MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
August 02, 2012

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

FORM 10-Q

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from to

Commission File No.: 1-16335

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

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

One Williams Center, P.O. Box 22186, Tulsa, Oklahoma 74121-2186
(Address of principal executive offices and zip code)
(918) 574-7000
(Registrant’s telephone number, including area code)

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

Indicate by check mark whether the registrant 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 x 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 x Accelerated filer £ Non-accelerated filer £ Smaller reporting company £

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

As of August 1, 2012, there were 113,100,436 outstanding limited partner units of Magellan Midstream Partners, L.P. that trade on the New York Stock Exchange under the ticker symbol "MMP."

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PART I
FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2012	2011	2012
Transportation and terminals revenues	$223,192	$248,761	$428,600	$466,315
Product sales revenues	159,943	200,568	397,239	476,298
Affiliate management fee revenue	192	198	385	397
Total revenues	383,327	449,527	826,224	943,010
Costs and expenses:				
Operating	81,323	82,326	143,684	150,778
Product purchases	118,836	144,498	330,066	393,110
Depreciation and amortization	30,664	31,486	60,027	62,996
General and administrative	25,281	25,414	49,871	49,158
Total costs and expenses	256,104	283,724	583,648	656,042
Equity earnings	1,443	1,478	2,810	3,126
Operating profit	128,666	167,281	245,386	290,094
Interest expense	25,988	29,118	52,474	58,241
Interest income	(1)	(29)	(11)	(64)
Interest capitalized	(1,190)	(1,028)	(1,861)	(1,892)
Debt placement fee amortization expense	385	518	770	1,037
Income before provision for income taxes	103,484	138,702	194,014	232,772
Provision for income taxes	485	881	950	1,427
Net income	$102,999	$137,821	$193,064	$231,345
Allocation of net income (loss):				
Non-controlling owners' interest	$—	$—	$(63)	$—
Limited partners' interest	102,999	137,821	193,127	231,345
Net income	$102,999	$137,821	$193,064	$231,345
Basic and diluted net income per limited partner unit	$0.91	$1.22	$1.71	$2.04
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	112,847	113,214	112,804	113,153

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2012	2011	2012
Net income	$102,999	$137,821	$193,064	$231,345
Other comprehensive income:				
Net gain on interest rate cash flow hedges	—	1,008	—	1,008
Net gain on commodity cash flow hedges	4,613	1,667	4,613	1,667
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Amortization of prior service credit and actuarial loss	77	853	155	1,705
Total other comprehensive income	4,649	3,487	4,686	4,298
Comprehensive income	107,648	141,308	197,750	235,643
Comprehensive loss attributable to non-controlling owners' interest in consolidated subsidiaries	—	—	(63)	—
Comprehensive income attributable to partners' capital	$107,648	$141,308	$197,813	$235,643

See notes to consolidated financial statements.

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

	December 31, 2011	June 30, 2012 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 209,620	$233,716
Trade accounts receivable (less allowance for doubtful accounts of $68 and $0 at December 31, 2011 and June 30, 2012, respectively)	82,497	82,201
Other accounts receivable	10,079	11,400
Inventory	258,860	215,667
Energy commodity derivatives contracts, net	4,914	13,878
Energy commodity derivatives deposits, net	26,917	8,239
Reimbursable costs	5,891	5,042
Other current assets	13,412	21,707
Total current assets	612,190	591,850
Property, plant and equipment	4,080,484	4,173,150
Less: accumulated depreciation	830,762	883,467
Net property, plant and equipment	3,249,722	3,289,683
Equity investments	35,594	51,439
Long-term receivables	2,534	3,097
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $14,813 and $15,955 at December 31, 2011 and June 30, 2012, respectively)	15,176	14,035
Debt placement costs (less accumulated amortization of $5,799 and $6,836 at December 31, 2011 and June 30, 2012, respectively)	14,615	13,578
Tank bottom inventory	59,473	55,025
Other noncurrent assets	2,437	3,022
Total assets	$ 4,045,001	$4,074,989
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 66,384	$67,235
Accrued payroll and benefits	30,184	21,696
Accrued interest payable	40,547	40,547
Accrued taxes other than income	27,570	24,856
Environmental liabilities	17,852	12,422
Deferred revenue	39,983	41,035
Accrued product purchases	59,800	55,142
Energy commodity derivatives deposits, net	—	17,196
Other current liabilities	28,735	19,144
Total current liabilities	311,055	299,273
Long-term debt	2,151,775	2,148,432
Long-term pension and benefits	67,080	69,771
Other noncurrent liabilities	19,905	15,283
Environmental liabilities	31,783	31,147
Commitments and contingencies		

Partners’ capital:		
Limited partner unitholders (112,737 units and 113,100 units outstanding at December 31, 2011 and June 30, 2012, respectively)	1,510,604	1,553,986
Accumulated other comprehensive loss	(47,201)	(42,903)
Total partners’ capital	1,463,403	1,511,083
Total liabilities and partners' capital	$ 4,045,001	$ 4,074,989

See notes to consolidated financial statements.

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

	Six Months Ended June 30, 2011	2012
Operating Activities:		
Net income	$193,064	$231,345
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	60,027	62,996
Debt placement fee amortization	770	1,037
Loss on sale, retirement and impairment of assets	7,106	7,359
Equity earnings	(2,810)	(3,126)
Distributions from equity investments	2,710	3,126
Equity-based incentive compensation expense	9,017	7,008
Amortization of prior service credit and actuarial loss	155	1,705
Changes in operating assets and liabilities:		
Restricted cash	14,379	—
Trade accounts receivable and other accounts receivable	9,830	(1,025)
Inventory	(69,588)	43,193
Energy commodity derivatives contracts, net of derivatives deposits	(14,159)	25,665
Reimbursable costs	5,925	849
Accounts payable	7,001	(9,882)
Accrued payroll and benefits	(7,220)	(8,488)
Accrued interest payable	372	—
Accrued taxes other than income	(3,412)	(2,714)
Accrued product purchases	(1,063)	(4,658)
Contingent liabilities	14,025	(805)
Current and noncurrent environmental liabilities	6,866	(6,066)
Other current and noncurrent assets and liabilities	(14,940)	(9,033)
Net cash provided by operating activities	218,055	338,486
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(95,273)	(108,098)
Proceeds from sale and disposition of assets	753	237
Increase in accounts payable related to capital expenditures	532	9,533
Acquisition of assets	(17,798)	—
Acquisition of non-controlling owners' interests	(40,500)	—
Equity investments	(3,500)	(15,872)
Distributions in excess of equity investment earnings	—	1,227
Other	(1,100)	—
Net cash used by investing activities	(156,886)	(112,973)
Financing Activities:		
Distributions paid	(172,205)	(187,181)
Net borrowings under revolver	135,000	—
Decrease in outstanding checks	(11,045)	(1,235)
Settlement of tax withholdings on long-term incentive compensation	(7,410)	(13,001)
Net cash used by financing activities	(55,660)	(201,417)

Change in cash and cash equivalents	5,509	24,096
Cash and cash equivalents at beginning of period	7,483	209,620
Cash and cash equivalents at end of period	$12,992	$233,716
Supplemental non-cash financing activity:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$4,315	$7,295

See notes to consolidated financial statements.

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

1. Organization and Basis of Presentation

Organization

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. We are a Delaware limited partnership and our limited partner units are traded on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC, a Delaware limited liability company that is wholly owned by us, serves as our general partner.

We operate and report in three business segments: the petroleum pipeline system, the petroleum 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.

Basis of Presentation

In the opinion of management, our accompanying consolidated financial statements, which are unaudited except for the consolidated balance sheet as of December 31, 2011, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2012, the results of operations for the three and six months ended June 30, 2011 and 2012 and cash flows for the six months ended June 30, 2011 and 2012. The results of operations for the six months ended June 30, 2012 are not necessarily indicative of the results to be expected for the full year ending December 31, 2012.

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, 2011.

2. Product Sales Revenues

The amounts reported as product sales revenues on our consolidated statements of income include revenues from the physical sale of petroleum products and mark-to-market adjustments from New York Mercantile Exchange ("NYMEX") contracts. We use NYMEX contracts to hedge against changes in the prices of petroleum products we expect to sell from our business activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these as either cash flow or fair value hedges. The effective portion of the fair value changes in contracts designated as cash flow hedges are recognized as adjustments to product sales when the hedged product is physically sold. Any ineffectiveness in these contracts is recognized as an adjustment to product sales in the period the ineffectiveness occurs. Changes in the fair value and any ineffectiveness of contracts designated as fair value hedges are recorded to other income/expense. We account for certain NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges, with the period changes in fair value recognized as product sales. See Note 7 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts.

For the three and six months ended June 30, 2011 and 2012, product sales revenues included the following (in thousands):

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2012	2011	2012
Physical sale of petroleum products	$157,793	$163,418	$433,422	$471,124
NYMEX contract adjustments:				
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment and the effective portion of gains and losses of matured NYMEX contracts that qualified for hedge accounting treatment associated with our petroleum products blending and fractionation activities(1)	(1,078)	27,850	(21,058)	2,961
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the Houston-to-El Paso pipeline section linefill working inventory(1)	3,228	9,020	(15,199)	1,921
Other	—	280	74	292
Total NYMEX contract adjustments	2,150	37,150	(36,183)	5,174
Total product sales revenues	$159,943	$200,568	$397,239	$476,298

(1) The associated petroleum products for these activities are, to the extent still owned as of the statement date, or were, to the extent no longer owned as of the statement date, classified as inventory in current assets on our consolidated balance sheets.

3. 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 used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. 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 depreciation and amortization expense and general and administrative ("G&A") expenses that management does not focus on when evaluating the core profitability of our separate operating segments.

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

	Three Months Ended June 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$161,168	$56,969	$5,755	$(700)	$223,192
Product sales revenues	152,891	7,140	—	(88)	159,943
Affiliate management fee revenue	192	—	—	—	192
Total revenues	314,251	64,109	5,755	(788)	383,327
Operating expenses	51,737	26,627	3,726	(767)	81,323
Product purchases	117,540	2,084	—	(788)	118,836
Equity earnings	(1,443)	—	—	—	(1,443)
Operating margin	146,417	35,398	2,029	767	184,611
Depreciation and amortization expense	19,291	10,243	363	767	30,664
G&A expenses	18,783	5,838	660	—	25,281
Operating profit	$108,343	$19,317	$1,006	$—	$128,666

	Three Months Ended June 30, 2012 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$178,757	$64,053	$6,659	$(708)	$248,761
Product sales revenues	193,040	7,699	—	(171)	200,568
Affiliate management fee revenue	198	—	—	—	198
Total revenues	371,995	71,752	6,659	(879)	449,527
Operating expenses	56,377	24,440	2,179	(670)	82,326
Product purchases	140,810	4,567	—	(879)	144,498
Equity earnings	(1,494)	16	—	—	(1,478)
Operating margin	176,302	42,729	4,480	670	224,181
Depreciation and amortization expense	19,875	10,516	425	670	31,486
G&A expenses	18,539	6,189	686	—	25,414
Operating profit	$137,888	$26,024	$3,369	$—	$167,281

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

	Six Months Ended June 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$305,230	$112,190	$12,787	$(1,607)	$428,600
Product sales revenues	379,879	17,558	—	(198)	397,239
Affiliate management fee revenue	385	—	—	—	385
Total revenues	685,494	129,748	12,787	(1,805)	826,224
Operating expenses	89,447	48,623	7,057	(1,443)	143,684
Product purchases	326,013	5,858	—	(1,805)	330,066
Equity earnings	(2,810)	—	—	—	(2,810)
Operating margin	272,844	75,267	5,730	1,443	355,284
Depreciation and amortization expense	37,843	20,014	727	1,443	60,027
G&A expenses	37,238	11,309	1,324	—	49,871
Operating profit	$197,763	$43,944	$3,679	$—	$245,386

	Six Months Ended June 30, 2012 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$327,487	$127,233	$13,008	$(1,413)	$466,315
Product sales revenues	459,297	17,464	—	(463)	476,298
Affiliate management fee revenue	397	—	—	—	397
Total revenues	787,181	144,697	13,008	(1,876)	943,010
Operating expenses	102,931	44,622	4,629	(1,404)	150,778
Product purchases	385,691	9,295	—	(1,876)	393,110
Equity earnings	(3,163)	37	—	—	(3,126)
Operating margin	301,722	90,743	8,379	1,404	402,248
Depreciation and amortization expense	39,538	21,245	809	1,404	62,996
G&A expenses	35,994	11,855	1,309	—	49,158
Operating profit	$226,190	$57,643	$6,261	$—	$290,094

4. Inventory

Inventory at December 31, 2011 and June 30, 2012 was as follows (in thousands):

	December 31, 2011	June 30, 2012
Refined petroleum products	$127,999	$81,655
Natural gas liquids	55,490	60,984
Transmix	60,251	53,067
Crude oil	8,065	12,116
Additives	7,055	7,845
Total inventory	$258,860	$215,667

The decrease in refined petroleum products was primarily due to the reduction in volumes of our Houston-to-El Paso linefill inventory.

5. Employee Benefit Plans

We sponsor two union pension plans for certain employees and a pension plan primarily for salaried 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 these plans for the three and six months ended June 30, 2011 and 2012 (in thousands):

	Three Months Ended June 30, 2011		Three Months Ended June 30, 2012	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$1,985	$91	$3,190	$137
Interest cost	950	260	1,204	258
Expected return on plan assets	(1,022)	—	(1,176)	—
Amortization of prior service cost (credit)	77	(213)	77	(211)
Amortization of actuarial loss	151	62	826	161
Net periodic benefit cost	$2,141	$200	$4,121	$345

	Six Months Ended June 30, 2011		Six Months Ended June 30, 2012	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$3,970	$182	$6,380	$275
Interest cost	1,899	519	2,407	515
Expected return on plan assets	(2,043)	—	(2,352)	—
Amortization of prior service cost (credit)	154	(426)	154	(424)
Amortization of actuarial loss	302	125	1,653	322

Net periodic benefit cost	$4,282	$400	$8,242	$688

Net periodic benefit costs for the pension plans increased in 2012 primarily due to a decrease in the discount rate at December 31, 2011.
Contributions estimated to be paid into the plans in 2012 are $13.3 million and $0.3 million for the pension and other

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postretirement benefit plans, respectively.

6. Debt

Consolidated debt at December 31, 2011 and June 30, 2012 was as follows (in thousands):

	December 31, 2011	June 30, 2012	Weighted-Average Interest Rate at June 30, 2012 (a)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,844	249,874	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,823	5.6%
$250.0 million of 6.40% Notes due 2018	263,477	262,445	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	576,804	5.6%
$550.0 million of 4.25% Notes due 2021	558,932	558,514	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,972	6.4%
Total debt	$2,151,775	$2,148,432	5.3%

(a) Weighted-average interest rate includes the impact of interest rate swaps, the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges on interest expense (see Note 7—Derivative Financial Instruments for detailed information regarding fair value hedges and interest rate swaps).

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2011 and June 30, 2012 was $2.1 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various terminated fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings, which was 0.2% at June 30, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of June 30, 2012, there were no borrowings outstanding under this facility and $5.0 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

7. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities produce gasoline products, and we can estimate the timing and quantities of sales of these products. We use a combination of forward purchase and sale contracts, NYMEX contracts and butane swap agreements to help manage price changes, which has the effect of locking in most of the product margin realized from our blending activities that we choose to hedge.

We account for the forward purchase and sale contracts we use in our blending and fractionation activities as normal 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, 2012, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Amount	Barrels
Forward purchase contracts	$41.2	0.6
Forward sale contracts	$27.4	0.3

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. Our NYMEX contracts fall into one of three categories:

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

Hedge Type	Hedge Purpose	Accounting Treatment
Qualifies For Hedge Accounting Treatment		
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the value of the hedge are recorded to accumulated other comprehensive income/loss and reclassified to earnings when the forecasted transaction occurs. Any ineffectiveness is recognized currently in earnings.
Fair Value Hedge	To hedge against changes in the fair value of a recognized asset or liability.	The effective portion of changes in the value of the hedge are recorded as adjustments to the asset or liability being hedged. Any ineffectiveness is recognized currently in earnings.
Does Not Qualify For Hedge Accounting Treatment		
Economic Hedge	To effectively serve as either a fair value or a cash flow hedge; however, the derivative agreement does not qualify for hedge accounting treatment or is not designated as a hedge in accordance with Accounting Standards Codification ("ASC") 815, Derivatives and Hedging.	Changes in the value of these agreements are recognized currently in earnings.

We also use butane swap agreements, which are not designated as hedges for accounting purposes, to hedge against changes in the price of selected butane purchases we expect to complete in the future. Changes in the fair value of these agreements are recognized currently in earnings. As outlined in the table below, we had the following open NYMEX contracts at June 30, 2012:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between August 2012 and November 2013
NYMEX - Economic Hedges	2.6 million barrels of refined petroleum products	Between July 2012 and April 2013
NYMEX - Cash Flow Hedges	0.1 million barrels of refined petroleum products	September 2012
Butane Swap Agreements - Economic Hedges	0.4 million barrels of butane	Between August 2012 and March 2013

At June 30, 2012, we held $17.2 million in margin deposits for our NYMEX contracts, which were recorded as a current liability under energy commodity derivatives deposits on our consolidated balance sheet. We have the right to offset the combined fair values of our open NYMEX contracts and our open butane swap agreements against our margin deposits under a master netting arrangement with each of our counterparties; however, we have elected to disclose the combined fair values of our open NYMEX and butane swap agreements separately from the related margin deposits on our consolidated balance sheet. Additionally, we have the right to offset the fair values of our NYMEX agreements and butane swap agreements together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets.

Interest Rate Derivatives

In June 2012, we entered into a total of $100.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.7% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance. We account for these agreements as cash flow hedges.

Impact of Derivatives on Income Statement, Balance Sheet and AOCL

The changes in derivative activity included in accumulated other comprehensive loss ("AOCL") for the three and six

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months ended June 30, 2011 and 2012 were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Gains Included in AOCL	2011	2012	2011	2012
Beginning balance	$3,284	$3,120	$3,325	$3,161
Net gain on interest rate cash flow hedges	—	1,008	—	1,008
Net gain on commodity cash flow hedges	4,613	1,667	4,613	1,667
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Ending balance	$7,856	$5,754	$7,856	$5,754

As of June 30, 2012, the net gain estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million and $1.7 million, respectively.

The following table provides a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2011 of derivatives accounted for under ASC 815-25, Derivatives and Hedging—Fair Value Hedges, that were designated as hedging instruments (in thousands):

	Location of Gain Recognized on Derivative	Amount of Gain Recognized on Derivative		Amount of Interest Expense Recognized on Fixed-Rate Debt (Related Hedged Item)	
Derivative Instrument		Three Months Ended June 30, 2011	Six Months Ended	Three Months Ended	Six Months Ended
Interest rate swap agreements	Interest expense	$808	$1,011	$4,001	$6,223

During 2012, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. Because there was no ineffectiveness recognized on these hedges, the unrealized losses of $1.9 million from the agreements as of June 30, 2012 were fully offset by an increase of $2.0 million to tank bottom inventory and a decrease of $0.1 million to other current assets; therefore, there was no net impact from these agreements on other income/expense.
The following tables provide a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2011 and 2012 of the effective portion of derivatives accounted for under ASC 815-30, Derivatives and Hedging—Cash Flow Hedges, that were designated as hedging instruments (in thousands).

	Three Months Ended June 30, 2011		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$ 41
NYMEX commodity contracts	4,613	Product sales revenues	—
Total cash flow hedges	$4,613	Total	$ 41

	Three Months Ended June 30, 2012
Derivative Instrument	

	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$1,008	Interest expense	$ 41
NYMEX commodity contracts	1,667	Product sales revenues	—
Total cash flow hedges	$2,675	Total	$ 41

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Six Months Ended June 30, 2011		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$ 82
NYMEX commodity contracts	4,613	Product sales revenues	—
Total cash flow hedges	$4,613	Total	$ 82

	Six Months Ended June 30, 2012		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$1,008	Interest expense	$ 82
NYMEX commodity contracts	1,667	Product sales revenues	—
Total cash flow hedges	$2,675	Total	$ 82

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the three and six months ended June 30, 2011 or 2012.

The following table provides a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2011 and 2012 of derivatives accounted for under ASC 815-10-35; Derivatives and Hedging—Overall—Subsequent Measurement, that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivative			
		Three Months Ended		Six Months Ended	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	June 30, 2011	June 30, 2012	June 30, 2011	June 30, 2012
NYMEX commodity contracts	Product sales revenues	$2,150	$37,150	$(36,183)	$5,174
NYMEX commodity contracts	Operating expenses	1,568	9,701	1,521	4,517
Butane swap agreements	Product purchases	(839)	(4,670)	(839)	(4,627)
	Total	$2,879	$42,181	$(35,501)	$5,064

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2011 and June 30, 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$31	Energy commodity derivatives contracts	$—
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	6,457
	Total	$31	Total	$6,457

	June 30, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$1,790	Energy commodity derivatives contracts	$—
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	2,008
	Other noncurrent assets	1,008	Other noncurrent liabilities	—

Forward-starting interest rate swap agreements				
	Total	$2,798	Total	$2,008

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, Derivatives and

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Hedging, which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2011 and June 30, 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$6,403	Energy commodity derivatives contracts	$1,514
Butane swap agreements	Energy commodity derivatives contracts	28	Energy commodity derivatives contracts	34
	Total	$6,431	Total	$1,548

	June 30, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$21,912	Energy commodity derivatives contracts	$5,149
Butane swap agreements	Energy commodity derivatives contracts	—	Energy commodity derivatives contracts	4,675
	Total	$21,912	Total	$9,824

8. Commitments and Contingencies

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states under certain conditions to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. The Environmental Protection Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality ("TCEQ") drafted a “Failure to Attain Rule” to implement the requirements of CAA 185. The initial Failure to Attain Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule. The initial Failure to Attain Rule was rejected by a federal court decision in July 2011. The TCEQ is now considering a new rule.

Management believes it is probable that the TCEQ will move forward with a new CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility no CAA 185 fees will be assessed to us for the period of 2008 through 2010. However, management believes it is probable we will be assessed fees for excess emissions at our Houston-area facilities for that period and estimates that the range of fees that could be assessed to us to be between $6.4 million and $13.7 million. We have recorded an accrual of $8.9 million related to this matter for the period of 2008 through 2010. This accrual is reflected as a long-term environmental liability at June 30, 2012.

Osage Complaint

On June 25, 2012, HollyFrontier Refining & Marketing LLC (“HollyFrontier”) filed a complaint with the Federal Energy Regulatory Commission ("FERC") alleging that Osage Pipe Line Company, LLC (“Osage”) has been over-earning on its rates for transportation on Osage's crude oil pipeline system from Cushing, Oklahoma to El Dorado, Kansas. We own 50% of Osage and serve as its operator. We believe that it is reasonably possible that Osage could incur a liability as a result of this complaint. As a 50% owner of Osage, we currently estimate that our ultimate exposure in this matter will be within a range of zero to approximately $5.5 million. We believe the claims should be denied and are defending the Osage rates vigorously.

MF Global Holdings Ltd. Bankruptcy

In October 2011, MF Global Holdings Ltd., the parent of MF Global Inc. (“MF Global”), filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy laws, and a trustee was appointed to oversee the liquidation of MF Global under the Securities Investor Protection Act ("SIPA"). At that time, MF Global served as our sole clearing agent for NYMEX futures contracts.

The Chicago Mercantile Exchange (“CME”) requires us to maintain adequate margin against our NYMEX positions, which our clearing agent is required to hold on our behalf in a segregated account. In October 2011, MF Global disclosed to the CME that it had a “significant shortfall” in its segregated customer accounts. We transferred our existing trading positions at MF Global to a new clearing agent in November 2011, and all of our NYMEX activity is now being conducted with a different clearing agent.

As of the date of transfer of our account, MF Global owed us $29.4 million; however, we have subsequently received $21.2 million as partial payment on our account. We have submitted a claim with the Trustee for the SIPA liquidation of MF Global for $8.2 million, which represents the remaining amount owed to us by MF Global. At this point it is uncertain what additional funds MF Global will have available for distribution to its former customers as well as how the claims against MF Global's remaining assets may be prioritized. As of June 30, 2012, we have not reserved any of our MF Global receivable balance.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $49.6 million and $43.6 million at December 31, 2011 and June 30, 2012, respectively. We have classified environmental liabilities 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 10 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 expenses were $8.6 million and $0.1 million for the three months ended June 30, 2011 and 2012, respectively, and $12.5 million and $2.7 million for the six months ended June 30, 2011 and 2012, respectively. The higher environmental expenses in 2011 were primarily due to the CAA 185 liability accrual (described above).

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2011 were $7.7 million, of which $5.2 million and $2.5 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers related to environmental matters at June 30, 2012 were $7.8 million, of which $4.7 million and $3.1 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets.

Unrecognized Product Gains

Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies and product evaporation, expansion, releases and 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 terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum 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 terminals operations had a market value of approximately $2.8 million as of June 30, 2012. 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 net future product shortages.

Other

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes 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 results of operations, financial position or cash flows.

9. Long-Term Incentive Plan

We have a long-term incentive plan ("LTIP") for certain of our employees and for directors of our general partner. The LTIP primarily consists of phantom units and, as of June 30, 2012, permits the grant of awards covering an aggregate of

4.7 million of our limited partner units. The remaining units available under the LTIP at June 30, 2012 total 1.2 million. The compensation committee of our general partner's board of directors administers our LTIP.

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

	Three Months Ended June 30, 2011			Six Months Ended June 30, 2011		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2009 awards	$2,308	$1,583	$3,891	$3,235	$2,205	$5,440
2010 awards	387	165	552	1,337	519	1,856
2011 awards	562	144	706	1,124	289	1,413
Retention awards	118	—	118	308	—	308
Total	$3,375	$1,892	$5,267	$6,004	$3,013	$9,017
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$4,663			$8,320
Operating expense			604			697
Total			$5,267			$9,017

	Three Months Ended June 30, 2012			Six Months Ended June 30, 2012		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2010 awards	$1,655	$770	$2,425	$2,177	$1,178	$3,355
2011 awards	684	182	866	1,427	455	1,882
2012 awards	569	147	716	1,130	298	1,428
Retention awards	158	—	158	343	—	343
Total	$3,066	$1,099	$4,165	$5,077	$1,931	$7,008
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$3,715			$6,220
Operating expense			450			788
Total			$4,165			$7,008

10. Distributions

Distributions we paid during 2011 and 2012 were as follows (in thousands, except per unit amounts):

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Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/14/2011	$0.7575	$85,398
5/13/2011	0.7700	86,807
Through 6/30/2011	1.5275	172,205
8/12/2011	0.7850	88,498
11/14/2011	0.8000	90,189
Total	$3.1125	$350,892
2/14/2012	$0.8150	$92,177
5/15/2012	0.8400	95,004
Through 6/30/2012	1.6550	187,181
8/14/2012[a]	0.9425	106,597
Total	$2.5975	$293,778

(a) Our general partner's board of directors declared this cash distribution on July 26, 2012 to be paid on August 14, 2012 to unitholders of record at the close of business on August 7, 2012.

11. Fair Value

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 on our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.
- Energy commodity derivatives deposits. This asset (liability) represents short-term deposits we paid (held) associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits paid (held) change daily in relation to the change in value of the associated contracts.
- Long-term receivables. Fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest.
- Energy commodity derivatives contracts. These include NYMEX and butane swap purchase agreements related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 7 - Derivative Financial Instruments for further disclosures regarding these contracts.
- Forward-starting interest rate swap agreements. Fair value was determined based on an assumed exchange, at the end of each period, in an orderly transaction with a market participant in the market in which the financial instrument is traded, adjusted for the effect of counterparty credit risk. We calculated the exchange value using present value techniques on estimated future cash flows based on forward interest rate curves.
- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2011 and June 30, 2012. The carrying amount of borrowings, if any, under our revolving credit facility approximates fair value due to the variable rates of that instrument.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2011 and June 30, 2012 (in thousands):

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Assets (Liabilities)	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value	June 30, 2012 Carrying Amount	June 30, 2012 Fair Value
Cash and cash equivalents	$209,620	$209,620	$233,716	$233,716
Energy commodity derivatives deposits (current assets)	$26,917	$26,917	$8,239	$8,239
Energy commodity derivatives deposits (current liabilities)	$—	$—	$(17,196)	$(17,196)
Long-term receivables	$2,534	$2,510	$3,097	$3,065
Energy commodity derivatives contracts (current assets)	$4,914	$4,914	$13,878	$13,878
Forward-starting interest rate swap agreements (noncurrent)	$—	$—	$1,008	$1,008
Energy commodity derivatives contracts (noncurrent liabilities)	$(6,457)	$(6,457)	$(2,008)	$(2,008)
Debt	$(2,151,775)	$(2,389,700)	$(2,148,432)	$(2,426,955)

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our long-term receivables, NYMEX commodity contracts, forward-starting interest rate swap agreements and debt as of December 31, 2011 and June 30, 2012, based on the three levels established by ASC 820-10-50; Fair Value Measurements and Disclosures—Overall—Disclosure (in thousands):

Assets (Liabilities)	Total	Fair Value Measurements as of December 31, 2011 using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term receivables	$2,510	$—	$—	$2,510
Energy commodity derivatives contracts (current assets)	$4,914	$4,914	$—	$—
Energy commodity derivatives contracts (noncurrent liabilities)	$(6,457)	$(6,457)	$—	$—
Debt	$(2,389,700)	$(2,389,700)	$—	$—

Assets (Liabilities)	Total	Fair Value Measurements as of June 30, 2012 using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term receivables	$3,065	$—	$—	$3,065
Energy commodity derivatives contracts (current assets)	$13,878	$13,878	$—	$—
	$1,008	$—	$1,008	$—

Forward-starting interest rate swap agreements (noncurrent)				
Energy commodity derivatives contracts (noncurrent liabilities)	$(2,008)	$(2,008)	$—	$—
Debt	$(2,426,955)	$(2,426,955)	$—	$—

12. Related Party Transactions

We own a 50% interest in Osage and receive a management fee for the operation of its crude oil pipeline. We received management fees from this company of $0.2 million for each of the three months ended June 30, 2011 and 2012, and $0.4

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million for each of the six months ended June 30, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which is in the process of constructing 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. Upon completion, these tanks will be leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have agreed to construct certain infrastructure assets at our Galena Park terminal which will allow for the operation of the tanks under construction by Texas Frontera. During 2012, the construction funding requests sent to us from Texas Frontera were $3.7 million, of which we paid $2.5 million in cash and $1.2 million was applied against our capital spending for the infrastructure assets under construction. We expect these assets to be fully operational by the end of 2012.

We own a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. During 2012, we paid construction funding requests to Double Eagle of $13.0 million. We expect these assets to be fully operational in mid-2013.

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase petroleum products from subsidiaries of Targa. For the three months ended June 30, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of less than $0.1 million and $0.3 million, respectively. For the six months ended June 30, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.5 million, respectively. These purchases were made on the same terms as comparable third-party transactions.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards that would otherwise have been forfeited would not be forfeited. Expense associated with these awards for the six months ended June 30, 2011 and 2012 was $1.9 million and $0.2 million, respectively.

13. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In July 2012, we entered into an additional $150.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our 6.45% notes due June 1, 2014. Including the $100.0 million of interest rate swap agreements entered into in June 2012 (see Note 7—Derivative Financial Instruments), we have fully hedged the $250.0 million of notes we expect to issue. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance. We account for these agreements as cash flow hedges.

In July 2012, we received a payment of $2.4 million on the amount owed to us by MF Global (see Note 8—Commitments and Contingencies), resulting in a remaining balance owed to us of $5.8 million.

In July 2012, our general partner's board of directors declared a quarterly distribution of $0.9425 per unit to be paid on August 14, 2012 to unitholders of record at the close of business on August 7, 2012. The total cash distributions to be paid are $106.6 million.

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

Introduction

We are a publicly traded limited partnership principally engaged in the transportation, storage and distribution of petroleum products. As of June 30, 2012, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 50 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) 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, 2011.

Recent Developments

Interest Rate Swap. In June and July 2012, we entered into a total of $100.0 million and $150.0 million, respectively, of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance. We account for these agreements as cash flow hedges.

Cash Distribution. In July 2012, the board of directors of our general partner declared a quarterly cash distribution of $0.9425 per unit for the period of April 1, 2012 through June 30, 2012. This quarterly cash distribution will be paid on August 14, 2012 to unitholders of record on August 7, 2012. Total distributions to be paid under this declaration are approximately $106.6 million.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. 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 following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP.

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Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2012

	Three Months Ended June 30,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$161.1	$178.8	$17.7	11
Petroleum terminals	57.0	64.0	7.0	12
Ammonia pipeline system	5.8	6.7	0.9	16
Intersegment eliminations	(0.7)	(0.8)	(0.1)	(14)
Total transportation and terminals revenues	223.2	248.7	25.5	11
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum pipeline system	51.7	56.3	(4.6)	(9)
Petroleum terminals	26.6	24.4	2.2	8
Ammonia pipeline system	3.8	2.1	1.7	45
Intersegment eliminations	(0.8)	(0.5)	(0.3)	(38)
Total operating expenses	81.3	82.3	(1.0)	(1)
Product margin:				
Product sales revenues	159.9	200.6	40.7	25
Product purchases	118.8	144.5	(25.7)	(22)
Product margin[(a)]	41.1	56.1	15.0	36
Equity earnings	1.4	1.5	0.1	7
Operating margin	184.6	224.2	39.6	21
Depreciation and amortization expense	30.6	31.5	(0.9)	(3)
G&A expense	25.3	25.4	(0.1)	—
Operating profit	128.7	167.3	38.6	30
Interest expense (net of interest income and interest capitalized)	24.8	28.1	(3.3)	(13)
Debt placement fee amortization expense	0.4	0.5	(0.1)	(25)
Income before provision for income taxes	103.5	138.7	35.2	34
Provision for income taxes	0.5	0.9	(0.4)	(80)
Net income	$103.0	$137.8	$34.8	34
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.097	$1.126		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	52.3	56.1		
Distillates	32.9	33.6		
Aviation fuel	7.7	5.2		
Liquefied petroleum gases	2.2	3.7		
Crude oil	10.2	17.2		
Total volume shipped	105.3	115.8		
Petroleum terminals:				
Storage terminal average utilization (million barrels per month)	31.1	34.8		

Inland terminal throughput (million barrels)	29.3	29.9
Ammonia pipeline system:		
Volume shipped (thousand tons)	191	193

(a) Product margin does not include depreciation or amortization expense.
(b) Excludes capacity leases.

Transportation and terminals revenues increased $25.5 million, primarily resulting from:

- an increase in petroleum pipeline system revenues of $17.7 million resulting from:
  - a 10% increase in transportation volumes primarily due to increases in gasoline and crude volumes. Gasoline volumes increased 7% attributable to an increase in consumer demand principally due to the impact of lower gasoline prices. Crude volumes increased 69% resulting from deliveries to additional customers that have been connected to our pipeline system and increased deliveries to existing customers;
  - a 3% increase in the average tariff as the 7% rate increase we implemented on July 1, 2011 was partially offset by more short-haul movements, in part due to significantly higher crude volumes, which ship at a lower rate than our other pipeline shipments; and
  - increased demand for pipeline capacity, storage leases and additive services.
- an increase in petroleum terminals revenues of $7.0 million primarily due to leasing newly-constructed tanks that were fully operational after second quarter 2011, including the new crude oil storage we built in Cushing, Oklahoma and higher rates at our marine terminals; and
- an increase in ammonia pipeline system revenues of $0.9 million primarily because of a higher weighted-average tariff in the current quarter.

Operating expenses increased $1.0 million, resulting from:

- an increase in petroleum pipeline system expenses of $4.6 million primarily due to lower product overages (which reduce operating expenses) and more maintenance projects in the current period, partially offset by impairment charges in second quarter 2011 for a system terminal we closed and a potential air emission fee accrual in second quarter 2011;
- a decrease in petroleum terminals expenses of $2.2 million primarily due to an accrual recognized in second quarter 2011 for potential air emission fees, partially offset by higher asset integrity costs in the current quarter; and
- a decrease in ammonia pipeline system expenses of $1.7 million primarily due to lower asset integrity costs now that our hydrostatic testing procedures are complete.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize New York Mercantile Exchange (“NYMEX”) contracts to hedge against changes in the price of petroleum products we expect to sell in the future. The period change in the mark-to-market value of these contracts that are not designated as hedges for accounting purposes, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenues. We use butane swap agreements to hedge against changes in the price of butane we expect to purchase in future periods. The period change in the mark-to-market value of these swap agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin increased $15.0 million primarily due to increased profits from our petroleum products blending activities mostly due to an increase in volumes, increased unrealized gains on NYMEX contracts due to a sharp decline in product prices at the end of the current quarter and increased revenues resulting from our linefill management activities, partially offset by decreased margins from our transmix fractionation and decreased terminal product gains.

Depreciation and amortization expense increased $0.9 million primarily due to expansion capital projects placed into service since second quarter 2011.

Interest expense, net of interest income and interest capitalized, increased $3.3 million. Our average debt outstanding increased to $2.1 billion for second quarter 2012 from $2.0 billion for second quarter 2011 principally due to borrowings for expansion capital expenditures, including $250.0 million of 4.25% senior notes issued in August 2011. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, was 5.3% in both second quarters of 2011 and 2012.

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	Six Months Ended June 30,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$305.2	$327.5	$22.3	7
Petroleum terminals	112.2	127.2	15.0	13
Ammonia pipeline system	12.8	13.0	0.2	2
Intersegment eliminations	(1.6)	(1.4)	0.2	13
Total transportation and terminals revenues	428.6	466.3	37.7	9
Affiliate management fee revenue	0.4	0.4	—	—
Operating expenses:				
Petroleum pipeline system	89.4	102.9	(13.5)	(15)
Petroleum terminals	48.6	44.6	4.0	8
Ammonia pipeline system	7.1	4.6	2.5	35
Intersegment eliminations	(1.4)	(1.3)	(0.1)	(7)
Total operating expenses	143.7	150.8	(7.1)	(5)
Product margin:				
Product sales revenues	397.2	476.3	79.1	20
Product purchases	330.0	393.1	(63.1)	(19)
Product margin[(a)]	67.2	83.2	16.0	24
Equity earnings	2.8	3.1	0.3	11
Operating margin	355.3	402.2	46.9	13
Depreciation and amortization expense	60.0	63.0	(3.0)	(5)
G&A expense	49.9	49.1	0.8	2
Operating profit	245.4	290.1	44.7	18
Interest expense (net of interest income and interest capitalized)	50.6	56.3	(5.7)	(11)
Debt placement fee amortization expense	0.8	1.0	(0.2)	(25)
Income before provision for income taxes	194.0	232.8	38.8	20
Provision for income taxes	0.9	1.5	(0.6)	(67)
Net income	$193.1	$231.3	$38.2	20
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.071	$1.094		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	104.7	102.0		
Distillates	62.5	63.4		
Aviation fuel	12.8	10.8		
Liquefied petroleum gases	3.1	4.7		
Crude oil	17.2	32.1		
Total volume shipped	200.3	213.0		
Petroleum terminals:				
Storage terminal average utilization (million barrels per month)	30.5	34.8		
Inland terminal throughput (million barrels)	56.9	58.0		
Ammonia pipeline system:				
Volume shipped (thousand tons)	412	382		

(a) Product margin does not include depreciation or amortization expense.
(b) Excludes capacity leases.

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Transportation and terminals revenues increased $37.7 million, primarily resulting from:

- an increase in petroleum pipeline system revenues of $22.3 million resulting from:
  - a 6% increase in transportation volumes primarily due to an increase in crude volumes resulting from deliveries to additional customers that have been connected to our pipeline system and increased deliveries to existing customers;
  - a 2% increase in the average tariff as the 7% rate increase we implemented on July 1, 2011 was partially offset by more short-haul movements, in part due to significantly higher crude volumes, which ship at a lower rate than our other pipeline shipments; and
  - increased demand for pipeline capacity, storage leases and additive services.
- an increase in petroleum terminals revenues of $15.0 million primarily due to leasing newly-constructed tanks that were fully operational throughout 2011, including the new crude oil storage we built in Cushing, Oklahoma, and higher rates at our marine terminals; and
- an increase in ammonia pipeline system revenues of $0.2 million due to higher terminalling revenues.

Operating expenses increased $7.1 million, resulting from:

- an increase in petroleum pipeline system expenses of $13.5 million primarily due to higher asset integrity costs, lower product overages (which reduce operating expenses), higher property taxes and higher compensation costs, which were partially offset by impairment charges in 2011 for a system terminal we closed and a potential air emission fee accrual in 2011;
- a decrease in petroleum terminals expenses of $4.0 million primarily due to an accrual recognized in 2011 for potential air emission fees with no corresponding charge in the current period, insurance reimbursements received in 2012 for a hurricane-related claim and lower environmental costs, partially offset by higher asset integrity costs; and
- a decrease in ammonia pipeline system expenses of $2.5 million primarily due to lower asset integrity costs and environmental accruals in the current period.

Product margin increased $16.0 million primarily due to higher profits from our petroleum products blending activities due to both higher volumes and higher product prices. Additionally, higher revenues from our linefill management activities, partially offset by lower margins from our transmix fractionation and lower terminal product gains, contributed to the favorable product margin variance.

Depreciation and amortization expense increased $3.0 million primarily due to expansion capital projects placed into service over the past year.

G&A expense decreased $0.8 million primarily due to lower equity-based incentive compensation expense and consulting fees, partially offset by higher compensation costs.

Interest expense, net of interest income and interest capitalized, increased $5.7 million. Our average debt outstanding increased to $2.1 billion for 2012 from $1.9 billion for 2011 primarily due to borrowings for expansion capital expenditures, including $250.0 million of 4.25% senior notes issued in August 2011. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.3% in 2012 from 5.4% in 2011.

Distributable Cash Flow

Distributable cash flow and adjusted EBITDA are non-GAAP measures that management uses to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this distributable cash flow measure as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. We believe that investors benefit from having access to the same financial measures utilized by management for these evaluations. A reconciliation of distributable cash flow and adjusted EBITDA for the six months ended June 30, 2011 and 2012 to net income, which is its nearest comparable GAAP financial measure, was as follows (in millions):

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	Six Months Ended June 30,		Increase
	2011	2012	(Decrease)
Net income	$193.1	$231.3	$38.2
Interest expense, net	50.6	56.3	5.7
Depreciation and amortization[(1)]	60.8	64.0	3.2
Equity-based incentive compensation expense[(2)]	1.6	(6.0)	(7.6)
Asset retirements and impairments	7.1	7.4	0.3
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions[(3)]	8.8	(17.9)	(26.7)
Derivative losses recognized in previous periods associated with products sold in the period[(4)]	(12.0)	(4.2)	7.8
Lower-of-cost-or-market adjustments	—	3.1	3.1
Houston-to-El Paso cost of sales adjustments[(5)]	(3.9)	8.1	12.0
Total commodity-related adjustments	(7.1)	(10.9)	(3.8)
Other	(0.7)	0.5	1.2
Adjusted EBITDA	305.4	342.6	37.2
Interest expense, net	(50.6)	(56.3)	(5.7)
Maintenance capital	(19.4)	(26.7)	(7.3)
Distributable cash flow	$235.4	$259.6	$24.2

(1) Depreciation and amortization includes debt placement fee amortization.

(2) Because we intend to satisfy vesting of units under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for distributable cash flow purposes. Total equity-based incentive compensation expense for the six months ended June 30, 2011 and 2012 was $9.0 million and $7.0 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2011 and 2012 of $7.4 million and $13.0 million, respectively, for equity-based incentive compensation units that vested on the previous year end, which reduce distributable cash flow.

(3) Derivatives we use as economic hedges that have not been designated as hedges for accounting purposes. These amounts represent the gains or losses from these economic hedges recognized in our earnings for products that had not physically sold as of the period end date.

(4) These amounts represent, for products physically sold in the reporting period, the gains or losses from the associated commodity derivative agreements recognized in our earnings during periods prior to these reporting periods..

(5) Cost of goods sold adjustment related to commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for distributable cash flow purposes rather than average inventory costing as used to determine our results of operations.

Distributable cash flow increased by $24.2 million. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above, the change in equity-based compensation is discussed in footnote 2 to the table above and a discussion of our maintenance capital expenditures is provided in Capital Requirements below. The change in distributable cash flow from commodity-related adjustments is primarily due to the impact of product price changes during each period on economic hedges that do not qualify for hedge accounting treatment.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $218.1 million and $338.5 million for the six months ended June 30, 2011 and 2012, respectively. The $120.4 million increase from 2011 to 2012 was primarily attributable to:

- a $38.2 million increase in net income;
- a $112.8 million increase primarily resulting from higher prices and volumes of inventory purchases in 2011 as compared to 2012; specifically, a $43.2 million decrease in inventory in 2012 versus a $69.6 million increase in inventory in 2011; and
- a $39.9 million increase resulting from a $25.7 million increase in energy commodity derivatives contracts, net of decreased derivatives deposits in 2012, versus a $14.2 million decrease in energy commodity derivatives

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contracts, net of increased derivatives deposits in 2011 primarily due to lower product prices and a decrease in the number of NYMEX commodity contracts during 2012.

These increases were partially offset by:

- a $16.9 million decrease resulting from a $9.9 million decrease in accounts payable in 2012 versus a $7.0 million increase in accounts payable in 2011 primarily due to the timing of invoices paid to vendors and suppliers;
- a $14.4 million decrease due to a change in restricted cash. During first quarter 2011, we acquired the non-controlling owner's interest in one of our subsidiaries, which removed our restriction to that entity's cash. As a result of that transaction, cash from operations increased $14.4 million in 2011;
- a $13.0 million decrease resulting from a $6.1 million decrease in current and noncurrent environmental liabilities in 2012 versus a $6.9 million increase in current and noncurrent environmental liabilities in 2011 primarily due to our CAA 185 contingent liability accrual (see Environmental below for further details regarding this matter) during 2011; and
- a $10.8 million decrease resulting from a $1.0 million increase in accounts receivable and other accounts receivable in 2012 versus a $9.8 million decrease during 2011 primarily due to timing of payments from our customers.

Net cash used by investing activities for the six months ended June 30, 2011 and 2012 was $156.9 million and $113.0 million, respectively. During 2012, we spent $108.1 million for capital expenditures, which included $26.7 million for maintenance capital and $81.4 million for expansion capital. Also during 2012, we paid $15.9 million for growth projects in conjunction with our joint venture partners. During 2011, we spent $95.3 million for capital expenditures, which included $19.4 million for maintenance capital and $75.9 million for expansion capital. Also during 2011, we acquired a private investment group's common equity in MCO for $40.5 million and spent $17.8 million on various asset acquisitions.

Net cash used by financing activities for the six months ended June 30, 2011 and 2012 was $55.7 million and $201.4 million, respectively. During 2012, we paid cash distributions of $187.2 million to our unitholders. During 2011, we paid cash distributions of $172.2 million to our unitholders while net borrowings on our revolving credit facility, primarily to finance expansion capital projects and the MCO buyout noted above, were $135.0 million.

The quarterly distribution amount related to our second-quarter 2012 financial results (to be paid in third quarter 2012) is $0.9425 per unit, which is a 20% increase over the distribution paid for second-quarter 2011 financial results. Taking into account the current distribution amount, management has increased its targeted distribution growth for 2012 to 18%. Assuming the number of outstanding limited partner units remains at 113.1 million, total cash distributions of approximately $423.3 million will be paid to our unitholders related to 2012.

In January 2012, the cumulative amounts of the January 2009 equity-based incentive compensation award grants were settled by issuing 361,383 limited partner units and distributing those units to the participants. Associated tax withholdings of $13.0 million and employer taxes of $1.3 million were paid in January 2012.

Capital Requirements

Our businesses require continual investment to maintain, upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending 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 capacity or develop pipeline connections to new supply sources.

For the six months ended June 30, 2011 and 2012, our maintenance capital spending was $19.4 million and $26.7 million, respectively. The pace of spending on projects in the current year has been accelerated from 2011; however, by the end of 2012 we expect to incur maintenance capital expenditures for our existing businesses of approximately $65.0 million, which is less than the prior year.

During the first six months of 2012, we spent $81.4 million for organic growth capital and $15.9 million for growth projects in conjunction with our joint venture partners. Based on the progress of expansion projects already underway,

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including the reversal and conversion of our Crane-to-Houston pipeline to crude oil, we expect to spend approximately $500.0 million for expansion capital during 2012, with an additional $200.0 million in 2013 to complete these projects.

Liquidity

Consolidated debt at December 31, 2011 and June 30, 2012 was as follows (in millions):

	December 31, 2011	June 30, 2012	Weighted-Average Interest Rate at June 30, 2012 (1)
Revolving credit facility	$—	$—	—
$250.0 million of 6.45% Notes due 2014	249.8	249.9	6.3%
$250.0 million of 5.65% Notes due 2016	252.0	251.8	5.6%
$250.0 million of 6.40% Notes due 2018	263.5	262.4	5.3%
$550.0 million of 6.55% Notes due 2019	578.5	576.8	5.6%
$550.0 million of 4.25% Notes due 2021	558.9	558.5	4.0%
$250.0 million of 6.40% Notes due 2037	249.0	249.0	6.4%
Total debt	$2,151.7	$2,148.4	5.3%

(1) Weighted-average interest rate includes the impact of current interest rate swaps, the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges on interest expense.

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2011 and June 30, 2012 was $2.1 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings, which was 0.2% at June 30, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of June 30, 2012, there were no borrowings outstanding under this facility and $5.0 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

Interest Rate Derivatives.
In June and July 2012, we entered into a total of $100.0 million and $150.0 million, respectively, of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance. We account for these agreements as cash flow hedges.

Off-Balance Sheet Arrangements

None.

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.

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Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states under certain conditions to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. The Environmental Protection Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality ("TCEQ") drafted a “Failure to Attain Rule” to implement the requirements of CAA 185. The initial Failure to Attain Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule. The initial Failure to Attain Rule was rejected by a federal court decision in July 2011. The TCEQ is now considering a new rule.

Management believes it is probable that the TCEQ will move forward with a new CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility no CAA 185 fees will be assessed to us for the period of 2008 through 2010. However, management believes it is probable we will be assessed fees for excess emissions at our Houston-area facilities for that period and estimates that the range of fees that could be assessed to us to be between \$6.4 million and \$13.7 million. We have recorded an accrual of \$8.9 million related to this matter for the period of 2008 through 2010. This accrual is reflected as a long-term environmental liability at June 30, 2012.

Stationary Engine Emission Standards

The EPA had set a May 2013 compliance date for the reduction of carbon monoxide from the exhausts of large stationary engines. The EPA rule generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. A portion of our petroleum pipeline system uses engines to provide power to our pipeline pumps that are subject to the EPA rule, and we are actively assessing the best option for compliance. We have received a one-year extension to modify or replace these engines. If we are not able to modify or replace these engines by May 2014, sections of our petroleum pipeline system could experience capacity reductions or we could be assessed penalties until the required emission reductions are achieved.

Other Items

Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use NYMEX contracts and butane swap agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use butane swap agreements to hedge against changes in the price of butane we expect to purchase in the future as part of our petroleum products blending activity. As of June 30, 2012, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

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NYMEX contracts for 0.1 million barrels of petroleum products to hedge against price changes in anticipated sales of petroleum products related to our petroleum products blending and fractionation activities, which we are accounting for as cash flow hedges. These contracts mature in September 2012. Through June 30, 2012, the cumulative amount of unrealized gains from these agreements was $1.7 million, which did not impact product sales and was recorded as an adjustment to accumulated other comprehensive loss.

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between August 2012 and November 2013. Through June 30, 2012, the cumulative amount of unrealized losses from these agreements was $1.9 million. The unrealized losses from these fair value hedges were recorded as adjustments to the asset being hedged and, as a result, none of these unrealized losses impacted product sales.

Open Derivative Contracts Not Designated as Hedges

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- NYMEX contracts covering 2.1 million barrels of petroleum products related to our petroleum products blending, fractionation and Houston-to-El Paso linefill management activities. These contracts mature between July 2012 and April 2013 and are being accounted for as economic hedges. Through June 30, 2012, the cumulative amount of net unrealized gains associated with these agreements was $18.1 million, of which all were recognized in 2012.

- NYMEX contracts covering 0.5 million barrels of petroleum products related to our pipeline product overages that mature between July and August 2012, which are being accounted for as economic hedges. Through June 30, 2012, the cumulative amount of unrealized losses associated with these agreements was $1.3 million. We recorded these losses as an increase in operating expenses, all of which was recognized during 2012.

- Butane swap positions to purchase 0.4 million barrels of butane that mature between August 2012 and March 2013, which are being accounted for as economic hedges. Through June 30, 2012, the cumulative amount of unrealized losses associated with these agreements was $4.6 million. We recorded these losses as an increase in product purchases, all of which was recognized in 2012.

Settled Derivative Contracts

Additionally, related to physical product sales during 2012, we recognized losses of $12.9 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2012.

Product Sales Revenues

The following tables provide a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting periods in which the gains and losses impacted product sales revenues in our consolidated statements of income for the periods ended June 30, 2011 and 2012 (in millions):

2011	
NYMEX losses recorded during the six months ended June 30, 2011 that were associated with physical product sales during the six months ended June 30, 2011	$(28.8)
NYMEX losses recorded during 2011 that were associated with future physical product sales	(7.4)
Net NYMEX losses which impacted product sales revenues during the six months ended June 30, 2011	$(36.2)

2012	
NYMEX losses recorded during the six months ended June 30, 2012 that were associated with physical product sales during the six months ended June 30, 2012	$(12.9)
NYMEX gains recorded during 2012 that were associated with future physical product sales	18.1
Net NYMEX gains which impacted product sales revenues during the six months ended June 30, 2012	$5.2

Pipeline Tariff Increase. The Federal Energy Regulatory Commission ("FERC") regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 35% of our tariffs are subject to this indexing methodology while the remaining 65% of the tariffs can be adjusted at our discretion based on competitive factors. The FERC-approved indexing method to be used for the five-year period beginning in July 2011 is the annual change in the producer price index for finished goods (“PPI-FG”) plus 2.65%. Based on this indexing methodology, we increased virtually all of our tariffs by 8.6% on July 1, 2012.

Pipeline Conversion to Crude Service. We are in the process of reversing and converting to crude oil service our pipeline from Crane, Texas to our East Houston, Texas terminal for a cost of $375.0 million. The 225,000 barrel-per-day ("bpd") capacity of the pipeline is fully-committed with long-term agreements. Subject to receiving the necessary permits and regulatory approvals, we expect the reversed pipeline to begin transporting crude oil at partial capacity by early 2013, increasing to its full 225,000 bpd capacity by mid-2013.

Prior to the completion of this pipeline reversal project, we expect to discontinue the pipeline linefill activities that we have conducted in connection with the current service for this pipeline, and we expect to sell all of the associated linefill inventory during the third quarter of 2012. At June 30, 2012, we owned 0.4 million barrels of refined petroleum products linefill inventory with a carrying value of approximately $42.9 million.

Osage Complaint. On June 25, 2012, HollyFrontier Refining & Marketing LLC (“HollyFrontier”) filed a complaint with the Federal Energy Regulatory Commission ("FERC") alleging that Osage Pipe Line Company, LLC (“Osage”) has been over-earning on its rates for transportation on Osage's crude oil pipeline system from Cushing, Oklahoma to El Dorado, Kansas. We own 50% of Osage and serve as its operator. We believe that it is reasonably possible that Osage could incur a liability as a result of this complaint. As the 50% owner of Osage, we currently estimate that our ultimate exposure in this matter will be within a range of zero to approximately $5.5 million. We believe the claims should be denied and are defending the Osage rates vigorously.

Unrecognized Product Gains. Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies and product evaporation, expansion, releases and 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 terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum 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 terminals operations had a market value of approximately $2.8 million as of June 30, 2012. 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.

Related Party Transactions. We own a 50% interest in Osage Pipe Line Company, LLC and receive a management fee for the operation of its crude oil pipeline. We received management fees from this company of $0.2 million for each of the three months ended June 30, 2011 and 2012, and $0.4 million for each of the six months ended June 30, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which is in the process of constructing 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. Upon completion, these tanks will be leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have agreed to construct certain infrastructure assets at our Galena Park terminal which will allow for the operation of the tanks under construction by Texas Frontera. During 2012, the construction funding requests sent to us from Texas Frontera were $3.7 million, of which we paid $2.5 million in cash and $1.2 million was applied against our capital spending for the infrastructure assets under construction. We expect these assets to be fully operational by the end of 2012.

We own a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. During 2012, we paid construction funding requests to Double Eagle of $13.0 million. We expect these assets to be fully operational in mid-2013.

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase petroleum products from subsidiaries of Targa. For the three months ended June 30, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of less than $0.1 million and $0.3 million, respectively. For the six months ended June 30, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.5 million, respectively. These purchases were made on the same terms as comparable third-party transactions.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards that would otherwise have been forfeited would not be forfeited. Expense associated with these awards for the six months ended June 30, 2011 and 2012 was $1.9 million and $0.2 million, respectively.

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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 commodity price risk. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of June 30, 2012, we had commitments under forward purchase and sale contracts used in our blending and fractionation activities as follows (in millions):

	Amount	Barrels
Forward purchase contracts	$41.2	0.6
Forward sale contracts	$27.4	0.3

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment, or are otherwise undesignated as cash flow or fair value hedges, as economic hedges. We also use butane swap agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At June 30, 2012, we had open NYMEX contracts representing 3.4 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane swap positions of 0.4 million barrels of butane we expect to purchase in the future.

At June 30, 2012, the fair value of our open NYMEX contracts was a net asset of $16.5 million and the fair value of our butane swap agreements was a liability of $4.7 million. Combined, the net asset was $11.8 million, of which $13.8 million was recorded as a current asset to energy commodity derivatives contracts and $2.0 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

At June 30, 2012, open NYMEX contracts representing 2.6 million barrels of petroleum products did not qualify for hedge accounting treatment. A $1.00 per barrel increase in the price of these NYMEX contracts for reformulated gasoline blendstock for oxygen blending ("RBOB") gasoline or heating oil would result in a $2.6 million decrease in our operating profit and a $1.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $2.6 million increase in our operating profit. However, the increases or decreases in operating profit we recognize from our open NYMEX contracts will be 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.

At June 30, 2012, open butane swap contracts representing 0.4 million barrels of butane were designated as economic hedges. A $1.00 per barrel increase in the price of butane would result in a $0.4 million decrease in our product purchases and a $1.00 per barrel decrease in the price of butane would result in a $0.4 million increase in our product purchases. However, the increases or decreases in product purchases we recognize from our open butane swap contracts will be substantially offset by higher or lower product purchases when the physical purchase 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 2012, we entered into a total of $100.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.7% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance. We account for these agreements as cash flow hedges. A 0.125% change in interest rates would result in an increase or decrease in the fair value of these agreements of approximately $2.7 million.

At June 30, 2012, we had no variable rate debt outstanding, including on our revolving credit facility. Our revolving

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credit facility has total borrowing capacity of $800.0 million, from which we could borrow in the future. To the extent we borrow funds under this facility in any future period, those borrowings would bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility.

ITEM 4. CONTROLS AND PROCEDURES

We performed 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) as of the end of the period covered by the date of this report. We performed this evaluation 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, 2012 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 within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "believes," "continue," "could," "estimates," "expects," "forecasts," "goal," "guidance," "intends," "may," "might," "plans," "potential," "projects," "scheduled," "should" 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 we have discussed in this report:

- overall demand for refined petroleum products, natural gas liquids, crude oil and ammonia in the U.S.;
- price fluctuations for refined petroleum products, natural gas liquids and crude oil and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties or lenders;
- 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, including without limitation, solar power, wind power and geothermal energy, 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 pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our petroleum terminals;

- changes in supply patterns for our storage 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 U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand

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for our services;

- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards, equipment failures, system failures 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 or more aggressive enforcement or increased assessments under existing forms of 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;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- actions by rating agencies concerning our credit ratings;
- our ability to receive all necessary approvals, consents and permits by applicable governmental entities within the time-line anticipated by project schedules for new or modified assets;
- our ability to obtain all necessary approvals, consents and permits required to operate our assets;
- our ability to promptly obtain all necessary materials and supplies required for construction, and to construct facilities without labor or contractor problems;
- risks inherent in the use of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations that govern the product quality specifications that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we are or become subject, including tax withholding issues, safety, security, employment and environmental laws and regulations, including laws and regulations designed to address climate change;
- 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 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;
- the ability of third parties to perform on their contractual obligations to us;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

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

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2011, we received an information request from the U.S. Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in February 2011 in Texas. We have accrued $0.1 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We have accrued approximately $0.1 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In April 2012, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in December 2011 in Nebraska. We have accrued $0.6 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

We are a party to various claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes 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 in this report, you should carefully consider the factors discussed in Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2011, 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.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of John D. Chandler, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101.INS	—	XBRL Instance Document.
Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.

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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 2, 2012.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its general partner

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

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