MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
November 07, 2011
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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 September 30, 2011

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 12-b-2 of the Exchange Act). Yes £ No x

As of November 4, 2011 there were 112,736,571 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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FINANCIAL INFORMATION

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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 September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Transportation and terminals revenues	$206,727	$232,064	$573,069	$660,664
Product sales revenues	199,284	203,253	585,318	600,492
Affiliate management fee revenue	190	193	569	578
Total revenues	406,201	435,510	1,158,956	1,261,734
Costs and expenses:				
Operating	87,584	89,458	219,980	233,142
Product purchases	186,993	159,550	503,516	489,616
Depreciation and amortization	27,403	30,234	79,460	90,261
General and administrative	23,624	20,470	67,044	70,341
Total costs and expenses	325,604	299,712	870,000	883,360
Equity earnings	1,654	1,955	4,323	4,765
Operating profit	82,251	137,753	293,279	383,139
Interest expense	25,316	27,332	69,611	79,806
Interest income	(74)	(11)	(85)	(22)
Interest capitalized	(884)	(665)	(2,535)	(2,526)
Debt placement fee amortization expense	358	410	1,015	1,180
Other expense	750	—	750	—
Income before provision for income taxes	56,785	110,687	224,523	304,701
Provision for income taxes	148	447	900	1,397
Net income	$56,637	$110,240	$223,623	$303,304
Allocation of net income (loss):				
Non-controlling owners’ interest	$(154)	$—	$(222)	$(63)
Limited partners’ interest	56,791	110,240	223,845	303,367
Net income	$56,637	$110,240	$223,623	$303,304
Basic and diluted net income per limited partner unit	$0.51	$0.98	$2.06	$2.69
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	111,522	112,864	108,437	112,825

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 September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Net income	$56,637	$110,240	223,623	303,304
Other comprehensive income:				
Net gain (loss) on commodity hedges	(179)	6,539	(468)	11,152
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(123)	(123)
Reclassification of net loss (gain) on commodity hedges to product sales revenues	(1,068)	(1,493)	967	(1,493)
Settlement cost and amortization of prior service credit and actuarial loss	101	701	80	856
Adjustment to recognize the funded status of postretirement plans	(2,167)	(10,254)	(2,167)	(10,254)
Total other comprehensive income (loss)	(3,354)	(4,548)	(1,711)	138
Comprehensive income	53,283	105,692	221,912	303,442
Comprehensive loss attributable to non-controlling owners' interest in consolidated subsidiaries	(154)	—	(222)	(63)
Comprehensive income attributable to partners' capital	$53,437	$105,692	$222,134	$303,505

See notes to consolidated financial statements.

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

	December 31, 2010	September 30, 2011 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$7,483	$198,065
Restricted cash	14,379	—
Trade accounts receivable (less allowance for doubtful accounts of $106 and $64 at December 31, 2010 and September 30, 2011, respectively)	92,192	89,838
Other accounts receivable	6,175	6,412
Inventory	216,408	257,120
Energy commodity derivatives contracts, net	—	36,205
Energy commodity derivatives deposits, net	22,302	—
Reimbursable costs	13,870	7,883
Other current assets	11,774	11,998
Total current assets	384,583	607,521
Property, plant and equipment	3,894,610	4,027,640
Less: accumulated depreciation	716,054	801,709
Net property, plant and equipment	3,178,556	3,225,931
Equity investments	23,728	31,726
Long-term receivables	1,167	3,862
Goodwill	39,925	53,262
Other intangibles (less accumulated amortization of $11,964 and $14,147 at December 31, 2010 and September 30, 2011, respectively)	16,924	15,840
Debt placement costs (less accumulated amortization of $5,439 and $6,619 at December 31, 2010 and September 30, 2011, respectively)	11,871	12,883
Tank bottom inventory	57,937	51,986
Other noncurrent assets	3,209	3,687
Total assets	$3,717,900	$4,006,698
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$41,425	$68,131
Accrued payroll and benefits	32,393	24,043
Accrued interest payable	35,799	33,250
Accrued taxes other than income	26,953	28,041
Environmental liabilities	12,202	18,655
Deferred revenue	34,733	36,923
Accrued product purchases	47,324	58,170
Energy commodity derivatives contracts, net	11,790	—
Energy commodity derivatives deposits, net	—	7,059
Other current liabilities	32,428	22,421
Total current liabilities	275,047	296,693
Long-term debt	1,906,148	2,153,437
Long-term pension and benefits	28,965	42,944

Other noncurrent liabilities	17,597	12,509
Environmental liabilities	20,572	24,787
Commitments and contingencies		
Owners' equity:		
Partners' capital:		
Limited partner unitholders (112,481 units and 112,737 units outstanding at December 31, 2010 and September 30, 2011, respectively)	1,466,404	1,487,286
Accumulated other comprehensive loss	(11,096)	(10,958)
Total partners' capital	1,455,308	1,476,328
Non-controlling owners' interest in consolidated subsidiaries	14,263	—
Total owners' equity	1,469,571	1,476,328
Total liabilities and owners' equity	$3,717,900	$4,006,698

See notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2010	2011
Operating Activities:		
Net income	$223,623	$303,304
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	79,460	90,261
Debt placement fee amortization	1,015	1,180
Loss on sale, retirement and impairment of assets	106	7,529
Equity earnings	(4,323)	(4,765)
Distributions from equity investments	3,240	4,365
Equity-based incentive compensation expense	11,482	11,751
Settlement cost and amortization of prior service credit and actuarial loss	80	856
Changes in operating assets and liabilities:		
Restricted cash	—	14,379
Trade accounts receivable and other accounts receivable	(10,553)	2,117
Inventory	(10,274)	(40,712)
Energy commodity derivatives contracts, net of derivatives deposits	2,633	(14,926)
Reimbursable costs	1,808	5,987
Accounts payable	15,233	27,293
Accrued payroll and benefits	(1,986)	(8,350)
Accrued interest payable	(1,717)	(3,228)
Accrued taxes other than income	4,312	1,088
Accrued product purchases	(7,745)	10,846
Tank bottom inventory	—	5,951
Current and noncurrent environmental liabilities	(1,676)	10,668
Other current and noncurrent assets and liabilities	11,171	548
Net cash provided by operating activities	315,889	426,142
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(160,691)	(143,163)
Proceeds from sale and disposition of assets	5,297	4,555
Increase (decrease) in accounts payable related to capital expenditures	3,888	(2,544)
Acquisition of business	(290,991)	—
Acquisition of assets	(29,300)	(17,798)
Acquisition of non-controlling owners' interests	—	(40,500)
Other	—	(6,600)
Net cash used by investing activities	(471,797)	(206,050)
Financing Activities:		
Distributions paid	(235,019)	(260,703)
Net borrowings under revolver	(101,600)	(15,000)
Borrowings under long-term notes, net of discounts and premiums	298,899	260,914
Debt placement costs	(2,372)	(2,192)
Net receipt from financial derivatives	16,238	5,926

Decrease in outstanding checks	(5,116)	(11,045)
Settlement of tax withholdings on long-term incentive compensation	(3,371)	(7,410)
Issuance of common units, net	258,400	—
Capital contributed by non-controlling owners	3,082	—
Other	(384)	—
Net cash provided (used) by financing activities	228,757	(29,510)
Change in cash and cash equivalents	72,849	190,582
Cash and cash equivalents at beginning of period	4,168	7,483
Cash and cash equivalents at end of period	$77,017	$198,065
Supplemental non-cash financing activity:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$2,034	$4,315
Non-cash capital contributed by non-controlling owners	$10,299	$—

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, 2010, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of September 30, 2011, and the results of operations for the three and nine months ended September 30, 2010 and 2011 and cash flows for the nine months ended September 30, 2010 and 2011. The results of operations for the nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year ending December 31, 2011.

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, 2010.

2. Owners’ Equity

The changes in owners’ equity for the nine months ended September 30, 2011 are provided in the table below (dollars in thousands):

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

	Limited Partners' Capital	Limited Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2011	$1,466,404	$ (11,096)	$14,263	$1,469,571
Comprehensive income:				
Net income (loss)	303,367	—	(63)	303,304
Net gain on commodity hedges	—	11,152	—	11,152
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(123)	—	(123)
Reclassification of net gain on commodity hedges to product sales revenues	—	(1,493)	—	(1,493)
Settlement cost and amortization of prior service credit and actuarial loss	—	856	—	856
Adjustment to recognize the funded status of postretirement plans	—	(10,254)	—	(10,254)
Total comprehensive income (loss)	303,367	138	(63)	303,442
Distributions	(260,703)	—	—	(260,703)
Equity method portion of equity-based incentive compensation expense	7,738	—	—	7,738
Issuance of 255,222 common units in settlement of long-term incentive plan awards and board of director retainer fees	4,315	—	—	4,315
Settlement of tax withholdings on long-term incentive compensation	(7,410)	—	—	(7,410)
Acquisition of non-controlling owners' interest	(26,300)	—	(14,200)	(40,500)
Other	(125)	—	—	(125)
Balance, September 30, 2011	$1,487,286	$ (10,958)	$—	$1,476,328

3. Acquisitions

Acquisitions of Assets

In January 2011, we acquired the remaining undivided interest in our Southlake, Texas terminal. We accounted for this purchase as an acquisition of assets. The operating results of the Southlake terminal are reported in our petroleum pipeline system segment.

In April 2011, we acquired a petroleum products pipeline segment connected to our petroleum pipeline system at Reagan, Texas. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

In May 2011, we acquired petroleum products storage tanks in Riverside, Missouri. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

Collectively, the costs for the above-noted asset acquisitions were $17.8 million.

Acquisition of Non-Controlling Owners' Interest

In February 2011, we acquired a private investment group's common equity in Magellan Crude Oil, LLC ("MCO") for $40.5 million, which represented all of the non-controlling owners' interest in subsidiaries on our consolidated balance sheet (see Note 2 - Owners' Equity). The operating results of MCO continue to be reported in our petroleum terminals segment.

Business Combination

In September 2010, we acquired certain assets from BP Pipelines (North America), Inc. ("BP") and accounted for this

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purchase as a business combination. We have completed our process of determining the fair value of the assets acquired and liabilities assumed. As a result, we have adjusted the preliminary purchase price and fair value of the assets acquired and liabilities assumed as reported in our Annual Report on Form 10-K for the year ended December 31, 2010. The final allocation of the purchase price of the fair value of the assets acquired and liabilities assumed were as follows (in thousands):

Purchase price	$291,292
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$249,381
Other current assets	2,877
Goodwill	38,496
Other intangibles	3,898
Environmental liabilities	(375)
Other current liabilities	(2,985)
Total	$291,292

Changes to the preliminary purchase price allocation were a reduction in property, plant and equipment of $13.3 million with a corresponding increase in goodwill. The change related to a fair value amount that was preliminarily assigned to an inactive pipeline section, which we subsequently determined had no value at the date of acquisition.
The following summarized pro forma consolidated income statement information assumes that the business acquired from BP referred to above occurred as of January 1, 2010. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2010 or the results that will be attained in the future. The amounts presented below are in thousands:

	Three Months Ended September 30,			
	2010			2011
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported
Revenues	$406,201	$9,027	$415,228	$435,510
Net income	$56,637	$4,790	$61,427	$110,240

	Nine Months Ended September 30,			
	2010			2011
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported
Revenues	$1,158,956	$36,483	$1,195,439	$1,261,734
Net income	$223,623	$15,740	$239,363	$303,304

Significant pro forma adjustments include historical results of the acquired assets and our calculation of general and administrative ("G&A") costs, depreciation expense and interest expense on borrowings necessary to finance the acquisition.

4. 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 from mark-to-market adjustments from New York Mercantile Exchange (“NYMEX”) contracts. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from our business activities where 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 of the contracts we designate 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 those 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 9 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts.
For the three and nine months ended September 30, 2010 and 2011, product sales revenues included the following (in

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

thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2011	2010	2011
Physical sale of petroleum products	$206,682	$173,181	$577,919	$606,603
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]	(3,279)	21,865	2,599	807
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]	(4,924)	8,281	3,995	(6,918)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with our crude oil activities	805	(74)	805	—
Total NYMEX contract adjustments	(7,398)	30,072	7,399	(6,111)
Total product sales revenues	$199,284	$203,253	$585,318	$600,492

(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.

5. 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. Operating profit includes expense items, such as depreciation and amortization expense and G&A expenses, that management does not consider 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 September 30, 2010 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$156,652	$49,905	$671	$(501)	$206,727
Product sales revenues	195,177	4,233	—	(126)	199,284
Affiliate management fee revenue	190	—	—	—	190
Total revenues	352,019	54,138	671	(627)	406,201
Operating expenses	56,941	23,044	8,242	(643)	87,584
Product purchases	186,023	1,597	—	(627)	186,993
Equity earnings	(1,654)	—	—	—	(1,654)
Operating margin (loss)	110,709	29,497	(7,571)	643	133,278
Depreciation and amortization expense	17,840	8,562	358	643	27,403
G&A expenses	16,965	6,033	626	—	23,624
Operating profit (loss)	$75,904	$14,902	$(8,555)	$—	$82,251

	Three Months Ended September 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$167,500	$60,621	$4,644	$(701)	$232,064
Product sales revenues	197,932	5,887	—	(566)	203,253
Affiliate management fee revenue	193	—	—	—	193
Total revenues	365,625	66,508	4,644	(1,267)	435,510
Operating expenses	61,075	22,780	6,349	(746)	89,458
Product purchases	157,356	3,461	—	(1,267)	159,550
Equity earnings	(1,954)	(1)	—	—	(1,955)
Operating margin (loss)	149,148	40,268	(1,705)	746	188,457
Depreciation and amortization expense	18,945	10,179	364	746	30,234
G&A expenses	15,162	4,743	565	—	20,470
Operating profit (loss)	$115,041	$25,346	$(2,634)	$—	$137,753

	Nine Months Ended September 30, 2010 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$421,028	$144,010	$9,547	$(1,516)	$573,069
Product sales revenues	570,366	15,106	—	(154)	585,318
Affiliate management fee revenue	569	—	—	—	569
Total revenues	991,963	159,116	9,547	(1,670)	1,158,956
Operating expenses	149,211	57,679	15,458	(2,368)	219,980
Product purchases	499,066	6,120	—	(1,670)	503,516
Equity earnings	(4,323)	—	—	—	(4,323)
Operating margin	348,009	95,317	(5,911)	2,368	439,783
Depreciation and amortization expense	51,200	24,809	1,083	2,368	79,460
G&A expenses	48,307	16,911	1,826	—	67,044
Operating profit (loss)	$248,502	$53,597	$(8,820)	$—	$293,279

	Nine Months Ended September 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$472,730	$172,811	$17,431	$(2,308)	$660,664
Product sales revenues	577,811	23,445	—	(764)	600,492
Affiliate management fee revenue	578	—	—	—	578
Total revenues	1,051,119	196,256	17,431	(3,072)	1,261,734
Operating expenses	150,522	71,403	13,406	(2,189)	233,142
Product purchases	483,369	9,319	—	(3,072)	489,616
Equity earnings	(4,764)	(1)	—	—	(4,765)
Operating margin	421,992	115,535	4,025	2,189	543,741
Depreciation and amortization expense	56,788	30,193	1,091	2,189	90,261
G&A expenses	52,400	16,052	1,889	—	70,341
Operating profit	$312,804	$69,290	$1,045	$—	$383,139
	As of September 30, 2011				
Segment assets	$2,702,501	$1,042,325	$36,790	$—	$3,781,616
Corporate assets					225,082
Total assets					$4,006,698

6. Inventory

Inventory at December 31, 2010 and September 30, 2011 was as follows (in thousands):

	December 31, 2010	September 30, 2011
Refined petroleum products	$146,211	$105,770
Natural gas liquids	27,982	91,354
Transmix	32,277	49,524
Crude oil	5,008	3,987
Additives	4,930	6,485
Total inventory	$216,408	$257,120

In third quarter 2011, we recorded a $2.3 million and a $0.7 million lower-of-average-cost-or-market adjustment to our refined petroleum products and transmix inventory, respectively, resulting from a decrease in market prices in late third quarter 2011. These adjustments were included in operating expenses on our consolidated statements of income.

The increase in natural gas liquids was due to the purchase of butane during 2011 in anticipation of the petroleum products blending season, which begins each September.

7. Employee Benefit Plans

We sponsor two union pension plans for certain employees and a pension plan primarily for salaried employees, a postretirement benefit plan for selected employees and a defined contribution plan. The following tables present our consolidated net periodic benefit costs related to these plans during the three and nine months ended September 30, 2010 and 2011 (in thousands):

	Three Months Ended September 30, 2010		Three Months Ended September 30, 2011	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$1,687	$63	$3,251	$141
Interest cost	840	338	1,358	230
Expected return on plan assets	(890)	—	(1,225)	—
Amortization of prior service cost (credit)	76	(213)	76	(212)
Amortization of actuarial loss	138	100	766	1
Settlement cost	—	—	70	—
Net periodic benefit cost	$1,851	$288	$4,296	$160

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

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2011	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$5,040	$239	$7,221	$323
Interest cost	2,506	744	3,257	749
Expected return on plan assets	(2,664)	—	(3,268)	—
Amortization of prior service cost (credit)	230	(638)	230	(638)
Amortization of actuarial loss	388	100	1,068	126
Settlement cost	—	—	70	—
Net periodic benefit cost	$5,500	$445	$8,578	$560

Contributions estimated to be paid into the plans in 2011 are $9.4 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

8. Debt

Consolidated debt at December 31, 2010 and September 30, 2011 was as follows (in thousands):

	December 31, 2010	September 30, 2011	Weighted-Average Interest Rate at September 30, 2011 (1)
Revolving credit facility	$15,000	$—	—
$250.0 million of 6.45% Notes due 2014	249,786	249,829	6.3%
$250.0 million of 5.65% Notes due 2016	252,466	252,144	5.7%
$250.0 million of 6.40% Notes due 2018	259,125	263,994	5.1%
$550.0 million of 6.55% Notes due 2019	581,890	579,372	5.9%
$550.0 million of 4.25% Notes due 2021	298,932	559,138	4.2%
$250.0 million of 6.40% Notes due 2037	248,949	248,960	6.3%
Total debt	$1,906,148	$2,153,437	

(1) Weighted-average interest rate includes the impact of outstanding 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 9—Derivative Financial Instruments for detailed information regarding interest rate swaps).

The face value of our debt at September 30, 2011 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.
The amounts outstanding under the notes and revolving credit facility described in the table above are senior indebtedness.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which would have matured in September 2012, was $550.0 million at September 30, 2011. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of September 30, 2011, there were no borrowings outstanding under this facility; however, $4.6 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but do decrease our borrowing capacity under the facility. In October 2011, we replaced the above-noted revolving credit facility with a new revolving facility. See Note 14 - Subsequent Events for details.

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2011 Debt Offering. In August 2011, we issued an additional $250.0 million of our 4.25% notes due 2021. We sold these notes at a price of 104.1% of their face value, or $260.2 million. Net proceeds from this offering, including accrued interest of $0.7 million, were $258.7 million after underwriting discounts of $1.6 million and other offering costs of $0.6 million. Proceeds from this debt offering were used to repay all of the borrowings outstanding under our revolving credit facility, which was $193.0 million at the time, and for general partnership purposes, including investments in capital expenditures.

9. 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 price swap purchase agreements to lock 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 activities as normal purchases and sales. As of September 30, 2011, we had commitments under forward purchase contracts for product purchases of approximately 0.4 million barrels that are being accounted for as normal purchases totaling approximately $32.4 million, and we had commitments under forward sales contracts for product sales of approximately 0.7 million barrels that are being accounted for as normal sales totaling approximately $82.7 million.

NYMEX Contracts & Butane Swap Agreements - We use NYMEX contracts and butane swap agreements to help manage commodity price risk. 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 the 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 in accordance with Accounting Standards Codification	Changes in the value of these agreements are recognized currently in earnings.

815, Derivatives and Hedging.

We also use butane swap agreements to hedge against changes in the price of selected butane purchases we expect to complete in the future. We elected to not designate the butane swap agreements we have entered into as hedges for accounting purposes because the related NYMEX contracts associated with the gasoline that will be produced and sold from these future butane purchases did not qualify for hedge accounting treatment. Changes in the fair value of these agreements are recognized currently in earnings. As outlined in the table below, at September 30, 2011, we had open NYMEX contracts representing 3.6 million barrels of petroleum products and open butane swap agreements on the purchase of 0.3 million barrels of butane.

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Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Cash Flow Hedges	0.6 million barrels of refined petroleum products	Between October and December 2011
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between October 2011 and November 2013
NYMEX - Economic Hedges	2.3 million barrels of refined petroleum products	Between October 2011 and April 2012
Butane Swap Agreements	0.3 million barrels of butane	Between October 2011 and March 2012

At September 30, 2011, the fair value of our open NYMEX contracts was a net asset of $38.2 million and the fair value of our butane swap agreements was a liability of $1.0 million. Combined, the net asset was $37.2 million, of which $36.2 million was recorded as energy commodity derivatives contracts and $1.0 million was recorded as other noncurrent assets on our consolidated balance sheet. At September 30, 2011, we had received margin cash of $7.1 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 our counterparty; however, we have elected to disclose the combined fair values of our open NYMEX and butane swap agreements separately from these 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 on our consolidated balance sheets.

Interest Rate Derivatives

During 2011, we entered into interest rate swap agreements with respect to $100.0 million of our long-term debt, which were accounted for as fair value hedges, to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. In third quarter 2011, we terminated and settled these interest rate swap agreements and received $6.1 million, of which $5.9 million was recorded as an adjustment to long-term debt and will be amortized over the remaining life of the notes and $0.2 million was recorded as a reduction of accrued interest.
Derivative activity included in accumulated other comprehensive loss ("AOCL") for the three and nine months ended September 30, 2010 and 2011 was as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Activity Included in AOCL	2010	2011	2010	2011
Beginning balance	$3,407	$7,856	$1,743	$3,325
Net gain (loss) on commodity hedges	(179)	6,539	(468)	11,152
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(123)	(123)
Reclassification of net loss (gain) on commodity hedges to product sales revenues	(1,068)	(1,493)	967	(1,493)
Ending balance	$2,119	$12,861	$2,119	$12,861

As of September 30, 2011, the net gain estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million and $9.7 million, respectively.

The following table provides a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2010 and 2011 of derivatives accounted for under Accounting Standards Codification ("ASC") 815-25, Derivatives and Hedging—Fair Value Hedges, that were designated as hedging instruments (in thousands):

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Derivative Instrument	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		Nine Months Ended		Three Months Ended		Nine Months Ended	
		Sept. 30, 2010	Sept. 30, 2011	Sept. 30, 2010	Sept. 30, 2011	Sept. 30, 2010	Sept. 30, 2011	Sept. 30, 2010	Sept. 30, 2011
Interest rate swap agreements	Interest expense	$—	$264	$4,604	$1,275	$—	$(1,333)	$(17,277)	$(7,556)

During 2011, we had open NYMEX contracts on 0.7 million barrels of crude oil which were designated as fair value hedges. Because there was no ineffectiveness recognized on these hedges, the unrealized gains of $1.4 million from the agreements as of September 30, 2011 were fully offset by adjustments of $1.0 million and $0.4 million to tank bottom inventory and other current assets, respectively; therefore, there was no net impact on product sales revenues.
The following is a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2010 and 2011 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). See Note 4 - Product Sales Revenues for further details regarding the impact of our NYMEX agreements on product sales.

	Three Months Ended September 30, 2010		
	Effective Portion		
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$41
NYMEX commodity contracts	(179)	Product sales revenues	1,068
Total cash flow hedges	$(179)	Total	$1,109

	Three Months Ended September 30, 2011		
	Effective Portion		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$41
NYMEX commodity contracts	6,539	Product sales revenues	1,493
Total cash flow hedges	$6,539	Total	$1,534

	Nine Months Ended September 30, 2010		
	Effective Portion		
Derivative Instrument	Amount of 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	$123
NYMEX commodity contracts	(468)	Product sales revenues	(967)

Total cash flow hedges	$(468)	Total	$(844)

	Nine Months Ended September 30, 2011		
	Effective Portion		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$123
NYMEX commodity contracts	11,152	Product sales revenues	1,493
Total cash flow hedges	$11,152	Total	$1,616

There was no ineffectiveness recognized for any of our cash flow or fair value hedges during the three and nine months ended September 30, 2010 or 2011.

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The following table provides a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2010 and 2011 of derivatives accounted for under ASC 815-10-35; Derivatives and Hedging—Overall—Subsequent Measurement, that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivative			
		Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	2010	2011	2010	2011
NYMEX commodity contracts	Product sales revenues	$(8,466)	$28,579	$8,366	$(7,604)
NYMEX commodity contracts	Operating expenses	—	(923)	—	598
Butane swap contracts	Product purchases	—	(50)	—	(889)
	Total	$(8,466)	$27,606	$8,366	$(7,895)

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, 2010 and September 30, 2011 (in thousands):

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Other noncurrent assets	$—	Other noncurrent liabilities	$4,920

	September 30, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$8,689	Energy commodity derivatives contracts, net	$—
NYMEX commodity contracts	Other noncurrent assets	1,030	Other noncurrent liabilities	—
	Total	$9,719	Total	$—

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, 2010 and September 30, 2011 (in thousands):

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$—	Energy commodity derivatives contracts, net	$11,790

	September 30, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$28,497	Energy commodity derivatives contracts, net	$—
Butane swap contracts	Energy commodity derivatives contracts, net	—	Energy commodity derivatives contracts, net	981

Total	$28,497	Total	$981

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10. Commitments and Contingencies

Clean Air Act - Section 185 Liability.

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. 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 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" (the "Rule") to implement the requirements of CAA 185. The 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. Under the Rule, the annual fees to be paid by entities within the Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed the established baseline. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

In January 2010, the Environmental Protection Agency ("EPA") issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. If TCEQ's request for a Termination Determination was approved by the EPA, the requirement to assess a CAA 185 fee would be terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

In July 2011, the court issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on states' CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request.

Based on the recent court decisions and statements by the EPA, management now believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees. However, management believes it is probable we will be assessed fees for excess emissions at our Houston area facilities and estimates that the range of fees that could be assessed to us for the periods from 2007 through 2010 to be between \$6.4 million and \$13.7 million. During second quarter 2011, we recorded an accrual of \$6.4 million related to this matter, of which \$4.8 million was recorded as a current environmental liability and \$1.6 million was recorded as a long-term environmental liability. Additionally, during third quarter 2011, we accrued \$0.6 million for estimated fees associated with 2011 operations, which was recorded as a long-term environmental liability.

Environmental Liabilities.

Liabilities recognized for estimated environmental costs were \$32.8 million and \$43.4 million at December 31, 2010 and September 30, 2011, 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 expense was $5.1 million and $10.2 million for the three and nine months ended September 30, 2010, respectively, and $3.6 million and $16.1 million for the three and nine months ended September 30, 2011. Year-to-date 2011 environmental expense includes expense recognized for the Section 185 contingent liability accrual discussed above.

Environmental Receivables.

Receivables from insurance carriers related to environmental matters at December 31, 2010 were $2.2 million, of which $1.0 million and $1.2 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet. Receivables from insurance carriers related to environmental matters at September 30, 2011 were $5.3 million, of which $1.4 million and $3.9 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet.

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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 $3.8 million as of September 30, 2011. 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 financial position, results of operations or cash flows.

11. 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 September 30, 2011, 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 September 30, 2011 total 1.6 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 September 30, 2010			Nine Months Ended September 30, 2010		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2007 awards	$—	$—	$—	$—	$6	$6
2008 awards	1,930	1,057	2,987	4,855	2,326	7,181
2009 awards	350	358	708	1,050	818	1,868
2010 awards	473	187	660	1,382	445	1,827
Retention awards	218	—	218	600	—	600
Total	$2,971	$1,602	$4,573	$7,887	$3,595	$11,482
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$3,975			$10,031
Operating expense			598			1,451
Total			$4,573			$11,482

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended September 30, 2011			Nine Months Ended September 30, 2011		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2009 awards	$600	$657	$1,257	$3,835	$2,862	$6,697
2010 awards	387	189	576	1,724	708	2,432
2011 awards	578	153	731	1,702	442	2,144
Retention awards	170	—	170	478	—	478
Total	$1,735	$999	$2,734	$7,739	$4,012	$11,751
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$2,375			$10,696
Operating expense			359			1,055
Total			$2,734			$11,751

In January 2011, the cumulative amounts of the 2008 LTIP awards were settled by issuing 252,746 limited partner units and distributing those units to the LTIP participants. The minimum tax withholdings associated with this settlement and employer taxes of $7.4 million and $0.9 million, respectively, were paid in January 2011.

In January 2011, the compensation committee of our general partner's board of directors approved 148,670 phantom unit awards pursuant to our LTIP. These awards have a three-year vesting period that will end on December 31, 2013.

12. Distributions

Distributions we paid during 2010 and 2011 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/12/2010	$0.7100	$75,779
5/14/2010	0.7200	76,847
8/13/2010	0.7325	82,393
Through 9/30/2010	2.1625	235,019
11/12/2010	0.7450	83,798
Total	$2.9075	$318,817
2/14/2011	$0.7575	$85,398
5/13/2011	0.7700	86,807
8/12/2011	0.7850	88,498
Through 9/30/2011	2.3125	260,703
11/14/2011[a]	0.8000	90,189
Total	$3.1125	$350,892

(a) Our general partner's board of directors declared this cash distribution on October 18, 2011 to be paid on November 14, 2011 to unitholders of record at the close of business on November 1, 2011.

13. 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 and restricted cash. The carrying amounts reported on our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
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- Energy commodity derivatives deposits. This asset (liability) represents short-term deposits we paid (held) associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits paid (held) change daily in relation to the associated contracts.
- Long-term receivables. Fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest.
- Energy commodity derivatives contracts. These include NYMEX and butane price 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 9 - Derivative Financial Instruments for further disclosures regarding these contracts.
- Debt. The fair value of our publicly traded notes, excluding the value of interest rate swaps qualifying as fair value hedges, was based on the prices of those notes at December 31, 2010 and September 30, 2011. The carrying amount of borrowings under our revolving credit facility approximates fair value due to the variable rates of that instrument. See Note 8 - Debt for further disclosures of our debt instruments.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2010 and September 30, 2011 (in thousands):

Assets (Liabilities)	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value	September 30, 2011 Carrying Amount	September 30, 2011 Fair Value
Cash and cash equivalents	$7,483	$7,483	$198,065	$198,065
Restricted cash	$14,379	$14,379	$—	$—
Energy commodity derivatives deposits	$22,302	$22,302	$(7,059)	$(7,059)
Long-term receivables	$1,167	$1,161	$3,862	$3,830
Energy commodity derivatives contracts (current)	$(11,790)	$(11,790)	$36,205	$36,205
Energy commodity derivatives contracts (noncurrent)	$(4,920)	$(4,920)	$1,030	$1,030
Debt	$(1,906,148)	$(2,048,895)	$(2,153,437)	$(2,401,380)

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our NYMEX commodity contracts as of December 31, 2010 and September 30, 2011, based on the three levels established by ASC 820-10-50; Fair Value Measurements and Disclosures—Overall—Disclosure (in thousands):

Assets (Liabilities)	Total	Fair Value Measurements as of December 31, 2010 using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (current)	$(11,790)	$(11,790)	$—	$—
Energy commodity derivatives contracts (noncurrent)	$(4,920)	$(4,920)	$—	$—

Assets (Liabilities)	Total	Fair Value Measurements as of September 30, 2011 using: Quoted Prices in Active Markets	Significant Other Observable	Significant Unobservable Inputs

		for Identical Assets (Level 1)	Inputs (Level 2)	(Level 3)
Energy commodity derivatives contracts (current)	$36,205	$36,205	$—	$—
Energy commodity derivatives contracts (noncurrent)	$1,030	$1,030	$—	$—

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14. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

Quarterly distribution. In October 2011, our general partner's board of directors declared a quarterly distribution of $0.80 per unit to be paid on November 14, 2011 to unitholders of record at the close of business on November 1, 2011. The total cash distributions to be paid are $90.2 million (see Note 12—Distributions for details).

New revolving credit facility. In October 2011, we terminated our existing revolving credit facility that would have matured in September 2012 and entered into a new revolving credit facility. The new facility has total borrowing capacity of $800 million and matures in October 2016. Borrowings under the new facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings. Additionally, a commitment fee is assessed on undrawn amounts at a rate between 0.125% and 0.30%, depending on our credit ratings.

Potential sale of our ammonia pipeline system. Because management has determined that the ammonia pipeline is not strategic to our long-range plans and because virtually all of the significant maintenance work required for the ammonia pipeline has now been completed, management determined that the timing was appropriate to explore a sale of this asset. We have engaged an investment advisor to determine strategic alternatives for this asset. Based on initial non-binding indications of interest, we believe the sale of this asset is likely within the next year and have classified the ammonia pipeline system as an asset held for sale beginning in October 2011. The major classes of assets and liabilities for the ammonia segment included only property, plant and equipment, net of accumulated depreciation, which was $34.5 million at September 30, 2011. See Note 5—Segment Disclosures for financial information of the ammonia pipeline system.

MF Global Holdings Ltd. bankruptcy. On October 31, 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. 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. On October 31, 2011, MF Global disclosed to the CME that it had a "significant shortfall" in its segregated customer accounts. Effective November 3, 2011, our existing trading positions at MF Global were transferred to a new clearing agent. All of our NYMEX activity is now being conducted with our new clearing agent.

As of November 3, 2011, the date of transfer of our account, MF Global owed us $29.4 million. On November 4, 2011, $14.1 million of this was transferred to our new clearing agent account. At this point, it is unclear when or how much of the remaining $15.3 million will be returned to us.

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

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of refined petroleum products, such as gasoline and diesel fuel, and crude oil. As of September 30, 2011, 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, 2010.

Recent Developments

Pipeline conversion to crude service. In September 2011, we announced that we are proceeding with the reversal and conversion of a large portion of our Houston-to-El Paso pipeline to crude oil service. The reversed pipeline system, which will transport crude oil from Crane, Texas to refiners in Houston and Texas City, Texas, is expected to have an initial capacity of 135,000 barrels per day. We have received long-term committed volumes for a portion of this capacity. Management expects that the tariffs we will charge on crude oil movements on this pipeline after the reversal will be between $1.60 and $2.30 per barrel, depending upon volumes committed. This project is expected to cost approximately $245.0 million, which we expect to finance through cash we have on hand and borrowings from our revolving credit facility.

Prior to the completion of this pipeline reversal project, we expect to discontinue substantially all of the pipeline linefill activities that we currently conduct in connection with our operation of the Houston-to-El Paso pipeline and we expect to sell substantially all of the associated linefill inventory which, at September 30, 2011, was 0.7 million barrels of refined petroleum products with a carrying value of approximately $76.4 million.

We will be able to shift the volumes of refined products we are currently transporting on the Houston-to-El Paso pipeline section to a nearby pipeline section that we own; therefore, we do not expect a loss of revenues or operating margin from these movements as a result of the reversal.

Subject to receiving the necessary permits and regulatory approvals, we expect the reversed pipeline to be operational by mid-2013. Estimates of the increases in revenues and operating margin from the reversal of the Houston-to-El Paso pipeline section are subject to change due to additional commitments we may obtain, finalization of the tariff agreements, the success of the reversal project and other factors.

Cash Distribution. On October 18, 2011, the board of directors of our general partner declared a quarterly cash distribution of $0.80 per unit for the period of July 1, 2011 through September 30, 2011. This quarterly cash distribution will be paid on November 14, 2011 to unitholders of record on November 1, 2011. Total distributions to be paid under this declaration are approximately $90.2 million.

New revolving credit facility. In October 2011, we terminated our existing revolving credit facility that would have matured in September 2012 and entered into a new revolving credit facility. The new facility has total borrowing capacity of $800 million and matures in October 2016. Borrowings under the new facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings. Additionally, a commitment fee is assessed on undrawn amounts at a rate between 0.125% and 0.30%, depending on our credit ratings.

Potential sale of ammonia pipeline system. Because management has determined that the ammonia pipeline is not strategic to our long-range plans and because virtually all of the significant maintenance work required for the ammonia pipeline has now been completed, management determined that the timing was appropriate to explore a sale of this asset. We have engaged an investment advisor to determine strategic alternatives for this asset. Based on initial non-binding indications

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of interest, we believe the sale of this asset is likely within the next year and have classified the ammonia pipeline system as an asset held for sale beginning in October 2011. We expect to recognize a substantial gain on completion of the sale of our ammonia pipeline system.

MF Global Holdings Ltd. bankruptcy. On October 31, 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. 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. On October 31, 2011, MF Global disclosed to the CME that it had a “significant shortfall” in its segregated customer accounts. Effective November 3, 2011, our existing trading positions at MF Global were transferred to a new clearing agent. All of our NYMEX activity is now being conducted with our new clearing agent.

As of November 3, 2011, the date of transfer of our account, MF Global owed us $29.4 million. On November 4, 2011, $14.1 million of this was transferred to our new clearing agent account. At this point, it is unclear when or how much of the remaining $15.3 million will be returned to us.

Results of Operations

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

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Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2011

	Three Months Ended September 30,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$156.6	$167.5	$10.9	7
Petroleum terminals	49.9	60.6	10.7	21
Ammonia pipeline system	0.7	4.6	3.9	557
Intersegment eliminations	(0.4)	(0.6)	(0.2)	(50)
Total transportation and terminals revenues	206.8	232.1	25.3	12
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum pipeline system	56.9	61.1	(4.2)	(7)
Petroleum terminals	23.1	22.8	0.3	1
Ammonia pipeline system	8.3	6.3	2.0	24
Intersegment eliminations	(0.7)	(0.7)	—	—
Total operating expenses	87.6	89.5	(1.9)	(2)
Product margin:				
Product sales revenues	199.3	203.3	4.0	2
Product purchases	187.0	159.6	27.4	15
Product margin(1)	12.3	43.7	31.4	255
Equity earnings	1.6	2.0	0.4	25
Operating margin	133.3	188.5	55.2	41
Depreciation and amortization expense	27.4	30.3	(2.9)	(11)
G&A expense	23.6	20.4	3.2	14
Operating profit	82.3	137.8	55.5	67
Interest expense (net of interest income and interest capitalized)	24.4	26.7	(2.3)	(9)
Debt placement fee amortization expense	0.3	0.4	(0.1)	(33)
Other expense	0.8	—	0.8	100
Income before provision for income taxes	56.8	110.7	53.9	95
Provision for income taxes	0.2	0.5	(0.3)	(150)
Net income	$56.6	$110.2	$53.6	95
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.155	$1.118		
Volume shipped (million barrels):				
Refined products:				
Gasoline	53.2	48.4		
Distillates	32.6	36.5		
Aviation fuel	6.5	7.5		
Liquefied petroleum gases	1.3	1.4		
Crude oil	3.9	12.6		
Total volume shipped	97.5	106.4		

Petroleum terminals:		
Storage terminal average utilization (million barrels per month)	25.6	33.1
Inland terminal throughput (million barrels)	30.2	29.4
Ammonia pipeline system:		
Volume shipped (thousand tons)	20	134

(1) Product margin does not include depreciation or amortization expense.

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Transportation and terminals revenues increased $25.3 million, primarily resulting from:

- an increase in petroleum pipeline system revenues of $10.9 million. Revenues from the pipelines we purchased in September 2010 contributed $4.3 million of this increase. Excluding the impact of this acquisition, revenues increased $6.6 million primarily attributable to higher transportation revenues resulting from:
  a 6% increase in the average per barrel tariff rate, going from $1.264 to $1.338, principally reflecting the 7% tariff rate increase we implemented on July 1, 2011, partially offset by
  a 3% decrease in volumes due primarily to weak demand for gasoline.
  Additionally, increased demand for pipeline capacity and storage leases contributed to the increase in revenues;
- an increase in petroleum terminals revenues of $10.7 million, of which approximately 35% was contributed by the increase in revenues from the Cushing, Oklahoma storage assets acquired in September 2010. Excluding this acquisition, revenues increased at our other storage terminals principally due to additional leases of new tanks placed in service at Cushing, Oklahoma. Further, despite lower throughput volumes, our inland terminals generated higher revenues due to increased ethanol and additive fees; and
- an increase in ammonia pipeline system revenues of $3.9 million primarily because our pipeline was unavailable for shipments during much of third quarter 2010 due to hydrostatic testing on the system.

Operating expenses increased $1.9 million, resulting from:

- an increase in petroleum pipeline system expenses of $4.2 million. Pipeline system expenses decreased $0.9 million related to our September 2010 pipeline purchase because favorable product overages (which reduce operating expenses) more than offset other operating expenses related to the acquired assets. Excluding this reduction, petroleum pipeline expenses increased $5.1 million primarily resulting from less favorable product overages, higher property taxes and costs in third quarter 2011 as a result of flooding along our pipeline system;
- a decrease in petroleum terminals expenses of $0.3 million. Expenses associated with the Cushing storage assets acquired in September 2010 increased $1.7 million. Excluding this acquisition, operating expenses decreased $2.0 million primarily related to lower asset maintenance costs. Maintenance costs in third quarter 2010 were higher as a result of periodic testing of the lines at our Galena Park, Texas terminal; and
- a decrease in ammonia pipeline system expenses of $2.0 million due primarily to lower asset integrity costs, which were higher in third quarter 2010 due to significant hydrostatic testing on the system, and lower environmental costs.

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 $31.4 million between periods due primarily to favorable unrealized gains from NYMEX contracts resulting from declining commodity prices in third quarter 2011, partially offset by lower profits from our Houston-to-El Paso pipeline linefill management and petroleum products blending activities. During third quarter 2011, we recorded $3.0 million of lower-of-cost-or-market ("LCM") adjustments, which increased product costs, compared to third quarter 2010 in which approximately $4.9 million of LCM adjustments recognized in second quarter 2010 were reversed (which reduced product costs).

Depreciation and amortization expense increased $2.9 million primarily due to expansion capital projects placed into service and recent acquisitions.

G&A expense decreased $3.2 million primarily due to lower equity-based incentive compensation expense and lower bonus accruals. Equity-based compensation in third quarter 2010 was higher due to an increase in the estimated payouts of the 2008 incentive awards.

Interest expense, net of interest income and interest capitalized, increased $2.3 million. Our average debt outstanding increased to $2.1 billion for third quarter 2011 from $1.8 billion for third quarter 2010 principally due to borrowings for expansion capital expenditures and acquisitions, including $250.0 million of 4.25% senior notes issued in August 2011. The

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weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.3% in third quarter 2011 from 5.7% in third quarter 2010.
Other expense decreased $0.8 million primarily because the 2010 period included the write-off of bank fees related to an unused acquisition bridge loan.

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Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2011

	Nine Months Ended September 30,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$421.0	$472.7	$51.7	12
Petroleum terminals	144.0	172.8	28.8	20
Ammonia pipeline system	9.6	17.4	7.8	81
Intersegment eliminations	(1.5)	(2.2)	(0.7)	(47)
Total transportation and terminals revenues	573.1	660.7	87.6	15
Affiliate management fee revenue	0.6	0.6	—	—
Operating expenses:				
Petroleum pipeline system	149.2	150.5	(1.3)	(1)
Petroleum terminals	57.7	71.4	(13.7)	(24)
Ammonia pipeline system	15.5	13.4	2.1	14
Intersegment eliminations	(2.4)	(2.1)	(0.3)	(13)
Total operating expenses	220.0	233.2	(13.2)	(6)
Product margin:				
Product sales revenues	585.3	600.5	15.2	3
Product purchases	503.5	489.6	13.9	3
Product margin(1)	81.8	110.9	29.1	36
Equity earnings	4.3	4.8	0.5	12
Operating margin	439.8	543.8	104.0	24
Depreciation and amortization expense	79.5	90.3	(10.8)	(14)
G&A expense	67.0	70.3	(3.3)	(5)
Operating profit	293.3	383.2	89.9	31
Interest expense (net of interest income and interest capitalized)	67.0	77.3	(10.3)	(15)
Debt placement fee amortization expense	1.0	1.2	(0.2)	(20)
Other expense	0.8	—	0.8	100
Income before provision for income taxes	224.5	304.7	80.2	36
Provision for income taxes	0.9	1.4	(0.5)	(56)
Net income	$223.6	$303.3	$79.7	36
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.222	$1.088		
Volume shipped (million barrels):				
Refined products:				
Gasoline	135.3	153.1		
Distillates	85.8	99.0		
Aviation fuel	16.5	20.3		
Liquefied petroleum gases	4.4	4.5		
Crude oil	3.9	29.8		
Total volume shipped	245.9	306.7		

Petroleum terminals:		
Storage terminal average utilization (million barrels per month)	24.4	31.4
Inland terminal throughput (million barrels)	86.6	86.3
Ammonia pipeline system:		
Volume shipped (thousand tons)	298	546

(1) Product margin does not include depreciation or amortization expense.

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Transportation and terminals revenues increased $87.6 million, primarily resulting from:

- an increase in petroleum pipeline system revenues of $51.7 million. Revenues from the pipelines we purchased in September 2010 contributed $18.2 million of the increase. Excluding the impact of this acquisition, revenues increased $33.5 million primarily attributable to higher transportation revenues resulting from:
  a 3% increase in the average per barrel tariff rate, going from $1.265 to $1.309, principally reflecting the 7% tariff rate increase we implemented on July 1, 2011; and
  a 3% increase in transportation volumes driven primarily by higher demand for diesel fuel.

Additionally, higher storage lease revenues, increased demand for pipeline capacity leases and incremental fees for terminal throughput, ethanol and other blending services contributed to the increase in revenues;

- an increase in petroleum terminals revenues of $28.8 million, of which almost half was contributed by the increase in revenues from our Cushing, Oklahoma storage assets acquired in September 2010. Excluding this acquisition, revenues increased at our other storage and inland terminals. Storage terminal revenues increased principally due to additional leases of new tanks at Cushing, Oklahoma and Galena Park, Texas that were placed in service over the last year. Inland revenues benefited primarily from higher ethanol fees; and

- an increase in ammonia pipeline system revenues of $7.8 million due to increased shipments during 2011. Our pipeline was unavailable for shipments during much of 2010 due to hydrostatic testing being performed on the pipeline.

Operating expenses increased $13.2 million, primarily resulting from:

- an increase in petroleum pipeline system expenses of $1.3 million. Pipeline system expenses decreased $5.4 million related to our September 2010 pipeline purchase because favorable product overages (which reduce operating expenses) more than offset other operating expenses. Excluding this reduction, petroleum pipeline expenses increased $6.7 million due in part to a $2.8 million impairment of one of our pipeline terminals recognized in the current year. Otherwise, higher losses from asset replacements and write-offs, increases in power costs due to increased pipeline volumes, higher compensation costs, expenses recognized in the current period related to contingent air emission fees and higher property taxes were partially offset by more favorable product overages;
- an increase in petroleum terminals expenses of $13.7 million, of which $5.3 million was attributable to the increase in expenses for the Cushing storage assets acquired in September 2010. Excluding these costs, operating expenses increased $8.4 million primarily related to expenses recognized in the current period for contingent air emission fees, product downgrade charges in the current period and higher losses on asset retirements resulting from the demolition of older tanks to make room for new tank construction at our Galena Park, Texas facility, partially offset by lower asset maintenance costs; and
- a decrease in ammonia pipeline system expenses of $2.1 million resulting primarily from lower asset integrity and environmental costs, partially offset by lower gains on asset sales. The 2010 period included a gain on the sale of a portion of pipeline linefill (pipeline linefill for our ammonia system is recorded as property, plant and equipment).

Product sales revenues primarily result 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 NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in the future related to these activities. The period change in the mark-to-market value of these contracts that do not qualify for hedge accounting treatment, 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 $29.1 million between periods due primarily to favorable unrealized gains from NYMEX contracts resulting from declining commodity prices in third quarter 2011 and higher profits from our fractionation activities, partially offset by lower profits from our petroleum products blending activities. The LCM adjustments for the nine months ended September 30, 2011 were $3.0 million. The LCM adjustments for the three months ended September 30, 2010 were $0.3 million (net of approximately $4.9 million of LCM reversals).

Depreciation and amortization expense increased $10.8 million primarily due to expansion capital projects placed into service and recent acquisitions.

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G&A expense increased $3.3 million primarily due to higher equity-based incentive compensation expense. Equity-based incentive compensation expense increased principally because, during second quarter 2011, we increased the 2009 incentive award accruals to the stretch payout amount based on our strong performance against the financial metric associated with those awards. Increases to the 2010 equity-based incentive compensation expense accruals for above-target payouts related to the 2008 incentive awards were not fully recognized until the fourth quarter of 2010.

Interest expense, net of interest income and interest capitalized, increased $10.3 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $2.0 billion for 2011 from $1.7 billion for 2010 principally due to borrowings for expansion capital expenditures and acquisitions, 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, increased slightly from 5.3% in 2010 to 5.4% in 2011. Other expense decreased $0.8 million primarily because the 2010 period included the write-off of bank fees related to an unused acquisition bridge loan.

Liquidity and Capital Resources

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 nine months ended September 30, 2010 and 2011 to net income, which is its nearest comparable GAAP financial measure, was as follows (in thousands):

	Nine Months Ended September 30,		Increase
	2010	2011	(Decrease)
Net income	$223,623	$303,304	$79,681
Depreciation and amortization[1]	80,475	91,441	10,966
Equity-based incentive compensation expense[2]	8,082	4,319	(3,763)
Asset retirements and impairments	107	7,529	7,422
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions[3]	(7,663)	(25,318)	(17,655)
Derivative losses recognized in previous periods associated with products sold in the period[4]	(2,195)	(15,697)	(13,502)
Lower-of-cost-or-market adjustments	293	2,984	2,691
Houston-to-El Paso cost of sales adjustments[5]	(2,055)	386	2,441
Total commodity-related adjustments	(11,620)	(37,645)	(26,025)
Maintenance capital	(26,932)	(38,285)	(11,353)
Other	(2,074)	(1,390)	684
Distributable cash flow	$271,661	$329,273	$57,612

(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 nine months ended September 30, 2010 and 2011 was $11.5 million and $11.7 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2010 and 2011 of $3.4 million and $7.4 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.

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Distributable cash flow increased $57.6 million. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above. We add back the non-cash portion of equity-based incentive compensation expense in determining distributable cash flow. Although equity-based incentive compensation was higher in 2011 as compared to the 2010 period, the cash taxes we paid on our awards were significantly higher in 2011, resulting in a lower adjustment for the current period. Asset retirements in the 2010 period included a $3.0 million insurance settlement and the gain from that settlement was excluded from our distributable cash flow. Further, 2011 amounts included an impairment expense of $2.8 million. The decrease in distributable cash flows from commodity-related adjustments is primarily due to the impact of sharp price decreases during the 2011 period. A discussion of our maintenance capital expenditures is provided in Capital Requirements below.

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $315.9 million and $426.1 million for the nine months ended September 30, 2010 and 2011, respectively. The $110.2 million increase from 2010 to 2011 was primarily attributable to:

- a $90.5 million increase in net income, excluding the increase in non-cash depreciation and amortization expense;
- an $18.5 million increase resulting from a $10.8 million increase in accrued product purchases in 2011 versus a $7.7 million decrease in accrued product purchases in 2010 primarily due to the timing of invoices paid to vendors and suppliers;
- a $14.4 million increase due to the elimination of restricted cash resulting from our purchase of the private investment group's common equity in Magellan Crude Oil, LLC ("MCO") during first quarter 2011. Prior to this, 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;
- a $12.7 million increase resulting from a $2.1 million decrease in accounts receivable and other accounts receivable in 2011 versus a $10.6 million increase in accounts receivable and other accounts receivable during 2010 primarily due to timing of payments from our customers;
- a $12.4 million increase resulting from a $10.7 million increase in current and noncurrent environmental liabilities in 2011 versus a $1.7 million decrease in current and noncurrent environmental liabilities in 2010 primarily due to our Section 185 of the Clean Air Act ("CAA 185") contingent liability accrual during 2011 (see Environmental below for further details regarding this matter); and
- a $12.1 million increase resulting from a $27.3 million increase in accounts payable in 2011 versus a $15.2 million increase in accounts payable in 2010 primarily due to the timing of invoices paid to vendors and suppliers.

These increases were partially offset by:

- a $30.4 million decrease primarily resulting from the impact of higher product prices and higher levels of inventory purchases in 2011 as compared to 2010; specifically, a $40.7 million increase in inventory in 2011 versus a $10.3 million increase in inventory in 2010; and
- a $17.5 million decrease resulting from a $14.9 million decrease in energy commodity derivatives contracts, net of derivatives deposits in 2011, versus a $2.6 million increase in 2010 primarily due to an increase in the number of contracts during 2011 and the change in commodity prices during the respective periods.

Net cash used by investing activities for the nine months ended September 30, 2010 and 2011 was $471.8 million and $206.1 million, respectively. During 2011, we spent $143.2 million for capital expenditures, which included $38.3 million for maintenance capital and $104.9 million for expansion capital. Also during 2011, we acquired a private investment group's common equity in MCO for $40.5 million and spent $17.8 million on various asset acquisitions. During 2010, we acquired certain storage and pipeline assets from BP Pipelines (North America), Inc. ("BP") for $291.0 million, which was reported as the acquisition of a business. Also during 2010, we acquired petroleum products storage tanks at various locations on our petroleum pipeline system for $29.3 million, and we spent $160.7 million for capital expenditures, which included $27.5 million for maintenance capital and $133.2 million for expansion capital. Also, during 2010, proceeds from the sale of assets were $5.3 million, including $3.0 million of proceeds from the settlement of our insurance claim related to a tank fire at one of our petroleum pipeline system terminals.

Net cash provided (used) by financing activities for the nine months ended September 30, 2010 and 2011 was $228.8 million and $(29.5) million, respectively. During 2011, we received net proceeds of $260.9 million from borrowings under notes, which were used to repay the outstanding balance on our revolving credit facility of $193.0 million at that time, with the balance used for general partnership purposes. Additionally, we paid cash distributions of $260.7 million to our unitholders while borrowings on our revolving credit facility of $178.0 million, prior to being repaid, were primarily used to finance expansion capital projects and acquisitions. During 2010, we received net proceeds of $258.4 million from our public offering of common units and $298.9 million, net of discounts, from borrowings under notes. Combined, these net proceeds were used to acquire certain assets from BP and to repay the outstanding balance on our revolving credit facility of $175.5 million at that time, with the balance used for general partnership purposes. Additionally, we paid cash distributions of $235.0 million to our unitholders while net repayments on our revolving credit facility, including the $175.5 million repayment above, were $101.6 million. During 2010 and 2011, respectively, we received proceeds of $16.2 million and $5.9 million from the termination and settlement of interest rate swap agreements. The settlement of tax withholdings on long-term incentive plan awards was $3.4 million and $7.4 million during 2010 and 2011, respectively.

The quarterly distribution amount related to our third-quarter 2011 financial results (to be paid in fourth quarter 2011) is $0.80 per unit. If we meet management's targeted distribution growth of 7% for 2011 and the number of outstanding limited partner units remains at 112.7 million, total cash distributions of approximately $357.4 million will be paid to our unitholders for 2011.

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 nine months ended September 30, 2010 and 2011, our maintenance capital spending was $27.5 million and $38.3 million, respectively. The $10.8 million increase was primarily attributable to an increase in the amount of regulatory and integrity work performed on our pipeline and terminals systems, maintenance capital for recently-acquired assets and the relocation of a river crossing on our Houston-to-El Paso pipeline section. For 2011, 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 nine months of 2011, we spent $104.9 million for organic growth capital, $40.5 million to acquire the remaining interest in MCO, and $17.8 million, collectively, to acquire the remaining undivided interest in our Southlake, Texas terminal, a petroleum products pipeline segment connected to our petroleum pipeline system at Reagan, Texas and petroleum products storage tanks in Riverside, Missouri. Based on the progress of expansion projects already underway, including the reversal and conversion of our Houston-to-El Paso pipeline to crude oil, we expect to spend approximately $240.0 million for expansion capital during 2011, including acquisitions, with an additional $270.0 million in 2012 and $65.0 million in 2013 to complete these projects.

Liquidity

Consolidated debt at December 31, 2010 and September 30, 2011 was as follows (in thousands):

	December 31, 2010	September 30, 2011	Weighted-Average Interest Rate at September 30, 2011 (1)
Revolving credit facility	$15,000	$—	—
$250.0 million of 6.45% Notes due 2014	249,786	249,829	6.3%
$250.0 million of 5.65% Notes due 2016	252,466	252,144	5.7%
$250.0 million of 6.40% Notes due 2018	259,125	263,994	5.1%
$550.0 million of 6.55% Notes due 2019	581,890	579,372	5.9%

$550.0 million of 4.25% Notes due 2021	298,932	559,138	4.2%
$250.0 million of 6.40% Notes due 2037	248,949	248,960	6.3%
Total debt	$1,906,148	$2,153,437	

(1) Weighted-average interest rate includes the impact of current interest rate swaps, the amortization/accretion of discounts and premiums and the

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amortization/accretion of gains and losses realized on historical cash flow and fair value hedges.

The face value of our debt at September 30, 2011 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.

The amounts outstanding under the notes and revolving credit facility described in the table above are senior indebtedness.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which matures in September 2012, was $550.0 million at September 30, 2011. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of September 30, 2011, there were no borrowings outstanding under this facility; however $4.6 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but do decrease our borrowing capacity under the facility. In October 2011, we replaced the above-noted revolving credit facility with a new revolving facility. See Recent Events above for details.

2011 Debt Offering. In August 2011, we issued an additional $250.0 million of our 4.25% notes due 2021. We priced these notes at a price of 104.1%, or $260.2 million. Net proceeds from this offering, including accrued interest of $0.7 million, were $258.7 million after underwriting discounts of $1.6 million and other offering costs of $0.6 million. Proceeds from this debt offering were used to repay all of the borrowings outstanding under our revolving credit facility, which was $193.0 million at the time, and for general partnership purposes, including investments in capital expenditures.

Interest Rate Derivatives

During 2011, we entered into interest rate swap agreements with respect to $100.0 million of our long-term debt, which were accounted for as fair value hedges, to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. In third quarter 2011, we terminated and settled these interest rate swap agreements and received $6.1 million, of which $5.9 million was recorded as an adjustment to long-term debt that will be amortized over the remaining life of the notes and $0.2 million was recorded as a reduction of accrued interest.

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 Contingent Liability.

CAA 185 requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. 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 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" (the "Rule") to implement the requirements of CAA 185. The 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. Under the Rule, the annual fees to be paid by entities within the Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed the established baseline. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

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In January 2010, the EPA issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. If TCEQ's request for a Termination Determination was approved by the EPA, the requirement to assess a CAA 185 fee would be terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

In July 2011, the court issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on states' CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request.

Based on the recent court decisions and statements by the EPA, management now believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees at all. However, management believes it is probable we will be assessed fees for excess emissions at our Houston area facilities and estimates that the range of fees that could be assessed to us for the periods from 2007 through 2010 to be between $6.4 million and $13.7 million. During second quarter 2011, we recorded an accrual of $6.4 million related to this matter, of which $4.8 million was recorded as a current environmental liability and $1.6 million was recorded as a long-term environmental liability. Additionally, during third quarter 2011, we accrued $0.6 million for estimated fees associated with 2011 operations, which was recorded as a long-term environmental liability.

Other Items

Derivative Agreements. Certain of the business activities in which we engage result in our holding 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 September 30, 2011, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts for 0.6 million barrels of petroleum products to hedge against price changes in anticipated sales of petroleum products related to our petroleum products blending and fractionation activities, which we are accounting for as cash flow hedges. These contracts mature between October and December 2011. Prior to becoming qualified cash flow hedges, we recognized unrealized losses of $1.4 million on these agreements during 2011, which were recorded as decreases in product sales revenues on our consolidated statements of income. Through September 30, 2011, the cumulative amount of unrealized gains from these agreements was $8.3 million. Additionally, we recognized gains of $1.5 million on NYMEX contracts that settled during 2011 related to physical product sales during the third quarter of 2011.

- 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 October

2011 and November 2013. Through September 30, 2011, the cumulative amount of unrealized gains from these agreements was $1.4 million.

We recorded the above noted unrealized gains from the cash flow hedges as adjustments to accumulated other comprehensive loss and the unrealized gains from the fair value hedges were recorded as adjustments to the asset being hedged. As a result, none of these unrealized gains impacted product sales.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 2.2 million barrels of petroleum products related to our petroleum products blending, fractionation and Houston-to-El Paso linefill management activities. These contracts mature between October 2011 and April 2012 and are being accounted for as economic hedges. Through September 30, 2011, the cumulative amount

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of unrealized gains associated with these agreements was $26.5 million, all of which was recognized in 2011. Additionally, we recognized losses of $34.2 million on NYMEX contracts that settled during 2011 related to physical product sales during 2011. Furthermore, we realized gains of $0.1 million on NYMEX contracts that settled during 2011 but were rolled to other hedges that are associated with products we expect to sell in the future, all of which were recognized during 2011. We recorded these unrealized gains and losses as adjustments to product sales revenues.

- NYMEX contracts covering 0.1 million barrels of petroleum products related to our pipeline product overages that mature in October 2011. Through September 30, 2011, the cumulative amount of unrealized gains associated with these agreements was $0.7 million. We recorded these gains as a decrease in operating expenses, all of which was recognized during 2011. Additionally, we realized losses of $0.1 million on NYMEX contracts that settled during 2011 related to physical product sales during 2011, all of which were recognized in 2011.

- Butane swap positions to purchase 0.3 million barrels of butane that mature between October 2011 and March 2012. Through September 30, 2011, the cumulative amount of unrealized losses associated with these agreements was $1.0 million. We recorded these losses as an increase in product purchases, all of which were recognized in 2011. Additionally, we realized gains of $0.1 million on butane swap positions that settled during 2011 related to physical product purchases during 2011, all of which were recognized in 2011.

The following table provides 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 September 30, 2010 and 2011 (in millions):

2010	
NYMEX losses recorded during the nine months ended September 30, 2010 that were associated with physical product sales during the nine months ended September 30, 2010	$5.2
NYMEX gains recorded during 2010 that were associated with future physical product sales	2.2
Total NYMEX gains which impacted product sales revenues during the nine months ended September 30, 2010	$7.4
2011	
NYMEX losses recorded during the nine months ended September 30, 2011 that were associated with physical product sales during the nine months ended September 30, 2011	$(32.7)
NYMEX gains, net of butane swap agreements, recorded during 2011 that were associated with future physical product sales	26.6
Total NYMEX losses which impacted product sales revenues during the nine months ended September 30, 2011	$(6.1)

Pipeline Tariff Increase. The Federal Energy Regulatory Commission ("FERC") regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 40% of our tariffs are subject to this indexing methodology while the remaining 60% of the tariffs can be adjusted at our discretion based on competitive factors. In December 2010, FERC approved the indexing methodology to be used for the five-year period beginning in July 2011 equal to the annual change in the producer price index for finished goods ("PPI-FG") plus 2.65%. Certain shippers requested a rehearing of this matter by the FERC, and the FERC issued an order denying the requests for rehearing in May 2011, rejecting all arguments alleged by shippers. In July 2011, a shipper filed a petition for review of this matter with the D.C. Circuit. At this time, management is unable to determine what outcome might result from this petition. Based on PPI-FG for 2010, we increased virtually all of our tariff rates by 7% on July 1, 2011, consistent with the new FERC-approved methodology.

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 $3.8 million as of September 30, 2011. 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.

New Accounting Pronouncements

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-08, Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment, which modifies the test for goodwill intangibles. Under this ASU, entities are no longer required to calculate the fair value of a reporting unit unless they determine that it is more likely than not that a reporting unit's fair value is less than its carrying amount. This ASU is effective for periods beginning after December 15, 2011. Our adoption of this ASU in the first quarter of 2012 will have no impact on our results of operations, financial position or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income, which requires either that the income statement include other comprehensive income or a separate comprehensive income statement be reported immediately after the income statement. The option to report other comprehensive income in the statement of owner's equity has been eliminated. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. Our adoption of this ASU in first quarter of 2011 had no impact on our results of operations, financial position or cash flows.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

We use derivatives to help manage commodity price risk. Derivatives that qualify as normal purchases and sales are accounted for using traditional accrual accounting. As of September 30, 2011, we had commitments under forward purchase contracts for product purchases of approximately 0.4 million barrels that are being accounted for as normal purchases totaling approximately $32.4 million, and we had commitments under forward sales contracts for product sales of approximately 0.7 million barrels that are being accounted for as normal sales totaling approximately $82.7 million.

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 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 September 30, 2011, we had open NYMEX contracts representing 3.6 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane swap positions on the purchase of 0.3 million barrels of butane.

At September 30, 2011, the fair value of our open NYMEX contracts was a net asset of $38.2 million and the fair value of our butane swap agreements was a liability of $1.0 million. Combined, the net asset was $37.2 million, of which $36.2 million was recorded as energy commodity derivatives contracts and $1.0 million was recorded as other noncurrent assets on our consolidated balance sheet.

At September 30, 2011, open NYMEX contracts representing 2.3 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 $2.3 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $2.3 million increase in our product sales revenues. However, the increases or decreases in product sales revenues we recognize from our open NYMEX contracts will be substantially offset by higher or lower product sales revenues when the physical sale of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

At September 30, 2011, we elected not to take hedge accounting treatment on our open butane swap contracts representing 0.3 million barrels of butane. A $1.00 per barrel increase in the price of butane would result in a $0.3 million decrease in our product purchases and a $1.00 per barrel decrease in the price of butane would result in a $0.3 million increase in our product purchases. However, the increases or decreases in product purchases we recognize from our open butane price swap contracts will be substantially offset by higher or lower product purchases when the physical purchase of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

ITEM 4. CONTROLS AND PROCEDURES

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. Additionally, these disclosure controls and practices are effective in ensuring that information required to be disclosed is accumulated and communicated to our Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures. There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. On September 1, 2010, we completed an acquisition of a business from BP Pipelines (North America), Inc. Effective with our 10-Q report for the quarterly period ended June 30, 2011, management began including this acquisition in its assessment of the effectiveness of our internal control over financial reporting.

Forward-Looking Statements

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "estimates," "forecasts," "projects," "should" and other simila 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 United States;
- 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, 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 and along our petroleum pipeline system;
- changes in supply patterns for our storage terminals;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the United States Surface Transportation Board and state regulatory agencies;

- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- weather patterns materially different than historical trends;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards or unforeseen interruptions for which we are not adequately insured;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;

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- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in laws and regulations 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 could become subject, including tax withholding issues, safety, 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 and the impact these could have on our unit price;
- 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.

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PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2011, Magellan received an information request from the U.S. Environmental Protection Agency, pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in February 2011 near Texas City, Texas. We have accrued an amount for potential monetary sanctions related to this matter of $0.1 million. 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, 2010, 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. RESERVED

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
Exhibit 10.1	—	Executive Severance Pay Plan dated July 21, 2011 (filed as Exhibit 10.2 to Form 10-Q filed August 4, 2011).
Exhibit 10.2	—	Magellan Midstream Partners' Long-Term Incentive Plan, Amended and Restated on July 21, 2011 (filed as Exhibit 10.1 to Form 10-Q/A filed August 4, 2011.
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of John D. Chandler, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101.INS	—	XBRL Instance Document.
Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma on November 7, 2011.

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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