt prepayment and refinance. On April 19, 2007, we issued $250.0 million of 6.4% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million, and the $1.1 million discount will be accreted over the life of the notes. Net proceeds from the offering, after underwriter discounts of $2.2 million and estimated offering costs of $0.5 million, were $246.2 million. The proceeds were used to prepay our Magellan Pipeline Company, L.P. (Magellan Pipeline) notes, which is discussed below. In connection with the offering of the notes, we unwound $250.0 million of forward starting interest rate swap agreements that we executed in September and November 2006 to hedge against the variability of future interest payments on the new notes. We received $5.5 million from the settlement of these agreements, of which $5.3 million was recorded to other comprehensive income and will be amortized against interest expense over the life of the notes, and $0.2 million was considered ineffective and recognized as a gain. Including the impact of the amortization of the realized gain on these hedges, the effective interest rate of the new notes is 6.3%.

On May 3, 2007, we repaid the $272.6 million outstanding balance of our Magellan Pipeline notes, together with a make-whole payment of $2.0 million and accrued interest of $1.5 million. In connection with that repayment, we also unwound $250.0 million of associated fair value hedges, resulting in payments totaling $1.1 million to the hedge counterparties. These payments were funded using the $246.2 million net proceeds of our notes offering described above, together with borrowings on our revolver.

Table of Contents

Results of Operations

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin, which is presented in the table below, is an important measure used by management to evaluate 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 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 affiliate general and administrative (G&A) costs, which management does not consider when evaluating the core profitability of an operation.

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

	Three Months Ended March 31,		Variance Favorable (Unfavorable)	
	2006	2007	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 91.9	$ 107.3	$ 15.4	17
Petroleum products terminals	34.4	31.7	(2.7)	(8)
Ammonia pipeline system	4.7	4.9	0.2	4
Intersegment eliminations	(0.8)	(0.8)		
Total transportation and terminals revenues	130.2	143.1	12.9	10
Product sales	148.9	148.7	(0.2)	
Affiliate management fees	0.2	0.2		
Total revenues	279.3	292.0	12.7	5
Operating expenses:				
Petroleum products pipeline system	41.0	42.9	(1.9)	(5)
Petroleum products terminals	11.6	14.0	(2.4)	(21)
Ammonia pipeline system	2.2	5.5	(3.3)	(150)
Intersegment eliminations	(1.4)	(1.4)		
Total operating expenses	53.4	61.0	(7.6)	(14)
Product purchases	133.6	134.0	(0.4)	
Equity earnings	(0.7)	(0.8)	0.1	14
Operating margin	93.0	97.8	4.8	5
Depreciation and amortization expense	15.2	15.4	(0.2)	(1)
Affiliate G&A expense	15.0	17.7	(2.7)	(18)
Operating profit	$ 62.8	$ 64.7	$ 1.9	3
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 1.025	$ 1.152		
Volume shipped (million barrels)	69.2	71.3		
Petroleum products terminals:				
Marine terminal average storage utilized per month (million barrels)	20.7	21.8		

Inland terminal throughput (million barrels)	25.2	28.2
Ammonia pipeline system:		
Volume shipped (thousand tons)	216	214

Table of Contents

Transportation and terminals revenues increased by $12.9 million primarily due to the business segments shown below:

- an increase in petroleum products pipeline system revenues of $15.4 million primarily attributable to increased transportation revenues resulting from higher diesel fuel shipments and higher average transportation rates, in part due to our mid-year 2006 tariff increase and surcharge related to ultra-low sulfur diesel shipments. We also earned more ancillary revenues related to higher fees for leased storage and data services and additional demand for our terminal, additive and renewable fuels services during 2007; and

- a decrease in petroleum products terminals revenues of $2.7 million primarily due to first-quarter 2006 revenue recognition from a variable-rate storage agreement that ended January 2006. Although we currently have another variable-rate agreement in place, the term for the new contract expires in December 2007, at which time we will recognize any related revenues, which are based on our share of our customer s net trading profits earned over the agreement term. Additional revenues at our marine terminals due to expansion projects, additive fees and higher rates as well as higher revenue at our inland terminals from increased throughput volumes and higher additive fees benefited the current period, partially offsetting the lower variable-rate storage revenues.

Operating expenses increased by $7.6 million. Each of our business segments incurred additional expenses as follows:

- an increase in petroleum products pipeline system expenses of $1.9 million primarily due to system integrity spending for pipeline testing and maintenance as well as higher personnel and environmental expenses. These increases were partially offset by more favorable product overages in the current period, which reduce operating expenses;

- an increase in petroleum products terminals expenses of $2.4 million primarily related to a product downgrade charge resulting from the accidental blending of a small amount of product during the current period as well as higher personnel costs and property taxes; and

- an increase in ammonia pipeline system expenses of $3.3 million primarily due to increased environmental accruals related to a 2004 pipeline release and higher system integrity costs. We expect the amount of 2007 system integrity spending to be higher than in 2006 on our ammonia system as we complete the work necessary for the high consequence area testing mandated by federal regulations.

Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending operation, system product gains and transmix fractionation. Revenues from product sales were $148.7 million for the three months ended March 31, 2007, while product purchases were $134.0 million, resulting in gross margin from these transactions of $14.7 million. The gross margin resulting from product sales and purchases for the 2007 period decreased $0.6 million compared to gross margin for the 2006 period of $15.3 million, resulting from product sales for the three months ended March 31, 2006 of $148.9 million and product purchases of $133.6 million.

Operating margin increased $4.8 million, primarily due to higher petroleum products pipeline system revenues partially offset by lower revenues from a variable-rate storage agreement that benefited the 2006 period and increased operating expenses in 2007.

Affiliate G&A expenses increased by $2.7 million primarily attributable to our equity-based incentive compensation program, which impacted G&A expenses by $3.2 million during first quarter 2007 and $1.3 million during first quarter 2006. The higher compensation expense resulted from the increase in our unit price during the current period and increases in the number of units management estimates will vest under our equity-based incentive compensation program. G&A expenses also were higher during 2007 due to higher legal, information technology and prospecting costs.

Interest expense, net of capitalized interest and interest income, was $13.6 million for the three months ended March 31, 2007, which was slightly higher than the $13.4 million related to the three months ended March 31, 2006. Although the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, remained unchanged at 7.0% for both periods, our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $857.4 million during 2007 from $817.0 million during 2006 principally due to borrowings on our revolver to fund capital expenditures. The amount of capitalized interest in the current period increased due to the increased level of capital spending in the current quarter compared to 2006.

Provision for income taxes was $0.7 million in first quarter 2007, compared to $0.0 million in 2006. Beginning in 2007, the state of Texas has implemented a partnership-level tax based on the financial results of our assets apportioned to the state of Texas.

Table of Contents

Net income was $49.7 million for the three months ended March 31, 2007 compared to $48.3 million for the three months ended March 31, 2006, an increase of $1.4 million, or 3%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $32.4 million and $50.5 million for the three months ended March 31, 2007 and 2006, respectively. The $18.1 million decrease from 2006 to 2007 was primarily attributable to a $16.5 million decrease in cash relative to net changes in accounts payable due to timing of payments to our vendors and suppliers.

Net cash used in investing activities for the three months ended March 31, 2007 and 2006 was $49.9 million and $21.5 million, respectively. During 2007, we spent $39.4 million for capital expenditures, of which $6.3 million was for maintenance capital and $33.1 million was for expansion capital. During 2006, we spent $24.5 million for capital expenditures, of which $3.6 million was for maintenance capital and $20.9 million was for expansion capital.

Net cash provided by (used in) financing activities for the three months ended March 31, 2007 and 2006 was $11.2 million and ($29.7) million, respectively. The principal components for both quarters were borrowings on our revolving credit facility and distributions paid to our unitholders and general partner.

During first-quarter 2007, we paid $56.3 million in cash distributions to our unitholders and general partner. Based on the declared quarterly distribution of $0.61625 per unit associated with the first quarter of 2007, we intend to pay $58.1 million in distributions during second quarter 2007. If we continue to pay cash distributions at this level and the number of outstanding units remains the same, total cash distributions of $232.5 million would be paid on an annual basis. Of this amount, $68.4 million, or 29%, is related to our general partner s approximate 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 first-quarter 2007, our maintenance capital spending was $5.3 million, excluding $0.8 million of spending that would have been covered by indemnifications settled in May 2004 and $0.2 million for which we expect to be reimbursed by insurance. To date, we have received $82.5 million under this indemnification settlement agreement. Please see Environmental below for additional discussion of this indemnification settlement.

For 2007, we expect to incur maintenance capital expenditures for our existing businesses of approximately $34.0 million, excluding $8.0 million of maintenance capital that would have been covered by the indemnification discussed above and $2.0 million we expect to receive from insurance reimbursements.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During first-quarter 2007, we spent cash of approximately $33.1 million for organic growth projects. Based on projects currently underway or in advanced stages of development, we currently plan to spend $135.0 million on organic growth capital in 2007, excluding future acquisitions, and approximately $65.0 million in 2008 to complete these projects.

Liquidity

As of March 31, 2007, total debt reported on our consolidated balance sheet was $856.8 million. The difference between this amount and the $859.9 million face value of our outstanding debt is due to adjustments associated with fair value hedges and unamortized discounts on debt issuances.

Table of Contents

Magellan Pipeline Notes. In connection with the long-term financing of our acquisition of Magellan Pipeline, we and Magellan Pipeline entered into a note purchase agreement on October 1, 2002. As of March 31, 2007, $272.6 million of senior notes were outstanding pursuant to this agreement. The notes were originally scheduled to mature on October 7, 2007; however, we repaid these notes on May 3, 2007, together with accrued interest of $1.5 million and a make-whole payment of $2.0 million, using borrowings under our revolving credit facility and proceeds from our 6.4% notes due 2037 as described in Recent Developments. Since these notes were refinanced with debt having maturities longer than twelve months, the carrying amount was included in long-term debt on our March 31, 2007 consolidated balance sheet. The weighted-average interest rate for the notes, including the impact of the swap of $250.0 million of the notes from fixed-rate to floating-rate, was approximately 8.7% at March 31, 2007.

Revolving Credit Facility. Our revolving credit facility has a borrowing capacity of $400.0 million and matures in May 2011. Borrowings under the facility are unsecured and incur interest at LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. As of March 31, 2007, $87.3 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 March 31, 2007, the weighted-average interest rate on borrowings outstanding under this facility was 5.8%.

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 March 31, 2007 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 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 March 31, 2007 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. We were engaged in the following derivative transactions as of March 31, 2007:

- In September and November 2006, we entered into a total of $250.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipated issuing no later than October 2007. The interest rate swap agreements had a 30-year term, which matched the tenor of the hedged debt issuance. We received payment of $5.5 million when these agreements were terminated in connection with the pricing of the anticipated debt issuance in April 2007. Of this gain, $0.2 million was considered ineffective and will be reflected in net income during second quarter 2007, with the remainder recorded in other comprehensive income and amortized over the life of the hedged notes as a reduction to interest expense;

- 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 notes. These agreements effectively changed 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. We paid $1.1 million when these swap agreements were terminated in May 2007 in connection with our prepayment of the Magellan Pipeline notes, and this amount will be reflected as expense during second quarter 2007.

Credit Ratings. Our current corporate credit ratings are BBB by Standard and Poor s and Baa3 (under review for possible upgrade) by Moody s Investor Services.

Table of Contents

Off-Balance Sheet Arrangements

None.

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 involves 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.

Indemnification settlement. Prior to May 2004, a former affiliate provided indemnifications to us for assets we had acquired from it. In May 2004, we entered into an agreement with our former affiliate under which our former affiliate agreed to pay us $117.5 million to release it from those indemnification obligations. To date, we have received $82.5 million pursuant to this agreement and expect to receive the remaining balance of $35.0 million in July 2007. As of March 31, 2007, known liabilities that would have been covered by these indemnifications were $46.9 million. In addition, we have spent $33.6 million through March 31, 2007 that would have been covered by these indemnifications, including $14.2 million of capital costs. We have not reserved the cash received from this indemnity settlement but have used it for our various other cash needs, including expansion capital spending.

EPA issue. 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. 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. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate, as described above. 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. We are in ongoing discussions with the EPA; however, we are unable to determine with any accuracy what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations or cash flows.

Ammonia releases. In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third party operator constituted violations of federal criminal statutes. We do not believe we have an obligation to indemnify or defend the third party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and third party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter.

Polychlorinated Biphenyls (PCB) impacts. We have identified PCB impacts at one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term after our delineation process is complete, the PCB contamination levels could require corrective actions. We are unable at this time to determine what these corrective actions and associated costs might be. These items would have been considered covered by the indemnity agreement settled in May 2004, as discussed above, however, the costs of these corrective actions could be material to our results of operations and cash flows.

Other Items

***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 used to offset product losses. The combined net unrecognized product overages for our operations had a market value of approximately $15.6 million as of March 31, 2007. 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.

***Board of director changes*.** Our general partner is partially owned by Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF). CRF is part of an investment group that has agreed to purchase Kinder Morgan, Inc. To alleviate competitive concerns the Federal Trade Commission (FTC) raised regarding the transaction, CRF agreed with the FTC to remove their representatives from our general partner s board of directors upon the closing of the purchase of Kinder Morgan, Inc. This agreement was announced on January 25, 2007. One of CRF s representatives, Jim H. Derryberry, had previously voluntarily resigned from our general partner s board of directors effective October 24, 2006 and its other representative, N. John Lancaster, Jr., voluntarily resigned as a director effective January 30, 2007. Due to the voluntary resignations of the CRF representatives from our general partner s board of directors, our commercial relationship with customers in which CRF has an investment are no longer considered to be related party transactions for us for accounting purposes.

On January 29, 2007, our general partner s board of directors elected Thomas T. Macejko, Jr. of Madison Dearborn Partners, LLC to fill one of the vacancies created by the CRF resignations. The other vacancy has not yet been filled.

***Affiliate transactions*.** Since December 2005, MGG s general partner has provided the employees necessary to conduct our business operations. We reimburse MGG s general partner for costs of employees necessary to conduct our operations. In addition, MGG has agreed to reimburse us for G&A expenses, excluding equity-based compensation, in excess of a defined G&A cap. For the three months ended March 31, 2007, we were allocated operating expenses from MGG s general partner of $19.2 million and G&A expenses of $10.4 million. For the three months ended March 31, 2006, we were allocated operating expenses from MGG s general partner of $17.7 million and G&A expenses of $10.0 million. MGG reimbursed us G&A costs of $0.3 million for the three months ended March 31, 2007 and $0.4 million for the three months ended March 31, 2006, respectively.

We own a 50% interest in a crude oil pipeline company. We earn a fee to operate this pipeline which was $0.2 million for both the three months ended March 31, 2007 and 2006. We report these fees as affiliate management fee revenue on our consolidated statements of income.

Related party transactions. Because our distributions have exceeded target levels as specified in our partnership agreement, MGG indirectly receives approximately 50% of any incremental cash distributed per limited partner unit. The executive officers of our general partner collectively own approximately 5% of MGG Midstream Holdings, L.P., which currently owns 28% of MGG, and therefore also indirectly benefit 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 $0.61625 per unit, MGG would receive annual distributions of approximately $68.4 million on its combined 2% general partner interest and incentive distribution rights.

Impact of Inflation

Inflation is a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass through increased costs to our customers in the form of higher fees.

New Accounting Pronouncements

In February 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This Statement permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of mitigating volatility in reported earnings caused by measuring related assets and liabilities differently (without being required to apply complex hedge accounting provisions). We are still evaluating this optional Statement which is effective for the reporting entity s first fiscal year after November 15, 2007.

In January 2007, the FASB issued Revised Statement 133 Implementation Issue No. G19, *Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate.* This Implementation Issue clarified that in a cash flow hedge of a variable-rate financial asset or liability, the designated risk being hedged cannot be the risk of changes in its cash flows attributable to changes in the specifically identified benchmark rate if the cash flows of the hedged transaction are explicitly based on a different index. This Implementation Issue will not have a material impact on our results of operation, financial position or cash flows.

In January 2007, the FASB issued Statement 133 Implementation Issue No. G26, *Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate.* This Implementation clarified, given the guidance in Implementation Issue No. G19, that an entity may hedge the variability in cash flows by designating the hedged risk as the risk of overall changes in cash flows. This Implementation Issue will not have a material impact on our results of operation, financial position or cash flows.

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.

As of March 31, 2007, we had $87.3 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of an interest rate swap agreement discussed below, we are exposed to interest rate market risk on an additional $100.0 million of our debt. Considering this swap agreement and the amount outstanding on our revolving credit facility as of March 31, 2007, our annual interest expense would change by $0.2 million if LIBOR were to change by 0.125%.

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. We recognized a deferred liability of $1.2 million at March 31, 2007 for the fair value of this agreement.

As of March 31, 2007, we had entered into futures contracts, qualifying as normal purchases, for the purchase of approximately 0.1 million barrels of petroleum products. The notional value of these agreements was approximately $10.3 million.

As of March 31, 2007, we had entered into futures contracts, qualifying as normal sales, for the sale of approximately 0.6 million barrels of petroleum products. The notional value of these agreements was approximately $51.3 million.

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. Additionally, these disclosure controls and practices are effective in ensuring that information required to be disclosed is accumulated and communicated to our Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures.

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.

Table of Contents

Forward-looking statements can be identified by words such as anticipates, believes, expects, estimates, forecasts, projects and other simi expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in such forward-looking statements included in this report.

The following are among the important factors that could cause future results to differ materially from any projected, forecasted, estimated or budgeted amounts that 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 or state income tax purposes or if we become subject to significant forms of other taxation;

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 and 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, which 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 our 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 that 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.

This list of important factors is not exclusive. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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. 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. 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. We are in ongoing discussions with the EPA; however, we are unable to determine with any accuracy what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations or 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.

In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third party operator constituted violations of federal criminal statutes. We do not believe we have an obligation to indemnify or defend the third party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and third party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter.

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 information set forth below, 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, 2006, which could materially affect our business, financial condition or future results. The risks described below and 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.

We have updated the following risk factors:

Risks Related to our Business

Rising short-term interest rates could increase our financing costs and reduce the amount of cash we generate.

Following a debt refinancing completed on May 3, 2007, we had fixed-rate debt of $750.0 million outstanding, excluding unaccreted discounts and fair value adjustments for interest rate hedges. We have effectively converted $100.0 million of this debt to floating-rate debt using interest rate swap agreements. In addition, we had $87.3 million of floating rate borrowings outstanding on our revolving credit facility as of March 31, 2007. As a result of these swap agreements and revolver borrowings, we have exposure to changes in short-term interest rates. Rising short-term rates could reduce the amount of cash we generate and adversely affect our ability to pay cash distributions.

Restrictions contained in our debt instruments may limit our financial flexibility.

We are subject to restrictions with respect to our debt that may limit our flexibility in structuring or refinancing existing or future debt and prevent us from engaging in certain beneficial transactions. These restrictions include, among other provisions, the maintenance of certain financial ratios, as well as limitations on our ability to incur additional indebtedness, to grant liens, to sell assets or to repay existing debt without penalties. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. In addition, a change in control of our general partner could, under certain circumstances, result in our debt becoming due and payable.

Risks Related to Our Partnership Structure

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner and its affiliates have limited fiduciary duties to us and our unitholders, which may permit them to favor their own interests to the detriment of us and our unitholders.

Conflicts of interest may arise among our general partner and it affiliates, including MGG, on the one hand, and us and our unitholders, on the other hand. The directors and officers of our general partner have fiduciary duties to manage us in a manner beneficial to us and our limited partners. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to MGG, the owner of our general partner, and its affiliates. The board of directors of our general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

These conflicts may include, among others, the following:

- our general partner is allowed to take into account the interests of parties other than us, including MGG, and their respective affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- our general partner determines whether or not we incur debt and that decision may affect our credit ratings;

- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;

- our general partner, through its ownership of our incentive distribution rights, is entitled to receive increasing percentages, up to a maximum of 48%, of any incremental cash we distribute per limited partner unit, which could reduce our ability to complete accretive transactions or otherwise increase the amount of cash available for distribution to our unitholders;

our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such additional contractual arrangements are fair and reasonable to us;

our general partner controls the enforcement of obligations owed to us by it and its affiliates;

Table of Contents

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- our general partner determines the allocation of shared overhead expenses to MGG and us; and
- our general partner interprets and enforces contractual obligations between us and our affiliates, on the one hand, and MGG, on the other hand.

Certain executive officers of our general partner own interests in MGG Midstream Holdings, L.P. amounting to approximately 5% of its total ownership. MGG Midstream Holdings, L.P. currently owns the general partner interest and less than a majority of the limited partner interests in MGG. As a result, these officers could experience additional conflicts between our interests and the interests of MGG.

Affiliates of our general partner may compete with us.

Under our partnership agreement, it is not a breach of our general partner s fiduciary duties for affiliates of our general partner to engage in activities that compete with us. For example, both MGG, which owns our general partner, and MGG s general partner are partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF), which also owns, through affiliates, an interest in the general partner of SemGroup, L.P. (SemGroup), which is engaged in the transportation, storage and distribution of refined petroleum products and may acquire other entities that compete with us. We will compete directly with SemGroup and perhaps other entities in which CRF has an interest for acquisition opportunities throughout the United States and potentially will compete with SemGroup and these other entities for new business or extensions of the existing services provided by our operating partnerships, creating actual and potential conflicts of interest between us and affiliates of our general partner. In addition, an affiliate of SemGroup is a significant customer of ours.

The following is a new risk factor:

Tax Risks to Common Unitholders

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The Internal Revenue Service (IRS) may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

Table of Contents

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 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.

Table of Contents

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 May 7, 2007.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: /s/ Magellan GP, LLC
its General Partner

/s/ John D. Chandler
John D. Chandler
Chief Financial Officer and Treasurer

(Principal Accounting and Financial Officer)

33

Table of Contents

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 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.