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

FORM 10-Q

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

For the quarterly period ended June 30, 2009

OR

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

For the transition period from to

Commission File No.: 1-16335

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

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

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

(918) 574-7000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

As of July 31, 2009, there were 66,953,879 outstanding common units of Magellan Midstream Partners, L.P., that trade on the New York Stock Exchange under the ticker symbol "MMP."

PART I
FINANCIAL INFORMATION

PART II
OTHER INFORMATION

PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2009	Six Months Ended June 30, 2008	Six Months Ended June 30, 2009
Transportation and terminals revenues	$162,367	$166,571	$306,959	$321,459
Product sales revenues	110,364	41,327	312,082	99,043
Affiliate management fee revenue	183	190	366	380
Total revenues	272,914	208,088	619,407	420,882
Costs and expenses:				
Operating	56,965	60,511	112,557	121,238
Product purchases	75,292	40,990	252,860	93,620
Depreciation and amortization	17,434	19,893	34,610	39,208
Affiliate general and administrative	18,454	19,721	36,234	40,246
Total costs and expenses	168,145	141,115	436,261	294,312
Gain on assignment of supply agreement	—	—	26,492	—
Equity earnings	1,377	939	1,782	1,458
Operating profit	106,146	67,912	211,420	128,028
Interest expense	12,751	15,809	25,687	31,358
Interest income	(291)	(210)	(584)	(433)
Interest capitalized	(1,110)	(942)	(2,412)	(1,878)
Debt placement fee amortization expense	169	224	337	444
Other income	(249)	(565)	(249)	(647)
Income before provision for income taxes	94,876	53,596	188,641	99,184
Provision for income taxes	502	452	945	809
Net income	$ 94,374	$ 53,144	$187,696	$ 98,375
Allocation of net income:				
Limited partners' interest	$ 61,268	$ 30,410	$135,031	$ 53,331
General partner's interest	33,106	22,734	52,665	45,044
Net income	$ 94,374	$ 53,144	$187,696	$ 98,375
Basic and diluted net income per limited partner unit	$ 0.92	$ 0.45	$ 2.02	$ 0.79
Weighted average number of limited partner units outstanding used for basic and diluted net income per limited partner unit calculation	66,851	67,127	66,812	67,101

See notes to consolidated financial statements.

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

	December 31, 2008	June 30, 2009 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33,241	$ 91,203
Accounts receivable (less allowance for doubtful accounts of $462 and $435 at December 31, 2008 and June 30, 2009, respectively)	37,517	41,926
Other accounts receivable	11,073	13,890
Affiliate accounts receivable	378	4,081
Inventory	47,734	73,125
Energy commodity derivative contracts	20,200	—
Energy commodity derivatives deposit	—	25,609
Reimbursable costs	8,176	13,392
Acquisition-related escrow deposits	—	14,800
Other current assets	7,264	10,259
Total current assets	165,583	288,285
Property, plant and equipment	2,724,326	2,813,254
Less: accumulated depreciation	674,317	708,156
Net property, plant and equipment	2,050,009	2,105,098
Equity investments	23,190	22,563
Long-term receivables	7,119	6,270
Goodwill	26,809	26,809
Other intangibles (less accumulated amortization of $8,290 and $9,133 at December 31, 2008 and June 30, 2009, respectively)	5,539	4,696
Debt placement costs (less accumulated amortization of $2,937 and $3,381 at December 31, 2008 and June 30, 2009, respectively)	7,649	9,301
Other noncurrent assets	10,217	11,359
Total assets	$2,296,115	$2,474,381
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 39,441	$ 33,125
Affiliate accounts payable	1,942	828
Affiliate payroll and benefits	18,119	19,499
Accrued interest payable	15,077	14,559
Accrued taxes other than income	20,151	19,050
Environmental liabilities	19,634	17,145
Deferred revenue	21,492	23,405
Accrued product purchases	23,874	21,395
Energy commodity derivative contracts	—	17,279
Energy commodity derivatives deposit	18,994	—
Other current liabilities	16,534	19,425
Total current liabilities	195,258	185,710
Long-term debt	1,083,485	1,314,520
Long-term affiliate payable	445	809
Long-term affiliate pension and benefits	31,787	34,381
Other noncurrent liabilities	7,532	5,725
Environmental liabilities	22,166	21,051
Commitments and contingencies		
Partners' capital:		
Partners' capital	978,046	933,500
Accumulated other comprehensive loss	(22,604)	(21,315)
Total partners' capital	955,442	912,185
Total liabilities and partners' capital	$2,296,115	$2,474,381

See notes to consolidated financial statements.

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2009
Operating Activities:		
Net income	$ 187,696	$ 98,375
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	34,610	39,208
Debt placement fee amortization expense	337	444
Loss on sale and retirement of assets	1,729	2,179
Equity earnings	(1,782)	(1,458)
Distributions from equity investment	2,500	2,075
Equity-based incentive compensation expense	2,874	5,180
Amortization of prior service cost and actuarial loss	656	1,371
Gain on assignment of supply agreement	(26,492)	—
Changes in components of operating assets and liabilities:		
Accounts receivable and other accounts receivable	(5,233)	(7,226)
Affiliate accounts receivable	154	(3,703)
Inventory	44,790	(25,391)
Energy commodity derivative contracts, net of margin deposit	—	(7,124)
Reimbursable costs	(2,539)	(5,216)
Accounts payable	(3,423)	(2,622)
Affiliate accounts payable	(2,872)	362
Affiliate payroll and benefits	(3,848)	1,380
Accrued interest payable	(212)	(518)
Accrued taxes other than income	(818)	(1,101)
Accrued product purchases	22,877	(2,479)
Supply agreement deposit	(18,500)	—
Current and noncurrent environmental liabilities	(13,214)	(3,604)
Other current and noncurrent assets and liabilities	(1,584)	2,022
Net cash provided by operating activities	217,706	92,154
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(132,016)	(96,378)
Proceeds from sale of assets	1,600	169
Changes in accounts payable	7,272	(3,694)
Acquisition of business	(12,010)	—
Acquisition-related escrow deposits	—	(14,800)
Net cash used by investing activities	(135,154)	(114,703)
Financing Activities:		
Distributions paid	(129,588)	(142,030)
Net borrowings (payments) under revolver	36,300	(70,000)
Borrowings under long-term notes, net	—	298,959
Debt placement costs	—	(2,096)
Net receipt from financial derivatives	4,030	—
Capital contributions by affiliate	2,045	408
Change in outstanding checks	4,661	2,490
Settlement of tax withholdings on long-term incentive compensation	—	(3,450)
Simplification of capital structure	—	(3,770)
Net cash provided (used) by financing activities	(82,552)	80,511
Change in cash and cash equivalents	—	57,962
Cash and cash equivalents at beginning of period	—	33,241
Cash and cash equivalents at end of period	$ —	$ 91,203
Supplemental non-cash financing activity:		
Issuance of common units in settlement of long-term incentive plan awards	$ 8,536	$ 1,943

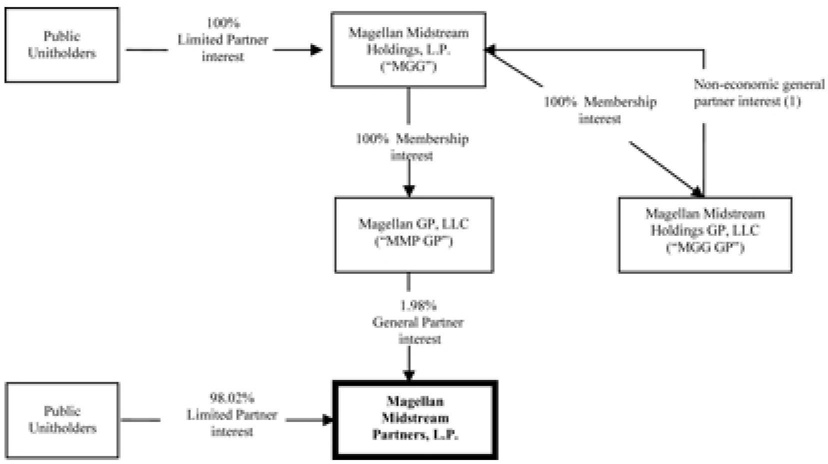
See notes to consolidated financial statements.

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

1. Organization and Basis of Presentation

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, and our units are traded on the New York Stock Exchange under the ticker symbol “MMP.” 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., a publicly traded Delaware limited partnership. We and Magellan GP, LLC have contracted with Magellan Midstream Holdings GP, LLC to provide all general and administrative (“G&A”) services and operating functions required for our operations. Our organizational structure at June 30, 2009 and that of our affiliate entities, as well as how we refer to these affiliates in our notes to consolidated financial statements, is provided below.



(1) MGG GP is MGG’s general partner but it does not hold an economic interest in MGG; therefore, MGG GP does not receive distributions from MGG and MGG GP is not allocated any of MGG’s net income.

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, 2008, which is derived from audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2009, and the results of operations for the three and six months ended June 30, 2008 and 2009 and cash flows for the six months ended June 30, 2008 and 2009. The results of operations for the six months ended June 30, 2009 are not necessarily indicative of the results to be expected for the full year ending December 31, 2009.

Pursuant to the rules and regulations of the Securities and Exchange Commission, the financial statements in this report 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, 2008.

2. Accounting Policies—Allocation of Net Income and Earnings Per Unit

On January 1, 2009, we adopted Emerging Issues Task Force ("EITF") Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. Under EITF No. 07-4, the excess of distributions over earnings or excess of earnings over distributions for each period are allocated to the entities' general partner based on the general partner's ownership interest at the time. We have retrospectively applied the provisions of EITF No. 07-4 to the three and six months ended June 30, 2008. Until January 1, 2009, our accounting practice, for purposes of calculating earnings per unit, was to allocate net income to the general partner based on the general partner's share of total or pro forma distributions, as applicable, including incentive distribution rights.

Under EITF No. 07-4, for the accounting periods included in this report, the allocation of net income between our general partner and limited partners was as follows (in thousands, except percentages):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2009	2008	2009
Net income	$ 94,374	$ 53,144	$187,696	$ 98,375
Direct charges (credits) to the general partner:				
Reimbursable G&A costs	408	—	816	—
Previously indemnified environmental charges (a)	(11,291)	396	(9,762)	1,066
Total direct charges (credits) to general partner	(10,883)	396	(8,946)	1,066
Income before direct charges (credits) to general partner	83,491	53,540	178,750	99,441
Less: Cash distributions for the period	67,797	71,016	133,592	142,031
Undistributed income / (distributions in excess of income)	$ 15,694	$ (17,476)	$ 45,158	$ (42,590)
Ownership interests:				
Limited partners	98.011%	98.017%	98.011%	98.017%
General partner	1.989%	1.983%	1.989%	1.983%
Total ownership interests	100.000%	100.000%	100.000%	100.000%
Allocation of net income:				
Limited partner allocation:				
Allocation of undistributed income / (distributions in excess of income)	$ 15,382	$ (17,128)	$ 44,260	$ (41,744)
Cash distributions paid for the period	45,886	47,538	90,771	95,075
Net income allocated to limited partners	$ 61,268	$ 30,410	$135,031	$ 53,331
General partner allocation:				
Allocation of undistributed income / (distributions in excess of income)	$ 312	$ (348)	$ 898	$ (846)
Cash distributions paid for the period	21,911	23,478	42,821	46,956
Direct (charges) credits to general partner	10,883	(396)	8,946	(1,066)
Net income allocated to general partner	$ 33,106	$ 22,734	$ 52,665	$ 45,044
Limited partners' allocation of net income	$ 61,268	$ 30,410	$135,031	$ 53,331
General partner's allocation of net income	33,106	22,734	52,665	45,044
Net income	$ 94,374	$ 53,144	$187,696	$ 98,375

(a) During second quarter 2008, we reached an agreement with the Environmental Protection Agency ("EPA") and the U.S. Department of Justice ("DOJ") to settle penalties proposed by the EPA associated with petroleum discharges from our pipeline. As a result of the settlement agreement, we reduced our environmental liability for this matter from $17.4 million to $5.3 million, resulting in a reduction to our operating expenses of $12.1 million. Of this reduction amount, $11.9 million was included as part of an indemnification settlement and, accordingly, was allocated to our general partner. As a result, limited partner net income and earnings per limited partner unit were impacted by only $0.2 million of the $12.1 million reduction in operating expense.

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 our general partner under the terms of an omnibus agreement between us and MGG GP. Because the limited partners do not share in these costs, we have allocated these G&A expense amounts directly to our general partner. We recorded these reimbursements by our general partner as capital contributions. Prior to 2008, we and our general partner entered into an agreement with a former affiliate to settle certain of our former affiliate's indemnification obligations to us. Under this agreement, our former affiliate paid us $117.5 million, which we recorded as a capital contribution from our general partner. Current period costs associated with this indemnification agreement settlement are designated as "previously indemnified environmental charges." Since our limited partners do not share in these costs, we have allocated these amounts directly to our general partner.

The difference between the amounts of net income allocated to the limited and general partners and the related earnings per unit calculations under EITF No. 07-4 and our previous accounting methodology for the three and six months ended June 30, 2008 is provided in the table below (in thousands):

	(in thousands, except per unit amounts)		
	Current Accounting Under EITF 07-4	As Previously Reported	Difference
Three Months Ended June 30, 2008			
Net income allocated to limited partners	$ 61,268	$ 53,736	$ 7,532
Net income allocated to general partner	33,106	40,638	(7,532)
Net income	$ 94,374	$ 94,374	$ —
Basic and diluted net income per limited partner unit	$ 0.92	$ 0.80	$ 0.12
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	66,851	66,851	—

	(in thousands, except per unit amounts)		
	Current Accounting Under EITF 07-4	As Previously Reported	Difference
Six Months Ended June 30, 2008			
Net income allocated to limited partners	$ 135,031	$113,356	$ 21,675
Net income allocated to general partner	52,665	74,340	(21,675)
Net income	$ 187,696	$187,696	$ —
Basic and diluted net income per limited partner unit	$ 2.02	$ 1.70	$ 0.32
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	66,812	66,812	—

3. Comprehensive Income

Comprehensive income is the change in equity of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners. The term other comprehensive income or other comprehensive loss refers to revenues, expenses, gains and losses that, under generally accepted accounting principles ("GAAP"), are included in comprehensive income but excluded from net income. A reconciliation of net income to comprehensive income follows below (in thousands). For information on our derivative instruments, see Note 9 – Derivative Financial Instruments.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2009	2008	2009
Net income	$ 94,374	$53,144	$187,696	$98,375
Change in fair value of cash flow hedges	6,706	—	—	—
Reclassification of net gain on cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Amortization of prior service cost and actuarial loss	279	1,037	656	1,371
Other comprehensive income	6,944	996	574	1,289
Comprehensive income	$101,318	$54,140	$188,270	$99,664

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 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 affiliate G&A expenses, that management does not consider when evaluating the core profitability of our operations.

	Three Months Ended June 30, 2008 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$121,169	$35,970	$ 5,986	$ (758)	$162,367
Product sales revenues	102,585	7,779	—	—	110,364
Affiliate management fee revenue	183	—	—	—	183
Total revenues	223,937	43,749	5,986	(758)	272,914
Operating expenses	39,977	15,685	2,812	(1,509)	56,965
Product purchases	73,577	1,845	—	(130)	75,292
Equity earnings	(1,377)	—	—	—	(1,377)
Operating margin	111,760	26,219	3,174	881	142,034
Depreciation and amortization expense	10,553	5,798	202	881	17,434
Affiliate G&A expense	12,976	4,459	1,019	—	18,454
Operating profit	$ 88,231	$15,962	$ 1,953	$ —	$106,146

	Three Months Ended June 30, 2009 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$121,874	$40,715	$ 5,248	$ (1,266)	$166,571
Product sales revenues	37,892	3,435	—	—	41,327
Affiliate management fee revenue	190	—	—	—	190
Total revenues	159,956	44,150	5,248	(1,266)	208,088
Operating expenses	44,034	14,964	3,220	(1,707)	60,511
Product purchases	39,914	1,570	—	(494)	40,990
Equity earnings	(939)	—	—	—	(939)
Operating margin	76,947	27,616	2,028	935	107,526
Depreciation and amortization expense	11,504	7,098	356	935	19,893
Affiliate G&A expense	14,033	5,120	568	—	19,721
Operating profit	$ 51,410	$15,398	$ 1,104	$ —	$ 67,912

	Six Months Ended June 30, 2008 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$227,492	$69,571	$11,406	$ (1,510)	$306,959
Product sales revenues	295,482	16,600	—	—	312,082
Affiliate management fee revenue	366	—	—	—	366
Total revenues	523,340	86,171	11,406	(1,510)	619,407
Operating expenses	82,237	28,214	5,066	(2,960)	112,557
Product purchases	248,198	4,922	—	(260)	252,860
Gain on assignment of supply agreement	(26,492)	—	—	—	(26,492)
Equity earnings	(1,782)	—	—	—	(1,782)
Operating margin	221,179	53,035	6,340	1,710	282,264
Depreciation and amortization expense	20,934	11,562	404	1,710	34,610
Affiliate G&A expense	25,717	8,574	1,943	—	36,234
Operating profit	$174,528	$32,899	$ 3,993	$ —	$211,420

	Six Months Ended June 30, 2009 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$236,643	$78,868	$ 8,477	$ (2,529)	$321,459
Product sales revenues	92,124	6,919	—	—	99,043
Affiliate management fee revenue	380	—	—	—	380
Total revenues	329,147	85,787	8,477	(2,529)	420,882
Operating expenses	87,989	30,348	6,338	(3,437)	121,238
Product purchases	91,502	3,106	—	(988)	93,620
Equity earnings	(1,458)	—	—	—	(1,458)
Operating margin	151,114	52,333	2,139	1,896	207,482
Depreciation and amortization expense	22,779	13,902	631	1,896	39,208
Affiliate G&A expense	28,881	10,189	1,176	—	40,246
Operating profit	$ 99,454	$28,242	$ 332	$ —	$128,028

5. Related Party Disclosures

Affiliate Entity Transactions

We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. During both the three months ended June 30, 2008 and 2009, we received operating fees from this pipeline company of $0.2 million, which we reported as affiliate management fee revenue. Affiliate management fee revenue for both the six months ended June 30, 2008 and 2009 was $0.4 million.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2009	2008	2009
MGG GP—allocated operating expenses	21,632	22,878	42,552	45,554
MGG GP—allocated G&A expenses	12,220	13,911	24,093	27,078

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, 2008 and June 30, 2009 were $18.1 million and $19.5 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2008 and June 30, 2009 were $31.8 million and $34.4 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 GP when MGG GP makes contributions to its pension funds.

Historically, MGG reimbursed us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap. The amount of G&A costs required to be reimbursed by MGG to us under this agreement for the three and six months ended June 30, 2008 was $0.4 million and $0.8 million, respectively. We have not received and will not receive any reimbursements under this agreement for excess G&A costs for 2009 and beyond.

Other Related Party Transactions

One of our general partner’s former independent board members, John P. DesBarres, served as a board member for American Electric Power Company, Inc. (“AEP”) of Columbus, Ohio until December 2008. For the three and six months ended June 30, 2008, our operating expenses included $0.6 million and $1.1 million, respectively, of power costs incurred with Public Service Company of Oklahoma (“PSO”), which is a subsidiary of AEP. We had no amounts payable to or receivable from PSO or AEP at December 31, 2008.

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 June 30, 2009, our executive officers collectively owned a beneficial interest of approximately 1% of MGG, the owner of our general partner. Therefore, our executive officers benefit from distributions paid 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 $0.71 per unit, our general partner would receive annual distributions of approximately $93.9 million on its combined general partner interest and incentive distribution rights.

6. Inventory

Inventory at December 31, 2008 and June 30, 2009 was as follows (in thousands):

	December 31, 2008	June 30, 2009
Refined petroleum products	$ 20,917	$15,529
Transmix	13,099	19,740
Natural gas liquids	7,534	31,419
Additives	6,184	6,437
Total inventory	$ 47,734	$73,125

The increase in natural gas liquids inventory from December 31, 2008 to June 30, 2009 was primarily attributable to purchases of butane during the favorable market environment in second quarter 2009.

7. Employee Benefit Plans

MGG GP sponsors two pension plans for certain union employees, a pension plan for certain non-union employees, a postretirement benefit plan for selected employees and a defined contribution plan. The following tables present our consolidated net periodic benefit costs related to the pension plans and other postretirement benefit plan during the three and six months ended June 30, 2008 and 2009 (in thousands):

	Three Months Ended June 30, 2008		Six Months Ended June 30, 2008	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,323	$ 77	$ 2,736	$ 218
Interest cost	695	237	1,349	515
Expected return on plan assets	(732)	—	(1,351)	—
Amortization of prior service cost	170	44	339	88
Amortization of actuarial loss	59	6	75	154
Net periodic benefit cost	$ 1,515	$ 364	$ 3,148	$ 975

	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,902	$ 116	$ 3,291	$ 232
Interest cost	821	278	1,605	557
Expected return on plan assets	(676)	—	(1,362)	—
Amortization of prior service cost	170	45	339	89
Amortization of actuarial loss	758	64	815	128
Net periodic benefit cost	$ 2,975	$ 503	$ 4,688	$ 1,006

8. Debt

Our debt at December 31, 2008 and June 30, 2009 was as follows (in thousands):

	December 31, 2008	June 30, 2009	Weighted-Average Interest Rate at June 30, 2009 (1)
Revolving credit facility	$ 70,000	$ —	—
6.45% Notes due 2014	249,681	249,706	6.3%
5.65% Notes due 2016	253,328	253,113	5.7%
6.40% Notes due 2018	261,555	260,947	5.9%
6.55% Notes due 2019	—	301,826	5.4%
6.40% Notes due 2037	248,921	248,928	6.3%
Total debt	$1,083,485	$1,314,520	

(1) Weighted-average interest rate includes the impact of the amortization of discounts and gains and losses realized on various hedges (see Note 9—Derivative Financial Instruments for detailed information regarding the amortization of these gains and losses).

Our debt is non-recourse to our general partner. The discounted amounts at issuance of the applicable notes, discussed below, are being accreted to the notes over their respective lives.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in September 2012, is $550.0 million. 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. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used primarily for general purposes, including capital expenditures. As of June 30, 2009, there was no outstanding balance under this facility; however, $3.9 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets.

6.45% Notes due 2014. In May 2004, we sold $250.0 million aggregate principal of 6.45% notes due 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million.

5.65% Notes due 2016. In October 2004, we issued $250.0 million of 5.65% notes due 2016 in an underwritten public offering. The notes were issued for the discounted price of 99.9%, or $249.7 million. The outstanding principal amount of the notes was increased by $3.5 million and $3.3 million at December 31, 2008 and June 30, 2009, respectively, for the unamortized portion of a gain realized upon termination of a related interest rate swap (see Note 9—Derivative Financial Instruments).

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased by $11.6 million and $11.0 million at December 31, 2008 and June 30, 2009, respectively, for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps (see Note 9—Derivative Financial Instruments).

6.55% Notes due 2019. In June 2009, we issued $300.0 million of 6.55% notes due 2019 in an underwritten public offering. The notes were issued for the discounted price of 99.7%, or $299.0 million. Net proceeds from the offering, after underwriter discounts of $2.0 million and offering costs of $0.1 million that we have incurred through June 30, 2009, were $296.9 million. The net proceeds were used to repay the $208.3 million of borrowings outstanding under our revolving credit facility at that time, and the balance will be used for general purposes including capital expenditures. In connection with this offering, we entered into interest rate swap agreements to effectively convert $150.0 million of these notes to floating-rate debt (see Note 9—Derivative Financial Instruments). The outstanding principal amount of the notes was increased by $2.9 million at June 30, 2009 for the fair value of the associated interest rate swap agreements.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million.

9. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities generate gasoline products and we can estimate the timing and quantities of sales of these products. We use a combination of forward sales contracts and New York Mercantile Exchange ("NYMEX") agreements to lock in most of the gross margins realized from our blending activities. We account for the forward sales contracts as normal sales.

Although the NYMEX contracts represent an economic hedge against price changes on the petroleum products we expect to sell in the future, they do not qualify as normal sales or for hedge accounting treatment under Statement of Financial Accounting Standard ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*; therefore, we recognize the change in fair value of these contracts currently in earnings. During the three and six months ended June 30, 2009, we closed our positions on NYMEX contracts associated with the sale of 0.6 million barrels and 1.1 million barrels, respectively, of gasoline and realized total gains (losses) of $(0.7) million and $14.1 million, respectively. At June 30, 2009, the fair value of our open NYMEX contracts, representing 1.2 million barrels of petroleum products, was a net loss of $17.3 million, which was recorded as energy commodity derivative contracts on our consolidated balance sheet. These open NYMEX contracts mature between July 2009 and March 2010. At June 30, 2009, we had made margin deposits of $25.6 million for these contracts, which was recorded as energy commodity derivatives deposit on our consolidated balance sheet.

Interest Rate Derivatives

We use interest rate derivatives to help manage interest rate risk. As of June 30, 2009, we had two offsetting interest rate swap agreements outstanding:

- In July 2008, we entered into a $50.0 million interest rate swap agreement ("Derivative A") to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. Derivative A effectively converted $50.0 million of those notes from a 6.40% fixed rate to a floating rate of six-month LIBOR plus 1.83%. Derivative A terminates in July 2018. We originally accounted for Derivative A as a fair value hedge. In December 2008, in order to capture the economic value of Derivative A at that time, we entered into an offsetting derivative, as described below, and discontinued hedge accounting for Derivative A. The $5.4 million fair value of Derivative A at that time was recorded as an adjustment to long-term debt which is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. For the three and six months ended June 30, 2009, a loss of $2.5 million and $3.3 million, respectively, was recorded to other income on our consolidated statement of income resulting from the change in fair value of Derivative A.
- In December 2008, concurrent with the discontinuance of hedge accounting for Derivative A, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which we pay a fixed rate of 6.40% and receive a floating rate of six-month LIBOR plus 3.23%. This agreement terminates in July 2018. We entered into this agreement to offset changes in the fair value of Derivative A, excluding changes due to changes in counterparty credit risks. We did not designate this agreement as a hedge for accounting purposes. For the three and six months ended June 30, 2009, a gain of $3.0 million and $3.9 million, respectively, was recorded to other income on our consolidated statement of income resulting from the change in fair value of this agreement.

In addition to the two interest rate swap agreements described above, we had the following interest rate swap agreements outstanding as of June 30, 2009:

- In June 2009, we entered into a total of $150.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the $300.0 million of 6.55% notes due 2019. We have accounted for these agreements as fair value hedges. These agreements effectively convert $150.0 million of our 6.55% fixed-rate notes issued in June 2009 to floating-rate debt. Under the terms of the agreements, we will receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18%. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments will settle in January and July each year. During each period, we will record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense.

The interest rate derivatives discussed above contain credit-risk-related contingency features. These features provide that: (i) in the event of our default on any obligation of $25.0 million or more or, (ii) in certain circumstances a change in control of our general partner or a merger in which our credit rating becomes "materially weaker", which would generally be interpreted as falling below investment grade, the counterparties to our interest rate derivatives agreements can terminate those agreements and require immediate settlement. None of our interest rate derivatives were in a liability position as of June 30, 2009.

The following is a summary of the current impact of our historical derivative activity on accumulated other comprehensive loss ("AOCL") as of and for the three and six months ended June 30, 2008 and 2009 (in thousands):

		Effective Portion of Gains					
		2008			2009		
		As of June 30, 2008	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008	As of June 30, 2009	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Hedge	Total Gain (Loss) Realized on Settlement of Hedge	Unamortized Amount Recognized in AOCL	Amount Reclassified to Interest Expense from AOCL	Amount Reclassified to Interest Expense from AOCL	Unamortized Amount Recognized in AOCL	Amount Reclassified to Interest Expense from AOCL	Amount Reclassified to Interest Expense from AOCL
Cash flow hedges (date executed):							
Interest rate swaps 6.40% Notes (April 2007)	$ 5,255	$ 5,044	$ (44)	$ (88)	$ 4,869	$ (44)	$ (88)
Interest rate swaps 5.65% Notes (October 2004)	(6,279)	(4,338)	131	262	(3,815)	131	262
Interest rate swaps and treasury lock 6.45% Notes (May 2004)	5,119	3,029	(128)	(256)	2,517	(128)	(256)
Total cash flow hedges		$ 3,735	$ (41)	$ (82)	$ 3,571	$ (41)	$ (82)

There was no ineffectiveness recognized on the financial instruments disclosed in the above table during the three and six months ended June 30, 2008 and 2009. As of June 30, 2009, the net gain estimated to be reclassified to interest expense over the next twelve months from AOCL is approximately $0.2 million.

The changes in derivative gains (losses) included in AOCL for the three and six months ended June 30, 2008 and 2009 are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Gains (Losses) Included in AOCL	2008	2009	2008	2009
Beginning balance	$(2,930)	$3,612	$3,817	$3,653
Change in fair value of cash flow hedges	6,706	—	—	—
Reclassification of net gain on cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Ending balance	$ 3,735	$3,571	$3,735	$3,571

The following is a summary of the current impact of our historical derivative activity on long-term debt resulting from the termination of or the discontinuance of hedge accounting treatment of our fair value hedges as of and for the three and six months ended June 30, 2009 (in thousands):

Hedge	Total Gain Realized	As of June 30, 2009 Unamortized Amount Recorded in Long-term Debt	Three Months Ended June 30, 2009 Amount Reclassified to Interest Expense from Long-term Debt	Six Months Ended June 30, 2009 Amount Reclassified to Interest Expense from Long-term Debt
Fair value hedges (date executed):				
Interest rate swaps 6.40% Notes (July 2008)	$ 11,652	$ 10,966	$ (304)	$ (608)
Interest rate swap 5.65% Notes (October 2004)	3,830	3,321	(113)	(227)
Total fair value hedges		$ 14,287	$ (417)	$ (835)

The following is a summary of the effect of derivatives accounted for under SFAS No. 133 that were designated as hedging instruments on our consolidated statement of income for the three and six months ended June 30, 2009 (in thousands):

		Amount of Gain Recognized on Derivative		Amount of Interest Expense Recognized on Fixed-Rate Debt (Related Hedged Item)	
Derivative Instrument	Location of Gain Recognized on Derivative	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Interest rate swap agreements	Interest expense	$ 48	$ 48	$ (274)	$ (274)

The following is a summary of the effect of derivatives accounted for under SFAS No. 133 that were not designated as hedging instruments on our consolidated statement of income for the three and six months ended June 30, 2009 (in thousands):

		Amount of Gain (Loss) Recognized on Derivative	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Interest rate swap agreements	Other income	$ 565	$ 647
NYMEX commodity contracts	Product sales revenues	(19,848)	(23,385)
	Total	$ (19,283)	$ (22,738)

The following is a summary of the amounts included in our consolidated balance sheet of the fair value of derivatives accounted for under SFAS No. 133 that were designated as hedging instruments as of June 30, 2009 (in thousands):

	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Interest rate swap agreements, current portion	Other current assets	$ 48	Other current liabilities	$ —
Interest rate swap agreements, noncurrent portion	Other noncurrent assets	2,866	Other noncurrent liabilities	—
	Total	$ 2,914	Total	$ —

The following is a summary of the amounts included in our consolidated balance sheet of the fair value of derivatives accounted for under SFAS No. 133 that were not designated as hedging instruments as of June 30, 2009 (in thousands):

	Asset Derivatives		Liability Derivatives	
Derivative Instrument	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Interest rate swap agreements, current portion	Other current assets	$ 718	Other current liabilities	$ 384
Interest rate swap agreements, noncurrent portion	Other noncurrent assets	5,723	Other noncurrent liabilities	—
NYMEX commodity contracts	Energy commodity derivative contracts	—	Energy commodity derivative contracts	17,279
	Total	$ 6,441	Total	$ 17,663

10. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $41.8 million and $38.2 million at December 31, 2008 and June 30, 2009, respectively. Environmental liabilities have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be paid over the next ten years. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expense (credit) was $(10.3) million and $(7.5) million, respectively, for the three and six months ended June 30, 2008 and $0.9 million and $2.2 million, respectively, for the three and six months ended June 30, 2009. Environmental expenses for second quarter 2008 included the impact of a favorable settlement of a civil penalty related to historical product releases, which resulted in our reducing our environmental liability accrual by $12.1 million.

Our environmental liabilities include, among other items, accruals for an ammonia EPA issue. 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 Clean Water Act ("the Act") with respect to two releases of anhydrous ammonia from our ammonia pipeline system that was operated by a third party at the time of the releases. 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, for which the third-party operator has requested indemnification from us. In March 2007, we also 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. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. 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 these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $4.5 million and $3.9 million at December 31, 2008 and June 30, 2009, respectively.

Unrecognized Product Gains. Our petroleum products terminals operations generate product overages and shortages that result from metering inaccuracies, product evaporation or expansion, product releases and product contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals 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 net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $3.6 million as of June 30, 2009. 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 financial position, results of operations or cash flows.

11. Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan ("LTIP") for certain MGG GP employees who perform services for us and for directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 3.2 million limited partner units. The remaining units available under the LTIP at June 30, 2009 total 1.3 million. The compensation committee of our general partner's board of directors (the "Compensation Committee") administers the LTIP and has approved the unit awards discussed below:

Vested Unit Awards

Grant Date	Unit Awards Granted	Forfeitures	Adjustments to Unit Awards for Attaining Above-Target Financial Results	Units Paid Out on Vesting Date	Vesting Date	Value of Unit Awards on Vesting Date (Millions)
February 2005	160,640	11,348	149,292	298,584	12/31/07	$ 12.9
June 2006	1,170	—	1,170	2,340	12/31/07	$ 0.1
February 2006	168,105	13,730	154,143	308,518	12/31/08	$ 9.3
Various 2006	9,201	2,640	6,561	13,122	12/31/08	$ 0.4
March 2007	2,640	—	—	2,640	12/31/08	$ 0.1

In January 2008, we settled the cumulative amounts of the February 2005 and June 2006 award grants by issuing 196,856 limited partner units and distributing those units to the participants. The difference between the limited partner units issued to the participants and the total units accrued represented the minimum tax withholdings associated with this award settlement. We paid associated tax withholdings and employer taxes totaling $5.1 million in January 2008.

In January 2009, we settled the cumulative amounts of the remaining 2006 and March 2007 award grants by issuing 209,321 limited partner units and distributing those units to the participants. The difference between the limited partner units issued to the participants and the total units accrued represented the minimum tax withholdings associated with this award settlement. We paid associated tax withholdings and employer taxes totaling $4.0 million in January 2009.

Performance-Based Unit Awards

The incentive awards discussed below are subject to forfeiture if employment is terminated for any reason other than 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 is prorated based upon the completed months of employment during the vesting period and the award is settled at the end of the vesting period. Our agreement with the LTIP participants requires the LTIP awards described below to be paid out in our limited partner units. The award grants do not have an early vesting feature except under certain circumstances following a change in control of our general partner.

On December 3, 2008, MGG purchased its general partner from MGG MH. When this transaction closed, a change in control occurred as defined in our LTIP. Even though a change in control has occurred, participants in the LTIP must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years of December 3, 2008 in order to receive enhanced LTIP payouts.

For each of the award grants listed below, the payout calculation for 80% of the unit awards will be based solely on the attainment of a financial metric established by the Compensation Committee. This portion of the award grants has been accounted for as equity. The payout calculation for the remaining 20% of the unit awards will be based on both the attainment of a financial metric and the individual employee's personal performance as determined by the Compensation Committee. This portion of the award grants has been accounted for as a liability.

The table below summarizes the performance based unit awards granted by the Compensation Committee that have not vested as of June 30, 2009. There was no impact to our cash flows associated with these award grants for the periods presented in this report.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Adjustment to Unit Awards in Anticipation of Achieving Above/ (Below) Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions) (1)	Intrinsic Value of Unvested Awards at June 30, 2009 (Millions)
2007 awards:							
Tranche 1:	53,230	1,597	51,633	103,266	12/31/09	$ 0.6	$ 3.6
Tranche 2:	53,230	1,597	(40,430)	11,203	12/31/09	0.1	0.4
Tranche 3:	53,230	1,597	8,624	60,257	12/31/09	0.9	2.1
2008 awards	189,832	5,695	—	184,137	12/31/10	2.6	6.4
2009 awards	275,994	8,281	—	267,713	12/31/11	4.7	9.3
Total	625,516	18,767	19,827	626,576		$ 8.9	$ 21.8

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the respective awards.

The unit awards approved during 2007 are broken into three equal tranches, with each tranche vesting on December 31, 2009. We began accruing for Tranche 1 in the first quarter of 2007, Tranche 2 in the first quarter of 2008 and Tranche 3 in the first quarter of 2009, when the Compensation Committee established the financial metric associated with each respective tranche. The unit awards allocated to each tranche are expensed over their respective vesting periods. As of June 30, 2009, the accruals for the payout of Tranches 1, 2 and 3 were 200%, 22% and 117%, respectively.

At its February 2009 meeting, the Compensation Committee adjusted the threshold, target and stretch performance levels for the 2008 awards to reflect the downturn in the economic environment. The Compensation Committee felt that the modifications were necessary to ensure that the awards continued to provide a motivational and retention feature in the current economic environment and maintain the link necessary to encourage our key employees to maximize our long-term financial results. At December 31, 2008, the accrual for the payout of the 2008 awards was 30%. As a result of the adjustment made by the Compensation Committee to the 2008 performance metric, the accrual for the estimated payout of the adjusted 2008 unit awards at June 30, 2009 was 100%.

Retention Awards

The retention awards below are subject to forfeiture if employment is terminated or the employee resigns from their current position for any reason prior to the applicable vesting date. The award grants do not have an early vesting feature. The award grants listed below have been accounted for as equity.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions) (1)	Intrinsic Value of Unvested Awards at June 30, 2009 (Millions)
Various	14,248	428	13,820	12/31/10	$ 0.2	$ 0.5
Various	41,688	1,876	39,812	12/31/11	0.7	1.4
	55,936	2,304	53,632		$ 0.9	$ 1.9

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the respective awards.

Fair Value of Unit Awards

	2007 Awards	2008 Awards	2009 Awards	Retention Awards
Weighted-average per unit grant date fair value of equity awards (1)	$ 32.30	$ 27.77	$ 19.61	$ 24.11
June 30, 2009 per unit fair value of liability awards (2)	$ 33.34	$ 30.49	$ 27.56	n/a

(1) Except for the retention awards, approximately 80% of the unit awards are accounted for as equity. Fair value is calculated as our unit price on the grant date less the present value of estimated cash distributions during the vesting period.
(2) Approximately 20% of the unit awards are accounted for as liabilities. Fair value is calculated as our unit price at the end of each accounting period less the present value of estimated cash distributions during the remaining portion of the vesting period.

Compensation Expense Summary

Our equity-based incentive compensation expense is summarized as follows (in thousands):

	Three Months Ended June 30, 2008			Six Months Ended June 30, 2008		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2005 awards	$ —	$ —	$ —	$ —	$ 26	$ 26
2006 awards	645	(8)	637	1,120	167	1,287
2007 awards	259	20	279	635	100	735
2008 awards	401	79	480	669	143	812
Retention awards	(6)	—	(6)	14	—	14
Total	$ 1,299	$ 91	$ 1,390	$ 2,438	$ 436	$ 2,874

	Three Months Ended June 30, 2009			Six Months Ended June 30, 2009		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2007 awards	$ 561	$ 272	$ 833	$ 1,495	$ 467	$ 1,962
2008 awards	341	187	528	1,597	479	2,076
2009 awards	351	151	502	700	246	946
Retention awards	100	—	100	196	—	196
Total	$ 1,353	$ 610	$ 1,963	$ 3,988	$ 1,192	$ 5,180

12. Distributions

We paid the following distributions during 2008 and 2009 (in thousands, except per unit amounts):

Date Cash Distribution Paid	Per Unit Cash Distribution Amount	Common Units	General Partner	Total Cash Distribution
02/14/08	$ 0.6575	$ 43,884	$19,909	$ 63,793
05/15/08	0.6725	44,885	20,910	65,795
Through 6/30/08	1.3300	88,769	40,819	129,588
08/14/08	0.6875	45,886	21,911	67,797
11/14/08	0.7025	46,887	22,912	69,799
Total	$ 2.7200	$181,542	$85,642	$ 267,184
02/13/09	$ 0.7100	$ 47,537	$23,478	$ 71,015
05/15/09	0.7100	47,537	23,478	71,015
Through 6/30/09	1.4200	95,074	46,956	142,030
08/14/09(a)	0.7100	47,537	23,478	71,015
Total	$ 2.1300	$142,611	$70,434	$ 213,045

(a) Our general partner declared this cash distribution in July 2009 to be paid on August 14, 2009 to unitholders of record at the close of business on August 7, 2009.

13. Fair Value Disclosures

Fair Value of Financial Instruments

We used the following methods and assumptions in estimating our fair value disclosure for financial instruments:

Cash and cash equivalents. The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity or variable rates of these instruments.

Energy commodity derivatives deposit. This asset (liability) represents a short-term deposit we paid (held) associated with our energy commodity derivative contracts. The carrying amount reported in the balance sheet approximates fair value due to the short-term maturity of the underlying contracts.

Acquisition-related escrow deposits. This asset represents various short-term escrow deposits we paid. The carrying amount reported in the balance sheet approximates fair value due to the short-term maturity of the instruments.

Long-term receivables. Fair value was determined by discounting estimated future cash flows by the rates inherent in the long-term instruments adjusted for the change in the risk-free rate since inception of the instrument.

Energy commodity derivative contracts. The carrying amounts reported in the balance sheet represent fair value of the asset (liability). See Note 9—Derivative Financial Instruments.

Debt. The fair value of our publicly traded notes, excluding the value of interest rate swaps qualifying as fair value hedges, was based on the prices of those notes at December 31, 2008 and June 30, 2009. The carrying amount of borrowings under our revolving credit facility at December 31, 2008 approximates fair value due to the variable rates of that instrument.

Interest rate swaps. Fair value was determined based on an assumed exchange, at each year end, in an orderly transaction with the financial institution counterparties of the interest rate derivative agreements.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2008 and June 30, 2009 (in thousands):

	December 31, 2008		June 30, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 33,241	$ 33,241	$ 91,203	$ 91,203
Energy commodity derivatives deposit	(18,994)	(18,994)	25,609	25,609
Acquisition-related escrow deposits	—	—	14,800	14,800
Long-term receivables	7,119	5,249	6,270	5,739
Energy commodity derivative contracts	20,200	20,200	(17,279)	(17,279)
Debt	(1,083,485)	(934,975)	(1,314,520)	(1,303,380)
Interest rate swaps:				
$50.0 million (July 2008)	7,542	7,542	3,876	3,876
$50.0 million (December 2008)	(1,770)	(1,770)	2,181	2,181
$75.0 million (June 2009)	—	—	1,457	1,457
$75.0 million (June 2009)	—	—	1,457	1,457

Fair Value Measurements

The following tables summarize the fair value measurements of our NYMEX commodity contracts and interest rate swap agreements as of December 31, 2008 and June 30, 2009, based on the three levels established by SFAS No. 157, *Fair Value Measurements* (in thousands):

		Asset Fair Value Measurements as of December 31, 2008 using:		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
NYMEX commodity contracts	$20,200	$ 20,200	$ —	$ —
Interest rate swap agreements (date executed):				
$50.0 million (July 2008)	7,542	—	7,542	—
$50.0 million (December 2008)	(1,770)	—	(1,770)	—

		Asset Fair Value Measurements as of June 30, 2009 using:		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
NYMEX commodity contracts:	$(17,279)	$ (17,279)	$ —	$ —
Interest rate swap agreements (date executed):				
$50.0 million (July 2008)	3,876	—	3,876	—
$50.0 million (December 2008)	2,181	—	2,181	—
$75.0 million (June 2009)	1,457	—	1,457	—
$75.0 million (June 2009)	1,457	—	1,457	—

14. Assignment of Supply Agreement

As part of our acquisition of a pipeline system in October 2004, we assumed a third-party supply agreement. Under this agreement, we were obligated to supply petroleum products to one of our customers until 2018. At the time of this acquisition, we believed that the profits we would receive from the supply agreement were below the fair value of our tariff-based shipments on this pipeline and we established a liability for the expected shortfall. On March 1, 2008, we assigned this supply agreement and sold related inventory of $47.6 million to a third-party entity. Further, we returned our former customer's cash deposit, which was $16.5 million at the time of the assignment. During first quarter 2008, we obtained a full release from the supply customer; therefore, we have no future obligation to perform under this supply agreement, even in the event the third-party assignee is unable to perform its obligations under the agreement. As a result, we wrote off the unamortized amount of the liability and recognized a gain of $26.5 million in the first quarter 2008.

15. Simplification Agreement

In March 2009, we and our general partner and MGG and its general partner entered into an Agreement Relating to Simplification of Capital Structure (the "Simplification Agreement"). Pursuant to the Simplification Agreement, if approved by both our and MGG's unitholders, we will amend and restate our existing partnership agreement to provide for the transformation of the incentive distribution rights and approximate 2% general partner interest owned by MMP GP, our general partner, into common units in us and a non-economic general partner interest (the "transformation"). Once the transformation is complete, MMP GP, MGG's wholly-owned subsidiary, will distribute the common units in us that it receives in the transformation to MGG (the "unit distribution"). Once the transformation and unit distribution are complete, pursuant to a Contribution and Assumption Agreement among MGG, MGG MH (MGG's general partner), us and MMP GP (our general partner): (i) MGG will contribute 100% of its member interests in its general partner to our general partner; (ii) MGG will contribute 100% of the member interests in our general partner to us; (iii) MGG will contribute to us all of its cash and assets, other than the common units in us it receives in the unit distribution; and (iv) we will assume all of MGG's liabilities (collectively, the "contributions"). Once the transformation, unit distribution and contributions are complete, MGG will dissolve and wind-up and distribute the common units in us it receives in the unit distribution to its unitholders (the "redistribution").

Pursuant to the Simplification Agreement, MGG will receive approximately 39.6 million of our common units in the transformation and unit distribution and each of MGG's unitholders will receive 0.6325 of our common units in the redistribution for each MGG common unit. Our unitholders will continue to own their existing common units.

Currently, we are a consolidated subsidiary of MGG. MGG controls and operates us through its 100% ownership interest in our general partner. Assuming the simplification of the capital structure as described above is approved by both our and MGG's unitholders, our general partner and MGG's general partner will legally become our wholly-owned subsidiaries and MGG will be dissolved. For accounting purposes, however, MGG will be considered the accounting acquirer of its non-controlling interest. Therefore, in accordance with SFAS No. 160, *Non-Controlling Interests in Consolidated Financial Statements*, the changes in MGG's ownership interest in us will be accounted for as an equity transaction and no gain or loss will be recognized as a result of the simplification of the capital structure.

Our general partner will continue to manage us after the simplification and our management team will continue in their respective roles. Additionally, three of the four members of MGG's general partner's board of directors will join the board of directors of our general partner following completion of the simplification. The other member of MGG's general partner's board of directors, Patrick C. Eilers, also serves as an independent member of our general partner's board of directors.

The terms of the Simplification Agreement were unanimously approved by the conflicts committee of the board of directors of our general partner and MGG's general partner. Each conflicts committee is comprised solely of independent directors and was previously delegated authority by the board of directors to negotiate and authorize the terms of the simplification.

During the three and six months ended June 30, 2009, we incurred $0.9 million and $3.8 million, respectively, of costs associated with the simplification of our capital structure. In accordance with SFAS No. 160, we charged these costs to equity. The amount for the six months ended June 30, 2009 was reported under the caption "Simplification of capital structure" in the financing activities section of our consolidated statements of cash flows.

16. Reimbursable Costs

The reimbursable costs reported as current assets on our consolidated balance sheets were $8.2 million and $13.4 million at December 31, 2008 and June 30, 2009, respectively. These balances primarily represent costs we have incurred related to claims we have not yet filed with our insurance carriers but for which we expect to be reimbursed.

17. Subsequent Events

We evaluated subsequent events through August 4, 2009, the date we issued our consolidated statements of income for the three and six months ended June 30, 2008 and 2009, our consolidated balance sheets as of December 31, 2008 and June 30, 2009 and our consolidated statements of cash flows for the six months ended June 30, 2008 and 2009. No recognizable subsequent events occurred during this period.

The following non-recognizable events occurred during the period in which we evaluated subsequent events:

- On July 29, 2009, we acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (“Longhorn”) for $250.0 million plus the fair market value of the line fill of $86.1 million. The assets of Longhorn include an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas, a terminal in El Paso, Texas comprised of a 5-bay truck loading rack and over 900,000 barrels of storage.
- In July 2009, our general partner declared a quarterly distribution of $0.71 per unit to be paid on August 14, 2009 to unitholders of record at the close of business on August 7, 2009. Total distributions to be paid under this declaration are approximately $71.0 million.

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

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of June 30, 2009, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our approximately 8,700-mile petroleum products pipeline system, including 49 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.

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, 2008.

Recent Developments

Simplification Agreement. In March 2009, we and our general partner and Magellan Midstream Holdings, L.P. ("MGG") and its general partner entered into an Agreement Relating to Simplification of Capital Structure (the "Simplification Agreement"). Pursuant to the Simplification Agreement, if approved by both our and MGG's unitholders, we will amend and restate our existing partnership agreement to provide for the transformation of the incentive distribution rights and approximate 2% general partner interest owned by Magellan GP, LLC, our general partner, into common units in us and a non-economic general partner interest (the "transformation"). Once the transformation is complete, Magellan GP, LLC, MGG's wholly-owned subsidiary, will distribute the common units in us that it receives in the transformation to MGG (the "unit distribution"). Once the transformation and unit distribution are complete, pursuant to a Contribution and Assumption Agreement among MGG, Magellan Midstream Holdings GP, LLC (MGG's general partner), us and Magellan GP, LLC (our general partner): (i) MGG will contribute 100% of its member interests in its general partner to our general partner; (ii) MGG will contribute 100% of the member interests in our general partner to us; (iii) MGG will contribute to us all of its cash and assets, other than the common units in us it receives in the unit distribution; and (iv) we will assume all of MGG's liabilities (collectively, the "contributions"). Once the transformation, unit distribution and contributions are complete, pursuant to the Simplification Agreement, MGG will dissolve and wind-up and distribute the common units in us it receives in the unit distribution to its unitholders (the "redistribution").

Pursuant to the Simplification Agreement, MGG will receive approximately 39.6 million of our common units in the transformation and unit distribution and each of MGG's unitholders will receive 0.6325 of our common units in the redistribution for each MGG common unit. Our unitholders will continue to own their existing common units.

Currently, we are a consolidated subsidiary of MGG. MGG controls and operates us through its 100% ownership interest in our general partner. Assuming the simplification of the capital structure as described above is approved by both our and MGG's unitholders, our general partner and MGG's general partner will legally become our wholly-owned subsidiaries and MGG will be dissolved. For accounting purposes, however, MGG will be considered the accounting acquirer of its non-controlling interest. Therefore, in accordance with Statement of Financial Accounting Standard ("SFAS") No. 160, *Non-Controlling Interests in Consolidated Financial Statements*, the changes in MGG's ownership interest in us will be accounted for as an equity transaction and no gain or loss will be recognized as a result of the simplification of the capital structure. Because MGG will be the surviving accounting entity, the amounts reported on our consolidated balance sheet for property, plant and equipment will increase by approximately $165.0 million and accumulated depreciation will increase by approximately $140.0 million. Additionally, depreciation and amortization expense on our consolidated income statement will increase by approximately $13.0 million on an annual basis.

Our general partner will continue to manage us after the simplification and our management team will continue in their respective roles. Additionally, three of the four members of MGG's general partner's board of directors will join the board of directors of our general partner following completion of the simplification. The other member of MGG's general partner's board of directors, Patrick C. Eilers, also serves as an independent member of our general partner's board of directors.

The terms of the Simplification Agreement were unanimously approved by the conflicts committee of the board of directors of our general partner and MGG's general partner. Each conflicts committee is comprised solely of independent directors and was previously delegated authority by the board of directors to negotiate and authorize the terms of the simplification.

The simplification is expected to be consummated in the third quarter of 2009, subject to customary closing conditions and majority approval of our and MGG's unitholders.

We and MGG have filed a joint proxy statement/prospectus and other documents with the Securities and Exchange Commission ("SEC") in relation to the simplification. Investors and security holders are urged to read these documents carefully because they contain important information regarding us, MGG and the simplification. A definitive joint proxy statement/prospectus has been sent to our and MGG's unitholders seeking their approvals as contemplated by the Simplification Agreement. Investors and unitholders may obtain a free copy of the joint proxy statement/prospectus and other documents containing information about us and MGG at the SEC's website at www.sec.gov. The meeting date for consideration of the Simplification Agreement is September 25, 2009. Unitholders of record on July 27, 2009 are eligible to vote on this matter. Copies of the joint proxy statement/prospectus and the SEC filings incorporated by reference in the joint proxy statement/prospectus may also be obtained free of charge by contacting our investor relations at (918) 574-7650, or by accessing www.magellanlp.com or www.mgglp.com.

We, MGG and the officers and directors of the general partner of each partnership may be deemed to be participants in the solicitation of proxies from their security holders. Information about these persons can be found in the annual report and proxy statement for each partnership as filed with the SEC, and additional information about such persons may be obtained from the joint proxy statement/prospectus.

This communication shall not constitute an offer to sell or the solicitation of an offer to sell or the solicitation of an offer to buy any securities, nor shall there be any sale of securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

Longhorn Pipeline Acquisition. On July 29, 2009, we acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. ("Longhorn") for $250.0 million plus the fair market value of the line fill of $86.1 million. The assets of Longhorn include an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas, a terminal in El Paso, Texas comprised of a 5-bay truck loading rack and over 900,000 barrels of storage. The El Paso, Texas terminal serves local petroleum products demand and distributes product to connecting third-party pipelines for ultimate delivery to markets in Arizona and New Mexico.

Debt Issuance. In June 2009, we issued $300.0 million of 6.55% notes due 2019. See *Liquidity and Capital Resources* below for further discussion of this matter.

Board of Directors. In May 2009, our board of directors elected Barry R. Pearl to serve as an independent member of our general partner's board of directors. Mr. Pearl will continue to serve on our general partner's board of directors following the completion of the simplification of our capital structure (discussed above under *Simplification Agreement*).

Cash Distribution. During July 2009, the board of directors of our general partner declared a quarterly cash distribution of $0.71 per unit for the period of April 1 through June 30, 2009. This quarterly cash distribution will be paid on August 14, 2009 to unitholders of record on August 7, 2009.

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 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 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 expense and affiliate general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of our operations. Additionally, product margin, which management primarily uses to evaluate the profitability of our petroleum products blending and fractionation activities, is provided in the tables below. Product margin is a non-GAAP measure; however, its components, product sales and product purchases, are determined in accordance with GAAP.

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2009

	Three Months Ended June 30,		Variance Favorable (Unfavorable)	
	2008	2009	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 121.2	$ 121.8	$ 0.6	—
Petroleum products terminals	36.0	40.7	4.7	13
Ammonia pipeline system	6.0	5.3	(0.7)	(12)
Intersegment eliminations	(0.8)	(1.2)	(0.4)	(50)
Total transportation and terminals revenues	162.4	166.6	4.2	3
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum products pipeline system	39.9	44.0	(4.1)	(10)
Petroleum products terminals	15.7	14.9	0.8	5
Ammonia pipeline system	2.8	3.2	(0.4)	(14)
Intersegment eliminations	(1.4)	(1.6)	0.2	14
Total operating expenses	57.0	60.5	(3.5)	(6)
Product margin:				
Product sales revenues	110.3	41.3	(69.0)	(63)
Product purchases	75.3	41.0	34.3	46
Product margin	35.0	0.3	(34.7)	(99)
Equity earnings	1.4	0.9	(0.5)	(36)
Operating margin	142.0	107.5	(34.5)	(24)
Depreciation and amortization expense	17.5	19.8	(2.3)	(13)
Affiliate G&A expense	18.4	19.8	(1.4)	(8)
Operating profit	106.1	67.9	(38.2)	(36)
Interest expense (net of interest income and interest capitalized)	11.4	14.6	(3.2)	(28)
Debt placement fee amortization expense	0.1	0.2	(0.1)	(100)
Other income	(0.3)	(0.5)	0.2	67
Income before provision for income taxes	94.9	53.6	(41.3)	(44)
Provision for income taxes	0.5	0.4	0.1	20
Net income	$ 94.4	$ 53.2	$ (41.2)	(44)
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 1.169	$ 1.202		
Volume shipped (million barrels)	77.3	73.9		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)	22.8	26.2		
Inland terminal throughput (million barrels)	28.3	27.9		
Ammonia pipeline system:				
Volume shipped (thousand tons)	227	171		

Transportation and terminals revenues increased by $4.2 million as shown below:

- an increase in petroleum products pipeline system revenues of $0.6 million primarily attributable to higher revenues related to leased storage, partially offset by lower transportation revenues. The higher leased storage revenues resulted from new storage capacity. The lower transportation revenues resulted from a decrease in distillate shipments reflecting weak trucking and rail demand, partially offset by an increase in gasoline shipments reflecting an overall increase in consumer demand for gasoline;
- an increase in petroleum products terminals revenues of $4.7 million due to higher revenues at both our marine and inland terminals. Marine revenues increased primarily due to operating results from additional storage tanks at our Galena Park, Texas and Wilmington, Delaware facilities that were placed into service over the past year. Inland revenues benefitted from higher butane blending and ethanol blending fees that offset lower throughput volumes; and
- a decrease in ammonia pipeline system revenues of $0.7 million due to lower shipments resulting primarily from an increase in system maintenance and testing, which negatively impacted volumes for the quarter, and unfavorable weather conditions.

Operating expenses increased by $3.5 million as shown below:

- an increase in petroleum products pipeline system expenses of $4.1 million due primarily to a $12.1 million reduction to our operating expenses in second quarter 2008 due to the favorable settlement of a civil penalty related to historical product releases. Otherwise, current period costs were $8.0 million favorable due to more favorable product overages, lower maintenance spending resulting from less testing and rehabilitation work being performed, and favorable power costs as a result of lower prices for natural gas and electricity in the current quarter;
- a decrease in petroleum products terminals expenses of $0.8 million primarily related to lower maintenance integrity costs;
- an increase in ammonia pipeline system expenses of $0.4 million primarily due to an increase in system maintenance and testing.

Product sales revenues primarily resulted from our petroleum products blending activities, terminal product gains and transmix fractionation. Product margin decreased $34.7 million primarily because of the timing differences of when profits on product sales are recognized under forward sales contracts, which we were using in second quarter 2008, versus under New York Mercantile Exchange ("NYMEX") contracts, which we have been predominately using to hedge price changes for future product sales since third quarter 2008. We applied normal sales accounting to the forward sales contracts we entered into; therefore, all of the profit on product sales under these agreements was recognized in the second quarter of 2008 when the physical delivery of the product occurred. Because the NYMEX contracts we have been using do not qualify for hedge accounting, we mark these contracts to market at the end of each accounting period. NYMEX losses in the current quarter totaled $19.9 million, which contributed to the $34.7 million decrease in product margin for the period. However, $15.7 million of the current quarter NYMEX losses were associated with commodity related activities that will occur in future periods. In addition, we recognized $3.5 million of profits from NYMEX contracts in prior periods associated with commodity related activities that occurred this quarter. These two NYMEX events combined accounted for $19.2 million of the $34.7 million decrease in product margin for the period. Lower product prices in 2009 compared to 2008 account for most of the remaining variance.

Depreciation and amortization increased by $2.3 million principally related to expansion capital projects placed into service over the past year.

Affiliate G&A expense increased by $1.4 million due primarily to higher personnel costs, additional costs associated with potential growth projects and higher equity-based incentive compensation expense. The increase in equity-based incentive compensation expense was principally due to the expense associated with the final tranche of the awards issued in 2007 being recognized over a shorter period.

Interest expense, net of interest income and interest capitalized, increased $3.2 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $1,178.8 million for the 2009 period from $945.1 million for the 2008 period principally due to borrowings for expansion capital expenditures. The weighted-average interest rate on our borrowings decreased to 5.3% in second quarter 2009 from 5.4% in second quarter 2008.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2009

	Six Months Ended June 30,		Variance Favorable (Unfavorable)	
	2008	2009	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum products pipeline system	$227.5	$236.6	$ 9.1	4
Petroleum products terminals	69.6	78.9	9.3	13
Ammonia pipeline system	11.4	8.5	(2.9)	(25)
Intersegment eliminations	(1.5)	(2.5)	(1.0)	(67)
Total transportation and terminals revenues	307.0	321.5	14.5	5
Affiliate management fee revenue	0.4	0.4	—	—
Operating expenses:				
Petroleum products pipeline system	82.2	88.0	(5.8)	(7)
Petroleum products terminals	28.2	30.3	(2.1)	(7)
Ammonia pipeline system	5.1	6.3	(1.2)	(24)
Intersegment eliminations	(2.9)	(3.4)	0.5	17
Total operating expenses	112.6	121.2	(8.6)	(8)
Product margin:				
Product sales revenues	312.0	99.0	(213.0)	(68)
Product purchases	252.9	93.6	159.3	63
Product margin	59.1	5.4	(53.7)	(91)
Gain on assignment of supply agreement	26.5	—	(26.5)	(100)
Equity earnings	1.8	1.4	(0.4)	(22)
Operating margin	282.2	207.5	(74.7)	(26)
Depreciation and amortization expense	34.6	39.2	(4.6)	(13)
Affiliate G&A expense	36.2	40.3	(4.1)	(11)
Operating profit	211.4	128.0	(83.4)	(39)
Interest expense (net of interest income and interest capitalized)	22.7	29.0	(6.3)	(28)
Debt placement fee amortization expense	0.3	0.4	(0.1)	(33)
Other income	(0.3)	(0.6)	0.3	100
Income before provision for income taxes	188.7	99.2	(89.5)	(47)
Provision for income taxes	1.0	0.8	0.2	20
Net income	$187.7	$ 98.4	$ (89.3)	(48)
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.161	$1.174		
Volume shipped (million barrels)	146.2	145.6		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)	22.8	25.6		
Inland terminal throughput (million barrels)	55.4	53.9		
Ammonia pipeline system:				
Volume shipped (thousand tons)	447	295		

Transportation and terminals revenues increased $14.5 million as shown below:

- an increase in petroleum products pipeline system revenues of $9.1 million primarily attributable to higher revenues related to leased storage, ethanol blending and higher transportation revenues. The higher leased storage revenues resulted from new storage capacity. Transportation revenues increased as a result of higher average tariffs due in part to our mid-year tariff escalations. Transportation volumes were down slightly between periods as an increase in gasoline shipments was offset by lower diesel and aviation fuel shipments;
- an increase in petroleum products terminals revenues of $9.3 million due to higher revenues at both our marine and inland terminals. Marine revenues increased primarily at our Galena Park, Texas and Wilmington, Delaware facilities due to leasing new storage tanks placed in service over the past year and higher storage rates. Inland revenues benefitted from higher fees due to ethanol blending; and
- a decrease in ammonia pipeline system revenues of $2.9 million due to lower shipments primarily resulting from operational issues at two of our customers' plants during first quarter 2009, increased system maintenance and testing during second quarter 2009 and unfavorable spring 2009 weather conditions, which slowed demand for ammonia, partially offset by higher average tariffs.

Operating expenses increased by $8.6 million as shown below:

- an increase in petroleum products pipeline system expenses of $5.8 million due primarily to a $12.1 million reduction to our operating expenses in 2008 resulting from the favorable settlement of a civil penalty related to historical product releases. Otherwise, current period costs were $6.3 million favorable due to lower power costs resulting from lower prices for natural gas and electricity, more favorable product overages and lower environmental expenses, partially offset by higher maintenance spending resulting from more testing and rehabilitation work being performed and higher personnel costs;
- an increase in petroleum products terminals expenses of $2.1 million due primarily to gains recognized in 2008 from insurance proceeds received for hurricane damages sustained during 2005. Additionally, higher personnel costs contributed to the increase; and
- an increase in ammonia pipeline system expenses of $1.2 million primarily due to an increase in system maintenance and testing and higher environmental costs in 2009 resulting from increases in several accruals related to historical product releases.

Product sales revenues primarily resulted from our petroleum products blending activities, terminal product gains and transmix fractionation. Product margin decreased $53.7 million primarily because of the timing differences of when profits on product sales are recognized under forward sales contracts, which we were using in first and second quarters of 2008, versus under NYMEX contracts, which we have been predominately using to hedge price changes for future product sales since third quarter 2008. We applied normal sales accounting to the forward sales contracts we entered into; therefore, all of the profit on product sales under these agreements that matured in the first and second quarters of 2008 was recognized in those periods, which was when the physical sale of the product occurred. Because the NYMEX contracts we have been using do not qualify for hedge accounting, we mark these contracts to market at the end of each accounting period. Year-to-date 2009 NYMEX losses totaled $23.4 million, which contributed to the $53.7 million decrease in product margins for the period. However, $17.3 million of these losses were associated with commodity related activities that will occur in future periods. In addition, we recognized $20.2 million of profits from NYMEX contracts during 2008 associated with commodity related activities that occurred during 2009. These two NYMEX events combined accounted for $37.5 million of the $53.7 million decrease in product margin for the period. Lower product prices in 2009 compared to 2008 account for most of the remaining variance.

The 2008 period benefited from a $26.5 million gain on the assignment of a third-party supply agreement during March 2008. The gain resulted from the write-off of the unamortized amount of a liability we recognized related to the fair value of the agreement, which we assumed as part of our acquisition of certain pipeline assets in October 2004.

Depreciation and amortization expense increased by $4.6 million related to expansion capital projects placed into service over the past year.

Affiliate G&A expense increased by $4.1 million primarily due to higher equity-based incentive compensation expense, higher personnel costs and higher costs associated with potential growth projects. Equity-based incentive compensation expense increased principally due to additional accruals recognized from the modification of our 2008 unit awards and because the expense associated with the final tranche of the awards issued in 2007 is being recognized over a shorter period.

Interest expense, net of interest income and interest capitalized, increased $6.3 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $1,135.9 million for the 2009 period from $951.4 million for the 2008 period principally due to borrowings for expansion capital expenditures. The weighted-average interest rate on our borrowings increased to 5.5% in 2009 from 5.4% in 2008.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $217.7 million and $92.2 million for the six months ended June 30, 2008 and 2009, respectively. The $125.5 million decrease from 2008 to 2009 was primarily attributable to:

- a decrease in net income of $62.8 million, excluding the $26.5 million non-cash gain on assignment of the supply agreement in 2008;
- a $70.2 million decrease resulting from a $25.4 million increase in inventory in 2009 versus a $44.8 million decrease in inventory in 2008. The increase in 2009 is primarily due to additional purchases of natural gas liquids inventory used for our petroleum products blending activity to take advantage of favorable market conditions. The decrease in 2008 is primarily due to the sale of petroleum products inventory when we assigned our product supply agreement to a third party in March 2008; and
- a $25.4 million decrease resulting from a $2.5 million decrease in accrued product purchases in 2009 versus a $22.9 million increase in 2008 due primarily to the timing of invoices received from our vendors and suppliers.

These decreases were partially offset by:

- an $18.5 million favorable cash flow variance resulting from the repayment of the supply agreement deposit in 2008 associated with the assignment of our product supply agreement to a third party; and
- a $9.6 million increase resulting from a $3.6 million decrease in environmental liabilities in 2009 versus a $13.2 million decrease in environmental liabilities in 2008. The decrease in environmental liabilities during 2008 is principally due to the favorable settlement of our petroleum products EPA issue.

Net cash used by investing activities for the six months ended June 30, 2008 and 2009 was $135.2 million and $114.7 million, respectively. During 2009, we spent $96.4 million for capital expenditures and $14.8 million for escrow deposits associated with acquisitions we expect to complete during third quarter 2009. Capital expenditures in 2009 included $22.4 million for maintenance capital, including $2.1 million of spending that would have been covered by our indemnification settlement with a former affiliate or by insurance, and $74.0 million for expansion capital. During 2008, we spent $132.0 million for capital expenditures, which included $18.2 million for maintenance capital, including $2.1 million of spending that would have been covered by our indemnification settlement or by insurance, and $113.8 million for expansion capital. Additionally, we acquired a petroleum products terminal in Bettendorf, Iowa for $12.0 million in first quarter 2008.

Net cash provided (used) by financing activities for the six months ended June 30, 2008 and 2009 was $(82.6) million and $80.5 million, respectively. During 2009, borrowings under notes (net of discounts) of $299.0 million were used to repay $208.3 million of borrowings on our revolving credit facility, with the balance to be used for general purposes, including capital expenditures. Net borrowings on the revolver during 2009, prior to our repayment of the $208.3 million in June 2009, were $138.3 million. Additionally, we paid cash distributions of $142.0 million to our unitholders and general partner during 2009. During 2008, we paid cash distributions of $129.6 million to our unitholders and general partner, while net borrowings on our revolving credit facility, primarily to finance expansion capital projects and acquisitions, were $36.3 million.

During second quarter 2009, we paid $71.0 million in cash distributions to our unitholders and general partner. Based on the declared quarterly distribution of $0.71 per unit associated with the second quarter of 2009, we will pay $71.0 million in distributions during third quarter 2009. If we continue to pay cash distributions at this level and the number of outstanding units remains the same, total cash distributions of $284.1 million would be paid on an annual basis. Of this amount, $93.9 million, or 33%, would be paid to our general partner on its approximate 2% ownership interest and incentive distribution rights. If the Simplification Agreement is approved, cash distributions will no longer be paid to the general partner, but our common units outstanding will increase to approximately 106.6 million units. In that event, a total annual distribution of approximately $302.7 million would be necessary to maintain the current quarterly distribution level of $0.71 per unit.

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, which we refer to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During second quarter 2009, our maintenance capital spending was $11.1 million, including $1.2 million of spending that would have been covered by our indemnification settlement with a former affiliate or by insurance. For the six months ended June 30, 2009, our maintenance capital spending was $22.4 million, including $2.1 million of spending that would have been covered by our indemnification settlement with a former affiliate or by insurance. We have received the entire $117.5 million under our indemnification settlement agreement.

For 2009, we expect to incur maintenance capital expenditures for our existing businesses of approximately $52.0 million, including $7.0 million of maintenance capital that has already been reimbursed to us through our indemnification settlement or will be reimbursed by third parties and $7.0 million of transition capital related to the acquisition of substantially all of the assets of Longhorn Pipeline.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During second quarter 2009, we spent $37.7 million for organic growth projects. For the six months ended June 30, 2009, we have spent $74.0 million for organic growth projects. Based on the progress of expansion projects already underway, we expect to spend approximately $250.0 million of organic growth capital during 2009, with an additional $90.0 million in future years to complete these projects. Further, we have spent $250.0 million on the acquisition of the Longhorn Pipeline assets during July 2009.

Liquidity

As of June 30, 2009, total debt reported on our consolidated balance sheet was $1,314.5 million. The difference between this amount and the $1,300.0 million face value of our outstanding debt results from gains and losses realized on various cash flow hedges and unamortized discounts on debt issuances.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in September 2012, is $550.0 million. 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. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used primarily for general purposes, including capital expenditures. As of June 30, 2009, there was no outstanding balance under this facility; however, $3.9 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets.

6.45% Notes due 2014. In May 2004, we sold $250.0 million of 6.45% notes due 2014 in an underwritten public offering at 99.8% of par. Including the impact of amortizing the gains realized on pre-issuance hedges associated with these notes, the effective interest rate of these notes is 6.3%.

5.65% Notes due 2016. In October 2004, we sold $250.0 million of 5.65% notes due 2016 in an underwritten public offering at 99.9% of par. The outstanding principal amount of the notes was increased by $3.3 million at June 30, 2009 for the unamortized portion of a gain realized upon termination of a related interest rate swap. Including the impact of amortizing this gain, as well as gains realized on pre-issuance hedges associated with these notes, the effective interest rate of these notes is 5.7%.

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased by $11.0 million at June 30, 2009 for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps. Including the impact of amortizing these gains, the effective interest rate of these notes is 5.9%.

6.55% Notes due 2019. In June 2009, we issued $300.0 million of 6.55% notes due 2019 in an underwritten public offering. The notes were issued for the discounted price of 99.7%, or $299.0 million. Net proceeds from the offering, after underwriter discounts of $2.0 million and offering costs of $0.1 million that we have incurred through June 30, 2009, were $296.9 million. The net proceeds were used to repay the $208.3 million of borrowings outstanding under our revolving credit facility at that time, and the balance will be used for general purposes, including capital expenditures. In connection with this offering, we entered into interest rate swap agreements to effectively convert $150.0 million of these notes to floating-rate debt (see *Interest Rate Derivatives*, below). The outstanding principal amount of the notes was increased by $2.9 million at June 30, 2009 for the fair value of the associated interest rate swap agreements. Including the impact of these agreements, the weighted-average interest rate of these notes at June 30, 2009 was 5.4%.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering at 99.6% of par. Including the impact of amortizing the gains realized on pre-issuance hedges associated with these notes, the effective interest rate on these notes is 6.3%.

Interest Rate Derivatives. We use interest rate derivatives to help manage interest rate risk. As of June 30, 2009, we had two offsetting interest rate swap agreements outstanding:

- In July 2008, we entered into a $50.0 million interest rate swap agreement ("Derivative A") to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. Derivative A effectively converted $50.0 million of those notes from a 6.40% fixed rate to a floating rate of six-month LIBOR plus 1.83%. Derivative A terminates in July 2018. We originally accounted for Derivative A as a fair value hedge. On December 8, 2008, in order to capture the economic value of Derivative A at that time, we entered into an offsetting derivative, as described below, and discontinued hedge accounting. The $5.4 million fair value of Derivative A at that time was recorded as an adjustment to long-term debt which is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. For the three and six months ended June 30, 2009, a loss of $2.5 million and $3.3 million, respectively, was recorded to other income on our consolidated statement of income resulting from the change in fair value of Derivative A.
- In December 2008, concurrent with the discontinuance of hedge accounting for Derivative A, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which we pay a fixed rate of 6.40% and receive a floating rate of six-month LIBOR plus 3.23%. This agreement terminates in July 2018. We entered into this agreement to offset changes in the fair value of Derivative A, excluding changes due to changes in counterparty credit risks. We did not designate this agreement as a hedge for accounting purposes. For the three and six months ended June 30, 2009, a gain of $3.0 million and $3.9 million, respectively, was recorded to other income on our consolidated statement of income resulting from the change in fair value of this agreement.

In addition to the two interest rate swap agreements described above, we had the following interest rate swap agreements outstanding as of June 30, 2009:

- In June 2009, we entered into a total of $150.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the $300.0 million of 6.55% notes due 2019. We have accounted for these agreements as fair value hedges. These agreements effectively convert $150.0 million of our 6.55% fixed-rate notes issued in June 2009 to floating-rate debt. Under the terms of the agreements, we will receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18%. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments will settle in January and July each year. During each period, we will record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense.

Credit Ratings. Our current corporate credit ratings are BBB by Standard and Poor's and Baa2 by Moody's Investor Services.

Off-Balance Sheet Arrangements

None.

Contractual Obligations Update

During July 2009, we entered into an unconditional agreement to acquire substantially all of the assets of Longhorn for $250.0 million plus the fair market value of the line fill of $86.1 million. This transaction was completed and the obligation settled in July 2009. This obligation was not reflected in the contractual obligations table in our 2008 Annual Report on Form 10-K.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are 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.

Ammonia EPA Issue. In February 2007, we received notice from the Department of Justice ("DOJ") that the Environmental Protection Agency ("EPA") had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act ("the Act") with respect to two releases of anhydrous ammonia from our ammonia pipeline system that was operated by a third party at the time of the releases. 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 for which the third-party operator has requested indemnification. In March 2007, we also 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. The third-party operator subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. 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 these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

Other Items

NYMEX Contracts. We began using NYMEX contracts during the third quarter of 2008 as economic hedges against changes in the future price of petroleum products. Gains and losses on these contracts are recognized in income each period when these contracts are marked to market and realized when the related physical sale of the product occurs and the NYMEX contracts are settled. The following tables provide a summary of losses realized in the current quarter and the periods in which the related marked-to-market gains and losses were recognized in our consolidated statement of income (in millions).

	Accounting Period				
	2008		2009		Total Marked-to-Market Gains / (Losses) Recognized
Period Physical Sale of Product Occurred / Will Occur	**3rd Qtr**	**4th Qtr**	**1st Qtr**	**2nd Qtr**	
1st Quarter 2009	$ 3.5	$11.8	$(0.5)	$ —	$ 14.8
2nd Quarter 2009	1.0	3.9	(1.4)	(4.2)	(0.7)
Year-to-Date	4.5	15.7	(1.9)	(4.2)	14.1
3rd Quarter 2009	—	—	(0.6)	(3.3)	(3.9)
4th Quarter 2009	—	—	(1.0)	(12.7)	(13.7)
1st Quarter 2010	—	—	—	0.3	0.3
Totals	$ 4.5	$15.7	$(3.5)	$(19.9)	$ (3.2)

Pipeline Tariff Increase. The Federal Energy Regulatory Commission regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted. Approximately 40% of our tariffs are subject to this indexing methodology while the remaining 60% of the tariffs can be adjusted at our discretion based on competitive factors. The current approved methodology is the annual change in the producer price index for finished goods ("PPI-FG") plus 1.3%. The change for 2008 was 6.3%, and we increased substantially all of our tariffs by 7.6% on July 1, 2009. Through June 2009, the change in PPI-FG for 2009 is approximately negative 3%. If the change in this index remains at this level for the full year 2009, we will be required to decrease tariffs in markets that are subject to the FERC's index methodology, which currently represent approximately 40% of our markets, by approximately 2% in July 2010.

Unrecognized Product Gains. Our petroleum products terminals operations generate product overages and shortages that result from metering inaccuracies, product evaporation or expansion, product releases and product contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals 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 net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $3.6 million as of June 30, 2009. 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.

Affiliate Transactions. We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. During the three and six months ended June 30, 2009, we received operating fees from this pipeline company of $0.2 million and $0.4 million, respectively, which we reported as affiliate management fee revenue.

The following table summarizes affiliate costs and expenses that are reflected in our consolidated statement of income (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2009	2008	2009
MGG GP—allocated operating expenses	21,632	22,878	42,552	45,554
MGG GP—allocated G&A expenses	12,220	13,911	24,093	27,078

Under our services agreement with Magellan Midstream Holdings GP, LLC ("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 June 30, 2009 were $19.5 million, and the long-term affiliate pension and benefits accruals associated with this agreement at June 30, 2009 were $34.4 million. 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 GP when MGG GP makes contributions to its pension funds.

Because our cash 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 June 30, 2009, our executive officers collectively owned a beneficial interest of approximately 1% of MGG, the owner of our general partner. Therefore, our executive officers indirectly benefit from distributions paid to our general partner. Assuming we have sufficient available cash to continue to pay cash distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.71 per unit, our general partner would receive annual cash distributions of approximately $93.9 million on its combined general partner interest and incentive distribution rights. If the Simplification Agreement (see Recent Developments—*Simplification Agreement,* above) is approved, once the transformation, unit distribution and contributions are complete, our general partner will own only a non-economic general partner interest in us and will no longer receive quarterly distributions from us. Like other MGG investors, our executive officers will receive 0.6325 units in us for each MGG unit they own on the applicable record date as a part of the simplification process.

New Accounting Pronouncements

In May 2009, The Financial Accounting Standards Board ("FASB") issued SFAS No. 165, *Subsequent Events (as amended)*. This Statement requires the disclosure of subsequent events to be distinguished between recognized and non-recognized subsequent events. Further, entities are required to include a description of the period through which subsequent events were evaluated. Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position ("FSP") No. FAS 107-1 and Accounting Principles Board ("APB") 28-1, *Interim Disclosures About Fair Value of Financial Instruments.* This FSP amends SFAS No. 107 (FASB ASC 825-10) and APB Opinion No. 28: (FASB ASC 270-10) by requiring quarterly as well as annual disclosures of the fair value of all financial instruments. The disclosures are to be in a form that makes it clear whether the fair value and carrying amounts represent assets or liabilities and how the carrying amounts relate to what is reported on the balance sheet. Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies*. This FSP amends and clarifies FASB Statement No. 141 (revised 2007), *Business Combinations*, to address application issues on the initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP is effective for assets or liabilities arising from contingencies in business combinations that occur following the start of the first fiscal year that begins on or after December 15, 2008. We do not expect that the adoption of this FSP will have a material impact on our financial position, results of operations or cash flows.

In December 2008, the FASB issued FSP FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. This FSP expands the disclosure requirements for employer pension plans and other postretirement benefit plans to include factors that are pertinent to an understanding of investment policies and strategies. The additional disclosure requirements include: (i) for annual financial statements, the fair value of each major category of plan assets separately for pension and other postretirement plans, (ii) a narrative description of the basis used to determine the expected long-term rate of return on asset assumptions, (iii) information to enable users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets at the annual reporting date, and (iv) for fair value measurements using unobservable inputs, disclosure of the effect of the measurements on changes in plan assets for the period. This FSP is effective for fiscal years ending after December 15, 2009, with early application permitted. Provisions of this FSP are not required for earlier periods that are presented for comparative purposes. Adoption of this FSP will not have a material impact on our financial position, results of operations or cash flows.

In September 2008, the FASB issued Emerging Issues Task Force ("EITF") No. 08-6, *Equity Method Investment Accounting Considerations*. This EITF requires entities to measure its equity method investments initially at cost in accordance with SFAS No. 141(R) *Business Combinations*. Further, the EITF clarified that entities should not separately test an investee's underlying indefinite-lived intangible asset for impairment; however, they are required to recognize other-than-temporary impairments of an equity method investment in accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. In addition, entities are required to account for a share issuance by an equity method investee as if the investor had sold a proportionate share of its investment. Any gain or loss to the investor resulting from an investee's share issuance is to be recognized in earnings. We adopted this EITF on January 1, 2009, which is applicable to both interim and annual periods and is to be applied prospectively. Our adoption of this EITF did not have a material impact on our financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*. This FSP clarifies that unvested share-based payment awards that contain non-forfeitable rights to distributions or distribution equivalents, whether paid or unpaid, are participating securities as defined in SFAS No. 128, *Earnings Per Share*, and are to be included in the computation of earnings per unit pursuant to the two-class method. We adopted this FSP on January 1, 2009, which is applicable to both interim and annual periods, with prior period earnings per unit data retrospectively adjusted. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. This Statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP in the United States. The Statement will not change our current accounting practices.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets*. This FSP also expands the disclosures required for recognized intangible assets. We adopted this FSP on January 1, 2009, which is applicable to both interim and annual periods. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

On January 1, 2009, we adopted EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships.* Under EITF No. 07-4, the excess of distributions over earnings and/or excess of earnings over distributions for each period are allocated to the entities' general partner based on the general partner's ownership interest at the time. For purposes of calculating earnings per unit, our previous accounting practice was to allocate net income to the general partner based on the general partner's share of total or pro forma distributions, as appropriate, including incentive distribution rights. The effect of adopting this EITF is: (i) for periods when net income exceeds distributions, our reported earnings per limited partner unit will be higher than under our previous accounting practice and (ii) for periods when distributions exceed net income, our reported earnings per limited partner unit will be lower than under our previous accounting practice. These differences will be material for those periods where there are material differences between our net income and the distributions we pay. For the periods included in this report, the differences between our previous methodology and those calculated under EITF 07-4 are provided in the table below:

	Three Months Ended June 30, 2009			Six Months Ended June 30, 2009		
	Under EITF No. 07-4	Under Previous Accounting	Difference	Under EITF No. 07-4	Under Previous Accounting	Difference
	(in thousands, except per unit amounts)			(in thousands, except per unit amounts)		
Net income allocated to limited partners	$ 30,410	$ 35,839	$ (5,429)	$ 53,331	$ 66,564	$(13,233)
Basic and diluted earnings per unit	$ 0.45	$ 0.53	$ (0.08)	$ 0.79	$ 0.99	$ (0.20)

	Three Months Ended June 30, 2008			Six Months Ended June 30, 2008		
	Under EITF No. 07-4	Under Previous Accounting	Difference	Under EITF No. 07-4	Under Previous Accounting	Difference
	(in thousands, except per unit amounts)			(in thousands, except per unit amounts)		
Net income allocated to limited partners	$ 61,268	$ 53,736	$ 7,532	$ 135,031	$113,356	$ 21,675
Basic and diluted earnings per unit	$ 0.92	$ 0.80	$ 0.12	$ 2.02	$ 1.70	$ 0.32

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, established, among other things, the disclosure requirements for derivative instruments and for hedging activities. SFAS No. 161 amends SFAS No. 133, requiring qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. We adopted SFAS No. 161 on January 1, 2009, which is applicable for both interim and annual periods. Our adoption of this Statement did not have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This Statement requires, among other things, that entities: (i) recognize, with certain exceptions, 100% of the fair values of assets acquired, liabilities assumed and non-controlling interests in acquisitions of less than a 100% controlling interest when the acquisition constitutes a change in control of the acquired entity; (ii) measure acquirer shares issued in consideration for a business combination at fair value on the acquisition date; (iii) recognize contingent consideration arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in earnings; (iv) recognize, with certain exceptions, pre-acquisition loss and gain contingencies at their acquisition-date fair values; (v) expense, as incurred, acquisition-related transaction costs; and (vi) capitalize acquisition-related restructuring costs only if the criteria in SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities (as amended)* are met as of the acquisition date. We adopted this Statement on January 1, 2009, and our initial adoption did not have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Non-Controlling Interests in Consolidated Financial Statements*. This Statement requires, among other things, that: (i) the non-controlling interest be clearly identified and presented in the consolidated statement of financial position within equity, but separate from the parent's equity; (ii) the amount of consolidated net income attributable to the parent and to the non-controlling interest be clearly identified and presented on the face of the consolidated statement of income; (iii) all changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently (as equity transactions); (iv) when a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value. The gain or loss on the deconsolidation of the subsidiary is measured using the fair value of any non-controlling equity investment rather than the carrying amount of that retained investment; and (v) sufficient disclosures be made to clearly identify and distinguish between the interests of the parent and the interests of non-controlling owners. We adopted SFAS No. 160 on January 1, 2009, which is applicable for both interim and annual periods. Our adoption of this Statement did not have a material impact on our financial position, results of operations 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.

Commodity Price Risk

We 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 June 30, 2009, we had commitments under forward purchase contracts for product purchases of approximately 0.3 million barrels that are being accounted for as normal purchases totaling approximately $8.8 million, and we had commitments under forward sales contracts for product sales of approximately 1.4 million barrels that are being accounted for as normal sales totaling approximately $106.8 million.

In addition to forward sales contracts, we use NYMEX contracts to lock in forward sales prices. Although these NYMEX contracts represent an economic hedge against price changes on the petroleum products we expect to sell in the future, they do not qualify as normal sales or for hedge accounting treatment under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*; therefore, we recognize the change in fair value of these contracts currently in earnings. During the six months ended June 30, 2009, we closed our positions on NYMEX contracts associated with the sale of 1.1 million barrels of gasoline and realized total gains of $14.1 million. At June 30, 2009, the fair value of our open NYMEX contracts, representing 1.2 million barrels of petroleum products, was a net loss of $17.3 million, which was recorded as energy commodity derivative contracts on our consolidated balance sheet. These open NYMEX contracts mature between July 2009 and March 2010. At June 30, 2009, we had made margin deposits of $25.6 million for these contracts, which was included in energy commodity derivative deposit on our consolidated balance sheet. Based on our open NYMEX contracts at June 30, 2009, a $1.00 per barrel increase in the price of the NYMEX contract for reformulated gasoline blendstock for oxygen blending ("RBOB") gasoline would result in a $1.2 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of the NYMEX contract for RBOB would result in a $1.2 million increase in our product sales revenues. However, the increases or decreases in product sales revenues we recognize from our open NYMEX contracts are substantially offset by higher or lower product sales revenues when the physical sale of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

In June 2009, we entered into a total of $150.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of our $300.0 million of 6.55% notes due 2019. We have accounted for these agreements as fair value hedges. These agreements effectively convert $150.0 million of our 6.55% fixed-rate notes issued in June 2009 to floating-rate debt. Under the terms of the agreements, we will receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18%. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments will settle in January and July each year. During each period, we will record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense of $0.4 million associated with this hedge.

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. There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended June 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "estimates," "forecasts," "projects" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may 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:

- overall demand for refined petroleum products, natural gas liquids, crude oil and ammonia in the United States;
- price fluctuations for refined petroleum products and natural gas liquids and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels in the United States;
- changes in the financial condition of our customers;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy and maintain adequate liquidity;
- development of alternative energy sources, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our assets;
- 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;
- 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;
- weather patterns materially different than historical trends;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards or unforeseen interruptions 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 identify growth projects or to complete identified growth projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- 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;
- 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 perform on their contractual obligations to us;
- conflicts of interests between us, our general partner and MGG;
- 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

Petroleum Products EPA Issue. In June 2009, we received notice from the Department of Justice ("DOJ") that the DOJ, at the request of the Environmental Protection Agency ("EPA"), is prepared to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act ("the Act") with respect to a discharge of gasoline that occurred on January 5, 2008 from our petroleum products pipeline near Oologah, Oklahoma. The DOJ stated that the maximum statutory penalty for the alleged violations of the Act, assuming only mere negligence, is approximately $1.2 million. The DOJ stated in its notice to us that it does not expect us to pay the maximum statutory penalty in a settlement although it will explore whether injunctive relief is necessary to prevent future violations of the Act. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalty.

Ammonia EPA Issue. 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 our ammonia pipeline system that was operated by a third party at the time of the releases. 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, for which the third-party operator has requested indemnification from us. In March 2007, we also 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. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. 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 these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

In June 2008, we received a Notice of Probable Violation ("NOPV") from the Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("DOT PHMSA") with a preliminary assessed civil penalty of $0.8 million for alleged violations associated with a May 2005 pipeline release that occurred in the Fairfax Industrial District of Kansas City, Kansas. The violations principally involve allegations of failing to follow our system integrity plan. We submitted a request on a timely basis and a hearing was held in March 2009. We have reached a tentative settlement of this matter with the DOT PHMSA.

In May 2006, we received a NOPV from the DOT PHMSA alleging two areas of non-compliance with 40 CFR 452 (Pipeline Integrity Management in High Consequence Areas); specifically that (1) adequate technical justification was not presented for our formula in calculating the spill volume of refined product for an overall spread analysis and (2) the baseline assessment plan was not established by risk priority. DOT PHMSA has preliminarily assessed a civil penalty of $0.2 million for both allegations. A hearing was held in September 2006. We submitted our post-hearing brief in October 2006. In February 2007, we responded to a series of questions from the hearing officer. In July 2009, DOT PHMSA issued a Final Order on this matter, which included a reduced penalty of $148 thousand. We are currently evaluating the Final Order and the terms of its associated Compliance Order.

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.

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, 2008, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

We have updated our risk factors as follows since issuing our Annual Report on Form 10-K:

Risks Related to Our Business

Our purchase of substantially all of the assets of Longhorn Partners Pipeline, L.P. may not immediately produce positive operating cash flows and will substantially increase the level of our indebtedness.

We completed the acquisition of substantially all of the assets of Longhorn Partners Pipeline, L.P. on July 29, 2009. The purchase price was $250.0 million plus $86.1 million for related line fill inventory. We financed the acquisition with debt, which substantially increased our indebtedness. Because this asset had minimal commercial activity following the former owner's bankruptcy filing last year, we anticipate a ramp-up of operations during the first one to two years of ownership as we build a customer base for this pipeline system. During that period, the operating cash flow derived from the assets may be significantly less than we ultimately anticipate receiving once the customer base has been developed. As a result, our cash from operations and our creditworthiness could be adversely affected during that ramp-up period. In addition, during that period we will likely continue to own a significant portion of the related line fill inventory, and we could be exposed to price fluctuations in the value of that inventory, or to margin deposits or similar arrangements required by any transactions we enter to hedge the value of that inventory. We cannot assure you that the ramp-up period will be limited to one or two years. In addition, we could experience other unanticipated delays in realizing the benefits of the acquisition, or we could discover previously unknown liabilities associated with the acquired assets.

Risks Related to the Simplification and Related Matters

While the Simplification Agreement is in effect, MGG's opportunities to enter into different business combination transactions with other parties on more favorable terms may be limited, and we and MGG may be limited in our ability to pursue other attractive business opportunities.

While the Simplification Agreement is in effect, MGG is prohibited from initiating, soliciting or knowingly encouraging the submission of any acquisition proposal or from participating in any discussions or negotiations regarding any acquisition proposal, subject to certain exceptions. As a result of these provisions in the Simplification Agreement, MGG's opportunities to enter into more favorable transactions may be limited. Likewise, if MGG were to sell directly to a third party, it might have received more value with respect to the general partner interest in us and our incentive distribution rights based on the value of the business at such time.

We and MGG have also agreed to refrain from taking certain actions with respect to our businesses and financial affairs pending completion of the simplification or termination of the Simplification Agreement. These restrictions could be in effect for an extended period of time if completion of the simplification is delayed. These limitations do not preclude us from conducting our business in the ordinary or usual course or from acquiring assets or businesses so long as such activity does not materially affect our or MGG's ability to complete the matters contemplated by the Simplification Agreement.

In addition to the economic costs associated with pursuing the simplification, MGG's general partner's management and our general partner's management will continue to devote substantial time and other human resources to the proposed simplification, which could limit MGG's and our ability to pursue other attractive business opportunities, including potential joint ventures, stand-alone projects and other transactions. If either we or MGG is unable to pursue such other attractive business opportunities, then the growth prospects and the long-term strategic position of the business and our business following the simplification could be adversely affected.

Our existing unitholders will be diluted by the simplification and will have reduced voting power.

The simplification will dilute the ownership position of our existing unitholders. After the simplification, our existing unitholders will have reduced voting power. Pursuant to the Simplification Agreement, MGG unitholders will receive approximately 39.6 million of our common units as a result of the simplification. Immediately following the liquidation and redistribution, we will be owned approximately 62.8% by our current unitholders and approximately 37.2% by former MGG unitholders.

The number of our outstanding common units will increase as a result of the simplification, which could make it more difficult to pay the current level of quarterly distributions.

As of July 31, 2009, there were approximately 67.0 million of our common units outstanding. We will issue approximately 39.6 million of our common units in connection with the simplification. Accordingly, the dollar amount required to pay the current per unit quarterly distributions will increase, which will increase the likelihood that we will not have sufficient funds to pay the current level of quarterly distributions to all of our common unitholders. Using the amount of $0.71 per common unit paid with respect to the first quarter of 2009, the cash distribution paid to our unitholders totaled $47.5 million, resulting in a distribution of $23.5 million to the general partner for its general partner interest and incentive distribution rights. Therefore, our combined total distribution paid with respect to the first quarter of 2009 was $71.0 million. Pursuant to the Simplification Agreement, MGG unitholders will receive approximately 39.6 million of our common units as a result of simplification. The combined pro forma distribution of our common units with respect to the first quarter 2009, had the simplification been completed prior to such distribution, would result in $0.71 per unit being distributed on approximately 106.6 million of our common units, or a total of $75.7 million, with the general partner no longer receiving any distributions. As a result, we will be required to distribute an additional $4.7 million per quarter in order to maintain the distribution level of $0.71 per common unit paid with respect to the first quarter of 2009.

Although the elimination of the incentive distribution rights may increase the cash available for distribution to our common units in the future, this source of funds may not be sufficient to meet the overall increase in cash required to maintain the current level of quarterly distributions to holders of our common units.

Failure to complete the simplification or delays in completing the simplification could negatively impact MMP common unit prices and MGG common unit prices and future business and operations.

If the simplification is not completed for any reason, we and MGG may be subject to a number of material risks, including the following:

- we will not realize the benefits expected from the simplification, including a potentially enhanced financial and competitive position;
- the price of our common units or MGG common units may decline to the extent that the current market price of these securities reflects a market assumption that the simplification will be completed; and
- some costs relating to the simplification, such as certain investment banking fees and legal and accounting fees, must be paid even if the simplification is not completed.

The costs of the simplification could adversely affect our operations and cash flows available for distribution to our unitholders.

We and MGG estimate the total costs of the simplification to be approximately $13.4 million, primarily consisting of investment banking and legal advisors' fees, accounting fees, financial printing and other related costs. These costs could adversely affect our operations and cash flows available for distributions to our unitholders. In addition, the foregoing estimate is preliminary and is subject to change.

Our amended and restated partnership agreement that will be in effect following the simplification limits the ability of our general partner to withdraw as our general partner and limits the ability of our unitholders to remove our general partner.

Under our amended and restated partnership agreement, to the fullest extent permitted by law, our general partner may not withdraw as our general partner at any time for any reason except in the event that the general partner has transferred all of its general partner interest in us in accordance with our amended and restated partnership agreement. In addition, our general partner may not be removed unless the removal is approved by the vote of the holders of 100% of the outstanding units, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of 100% of our outstanding units.

Tax Risks Related to the Simplification

No ruling has been obtained with respect to the tax consequences of the simplification.

No ruling has been or will be requested from the Internal Revenue Service ("IRS") with respect to the tax consequences of the simplification. Instead, we and MGG are relying on the opinions of our respective counsel as to the tax consequences of the simplification, and counsel's conclusions may not be sustained if challenged by the IRS.

The intended tax consequences of the simplification are dependent upon our and MGG being treated as a partnership for tax purposes.

The treatment of the simplification as nontaxable to our unitholders and MGG unitholders is dependent upon our and MGG being treated as a partnership for federal income tax purposes. If either we or MGG were treated as a corporation for federal income tax purposes, the consequences of the simplification would be materially different and would be taxable to an MGG unitholder.

An existing unitholder of ours may be required to recognize gain as a result of the decrease in his allocable share of our nonrecourse liabilities as a result of the simplification.

As a result of the simplification, the allocable shares of nonrecourse liabilities allocated to our existing unitholders will be recalculated to take into account common units issued by us in the transformation. If an existing unitholder of ours experiences a reduction in their share of nonrecourse liabilities as a result of the transformation, a "reducing debt shift," such unitholder will be deemed to have received a cash distribution equal to the amount of the reduction. A reduction in a unitholder's share of liabilities will result in a corresponding basis reduction in a unitholder's common units. A reducing debt shift and the resulting deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder of ours. If the reduction in a unitholder's share of nonrecourse liabilities and the resulting deemed cash distribution exceeds such unitholder's common unit basis, such unitholder would recognize gain in an amount equal to such excess. Although we have not received an opinion with respect to the shift of nonrecourse liabilities, we do not expect that any constructive cash distribution will exceed an existing unitholder's tax basis in his common units.

We estimate that the transformation will result in an increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders for the period from January 1, 2009 through December 31, 2010 (the "Projection Period").

We estimate that the effectiveness of the simplification will result in an increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders for the Projection Period. In addition, the federal income tax liability of an existing unitholder could be increased during the Projection Period if we make a future offering of our common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the Projection Period, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

Tax Risks

Our tax treatment will depend on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by individual states. If the IRS treats us as a corporation for tax purposes or we become subject to entity-level taxation, it would reduce the amount of cash available for payment of principal and interest on the notes.

If we were classified as a corporation for federal income tax purposes, we would be required to pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Treatment of us as a corporation would cause a material reduction in our anticipated cash flow, which could materially and adversely affect our ability to make payments on the notes.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could materially and adversely affect our ability to make payments on the notes. At the state level, because of widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, partnerships operating in Texas are required to pay franchise tax at a maximum effective rate of 0.7% of gross income apportioned to Texas in the prior year. If any other state were to impose a tax on us, the cash we have available to make payments on the notes could be materially reduced.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

The annual meeting of our limited partners was held on April 22, 2009. At this meeting, George A. O’Brien, Jr. was elected as a Class I director of our general partner’s board of directors. A tabulation of the voting on this issue follows:

Name	For	Withheld	Abstain	Broker Non-Votes
George A. O’Brien, Jr.	57,005,914	2,831,568	—	—

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
4.1*	Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed June 26, 2009).
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.
99	Magellan GP, LLC balance sheets as of December 31, 2008 and June 30, 2009 and notes thereto.

* Each such exhibit has previously been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma on August 4, 2009.

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)

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