MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
May 03, 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 March 31, 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 May 2, 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 March 31,	
	2011	2012
Transportation and terminals revenues	$205,408	$217,554
Product sales revenues	237,296	275,730
Affiliate management fee revenue	193	199
Total revenues	442,897	493,483
Costs and expenses:		
Operating	62,361	68,452
Product purchases	211,230	248,612
Depreciation and amortization	29,363	31,510
General and administrative	24,590	23,744
Total costs and expenses	327,544	372,318
Equity earnings	1,367	1,648
Operating profit	116,720	122,813
Interest expense	26,486	29,123
Interest income	(10)	(35)
Interest capitalized	(671)	(864)
Debt placement fee amortization expense	385	519
Income before provision for income taxes	90,530	94,070
Provision for income taxes	465	546
Net income	$90,065	$93,524
Allocation of net income (loss):		
Non-controlling owners' interest	$(63)	$—
Limited partners' interest	90,128	93,524
Net income	$90,065	$93,524
Basic and diluted net income per limited partner unit	$0.80	$0.83
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	112,762	113,091

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 March 31, 2011	Three Months Ended March 31, 2012
Net income	$90,065	$93,524
Other comprehensive income:		
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)
Amortization of prior service credit and actuarial loss	78	852
Total other comprehensive income	37	811
Comprehensive income	90,102	94,335
Comprehensive loss attributable to non-controlling owners’ interest in consolidated subsidiaries	(63)	—
Comprehensive income attributable to partners’ capital	$90,165	$94,335

See notes to consolidated financial statements.

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

	December 31, 2011	March 31, 2012 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 209,620	$151,642
Trade accounts receivable (less allowance for doubtful accounts of $68 and $2 at December 31, 2011 and March 31, 2012, respectively)	82,497	103,052
Other accounts receivable	10,079	12,338
Inventory	258,860	240,167
Energy commodity derivatives contracts, net	4,914	—
Energy commodity derivatives deposits, net	26,917	41,667
Reimbursable costs	5,891	4,806
Other current assets	13,412	12,776
Total current assets	612,190	566,448
Property, plant and equipment	4,080,484	4,105,951
Less: accumulated depreciation	830,762	853,660
Net property, plant and equipment	3,249,722	3,252,291
Equity investments	35,594	39,379
Long-term receivables	2,534	2,852
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $14,813 and $15,479 at December 31, 2011 and March 31, 2012, respectively)	15,176	14,510
Debt placement costs (less accumulated amortization of $5,799 and $6,318 at December 31, 2011 and March 31, 2012, respectively)	14,615	14,096
Tank bottom inventory	59,473	64,761
Other noncurrent assets	2,437	2,197
Total assets	$ 4,045,001	$4,009,794
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 66,384	$48,542
Accrued payroll and benefits	30,184	16,200
Accrued interest payable	40,547	33,259
Accrued taxes other than income	27,570	21,863
Environmental liabilities	17,852	16,881
Deferred revenue	39,983	41,993
Accrued product purchases	59,800	67,505
Energy commodity derivatives contracts, net	—	4,654
Other current liabilities	28,735	21,362
Total current liabilities	311,055	272,259
Long-term debt	2,151,775	2,150,107
Long-term pension and benefits	67,080	71,319
Other noncurrent liabilities	19,905	23,659
Environmental liabilities	31,783	30,645
Commitments and contingencies		

Partners’ capital:		
Limited partner unitholders (112,737 units and 113,100 units outstanding at December 31, 2011 and March 31, 2012, respectively)	1,510,604	1,508,195
Accumulated other comprehensive loss	(47,201)	(46,390)
Total partners’ capital	1,463,403	1,461,805
Total liabilities and partners' capital	$ 4,045,001	$ 4,009,794

See notes to consolidated financial statements.

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

	Three Months Ended March 31, 2011	2012
Operating Activities:		
Net income	$90,065	$93,524
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	29,363	31,510
Debt placement fee amortization	385	519
Loss on sale, retirement and impairment of assets	1,830	5,407
Equity earnings	(1,367)	(1,648)
Distributions from equity investments	1,367	1,648
Equity-based incentive compensation expense	3,750	2,843
Amortization of prior service credit and actuarial loss	78	852
Changes in operating assets and liabilities:		
Restricted cash	14,379	—
Trade accounts receivable and other accounts receivable	(8,658)	(22,814)
Inventory	(8,151)	18,693
Energy commodity derivatives contracts, net of derivatives deposits	(1,404)	(8,358)
Reimbursable costs	6,263	1,085
Accounts payable	2,596	(16,863)
Accrued payroll and benefits	(13,388)	(13,984)
Accrued interest payable	(4,285)	(7,288)
Accrued taxes other than income	(6,163)	(5,707)
Accrued product purchases	37,311	7,705
Current and noncurrent environmental liabilities	2,032	(2,109)
Other current and noncurrent assets and liabilities	1,382	4,726
Net cash provided by operating activities	147,385	89,741
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(50,219)	(37,139)
Proceeds from sale and disposition of assets	27	40
Increase (decrease) in accounts payable related to capital expenditures	2,583	(1,979)
Acquisition of assets	(7,363)	—
Acquisition of non-controlling owners' interests	(40,500)	—
Equity investments	(1,500)	(3,655)
Distributions in excess of equity investment earnings	151	870
Other	(1,100)	—
Net cash used by investing activities	(97,921)	(41,863)
Financing Activities:		
Distributions paid	(85,398)	(92,177)
Net borrowings under revolver	62,000	—
Increase (decrease) in outstanding checks	2,393	(678)
Settlement of tax withholdings on long-term incentive compensation	(7,410)	(13,001)
Net cash used by financing activities	(28,415)	(105,856)

Change in cash and cash equivalents	21,049	(57,978)
Cash and cash equivalents at beginning of period	7,483	209,620
Cash and cash equivalents at end of period	$28,532	$151,642
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 wholly-owned Delaware limited liability company, 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 March 31, 2012, and the results of operations and cash flows for the three months ended March 31, 2011 and 2012. The results of operations for the three months ended March 31, 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 do not impact product sales. 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 months ended March 31, 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 March 31,	
	2011	2012
Physical sale of petroleum products	$275,629	$307,706
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)]	(19,980)	(24,889)
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)]	(18,427)	(7,099)
Other	74	12
Total NYMEX contract adjustments	(38,333)	(31,976)
Total product sales revenues	$237,296	$275,730

(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 operations.

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

	Three Months Ended March 31, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$144,062	$55,221	$7,032	$(907)	$205,408
Product sales revenues	226,988	10,418	—	(110)	237,296
Affiliate management fee revenue	193	—	—	—	193
Total revenues	371,243	65,639	7,032	(1,017)	442,897
Operating expenses	37,710	21,996	3,331	(676)	62,361
Product purchases	208,473	3,774	—	(1,017)	211,230
Equity earnings	(1,367)	—	—	—	(1,367)
Operating margin	126,427	39,869	3,701	676	170,673
Depreciation and amortization expense	18,552	9,771	364	676	29,363
G&A expenses	18,455	5,471	664	—	24,590
Operating profit	$89,420	$24,627	$2,673	$—	$116,720

	Three Months Ended March 31, 2012 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$148,730	$63,180	$6,349	$(705)	$217,554
Product sales revenues	266,257	9,765	—	(292)	275,730
Affiliate management fee revenue	199	—	—	—	199
Total revenues	415,186	72,945	6,349	(997)	493,483
Operating expenses	46,554	20,182	2,450	(734)	68,452
Product purchases	244,881	4,728	—	(997)	248,612
Equity earnings	(1,669)	21	—	—	(1,648)
Operating margin	125,420	48,014	3,899	734	178,067
Depreciation and amortization expense	19,663	10,729	384	734	31,510
G&A expenses	17,455	5,666	623	—	23,744
Operating profit	$88,302	$31,619	$2,892	$—	$122,813

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

4. Inventory

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

	December 31, 2011	March 31, 2012
Refined petroleum products	$127,999	$117,865
Natural gas liquids	55,490	46,691
Transmix	60,251	55,968
Crude oil	8,065	12,064
Additives	7,055	7,579
Total inventory	$258,860	$240,167

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 table presents our consolidated net periodic benefit costs related to these plans during the three months ended March 31, 2011 and 2012 (in thousands):

	Three Months Ended March 31, 2011		Three Months Ended March 31, 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	$138
Interest cost	949	259	1,203	257
Expected return on plan assets	(1,021)	—	(1,176)	—
Amortization of prior service cost (credit)	77	(213)	77	(213)
Amortization of actuarial loss	151	63	827	161
Net periodic benefit cost	$2,141	$200	$4,121	$343

Net periodic benefit costs for the pension plans increased approximately $2.0 million in first quarter 2012 primarily due to decreases in the discount rate at December 31, 2011.

Contributions estimated to be paid into the plans in 2012 are $12.7 million and $0.6 million for the pension and other postretirement benefit plans, respectively.

6. Debt

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

	December 31, 2011	March 31, 2012	Weighted-Average Interest Rate at March 31, 2012 (a)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,844	249,859	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,930	5.6%
$250.0 million of 6.40% Notes due 2018	263,477	262,962	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	577,665	5.6%
$550.0 million of 4.25% Notes due 2021	558,932	558,723	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,968	6.4%
Total debt	$2,151,775	$2,150,107	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 (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 March 31, 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. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated note.

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 March 31, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of March 31, 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 sales contracts, NYMEX contracts and butane swap agreements to help manage price changes, which has the effect of locking in most of the product margins realized from our blending activities that we choose to hedge.

We account for the forward purchase and sales 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 March 31, 2012, we had commitments under these forward purchase and sales contracts as follows (in millions):

	Amount	Barrels
Forward purchase contracts	$55.3	0.6
Forward sales contracts	$44.4	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:

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, at March 31, 2012, we had open NYMEX contracts representing 3.1 million barrels of petroleum products and open butane swap agreements on the purchase of 25 thousand barrels of butane.

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 June 2012 and November 2013
NYMEX - Economic Hedges	2.4 million barrels of refined petroleum products	Between April and December 2012
Butane Swap Agreements - Economic Hedges	25 thousand barrels of butane	August 2012

At March 31, 2012, the fair value of our open NYMEX contracts was a net liability of $16.4 million and the fair value of our butane swap agreements was a liability of less than $0.1 million. Combined, the net liability was $16.4 million, of which $4.7 million was recorded as a current liability to energy commodity derivatives contracts and $11.7 million was recorded as other noncurrent liabilities on our consolidated balance sheet. At March 31, 2012, we had made margin deposits of $41.7 million for these contracts, which were recorded as 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. We have the right of offset under the agreements and, therefore, have offset the fair values of our NYMEX agreements and butane swap agreements together for each counterparty separately on our consolidated balance sheets.

Impact of Derivatives on Income Statement, Balance Sheet and AOCL

The changes in derivative gains included in accumulated other comprehensive loss ("AOCL") for the three months ended March 31, 2011 and 2012 were as follows (in thousands):

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

	Three Months Ended March 31,	
Derivative Gains Included in AOCL	2011	2012
Beginning balance	$3,325	$3,161
Reclassification of net gain on cash flow hedges to interest expense	(41)	(41)
Ending balance	$3,284	$3,120

As of March 31, 2012, the net gain estimated to be classified to interest expense over the next twelve months from AOCL is approximately $0.2 million.

The following table provides a summary of the effect on our consolidated statements of income for the three months ended March 31, 2011 and 2012 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)	
		Three Months Ended March 31,		Three Months Ended March 31,	
Derivative Instrument		2011	2012	2011	2012
Interest rate swap agreements	Interest expense	$203	$—	$2,222	$—

During first quarter 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 $11.6 million from the agreements as of March 31, 2012 were fully offset by an increase of $11.7 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 months ended March 31, 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 March 31, 2011		
Derivative Instrument	Amount of Gain (Loss) Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$ 41

	Three Months Ended March 31, 2012		
Derivative Instrument	Amount of Gain (Loss) Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$ 41

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the three months ended March 31, 2011 or 2012.
The following table provides a summary of the effect on our consolidated statements of income for the three months ended March 31, 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):

Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Amount of Gain (Loss) Recognized on Derivative Three Months Ended March 31, 2011	March 31, 2012
NYMEX commodity contracts	Product sales revenues	$(38,333)	$(31,976)
NYMEX commodity contracts	Operating expenses	(47)	(5,184)
Butane swap agreements	Product purchases	—	43
	Total	$(38,380)	$(37,117)

The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were designated as hedging instruments as of December 31, 2011 and March 31, 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

	March 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$169	Energy commodity derivatives contracts	$—
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	11,744
	Total	$169	Total	$11,744

The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were not designated as hedging instruments as of December 31, 2011 and March 31, 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

	March 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		$3,414		$8,230

NYMEX commodity contracts	Energy commodity derivatives contracts		Energy commodity derivatives contracts	
Butane swap agreements	Energy commodity derivatives contracts	—	Energy commodity derivatives contracts	7
	Total	$3,414	Total	$8,237

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. However, management believes it is probable we will be assessed fees for excess emissions at our Houston area facilities for the years following 2007 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 $10.8 million related to this matter, which we believe is the most likely outcome based on our discussions with the TCEQ. This accrual was recorded as a long-term environmental liability at March 31, 2012.

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 our new 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 March 31, 2012, we have not reserved any of the receivable balance owed to us by MF Global.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $49.6 million and $47.5 million at December 31, 2011 and March 31, 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 $3.9 million and $2.5 million for the three months ended March 31, 2011 and 2012, respectively.

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

March 31, 2012 were $7.7 million, of which $4.8 million and $2.9 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 $6.8 million as of March 31, 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 March 31, 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 March 31, 2012 total 1.2 million. The compensation committee of our general partner's board of directors administers the LTIP.

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

	Three Months Ended March 31, 2011		
	Equity Method	Liability Method	Total
2009 awards	$927	$622	$1,549
2010 awards	950	354	1,304
2011 awards	562	145	707
Retention awards	190	—	190
Total	$2,629	$1,121	$3,750
Allocation of LTIP expense on our consolidated statements of income:			
G&A expense			$3,657
Operating expense			93
Total			$3,750

	Three Months Ended March 31, 2012		
	Equity Method	Liability Method	Total
2010 awards	$522	$408	$930
2011 awards	743	273	1,016
2012 awards	561	151	712
Retention awards	185	—	185
Total	$2,011	$832	$2,843

Allocation of LTIP expense on our consolidated statements of income:	
G&A expense	$2,505
Operating expense	338
Total	$2,843

In January 2012, the cumulative amounts of the 2009 LTIP awards were settled by issuing 361,383 limited partner units and distributing those units to the LTIP participants. The minimum tax withholdings associated with this settlement and employer taxes of $13.0 million and $1.3 million, respectively, were paid in January 2012.

In January 2012, the compensation committee of our general partner's board of directors approved 131,687 phantom unit awards pursuant to our LTIP. These awards have a three-year vesting period that will end on December 31, 2014.

10. Distributions

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

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
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[a]	0.8400	95,004
Total	$1.6550	$187,181

(a) Our general partner's board of directors declared this cash distribution on April 24, 2012 to be paid on May 15, 2012 to unitholders of record at the close of business on May 8, 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 represents short-term deposits we paid associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits paid change daily in relation to 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.

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

- 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.
- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2011 and March 31, 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 March 31, 2012 (in thousands):

Assets (Liabilities)	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value	March 31, 2012 Carrying Amount	March 31, 2012 Fair Value
Cash and cash equivalents	$209,620	$209,620	$151,642	$151,642
Energy commodity derivatives deposits	$26,917	$26,917	$41,667	$41,667
Long-term receivables	$2,534	$2,510	$2,852	$2,816
Energy commodity derivatives contracts (current)	$4,914	$4,914	$(4,654)	$(4,654)
Energy commodity derivatives contracts (noncurrent)	$(6,457)	$(6,457)	$(11,744)	$(11,744)
Debt	$(2,151,775)	$(2,389,700)	$(2,150,107)	$(2,387,630)

Fair Value Measurements

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

		Fair Value Measurements as of December 31, 2011 using:		
Assets (Liabilities)	Total	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)	$4,914	$4,914	$—	$—
Energy commodity derivatives contracts (noncurrent)	$(6,457)	$(6,457)	$—	$—
Debt	$(2,389,700)	$(2,389,700)	$—	$—

		Fair Value Measurements as of March 31, 2012 using:		
Assets (Liabilities)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Long-term receivables	$2,816	$—	$—	$2,816

Energy commodity derivatives contracts (current)	$(4,654)	$(4,654)	$—	$—
Energy commodity derivatives contracts (noncurrent)	$(11,744)	$(11,744)	$—	$—
Debt	$(2,387,630)	$(2,387,630)	$—	$—

12. 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

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oil pipeline. We received operating fees from this company of $0.2 million for each of the three months ended March 31, 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 first quarter 2012, the construction funding requests sent to us from Texas Frontera were $2.5 million, of which we paid $1.5 million in cash and $1.0 million was applied against our capital spending for the infrastructure assets under construction.

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 first quarter 2012, we paid construction funding requests to Double Eagle of $2.0 million.

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 March 31, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.2 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.

13. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

Quarterly distribution. In April 2012, our general partner's board of directors declared a quarterly distribution of $0.84 per unit to be paid on May 15, 2012 to unitholders of record at the close of business on May 8, 2012. The total cash distributions to be paid are $95.0 million (see Note 10—Distributions for details).

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 March 31, 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

Pipeline Conversion to Crude Service. In March 2012, we announced our intention to expand the capacity of our Crane-to-Houston crude oil pipeline from 135,000 to 225,000 barrels per day. The expanded pipeline capacity is fully-committed with long-term agreements. We had previously announced the initiation of a project to reverse and convert to crude oil service our pipeline from Crane, Texas to our East Houston, Texas terminal, with an expected initial capacity of 135,000 barrels per day and a cost of $245.0 million. The project is now estimated to cost $375.0 million based on the expanded scope. 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 barrel per day capacity by mid-2013.

Unitholder Elections. In April 2012, at our annual meeting of limited partners, our limited partners:

- Elected Robert G. Croyle and Barry R. Pearl to serve as Class I directors of our general partner's board of directors until the 2015 annual meeting of limited partners;
- Approved, on an advisory basis, the compensation of our named executive officers (as described in our proxy statement dated February 24, 2012); and
- Ratified the appointment of Ernst & Young LLP to audit our 2012 financial statements.

Collective Bargaining Agreement with the United Steel Workers ("USW"). During first quarter 2012, we reached agreement with the USW which represents approximately 250 employees assigned to our petroleum pipeline system. The current collective bargaining agreement with the USW will be effective through January 31, 2015.

Cash Distribution. In April 2012, the board of directors of our general partner declared a quarterly cash distribution of $0.84 per unit for the period of January 1, 2012 through March 31, 2012. This quarterly cash distribution will be paid on May 15, 2012 to unitholders of record on May 8, 2012. Total distributions to be paid under this declaration are approximately $95.0 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 table, 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 table. 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 operations. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-

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related activities, is provided in this table. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2012

	Three Months Ended March 31,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$144.1	$148.7	$4.6	3
Petroleum terminals	55.2	63.2	8.0	14
Ammonia pipeline system	7.0	6.3	(0.7)	(10)
Intersegment eliminations	(0.9)	(0.6)	0.3	33
Total transportation and terminals revenues	205.4	217.6	12.2	6
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum pipeline system	37.7	46.6	(8.9)	(24)
Petroleum terminals	22.0	20.2	1.8	8
Ammonia pipeline system	3.3	2.5	0.8	24
Intersegment eliminations	(0.6)	(0.8)	0.2	33
Total operating expenses	62.4	68.5	(6.1)	(10)
Product margin:				
Product sales revenues	237.3	275.7	38.4	16
Product purchases	211.2	248.6	(37.4)	(18)
Product margin[(a)]	26.1	27.1	1.0	4
Equity earnings	1.4	1.6	0.2	14
Operating margin	170.7	178.0	7.3	4
Depreciation and amortization expense	29.4	31.5	(2.1)	(7)
G&A expense	24.6	23.7	0.9	4
Operating profit	116.7	122.8	6.1	5
Interest expense (net of interest income and interest capitalized)	25.8	28.2	(2.4)	(9)
Debt placement fee amortization expense	0.4	0.5	(0.1)	(25)
Income before provision for income taxes	90.5	94.1	3.6	4
Provision for income taxes	0.4	0.6	(0.2)	(50)
Net income	$90.1	$93.5	$3.4	4
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.043	$1.056		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	52.4	45.9		
Distillates	29.6	29.8		
Aviation fuel	5.1	5.6		
Liquefied petroleum gases	0.9	1.0		
Crude oil	7.0	14.9		

Total volume shipped	95.0	97.2
Petroleum terminals:		
Storage terminal average utilization (million barrels per month)	30.0	34.8
Inland terminal throughput (million barrels)	27.6	28.1
Ammonia pipeline system:		
Volume shipped (thousand tons)	221	189

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

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Transportation and terminals revenues increased $12.2 million, primarily resulting from:

- an increase in petroleum pipeline system revenues of $4.6 million resulting from:
  - a 2% increase in transportation volumes primarily due to an increase in crude volumes resulting from more refinery supply being diverted to our south Texas crude pipelines due to one of our customer's increasing their usage of domestic crude oil, partially offset by lower gasoline shipments due to weak gasoline demand in the current quarter;
  - a 1% increase in the average tariff as the 7% rate increase we implemented on July 1, 2011 was mostly offset by more shorter-haul movements, in part due to significantly higher crude volumes, as described above, which are at a lower rate than our other pipeline shipments; and
  - increased demand for pipeline capacity and storage leases.
- an increase in petroleum terminals revenues of $8.0 million primarily due to leasing newly-constructed tanks placed into service since first quarter 2011, such as the new crude oil storage we built in Cushing, Oklahoma; and
- a decrease in ammonia pipeline system revenues of $0.7 million primarily because of lower shipments.

Operating expenses increased $6.1 million, resulting from:

- an increase in petroleum pipeline system expenses of $8.9 million primarily due to higher asset integrity costs, property taxes and asset retirements due to replaced assets;
- a decrease in petroleum terminals expenses of $1.8 million primarily due to insurance reimbursements for maintenance work necessary following historical hurricane-related damage; and
- a decrease in ammonia pipeline system expenses of $0.8 million primarily due to lower environmental accruals in the current quarter.

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 $1.0 million between periods primarily due to higher profits from our petroleum products blending activities mostly due to higher product prices, partially offset by higher unrealized losses on NYMEX contracts and lower terminal product gains, principally due to lower volume of product sales.

Depreciation and amortization expense increased $2.1 million primarily due to expansion capital projects placed into service since first quarter 2011.

G&A expense decreased $0.9 million primarily due to lower equity-based incentive compensation expense.

Interest expense, net of interest income and interest capitalized, increased $2.4 million. Our average debt outstanding increased to $2.2 billion for first quarter 2012 from $1.9 billion for first 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, decreased to 5.3% in first quarter 2012 from 5.5% in first quarter 2011.

Distributable Cash Flow

Distributable cash flow is a non-GAAP measure that management uses to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this 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 for the three months ended March 31, 2011 and 2012 to net income, which is its nearest comparable GAAP financial measure, was as follows (in thousands):

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	Three Months Ended March 31, 2011	2012	Increase (Decrease)
Net income	$90,065	$93,524	$3,459
Interest expense, net	25,805	28,224	2,419
Depreciation and amortization[1]	29,748	32,029	2,281
Equity-based incentive compensation expense[2]	(3,660)	(10,156)	(6,496)
Asset retirements and impairments	1,830	5,407	3,577
Commodity-related adjustments:			
Derivative losses recognized in the period associated with future product transactions[3]	23,971	13,162	(10,809)
Derivative gains (losses) recognized in previous periods associated with products sold in the period[4]	(9,606)	3,163	12,769
Lower-of-cost-or-market adjustments	—	(1,017)	(1,017)
Houston-to-El Paso cost of sales adjustments[5]	(5,844)	1,039	6,883
Total commodity-related adjustments	8,521	16,347	7,826
Other	(138)	520	658
Adjusted EBITDA	152,171	165,895	13,724
Interest expense, net	(25,805)	(28,224)	(2,419)
Maintenance capital	(8,650)	(11,958)	(3,308)
Distributable cash flow	$117,716	$125,713	$7,997

(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 three months ended March 31, 2011 and 2012 was $3.7 million and $2.8 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) When we physically sell products that are economically hedged (but were not designated as hedges for accounting purposes), we include in our distributable cash flow calculations the full amount of the change in fair value of the associated derivative agreement.

(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 $8.0 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 $147.4 million and $89.7 million for the three months ended March 31, 2011 and 2012, respectively. The $57.7 million decrease from 2011 to 2012 was primarily attributable to:

- a $29.6 million decrease resulting from a $7.7 million increase in accrued product purchases in 2012 versus a $37.3 million increase in accrued product purchases in 2011 primarily due to the timing of invoices paid to vendors and suppliers;
- a $19.5 million decrease resulting from a $16.9 million decrease in accounts payable in 2012 versus a $2.6 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 the elimination of restricted cash resulting from our purchase of a private group's investment in a Cushing, Oklahoma storage project ("MCO") during first quarter 2011. MCO's cash on hand was unavailable to us for our partnership matters and was recorded as restricted cash on our consolidated balance sheet at December 31, 2010; and
- a $14.1 million decrease resulting from a $22.8 million increase in accounts receivable and other accounts receivable in 2012 versus an $8.7 million increase during 2011 primarily due to timing of payments from our customers.

These decreases were partially offset by:

- a $26.9 million increase primarily resulting from higher levels of inventory purchases in 2011 as compared to 2012; specifically, an $18.7 million decrease in inventory in 2012 versus an $8.2 million increase in inventory in 2011.

Net cash used by investing activities for the three months ended March 31, 2011 and 2012 was $97.9 million and $41.9 million, respectively. During 2012, we spent $37.1 million for capital expenditures, which included $12.0 million for maintenance capital and $25.1 million for expansion capital. During 2011, we spent $50.2 million for capital expenditures, which included $8.7 million for maintenance capital and $41.5 million for expansion capital. Also during first quarter 2011, we acquired a private investment group's common equity in MCO for $40.5 million and spent $7.4 million to acquire the remaining undivided interest in our Southlake, Texas terminal.

Net cash used by financing activities for the three months ended March 31, 2011 and 2012 was $28.4 million and $105.9 million, respectively. During 2012, we paid cash distributions of $92.2 million to our unitholders. During the first quarter of 2011, we paid cash distributions of $85.4 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 $62.0 million.

The quarterly distribution amount related to our first-quarter 2012 financial results (to be paid in second quarter 2012) is $0.84 per unit. If we meet management's targeted distribution growth of 9% for 2012 and the number of outstanding limited partner units remains at 113.1 million, total cash distributions of approximately $391.0 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 three months ended March 31, 2011 and 2012, our maintenance capital spending was $8.7 million and $12.0 million, respectively. For 2012, we expect to incur maintenance capital expenditures for our existing businesses of approximately $70.0 million.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During the first three months of 2012, we spent $25.1 million for organic growth capital and $3.7 million for growth projects in conjunction with our joint venture partners. Based on the progress of expansion projects already underway, 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 $180.0 million in 2013 to complete these projects.

Liquidity

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

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	December 31, 2011	March 31, 2012	Weighted-Average Interest Rate at March 31, 2012 (1)
Revolving credit facility	$—	$—	—
$250.0 million of 6.45% Notes due 2014	249,844	249,859	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,930	5.6%
$250.0 million of 6.40% Notes due 2018	263,477	262,962	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	577,665	5.6%
$550.0 million of 4.25% Notes due 2021	558,932	558,723	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,968	6.4%
Total debt	$2,151,775	$2,150,107	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.

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 March 31, 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. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated note.

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 March 31, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of March 31, 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.

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.

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.

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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. However, management believes it is probable we will be assessed fees for excess emissions at our Houston area facilities for the years following 2007 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 $10.8 million related to this matter, most of which was recorded in 2011, which we believe is the most likely outcome based on our discussions with the TCEQ. This accrual was recorded as a long-term environmental liability at March 31, 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 our maintenance capital estimates include funding to comply with the EPA rule. Initial efforts to reduce emissions with catalytic converters have not been successful so far, but 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 March 31, 2012, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- 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 June 2012 and November 2013. Through March 31, 2012, the cumulative amount of unrealized losses from these agreements was $11.6 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

- NYMEX contracts covering 1.9 million barrels of petroleum products related to our petroleum products blending, fractionation and Houston-to-El Paso linefill management activities. These contracts mature between April and December 2012 and are being accounted for as economic hedges. Through March 31, 2012, the cumulative amount of net unrealized losses associated with these agreements was $6.6 million, of which $1.6 million of net gains were recognized in 2011 and $8.2 million of net losses were recognized in 2012.

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NYMEX contracts covering 0.5 million barrels of petroleum products related to our pipeline product overages that mature between April and June 2012. Through March 31, 2012, the cumulative amount of unrealized gains associated with these agreements was $1.7 million. We recorded these gains as a decrease in operating expenses, all of which was recognized during 2012.

• Butane swap positions to purchase 25 thousand barrels of butane that mature August 2012. Through March 31, 2012, the cumulative amount of unrealized losses associated with these agreements was less than $0.1 million. We recorded these losses as an increase in product purchases, all of which was recognized in 2012.

Settled Derivative Contracts

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Additionally, related to physical product sales during 2012, we recognized losses of $23.8 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2012.

The following tables provide a summary of the mark-to-market gains and losses associated with NYMEX contracts and butane swap agreements and the accounting periods in which the gains and losses were recognized in our consolidated statements of income for the periods ended March 31, 2011 and 2012 (in millions):

2011	
NYMEX losses recorded in first quarter 2011 that were associated with physical product sales during first quarter 2011	$(14.9)
NYMEX losses recorded in first quarter 2011 that were associated with future physical product sales	(23.4)
Total NYMEX losses which impacted product sales revenues during the three months ended March 31, 2011	$(38.3)

2012	
NYMEX losses recorded in first quarter 2012 that were associated with physical product sales during first quarter 2012	$(23.8)
NYMEX losses recorded in first quarter 2012 that were associated with future physical product sales	(8.2)
Total NYMEX losses which impacted product sales revenues during the three months ended March 31, 2012	$(32.0)

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 $6.8 million as of March 31, 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 operating fees from this company of $0.2 million for each of the three months ended March 31, 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 first quarter 2012, the construction funding requests sent to us from Texas Frontera were $2.5 million, of which we paid $1.5 million in cash and $1.0 million was applied against our capital spending for the infrastructure assets under construction.

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 first quarter 2012, we paid construction funding requests to Double Eagle of $2.0 million.

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 March 31, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.2 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.

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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 March 31, 2012, we had commitments under forward purchase and sales contracts used in our blending and fractionation activities as follows (in millions):

	Amount	Barrels
Forward purchase contracts	$55.3	0.6
Forward sales contracts	$44.4	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 March 31, 2012, we had open NYMEX contracts representing 3.1 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane swap positions of 25 thousand barrels of butane we expect to purchase in the future.

At March 31, 2012, the fair value of our open NYMEX contracts was a net liability of $16.4 million and the fair value of our butane swap agreements was a liability of less than $0.1 million. Combined, the net liability was $16.4 million, of which $4.7 million was recorded as a current liability to energy commodity derivatives contracts and $11.7 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

At March 31, 2012, open NYMEX contracts representing 2.4 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 $2.4 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 $2.4 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.

Interest Rate Risk

At March 31, 2012, we had no variable rate debt outstanding, including on our revolving credit facility. Our revolving 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

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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 March 31, 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 petroleum products, crude oil and natural gas liquids 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 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;

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- 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 near Texas City, 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 near Nemaha, 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 10.1*		Description of Magellan 2012 Annual Incentive Program (filed as Exhibit 10(b) to Form 10-K filed February 28, 2012).
Exhibit 10.2*		Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2012 (filed as Exhibit 10(c) to Form 10-K filed February 28, 2012).
Exhibit 10.3*		Form of 2012 Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan (filed as Exhibit 10(q) to Form 10-K filed February 28, 2012).
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.

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

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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 May 3, 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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