MARTIN MIDSTREAM PARTNERS LP
Form 10-Q
August 06, 2012

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

FORM 10-Q

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from ____________ to ____________

Commission File Number
000-50056

MARTIN MIDSTREAM PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	05-0527861
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

4200 Stone Road
Kilgore, Texas 75662
(Address of principal executive offices, zip code)

Registrant’s telephone number, including area code: (903) 983-6200

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 o

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 o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicated by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

The number of the registrant's Common Units outstanding at August 6, 2012, was 23,116.776.

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PART I – FINANCIAL INFORMATION

Item 1.Financial Statements

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED BALANCE SHEETS
(Dollars in thousands)

	June 30, 2012 (Unaudited)	December 31, 2011 (Audited)
Assets		
Cash	$ 106	$ 266
Accounts and other receivables, less allowance for doubtful accounts of $3,093 and $3,021, respectively	97,471	126,461
Product exchange receivables	8,129	17,646
Inventories	83,759	77,677
Due from affiliates	17,199	5,968
Fair value of derivatives	41	622
Other current assets	2,074	1,978
Assets held for sale	211,588	212,787
Total current assets	420,367	443,405
Property, plant and equipment, at cost	678,263	632,728
Accumulated depreciation	(234,168)	(215,272)
Property, plant and equipment, net	444,095	417,456
Goodwill	8,337	8,337
Investment in unconsolidated entities	76,411	62,948
Debt issuance costs, net	11,603	13,330
Other assets, net	6,043	3,633
	$ 966,856	$ 949,109
Liabilities and Partners' Capital		
Current installments of long-term debt and capital lease obligations	$ 206	$ 1,261
Trade and other accounts payable	109,429	125,970
Product exchange payables	15,779	37,313
Due to affiliates	12,316	18,485
Income taxes payable	839	893
Fair value of derivatives	—	362
Other accrued liabilities	9,317	11,022
Liabilities held for sale	508	501
Total current liabilities	148,394	195,807
Long-term debt and capital leases, less current maturities	452,970	458,941
Deferred income taxes	7,336	7,657
Other long-term obligations	1,061	1,088
Total liabilities	609,761	663,493

Partners’ capital	357,032	284,990
Accumulated other comprehensive income	63	626
Total partners’ capital	357,095	285,616
Commitments and contingencies		
	$966,856	$949,109

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)
(Dollars in thousands, except per unit amounts)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenues:				
Terminalling and storage *	$21,046	$19,327	$41,232	$37,450
Marine transportation *	20,714	17,376	41,576	36,775
Sulfur services	2,925	2,850	5,851	5,700
Product sales: *				
Natural gas services	164,817	127,050	336,928	264,205
Sulfur services	64,168	74,083	135,794	130,991
Terminalling and storage	19,208	19,371	40,881	37,916
	248,193	220,504	513,603	433,112
Total revenues	292,878	260,057	602,262	513,037
Costs and expenses:				
Cost of products sold: (excluding depreciation and amortization)				
Natural gas services *	163,043	125,648	330,242	257,926
Sulfur services *	47,350	59,892	102,310	104,334
Terminalling and storage	17,367	17,395	37,387	33,955
	227,760	202,935	469,939	396,215
Expenses:				
Operating expenses *	34,442	33,372	71,454	66,322
Selling, general and administrative *	4,603	3,751	9,007	7,477
Depreciation and amortization	9,791	9,928	19,491	19,498
Total costs and expenses	276,596	249,986	569,891	489,512
Other operating income	378	98	373	98
Operating income	16,660	10,169	32,744	23,623
Other income (expense):				
Equity in earnings (loss) of unconsolidated entities	(745)	153	(363)	153
Interest expense	(8,265)	(4,403)	(15,472)	(12,805)
Debt prepayment premium	(2,219)	—	(2,470)	—
Other, net	84	44	145	102
Total other expense	(11,145)	(4,206)	(18,160)	(12,550)
Income from continuing operations before taxes	5,515	5,963	14,584	11,073
Income tax expense	(307)	(223)	(572)	(444)
Income from continuing operations	5,208	5,740	14,012	10,629
Income from discontinued operations, net of income taxes	1,984	3,030	3,709	5,463
Net income	$7,192	$8,770	$17,721	$16,092

*Related Party Transactions Included Above

Revenues:				
Terminalling and storage	$14,805	$12,897	$30,080	$25,835
Marine transportation	4,446	6,306	9,303	12,871
Product Sales	1,958	1,768	4,147	5,569
Costs and expenses:				
Cost of products sold: (excluding depreciation and amortization)				
Natural gas services	7,707	1,961	12,022	4,422
Sulfur services	3,970	4,492	8,401	8,645
Expenses:				
Operating expenses	14,392	13,477	28,208	25,265
Selling, general and administrative	2,828	1,965	5,494	3,971

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)
(Dollars and units in thousands, except per unit amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Allocation of net income attributable to:				
Limited partner interest:				
Continuing operations	$ 4,090	$ 4,633	$ 11,517	$ 8,517
Discontinued operations	1,558	2,445	3,049	4,377
	5,648	7,078	14,566	12,894
General partner interest:				
Continuing operations	1,118	926	2,495	1,746
Discontinued operations	426	489	660	898
	1,544	1,415	3,155	2,644
Net income attributable to:				
Continuing operations	5,208	5,559	14,012	10,263
Discontinued operations	1,984	2,934	3,709	5,275
Net income attributable to limited partners:	$ 7,192	$ 8,493	$ 17,721	$ 15,538
Basic:				
Continuing operations	$ 0.18	$ 0.24	$ 0.51	$ 0.44
Discontinued operations	0.07	0.13	0.13	0.23
	$ 0.25	$ 0.37	$ 0.64	$ 0.67
Weighted average limited partner units - basic	23,103	19,159	22,839	19,163
Diluted:				
Continuing operations	$ 0.18	$ 0.24	$ 0.51	$ 0.44
Discontinued operations	0.07	0.13	0.13	0.23
	$ 0.25	$ 0.37	$ 0.64	$ 0.67
Weighted average limited partner units - diluted	23,104	19,159	22,842	19,164

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(Dollars in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$7,192	$8,770	$17,721	$16,092
Other comprehensive income adjustments:				
Changes in fair values of commodity cash flow hedges	—	843	126	(65)
Commodity cash flow hedging gains (losses) reclassified to earnings	(499)	(318)	(689)	(752)
Interest rate cash flow hedging losses reclassified to earnings	—	—	—	18
Other comprehensive income	(499)	525	(563)	(799)
Comprehensive income	$6,693	$9,295	$17,158	$15,293

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF CAPITAL
(Unaudited)
(Dollars in thousands)

	Partners' Capital						
	Common Limited		Subordinated Limited		General Partner	Accumulated Other Comprehensive Income (Loss)	
	Units	Amount	Units	Amount	Amount		Total
Balances – January 1, 2011	17,707,832	$250,785	889,444	$17,721	$4,881	$1,419	$274,806
Net income	—	13,448	—	—	2,644	—	16,092
Recognition of beneficial conversion feature	—	(554)	—	554	—	—	—
Follow-on public offering	1,874,500	70,330	—	—	—	—	70,330
General partner contribution	—	—	—	—	1,505	—	1,505
Cash distributions	—	(28,390)	—	—	(3,025)	—	(31,415)
Excess purchase price over carrying value of acquired assets	—	(19,685)	—	—	—	—	(19,685)
Unit-based compensation	15,350	96	—	—	—	—	96
Purchase of treasury units	(14,850)	(582)	—	—	—	—	(582)
Unit-based compensation grant forfeitures	(500)	—	—	—	—	—	—
Adjustment in fair value of derivatives	—	—	—	—	—	(799)	(799)
Balances – June 30, 2011	19,582,332	$285,448	889,444	$18,275	$6,005	$620	$310,348
Balances – January 1, 2012	20,471,776	$279,562	—	$—	$5,428	$626	$285,616
Net income	—	14,566	—		3,155	—	17,721
Follow-on public offering	2,645,000	91,361	—	—	—	—	91,361
General partner contribution	—	—	—	—	1,951	—	1,951
Cash distributions	—	(35,253)	—	—	(3,635)	—	(38,888)
Unit-based compensation	6,250	118	—	—	—	—	118

Purchase of treasury units	(6,250)	(221)	—	—	—	—	(221)
Adjustment in fair value of derivatives	—	—	—	—	—	(563)	(563)
Balances – June 30, 2012	23,116,776	$350,133	—	$—	$6,899	$63	$357,095

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED AND CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash flows from operating activities:		
Net income	$17,721	$16,092
Less: Income from discontinued operations	(3,709)	(5,463)
Net income from continuing operations	14,012	10,629
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	19,491	19,498
Amortization of deferred debt issuance costs	1,931	2,390
Amortization of debt discount	427	175
Deferred taxes	(321)	(32)
Loss on sale of property, plant and equipment	3	714
Equity in earnings (loss) of unconsolidated entities	363	(153)
Non-cash mark-to-market on derivatives	(344)	(2,346)
Other	118	96
Change in current assets and liabilities, excluding effects of acquisitions and dispositions:		
Accounts and other receivables	28,990	(3,843)
Product exchange receivables	9,517	(7,542)
Inventories	(6,082)	(10,344)
Due from affiliates	(11,231)	(12,685)
Other current assets	(96)	1,176
Trade and other accounts payable	(16,541)	7,848
Product exchange payables	(21,534)	5,257
Due to affiliates	(6,169)	10,270
Income taxes payable	(54)	(210)
Other accrued liabilities	(1,705)	(365)
Change in other non-current assets and liabilities	(574)	(92)
Net cash provided by continuing operating activities	10,201	20,441
Net cash provided by discontinued operating activities	6,918	9,634
Net cash provided by operating activities	17,119	30,075
Cash flows from investing activities:		
Payments for property, plant and equipment	(45,616)	(29,473)
Acquisitions	—	(16,815)
Payments for plant turnaround costs	(2,403)	(2,044)
Proceeds from sale of property, plant and equipment	23	—
Investment in unconsolidated subsidiaries	(775)	(59,319)
Return of investments from unconsolidated entities	4,297	—
Distributions from (contributions to) unconsolidated entities for operations	(17,348)	—
Net cash used in continuing investing activities	(61,822)	(107,651)
Net cash used in discontinued investing activities	(2,003)	(5,923)
Net cash used in investing activities	(63,825)	(113,574)
Cash flows from financing activities:		
Payments of long-term debt	(217,000)	(301,500)

Payments of notes payable and capital lease obligations	(6,453)	(543)
Proceeds from long-term debt	216,000	357,500
Net proceeds from follow on offering	91,361	70,330
General partner contribution	1,951	1,505
Treasury units purchased	(221)	(582)
Payment of debt issuance costs	(204)	(3,424)
Excess purchase price over carrying value of acquired assets	—	(19,685)
Cash distributions paid	(38,888)	(31,415)
Net cash provided by financing activities	46,546	72,186
Net decrease in cash	(160)	(11,313)
Cash at beginning of period	266	11,380
Cash at end of period	$106	$67

See accompanying notes to consolidated and condensed financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2012
(Unaudited)

(1) General

Martin Midstream Partners L.P. (the “Partnership”) is a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Its four primary business lines include: terminalling and storage services for petroleum products and by-products, natural gas services, sulfur and sulfur-based products processing, manufacturing, marketing and distribution, and marine transportation services for petroleum products and by-products.

The Partnership’s unaudited consolidated and condensed financial statements have been prepared in accordance with the requirements of Form 10-Q and United States generally accepted accounting principles for interim financial reporting. Accordingly, these financial statements have been condensed and do not include all of the information and footnotes required by generally accepted accounting principles for annual audited financial statements of the type contained in the Partnership’s annual reports on Form 10-K. In the opinion of the management of the Partnership’s general partner, all adjustments and elimination of significant intercompany balances necessary for a fair presentation of the Partnership’s results of operations, financial position and cash flows for the periods shown have been made. All such adjustments are of a normal recurring nature. Results for such interim periods are not necessarily indicative of the results of operations for the full year. These financial statements should be read in conjunction with the Partnership’s audited consolidated financial statements and notes thereto included in the Partnership’s annual report on Form 10-K for the year ended December 31, 2011, filed with the Securities and Exchange Commission (the “SEC”) on March 5, 2012.

As discussed in Notes 4 and 16, on July 31, 2012, the Partnership completed the sale of its East Texas and Northwest Louisiana natural gas gathering and processing assets. These assets, along with additional gathering and processing assets discussed in Note 4 are collectively referred to as the "Prism Assets". The Partnership has classified the Prism Assets, including related liabilities as held for sale at June 30, 2012 and December 31, 2011, and has presented the results of operations and cash flows as discontinued operations for the periods ended June 30, 2012 and 2011, respectively. The Partnership has retrospectively adjusted its prior period consolidated financial statements to comparably classify the amounts related to the net assets and operations and cash flows of the Prism Assets as assets held for sale and discontinued operations, respectively.

(a) Use of Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States. Actual results could differ from those estimates.

(b) Unit Grants

In May 2012, the Partnership issued 6,250 restricted common units to certain Martin Resource Management employees under its long-term incentive plan from 6,250 treasury units purchased by the Partnership in the open market for $221. These units vest in 25% increments beginning in January 2013 and will be fully vested in January 2016.

In May 2011, the Partnership issued 6,250 restricted common units to certain Martin Resource Management employees under its long-term incentive plan from 5,750 treasury units purchased by the Partnership in the open market for $235 and 500 treasury units from forfeitures. These units vest in 25% increments beginning in January 2012 and will be fully vested in January 2015.

In February 2011, the Partnership issued 9,100 restricted common units to certain Martin Resource Management employees under its long-term incentive plan from 9,100 treasury units purchased by the Partnership in the open market for $347. These units vest in 25% increments beginning in February 2012 and will be fully vested in February 2015.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2012
(Unaudited)

The cost resulting from share-based payment transactions was $62 and $59 for the three months ended June 30, 2012 and 2011, respectively, and $118 and $96 for the six months ended June 30, 2012 and 2011, respectively.

(c) Incentive Distribution Rights

The Partnership's general partner, Martin Midstream GP LLC, holds a 2% general partner interest and certain incentive distribution rights ("IDRs") in the Partnership. IDRs are a separate class of non-voting limited partner interest that may be transferred or sold by the general partner under the terms of the partnership agreement of the Partnership (the "Partnership Agreement"), and represent the right to receive an increasing percentage of cash distributions after the minimum quarterly distribution and any cumulative arrearages on common units once certain target distribution levels have been achieved. The Partnership is required to distribute all of its available cash from operating surplus, as defined in the Partnership Agreement.

The target distribution levels entitle the general partner to receive 2% of quarterly cash distributions up to $0.55 per unit, 15% of quarterly cash distributions in excess of $0.55 per unit until all unitholders have received $0.625 per unit, 25% of quarterly cash distributions in excess of $0.625 per unit until all unitholders have received $0.75 per unit and 50% of quarterly cash distributions in excess of $0.75 per unit.

For the three months ended June 30, 2012 and 2011, the general partner received $1,429 and $1,265, respectively, in incentive distributions. For the six months ended June 30, 2012 and 2011, the general partner received $2,857 and $2,370, respectively, in incentive distributions.

(d) Net Income per Unit

The Partnership follows the provisions of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 260-10 related to earnings per share, which addresses the application of the two-class method in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions accounted for as equity distributions. To the extent the Partnership Agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the Partnership Agreement. When current period distributions are in excess of earnings, the excess distributions for the period are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the Partnership Agreement.

The provisions of ASC 260-10 did not impact the Partnership's computation of earnings per limited partner unit as cash distributions exceeded earnings for the three months and six months ended June 30, 2012 and 2011, respectively, and the IDRs do not share in losses under the Partnership Agreement. In the event the Partnership's earnings exceed cash distributions, ASC 260-10 will have an impact on the computation of the Partnership's earnings per limited partner unit. For the three and six months ended June 30, 2012 and 2011, the general partner's interest in net income, including the IDRs, represents distributions declared after period-end on behalf of the general partner interest and IDRs less the allocated excess of distributions over earnings for the periods.

For purposes of computing diluted net income per unit, the Partnership uses the more dilutive of the two-class and if-converted methods. Under the if-converted method, the beneficial conversion feature is added back to net income available to common limited partners, the weighted-average number of subordinated units outstanding for the period is added to the weighted-average number of common units outstanding for purposes of computing basic net income per unit and the resulting amount is compared to the diluted net income per unit computed using the two-class method.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2012
(Unaudited)

The following is a reconciliation of net income from continuing operations and net income from discontinued operations allocated to the general partner and limited partners for purposes of calculating net income attributable to limited partners per unit:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Continuing operations:				
Net income attributable to Martin Midstream Partners L.P.	$5,208	$5,740	$14,012	$10,629
Less general partner's interest in net income:				
Distributions payable on behalf of IDRs	1,034	828	2,259	1,565
Distributions payable on behalf of general partner interest	282	226	615	433
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	(198)	(128)	(380)	(252)
Less beneficial conversion feature	—	181	—	366
Limited partners' interest in net income	$4,090	$4,633	$11,518	$8,517

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Discontinued operations:				
Net income attributable to Martin Midstream Partners L.P.	$1,984	$3,030	$3,709	$5,463
Less general partner's interest in net income:				
Distributions payable on behalf of IDRs	394	437	598	805
Distributions payable on behalf of general partner interest	107	119	163	222
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	(75)	(67)	(100)	(129)
Less beneficial conversion feature	—	96	—	188
Limited partners' interest in net income	$1,558	$2,445	$3,048	$4,377

The weighted average units outstanding for basic net income per unit were 23,102,534 and 22,839,470 for the three months and six months ended June 30, 2012, respectively, and 19,158,507 and 19,162,963 for the three months and six months ended June 30, 2011, respectively. For diluted net income per unit, the weighted average units outstanding were increased by 1,562 and 2,688 for the three and six months ended June 30, 2012, respectively, and 394 and 997 for the three and six months ended June 30, 2011, respectively, due to the dilutive effect of restricted units granted under the Partnership's long-term incentive plan.

(e) Income Taxes

With respect to the Partnership's taxable subsidiary, Woodlawn Pipeline Co., Inc. ("Woodlawn"), income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

(2) New Accounting Pronouncements

In September 2011, the FASB amended the provisions of ASC 350 related to testing goodwill for impairment. This update simplifies the goodwill impairment assessment by allowing a company to first review qualitative factors to determine the likelihood of whether the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test. If it is determined that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, the company would not be required to perform the two-step goodwill impairment test for that reporting unit. This update is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. This amended guidance was adopted by the Partnership effective January 1, 2012.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2012
(Unaudited)

In June 2011, the FASB amended the provisions of ASC 220 related to other comprehensive income. This newly issued guidance: (1) eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity; (2) requires the consecutive presentation of the statement of net income and other comprehensive income; and (3) requires an entity to present reclassification adjustments on the face of the financial statements from other comprehensive income to net income. The amendments in this guidance do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income nor do the amendments affect how earnings per share is calculated or presented. This guidance is required to be applied retrospectively and is effective for fiscal years and interim periods within those years beginning after December 15, 2011. This amended guidance was adopted by the Partnership effective January 1, 2012. As this new guidance only requires enhanced disclosure, adoption did not impact the Partnership's financial position or results of operations.

(3) Acquisitions

Redbird Gas Storage

On May 31, 2011, the Partnership acquired all of the Class B equity interests in Redbird Gas Storage LLC ("Redbird") for approximately $59,319. This amount was recorded as an investment in an unconsolidated entity. Redbird, a subsidiary of Martin Resource Management, is a natural gas storage joint venture formed to invest in Cardinal Gas Storage Partners, LLC ("Cardinal"). Cardinal is a joint venture between Redbird and Energy Capital Partners that is focused on the development, construction, operation and management of natural gas storage facilities across North America. Redbird owns an unconsolidated 40.81% interest in Cardinal. Concurrent with the closing of this transaction, Cardinal acquired all of the outstanding equity interests in Monroe Gas Storage Company, LLC ("Monroe") as well as an option on development rights to an adjacent depleted reservoir facility. This acquisition was funded by borrowings under the Partnership's revolving credit facility. In addition to owning all of the Class B equity interests of Redbird, the Partnership also owns 9.13% of the Class A equity interests of Redbird at June 30, 2012.

Terminalling Facilities

On January 31, 2011, the Partnership acquired 13 shore-based marine terminalling facilities, one specialty terminalling facility and certain terminalling related assets from Martin Resource Management for $36,500. These assets are located across the Louisiana Gulf Coast. This acquisition was funded by borrowings under the Partnership's revolving credit facility.

These terminalling assets were acquired by Martin Resource Management in its acquisition of L&L Holdings LLC ("L&L") on January 31, 2011. During the second quarter of 2011, Martin Resource Management finalized the purchase price allocation for the acquisition of L&L, including the final determination of the fair value of the terminalling assets acquired by the Partnership. The Partnership recorded an adjustment in the amount of $19,685 to reduce property, plant and equipment and partners' capital for the difference between the purchase price and the fair value of the terminalling assets acquired based on Martin Resource Management's final purchase price allocation.

(4) Discontinued operations and divestitures

On June 18, 2012, the Partnership and a subsidiary of CenterPoint Energy Inc. (NYSE: CNP), (“CenterPoint”) entered into a definitive agreement under which CenterPoint would acquire the Partnership’s East Texas and Northwest Louisiana natural gas gathering and processing assets owned by Prism Gas Systems 1, L.P. (“Prism Gas”), a wholly-owned subsidiary of the Partnership, and other natural gas gathering and processing assets also owned by the Partnership, for cash in a transaction valued at approximately $275,000 excluding any transaction costs and purchase price adjustments. The asset sale includes the Partnership’s 50% operating interest in Waskom Gas Processing Company (“Waskom”). A subsidiary of CenterPoint currently owns the other 50% percent interest. As discussed in Note 16, the sale was completed on July 31, 2012.

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Additionally, the Partnership has reached agreement with a private investor group to sell its interest in Matagorda Offshore Gathering System ("Matagorda") and Panther Interstate Pipeline Energy LLC ("PIPE") for $2,000. These assets, along with the assets sold to CenterPoint are collectively referred to as the "Prism Gas Business". This sale is expected to be completed in the third quarter of 2012.

The assets described above collectively are referred to herein as the Prism Assets.

As of June 30, 2012, the Partnership classified the results of operations of the Prism Gas Assets which were previously presented as a component of the Natural Gas Services segment, as discontinued operations in the consolidated and condensed statements of operations for all periods presented. The assets and liabilities to be sold met the accounting criteria to be classified as held for sale and have been aggregated and reported on separate lines in the consolidated and condensed balance sheets for all periods presented.

The assets and liabilities held for sale as of June 30, 2012 and December 31, 2011 were as follows:

	June 30, 2012	December 31, 2011
Assets		
Inventories	$ 978	$ 486
Property, plant and equipment	79,274	78,324
Accumulated depreciation	(20,273)	(18,438)
Goodwill	28,931	28,931
Investment in unconsolidated entities	107,198	107,549
Other assets, net	15,480	15,935
Assets held for sale	$ 211,588	$ 212,787
Liabilities		
Other long-term obligations	508	501
Liabilities held for sale	$ 508	$ 501

The Prism Gas Assets' operating results, which are included within income from discontinued operations, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Total revenues from third parties1	$28,672	$32,149	$57,574	$62,204
Total costs and expenses and other, net, excluding depreciation and amortization2	(27,677)	(30,369)	(56,101)	(58,994)
Depreciation and amortization	(925)	(1,382)	(2,320)	(2,753)
Other operating income	—	—	10	—
Equity in earnings of Waskom, Matagorda, and PIPE	1,769	2,639	4,234	5,015

Income from discontinued operations before income taxes	1,839	3,037	3,397	5,472
Income tax expense (benefit)	(145)	7	(312)	9
Income from discontinued operations, net of income taxes	$1,984	$3,030	$3,709	$5,463

1Total revenues from third parties excludes intercompany revenues of $9,713, $17,193, $23,146, and $31,703 for the three months ended June 30, 2012 and 2011, and six months ended June 30, 2012 amd 2011, respectively.

2Total costs and expenses and other, net, excluding depreciation and amortization includes $841 of transaction costs related to the disposition of the Prism Assets. These costs are recorded in discontinued operations for the three and six months ended June 30, 2012 and 2011, respectively, presented above.

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(5) Inventories

Components of inventories at June 30, 2012 and December 31, 2011 were as follows:

	June 30, 2012	December 31, 2011
Natural gas liquids	$ 43,752	$ 25,178
Sulfur	14,793	24,335
Sulfur based products	12,140	14,857
Lubricants	10,839	11,012
Other	2,235	2,295
	$ 83,759	$ 77,677

(6) Investments in Unconsolidated Entities and Joint Ventures

At June 30, 2012, Prism Gas owned an unconsolidated 50% interest in Waskom, Matagorda, and PIPE.

As discussed in detail in note 4, the Partnership's investment in Waskom, Matagorda, and PIPE are included in assets held for sale at June 30, 2012. Additionally, the equity in earnings associated with these investments is recorded in income from discontinued operations for the three and six months ending June 30, 2012 and 2011, respectively.

In accounting for the acquisition of the interests in Waskom, Matagorda and PIPE, the carrying amount of these investments exceeded the underlying net assets by approximately $46,176. The difference was attributable to property and equipment of $11,872 and equity-method goodwill of $34,304. The excess investment relating to property and equipment is being amortized over an average life of 20 years, which approximates the useful life of the underlying assets. Such amortization amounted to $148 and $297 for the three and six months ended June 30, 2012 and 2011, respectively, and has been recorded as a reduction of equity in earnings of unconsolidated entities in income from discontinued operations. The remaining unamortized excess investment relating to property and equipment was $8,013 and $8,310 at June 30, 2012 and December 31, 2011, respectively. The equity-method goodwill is not amortized; however, it is analyzed for impairment annually or when changes in circumstance indicate that a potential impairment exists. No impairment was recognized for the six months ended June 30, 2012 or 2011.

As a partner in Waskom, the Partnership receives distributions in kind of natural gas liquids ("NGLs") that are retained according to Waskom's contracts with certain producers. The NGLs are valued at prevailing market prices. In addition, cash distributions are received and cash contributions are made to fund operating and capital requirements of Waskom.

The Partnership and Martin Resource Management formed Redbird, a natural gas storage joint venture formed to invest in Cardinal. The Partnership owns 9.13% of the Class A equity interests and all the Class B equity interests in Redbird. Redbird owns an unconsolidated 40.81% interest in Cardinal. Redbird utilized the investments by the Partnership to invest in Cardinal to fund projects for natural gas storage facilities.

During the second quarter of 2012, the Partnership acquired an unconsolidated 50% interest in Caliber Gathering System, LLC (“Caliber”) and Pecos Valley Producer Services LLC (“Pecos Valley”).

These investments are accounted for by the equity method.

The following tables summarize the components of the investment in unconsolidated entities on the Partnership’s consolidated and condensed balance sheets and the components of equity in earnings of unconsolidated entities included in the Partnership’s consolidated and condensed statements of operations:

	June 30, 2012	December 31, 2011
Investment in Waskom1	$ 102,490	$ 102,896
Investment in PIPE1	1,222	1,291
Investment in Matagorda1	3,486	3,362
Investment in unconsolidated entities classified as assets held for sale	107,198	107,549
Investment in Redbird	75,669	62,948
Investment in Caliber	729	—
Investment in Pecos Valley	13	—
Investment in unconsolidated entities	76,411	62,948
Total Investment in unconsolidated entities	$ 183,609	$ 170,497

1 For all periods presented, the financial information for Waskom, Matagorda, and PIPE is included in the consolidated and condensed balance sheet as assets held for sale, and on the consolidated and condensed statement of operations and cash flows as discontinued operations.

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	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Equity in earnings of Waskom1	$1,559	$2,662	$3,884	$5,012
Equity in earnings of PIPE1	(21)	(11)	(69)	(29)
Equity in earnings of Matagorda1	231	(11)	419	33
Equity in earnings of discontinued operations	1,769	2,640	4,234	5,016
Equity in earnings of Redbird	(712)	153	(330)	153
Equity in earnings of Caliber	(21)	—	(21)	—
Equity in earnings of Pecos Valley	(12)	—	(12)	—
Equity in earnings of unconsolidated entities	(745)	153	(363)	153
Total equity in earnings of unconsolidated entities	$1,024	$2,793	$3,871	$5,169

1 For all periods presented, the financial information for Waskom, Matagorda, and PIPE is included in the consolidated and condensed balance sheet as assets held for sale, and on the consolidated and condensed statement of operations and cash flows as discontinued operations.

Selected financial information for significant unconsolidated equity-method investees is as follows:

	As of June 30		Three Months Ended June 30		Six Months Ended June 30	
	Total Assets	Partner's Capital	Revenues	Net Income	Revenues	Net Income
2012						
Waskom	$143,634	$126,601	$27,207	$3,394	$58,491	$8,318
	As of December 31					
2011						
Waskom	$146,655	$126,863	$34,072	$5,672	$65,578	$10,574

As of June 30, 2012 and December 31, 2011 the amount of the Partnership's consolidated retained earnings that represents undistributed earnings related to the unconsolidated equity-method investees is $46,568 and $47,152, respectively. There are no material restrictions to transfer funds in the form of dividends, loans or advances related to the equity-method investees.

As of June 30, 2012 and December 31, 2011, the Partnership's interest in cash of the unconsolidated equity-method investees was $1,804 and $565, respectively.

(7) Derivative Instruments and Hedging Activities

The Partnership's results of operations are materially impacted by changes in crude oil, natural gas and NGL prices and interest rates. In an effort to manage its exposure to these risks, the Partnership periodically enters into various derivative instruments, including commodity and interest rate hedges. The Partnership is required to recognize all derivative instruments as either assets or liabilities at fair value on the Partnership’s Consolidated Balance Sheets and to recognize certain changes in the fair value of derivative instruments on the Partnership’s Consolidated Statements of Operations.

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The Partnership performs, at least quarterly, a retrospective assessment of the effectiveness of its hedge contracts, including assessing the possibility of counterparty default. If the Partnership determines that a derivative is no longer expected to be highly effective, the Partnership discontinues hedge accounting prospectively and recognizes subsequent changes in the fair value of the hedge in earnings.

All derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in accumulated other comprehensive income ("AOCI") until such time as the hedged item is recognized in earnings. The Partnership is exposed to the risk that periodic changes in the fair value of derivatives qualifying for hedge accounting will not be effective, as defined, or that derivatives will no longer qualify for hedge accounting. To the extent that the periodic changes in the fair value of the derivatives are not effective, that ineffectiveness is recorded to earnings. Likewise, if a hedge ceases to qualify for hedge accounting, any change in the fair value of derivative instruments since the last period is recorded to earnings; however, any amounts previously recorded to AOCI would remain there until such time as the original forecasted transaction occurs, then would be reclassified to earnings or if it is determined that continued reporting of losses in AOCI would lead to recognizing a net loss on the combination of the hedging instrument and the hedge transaction in future periods, then the losses would be immediately reclassified to earnings. If a forecasted hedge transaction is no longer probable of occurring, any gain or loss in AOCI is reclassified to earnings.

For derivative instruments that are designated and qualify as cash flow hedges, the effective portion of the gain or loss on the derivative is reported as a component of AOCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in fair value of the hedged item. To the extent the change in the fair value of the hedge does not perfectly offset the change in the fair value of the hedged item, the ineffective portion of the hedge is immediately recognized in earnings.

(a) Commodity Derivative Instruments

The Partnership is exposed to market risks associated with commodity prices and uses derivatives to manage the risk of commodity price fluctuation. The Partnership has established a hedging policy and monitors and manages the commodity market risk associated with its commodity risk exposure. These hedging arrangements are in the form of swaps for crude oil, natural gas and natural gasoline. In addition, the Partnership is focused on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

Due to the volatility in commodity markets, the Partnership is unable to predict the amount of ineffectiveness each period, including the loss of hedge accounting, which is determined on a derivative by derivative basis. This may result, and has resulted, in increased volatility in the Partnership's financial results. Factors that have and may continue to lead to ineffectiveness and unrealized gains and losses on derivative contracts include: a substantial fluctuation in energy prices, the number of derivatives the Partnership holds and significant weather events that have affected energy production. Instances in which the Partnership has discontinued hedge accounting for specific hedges is primarily due to those reasons. However, even though these derivatives may not qualify for hedge accounting, the Partnership continues to hold the instruments as it believes they continue to afford the Partnership opportunities to manage commodity risk exposure.

As of June 30, 2011, the Partnership has both derivative instruments qualifying for hedge accounting with fair value changes being recorded in AOCI as a component of partners' capital and derivative instruments not designated as hedges being marked to market with all market value adjustments being recorded in earnings. Due to the sale of the Prism Assets that was completed on July 31, 2012, as of June 30, 2012, the Partnership was in the process of terminating and settling its commodity derivative instruments and only has derivative instruments not designated as hedges that are marked to market.

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Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2012 (all gas quantities are expressed in British Thermal Units, crude oil and natural gas liquids are expressed in barrels). As of June 30, 2012, the remaining term of the contracts extend no later than July 31, 2012. For the three and six months ended June 30, 2012 and 2011, changes in the fair value of the Partnership's derivative contracts were recorded in both earnings and in AOCI as a component of partners' capital.

Transaction Type	Total Volume Per Month	Pricing Terms	Remaining Terms of Contracts	Fair Value
Mark to Market Derivatives::				
Crude Oil Swap	2,000 BBL	Fixed price of $88.63/bbl settled against WTI NYMEX average monthly closings	July 2012	$ 7
Natural Gasoline Swap	1,000 BBL	Fixed price of $90.20/bbl settled against WTI NYMEX average monthly closings	July 2012	5
Natural Gasoline Swap	1,000 BBL	Fixed price of $2.34/gal settled against Mont Belvieu Non-TET OPIS Average	July 2012	29
Total fair value of commodity derivative instruments				$ 41

The Partnership's credit exposure related to commodity cash flow hedges is represented by the positive fair value of contracts to the Partnership at June 30, 2012. These outstanding contracts expose the Partnership to credit loss in the event of nonperformance by the counterparties to the agreements. The Partnership has incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement; establishes a maximum credit limit threshold pursuant to its hedging policy; and monitors the appropriateness of these limits on an ongoing basis. The Partnership has an agreement with one counterparty containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by the Partnership if the value of derivatives is a liability to the Partnership. As of June 30, 2012, the Partnership has no cash collateral deposits posted with counterparties.

Substantially all of the Partnership's natural gas and NGL sales are made at market-based prices. The Partnership's standard gas and NGL sales contracts contain adequate assurance provisions, which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to the Partnership.

(b) Impact of Commodity Cash Flow Hedges

Crude Oil. For the three months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased crude revenue (included in income from discontinued operations) by $618 and $357, respectively. For the six months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased crude revenue (included in income from discontinued operations) by $533 and $297, respectively. As of June 30, 2012, an unrealized derivative fair value loss of $30, related to current and terminated cash flow hedges of crude oil price risk, was recorded in AOCI. This fair value loss will be reclassified into earnings in the third quarter of 2012. The actual reclassification to earnings for contracts remaining in effect will be based on the contract price at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2012, adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

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Natural Gas. For the three months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased gas revenue (included in income from discontinued operations) by $533 and $68, respectively. For the six months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased gas revenue (included in income from discontinued operations) by $736 and $143, respectively. As of June 30, 2012, an unrealized derivative fair value gain of $76 related to current and terminated cash flow hedges of natural gas was recorded in AOCI. This fair value gain will be reclassified into earnings in July 2012. The actual reclassification to earnings for contracts remaining in effect will be based on contract prices at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2012, adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

Natural Gas Liquids. For the three months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased liquids revenue (included in income from discontinued operations) by $1,116 and $60, respectively. For the six months ended June 30, 2012 and 2011, net gains and losses on swap hedge contracts increased liquids revenue (included in income from discontinued operations) by $1,061 and $222, respectively. As of June 30, 2012, an unrealized derivative fair value gain of $17 related to current and terminated cash flow hedges of NGLs price risk was recorded in AOCI. This fair value gain will be reclassified into earnings in July 2012. The actual reclassification to earnings for contracts remaining in effect will be based on contract prices at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2012, adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

For information regarding fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see “Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items” within this Note.

(c) Impact of Interest Rate Derivative Instruments

The Partnership is exposed to market risks associated with interest rates. The Partnership enters into interest rate swaps to manage interest rate risk associated with the Partnership’s variable rate debt credit facility and its’ senior notes. All derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in AOCI until such time as the hedged item is recognized in earnings.

In August 2011, the Partnership terminated all of its existing interest swap agreements with an aggregate notional amount of $100,000, which it had entered to hedge its exposure to changes in the fair value of Senior Notes as described in Note 11. These interest rate swap contracts were not designated as fair value hedges and therefore, did not receive hedge accounting but were marked to market through earnings. Termination fees of $2,800 were received on the early extinguishment of the interest rate swap agreements in August 2011.

The Partnership was not party to interest rate derivatives during the six months ended June 30, 2012. The Partnership recognized increases in interest expense of $3,167 and $2,535 for the three and six months ended June 30, 2011, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and net cash settlement of interest rate swaps and hedges.

For information regarding fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see “Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items” below.

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(d) Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table summarizes the fair values and classification of the Partnership's derivative instruments in its Consolidated Balance Sheet:

Fair Values of Derivative Instruments in the Consolidated Balance Sheet

	Derivative Assets	Fair Values		Derivative Liabilities	Fair Values	
	Balance Sheet Location	June 30, 2012	December 31, 2011	Balance Sheet Location	June 30, 2012	December 31, 2011
Derivatives designated as hedging instruments	Current:			Current:		
Commodity contracts	Fair value of derivatives	$ —	$ 622	Fair value of derivatives	$ —	$ 245
Total derivatives designated as hedging instruments		$ —	$ 622		$ —	$ 245
Derivatives not designated as hedging instruments						
	Current:			Current:		
Commodity contracts	Fair value of derivatives	$ 41	$ —	Fair value of derivatives	$ —	$ 117
Total derivatives not designated as hedging instruments		$ 41	$ —		$ —	$ 117

Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Three Months Ended June 30, 2012 and 2011

	Effective Portion					Ineffective Portion and Amount Excluded from Effectiveness Testing		
	Amount of Gain or (Loss) Recognized in OCI on Derivatives		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income		Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
	2012	2011		2012	2011		2012	2011
Derivatives designated as hedging instruments								
Commodity contracts	$ —	$ 843	Income from discontinued operations	$ 499	$ 329	Income from discontinued operations	$ —	$ (11)
Total derivatives designated as hedging instruments	$ —	$ 843		$ 499	$ 329		$ —	$ (11)

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
		2012	2011
Derivatives not designated as hedging instruments			
Interest rate contracts	Interest expense	$ —	$ 3,167
Commodity contracts	Income from discontinued operations	1,768	167
Total derivatives not designated as hedging instruments		$ 1,768	$ 3,334

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Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Six Months Ended June 30, 2012 and 2011

	Effective Portion					Ineffective Portion and Amount Excluded from Effectiveness Testing		
	Amount of Gain or (Loss) Recognized in OCI on Derivatives		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income		Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
	2012	2011		2012	2011		2012	2011
Derivatives designated as hedging instruments								
Interest rate contracts	$ —	$ —	Interest expense	$ —	$ (18)	Interest expense	$ —	$ —
Commodity contracts	126	(65)	Income from discontinued operations	685	763	Income from discontinued operations	4	$ (11)
Total derivatives designated as hedging instruments	$ 126	$ (65)		$ 685	$ 745		$ 4	$ (11)

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
		2012	2011
Derivatives not designated as hedging instruments			
Interest rate contracts	Interest Expense	$ —	$ 2,553
Commodity contracts	Income from discontinued operations	1,641	(90)
Total derivatives not designated as hedging instruments		$ 1,641	$ (2,463)

Amounts expected to be reclassified into earnings for the subsequent 12-month period are gains of $63 for commodity cash flow hedges.

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(8) Fair Value Measurements

The Partnership provides disclosures pursuant to certain provisions of ASC 820, which provides a framework for measuring fair value and expanded disclosures about fair value measurements. ASC 820 applies to all assets and liabilities that are being measured and reported on a fair value basis. This statement enables the reader of the financial statements to assess the inputs used to develop those measurements by establishing a hierarchy for ranking the quality and reliability of the information used to determine fair values. ASC 820 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value of each asset and liability carried at fair value into one of the following categories:

Level 1: Quoted market prices in active markets for identical assets or liabilities.
Level 2: Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3: Unobservable inputs that are not corroborated by market data.

The Partnership's derivative instruments, which consist of commodity and interest rate swaps, are required to be measured at fair value on a recurring basis. The fair value of the Partnership's derivative instruments is determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets, which is considered Level 2. Refer to Note 7 for further information on the Partnership's derivative instruments and hedging activities.

The following items are measured at fair value on a recurring basis subject to the disclosure requirements of ASC 820 at June 30, 2012:

		Fair Value Measurements at Reporting Date Using		
Description	June 30, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Natural gas liquids derivatives	$ 34	—	34	—
Crude oil derivatives	7	—	7	—
Total assets	$ 41	$ —	$ 41	$ —

The following items are measured at fair value on a recurring basis subject to the disclosure requirements of ASC 820 at December 31, 2011:

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Natural gas derivatives	$ 622	$ —	$ 622	$ —
Total assets	$ 622	$ —	$ 622	$ —
Liabilities				
Crude oil derivatives	245	—	245	—
Natural gas liquids derivatives	117	—	117	—
Total liabilities	$ 362	$ —	$ 362	$ —

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ASC 825-10-65, related to disclosures about fair value of financial instruments, requires that the Partnership disclose estimated fair values for its financial instruments. Fair value estimates are set forth below for the Partnership's financial instruments. The following methods and assumptions were used to estimate the fair value of each class of financial instrument:

- Accounts and other receivables, trade and other accounts payable, other accrued liabilities, income taxes payable and due from/to affiliates — the carrying amounts approximate fair value due to the short maturity and highly liquid nature of these instruments.
- Long-term debt including current installments — the carrying amount of the revolving credit facility approximates fair value due to the debt having a variable interest rate.

The estimated fair value of the Senior Notes was approximately $177,446 as of June 30, 2012 based on quoted market prices of similar debt at June 30, 2012, which is deemed a Level 2 measurement.

(9) Related Party Transactions

As of June 30, 2012, Martin Resource Management owns 6,593,267 of the Partnership's common units representing approximately 28.5% of the Partnership's outstanding limited partnership units. The Partnership's general partner is a wholly-owned subsidiary of Martin Resource Management. The Partnership's general partner owns a 2.0% general partner interest in the Partnership and the Partnership's incentive distribution rights. The Partnership's general partner's ability, as general partner, to manage and operate the Partnership, and Martin Resource Management's ownership as of June 30, 2012, of approximately 28.5% of the Partnership's outstanding limited partnership units, effectively gives Martin Resource Management the ability to veto some of the Partnership's actions and to control the Partnership's management.

The following is a description of the Partnership's material related party transactions:

Omnibus Agreement

Omnibus Agreement. The Partnership and its general partner are parties to an omnibus agreement dated November 1, 2002, with Martin Resource Management that governs, among other things, potential competition and indemnification obligations among the parties to the agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and the Partnership's use of certain of Martin Resource Management's trade names and trademarks. The omnibus agreement was amended on November 24, 2009, to include processing crude oil into finished products including naphthenic lubricants, distillates, asphalt and other intermediate cuts.

Non-Competition Provisions. Martin Resource Management has agreed for so long as it controls the general partner of the Partnership, not to engage in the business of:

- providing terminalling, refining, processing, distribution and midstream logistical services for hydrocarbon products and by-products;

- providing marine and other transportation of hydrocarbon products and by-products; and
- manufacturing and marketing fertilizers and related sulfur-based products.

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This restriction does not apply to:

- the ownership and/or operation on the Partnership's behalf of any asset or group of assets owned by it or its affiliates;
- any business operated by Martin Resource Management, including the following:
  - providing land transportation of various liquids;
  - distributing fuel oil, sulfuric acid, marine fuel and other liquids;
  - providing marine bunkering and other shore-based marine services in Alabama, Florida, Louisiana, Mississippi and Texas;
  - operating a small crude oil gathering business in Stephens, Arkansas;
  - operating an underground NGL storage facility in Arcadia, Louisiana;
  - building and marketing sulfur processing equipment; and
  - developing an underground natural gas storage facility in Arcadia, Louisiana.
- any business that Martin Resource Management acquires or constructs that has a fair market value of less than $5,000;
- any business that Martin Resource Management acquires or constructs that has a fair market value of $5,000 or more if the Partnership has been offered the opportunity to purchase the business for fair market value and the Partnership declines to do so with the concurrence of the conflicts committee; and
- any business that Martin Resource Management acquires or constructs where a portion of such business includes a restricted business and the fair market value of the restricted business is $5,000 or more and represents less than 20% of the aggregate value of the entire business to be acquired or constructed; provided that, following completion of the acquisition or construction, the Partnership will be provided the opportunity to purchase the restricted business.

Services. Under the omnibus agreement, Martin Resource Management provides the Partnership with corporate staff, support services, and administrative services necessary to operate the Partnership's business. The omnibus agreement requires the Partnership to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on the Partnership's behalf or in connection with the operation of the Partnership's business. There is no monetary limitation on the amount the Partnership is required to reimburse Martin Resource Management for direct expenses. In addition to the direct expenses, Martin Resource Management is entitled to reimbursement for a portion of indirect general and administrative and corporate overhead expenses. Under the omnibus agreement, the Partnership is required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses.

Effective October 1, 2011, through September 30, 2012, the Conflicts Committee of the board of directors of the general partner of the Partnership (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $6,582. The Partnership reimbursed Martin Resource Management for $1,645 and $3,291 of indirect expenses for the three and six months ended June 30, 2012, respectively. The Partnership reimbursed Martin Resource Management for $1,042 and $2,084 of indirect expenses for the three and six months ended June 30, 2011, respectively. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

These indirect expenses are intended to cover the centralized corporate functions Martin Resource Management provides for the Partnership, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions the Partnership shares with Martin Resource Management retained businesses. The provisions of the omnibus agreement regarding Martin Resource Management's services will terminate if Martin Resource Management ceases to control the general partner of the Partnership.

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Related Party Transactions. The omnibus agreement prohibits the Partnership from entering into any material agreement with Martin Resource Management without the prior approval of the conflicts committee of the general partner's board of directors. For purposes of the omnibus agreement, the term material agreements means any agreement between the Partnership and Martin Resource Management that requires aggregate annual payments in excess of then-applicable agreed upon reimbursable amount of indirect general and administrative expenses. Please read "Services" above.

License Provisions. Under the omnibus agreement, Martin Resource Management has granted the Partnership a nontransferable, nonexclusive, royalty-free right and license to use certain of its trade names and marks, as well as the trade names and marks used by some of its affiliates.

Amendment and Termination. The omnibus agreement may be amended by written agreement of the parties; provided, however, that it may not be amended without the approval of the conflicts committee of the Partnership's general partner if such amendment would adversely affect the unitholders. The omnibus agreement was amended on November 24, 2009, to permit the Partnership to provide refining services to Martin Resource Management. Such amendment was approved by the conflicts committee of the Partnership's general partner. The omnibus agreement, other than the indemnification provisions and the provisions limiting the amount for which the Partnership will reimburse Martin Resource Management for general and administrative services performed on its behalf, will terminate if the Partnership is no longer an affiliate of Martin Resource Management.

Motor Carrier Agreement

Motor Carrier Agreement. The Partnership is a party to a motor carrier agreement effective January 1, 2006, with Martin Transport, Inc., a wholly owned subsidiary of Martin Resource Management through which Martin Resource Management operates its land transportation operations. This agreement replaced a prior agreement effective November 1, 2002, between the Partnership and Martin Transport, Inc. for land transportation services. Under the agreement, Martin Transport Inc. agreed to ship our NGL shipments as well as other liquid products.

Term and Pricing. This agreement was amended in November 2006, January 2007, April 2007 and January 2008 to add additional point-to-point rates and to modify certain fuel and insurance surcharges being charged to the Partnership. The agreement has an initial term that expired in December 2007 but automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 30 days prior to the expiration of the then-applicable term. The Partnership has the right to terminate this agreement at any time by providing 90 days prior notice. Under this agreement, Martin Transport, Inc. transports the Partnership's NGL shipments as well as other liquid products. These rates are subject to any adjustment which are mutually agreed or in accordance with a price index. Additionally, during the term of the agreement, shipping charges are also subject to fuel surcharges determined on a weekly basis in accordance with the U.S. Department of Energy's national diesel price list.

Marine Agreements

Marine Transportation Agreement. The Partnership is a party to a marine transportation agreement effective January 1, 2006, which was amended January 1, 2007, under which the Partnership provides marine transportation services to

Martin Resource Management on a spot-contract basis at applicable market rates. This agreement replaced a prior agreement effective November 1, 2002 between the Partnership and Martin Resource Management covering marine transportation services which expired November 2005. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then applicable term. The fees the Partnership charges Martin Resource Management are based on applicable market rates.

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Cross Marine Charter Agreements. Cross Oil & Refining Marketing Inc. ("Cross") entered into two marine charter agreements with the Partnership effective March 1, 2012. These agreements have an initial term of five years and continue indefinitely thereafter subject to cancellation after the initial term by either party upon a 30 day written notice of cancellation. The charter hire payable under these agreements will be adjusted annually to reflect the percentage change in the Consumer Price Index.

Marine Fuel. The Partnership is a party to an agreement with Martin Resource Management under which Martin Resource Management provides the Partnership with marine fuel from its locations in the Gulf of Mexico at a fixed rate over the Platt's U.S. Gulf Coast Index for #2 Fuel Oil. Under this agreement, the Partnership agreed to purchase all of its marine fuel requirements that occur in the areas serviced by Martin Resource Management.

Terminal Services Agreements

Diesel Fuel Terminal Services Agreement. The Partnership is a party to an agreement under which the Partnership provides terminal services to Martin Resource Management. This agreement was amended and restated as of October 27, 2004, and was set to expire in December 2006, but automatically renewed and will continue to automatically renew on a month-to-month basis until either party terminates the agreement by giving 60 days written notice. The per gallon throughput fee the Partnership charges under this agreement may be adjusted annually based on a price index.

Miscellaneous Terminal Services Agreements. The Partnership is currently party to several terminal services agreements and from time to time the Partnership may enter into other terminal service agreements for the purpose of providing terminal services to related parties. Individually, each of these agreements is immaterial but when considered in the aggregate they could be deemed material. These agreements are throughput based with a minimum volume commitment. Generally, the fees due under these agreements are adjusted annually based on a price index.

Other Agreements

Cross Tolling Agreement. The Partnership is a party to an agreement under which it processes crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts for Cross. The Tolling Agreement has a 22 year term which expires November 25, 2031. Under this Tolling Agreement, Martin Resource Management agreed to process a minimum of 6,500 barrels per day of crude oil at the facility at a fixed price per barrel. Any additional barrels are processed at a modified price per barrel. In addition, Martin Resource Management agreed to pay a monthly reservation fee and a periodic fuel surcharge fee based on certain parameters specified in the Tolling Agreement. All of these fees (other than the fuel surcharge) are subject to escalation annually based upon the greater of 3% or the increase in the Consumer Price Index for a specified annual period. In addition, every three years, the parties can negotiate an upward or downward adjustment in the fees subject to their mutual agreement.

Sulfuric Acid Sales Agency Agreement. The Partnership is party to an agreement under which Martin Resource Management purchases and markets the sulfuric acid produced by the Partnership's sulfuric acid production plant at Plainview, Texas, that is not consumed by the Partnership's internal operations. This agreement, which was amended and restated in July 2011, will remain in place until the Partnership terminates it by providing 180 days' written notice. Under this agreement, the Partnership sells all of its excess sulfuric acid to Martin Resource

Management. Martin Resource Management then markets such acid to third-parties and the Partnership shares in the profit of Martin Resource Management's sales of the excess acid to such third parties.

Other Miscellaneous Agreements. From time to time the Partnership enters into other miscellaneous agreements with Martin Resource Management for the provision of other services or the purchase of other goods.

The tables below summarize the related party transactions that are included in the related financial statement captions on the face of the Partnership's Consolidated Statements of Operations. The revenues, costs and expenses reflected in these tables are tabulations of the related party transactions that are recorded in the corresponding caption of the consolidated financial statement and do not reflect a statement of profits and losses for related party transactions.

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The impact of related party revenues from sales of products and services is reflected in the consolidated financial statement as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues:				
Terminalling and storage	$ 14,805	$ 12,897	$ 30,080	$ 25,835
Marine transportation	4,446	6,306	9,303	12,871
Product sales:				
Natural gas services	30	30	105	634
Sulfur services	1,645	1,635	3,360	4,821
Terminalling and storage	283	103	682	114
	1,958	1,768	4,147	5,569
	$ 21,209	$ 20,971	$ 43,530	$ 44,275

The impact of related party cost of products sold is reflected in the consolidated financial statement as follows:

Cost of products sold:				
Natural gas services	$7,707	$1,961	$12,022	$4,422
Sulfur services	3,970	4,492	8,401	8,645
Terminalling and storage	78	83	165	138
	$11,755	$6,536	$20,588	$13,205

The impact of related party operating expenses is reflected in the consolidated financial statement as follows:

Expenses:				
Operating expenses				
Marine transportation	$7,002	$6,793	$13,981	$12,781
Natural gas services	444	342	915	696
Sulfur services	1,985	1,658	3,302	2,902
Terminalling and storage	4,961	4,684	10,010	8,886
	$14,392	$13,477	$28,208	$25,265

The impact of related party selling, general and administrative expenses is reflected in the consolidated financial statement as follows:

Selling, general and administrative:				
Marine transportation	$27	$15	$32	$30
Natural gas services	382	269	686	576
Sulfur services	735	639	1,446	1,281
Terminalling and storage	39	—	39	—

Indirect overhead allocation, net of reimbursement	1,645	1,042	3,291	2,084
	$2,828	$1,965	$5,494	$3,971

(10) Business Segments

The Partnership has four reportable segments: terminalling and storage, natural gas services, sulfur services and marine transportation. The Partnership's reportable segments are strategic business units that offer different products and services. The operating income of these segments is reviewed by the chief operating decision maker to assess performance and make business decisions.

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The accounting policies of the operating segments are the same as those described in Note 2 in the Partnership's annual report on Form 10-K for the year ended December 31, 2011, filed with the SEC on March 5, 2012. The Partnership evaluates the performance of its reportable segments based on operating income. There is no allocation of administrative expenses or interest expense.

The natural gas services segment information below excludes the discontinued operations of the Prism Assets for all periods. See Note 4.

	Operating Revenues	Intersegment Revenues Eliminations	Operating Revenues after Eliminations	Depreciation and Amortization	Operating Income (loss) after eliminations	Capital Expenditures
Three months ended June 30, 2012						
Terminalling and storage	$41,430	$ (1,176)	$ 40,254	$ 4,944	$ 4,344	$ 15,050
Natural gas services	164,817	—	164,817	144	(33)	253
Sulfur services	67,093	—	67,093	1,782	13,420	667
Marine transportation	21,466	(752)	20,714	2,921	1,278	208
Indirect selling, general and administrative	—	—	—	—	(2,349)	—
Total	$294,806	$ (1,928)	$ 292,878	$ 9,791	$ 16,660	$ 16,178
Three months ended June 30, 2011						
Terminalling and storage	$39,766	$ (1,068)	$ 38,698	$ 4,745	$ 2,951	$ 5,706
Natural gas services	127,050	—	127,050	144	(40)	233
Sulfur services	76,933	—	76,933	1,700	11,986	4,981
Marine transportation	19,351	(1,975)	17,376	3,339	(2,966)	4,123
Indirect selling, general and administrative	—	—	—	—	(1,762)	—
Total	$263,100	$ (3,043)	$ 260,057	$ 9,928	$ 10,169	$ 15,043
Three months ended June 30, 2011						
Six months ended June 30, 2012						
Terminalling and storage	$84,464	$ (2,351)	$ 82,113	$ 9,667	$ 7,426	$ 37,777
Natural gas services	336,928	—	336,928	287	3,187	268
Sulfur services	141,645	—	141,645	3,575	27,047	1,655
Marine transportation	43,033	(1,457)	41,576	5,962	(149)	5,916
Indirect selling, general and administrative	—	—	—	—	(4,767)	—

Total	$606,070	$ (3,808)	$ 602,262	$ 19,491	$ 32,744	$ 45,616
Six months ended June 30, 2011						
Terminalling and storage	$77,412	$ (2,046)	$ 75,366	$ 9,285	$ 6,119	$ 9,909
Natural gas services	264,205	—	264,205	287	3,434	304
Sulfur services	136,691	—	136,691	3,322	21,897	12,229
Marine transportation	40,790	(4,015)	36,775	6,604	(4,247)	7,031
Indirect selling, general and administrative	—	—	—	—	(3,580)	—
Total	$519,098	$ (6,061)	$ 513,037	$ 19,498	$ 23,623	$ 29,473

The Partnership's assets by reportable segment, which exclude assets held for sale of $211,588 and $212,787, respectively, as of June 30, 2012 and December 31, 2011, are as follows:

	June 30, 2012	December 31, 2011
Total assets:		
Terminalling and storage	$268,824	$231,764
Natural gas services	195,882	198,845
Sulfur services	146,558	162,289
Marine transportation	144,004	143,424
Total assets	$755,268	$736,322

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(11) Long-Term Debt and Capital Leases

At June 30, 2012 and December 31, 2011, long-term debt consisted of the following:

	June 30, 2012	December 31, 2011
$200,000*** Senior notes, 8.875% interest, net of unamortized discount of $1,765 and $2,192, respectively, issued March 2010 and due April 2018, unsecured**	$173,235	$197,808
$400,000 Revolving loan facility at variable interest rate (3.35%* weighted average at June 30, 2012), due April 2016 secured by substantially all of the Partnership's assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in the Partnership's operating subsidiaries and equity method investees	274,000	250,000
$7,354 Note payable to bank, interest rate at 7.50%, maturity date of January 2017, secured by equipment	—	6,363
Capital lease obligations	5,941	6,031
Total long-term debt and capital lease obligations	453,176	460,202
Less current installments	206	1,261
Long-term debt and capital lease obligations, net of current installments	$452,970	$458,941

* Interest rate fluctuates based on the LIBOR rate plus an applicable margin set on the date of each advance. The margin above LIBOR is set every three months. Indebtedness under the credit facility bears interest at LIBOR plus an applicable margin or the base prime rate plus an applicable margin. The applicable margin for revolving loans that are LIBOR loans ranges from 2.00% to 3.25% and the applicable margin for revolving loans that are base prime rate loans ranges from 1.00% to 2.25%. The applicable margin for existing LIBOR borrowings is 3.00%. Effective July 1, 2012, the applicable margin for existing LIBOR borrowings remained at 3.00%. Effective October 1, 2012, the applicable margin for existing LIBOR borrowings will remain at 3.00%.

** Effective September 2010, the Partnership entered into an interest rate swap that swapped $40,000 of fixed rate to floating rate. The floating rate cost was the applicable three-month LIBOR rate. This interest rate swap was scheduled to mature in April 2018, but was terminated in August 2011.

** Effective September 2010, the Partnership entered into an interest rate swap that swapped $60,000 of fixed rate to floating rate. The floating rate cost was the applicable three-month LIBOR rate. This interest rate swap was scheduled to mature in April 2018, but was terminated in August 2011.

*** Pursuant to the Indenture under which the Senior Notes were issued, the Partnership has the option to redeem up to 35% of the aggregate principal amount at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest with the proceeds of certain equity offerings. On April 24, 2012 the Partnership notified the Trustee of its intention to exercise a partial redemption of the Partnership's Senior Notes pursuant to the Indenture. On May 24, 2012, the Partnership redeemed $25,000 of the Senior Notes from various holders using proceeds of the

Partnership's January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under the Partnership's revolving credit facility. In conjunction with the redemption, the Partnership incurred a debt prepayment premium in the amount of $2,219, which is included in the consolidated and condensed statements of operations for the three and six months ending June 30, 2012.

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In August 2011, the Partnership terminated all of its existing interest rate swap agreements with an aggregate notional amount of $100,000, which it had entered to hedge its exposure to changes in the fair value of Senior Notes. These interest rate swap contracts were not designated as fair value hedges and therefore, did not receive hedge accounting but were marked to market through earnings. The Partnership received a termination benefit of $2,800 upon cancellation of these swap agreements.

Effective May 10, 2012, the Partnership increased the maximum amount of borrowings and letters of credit available under the Credit Facility from $375,000 to $400,000.

The Partnership paid cash interest in the amount of $14,343 and $9,505 for the three months ended June 30, 2012 and 2011, respectively. The Partnership paid cash interest in the amount of $16,751 and $11,779 for the six months ended June 30, 2012 and 2011, respectively. Capitalized interest was $270 and $151 for the three months ended June 30, 2012 and 2011, respectively. Capitalized interest was $624 and $245 for the six months ended June 30, 2012 and 2011, respectively.

(12) Equity Offering

On January 25, 2012, the Partnership completed a public offering of 2,645,000 common units at a price of $36.15 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 2,645,000 common units, net of underwriters' discounts, commissions and offering expenses were $91,361. The Partnership's general partner contributed $1,951 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. On January 25, 2012, all of the net proceeds were used to reduce outstanding indebtedness of the Partnership.

On February 9, 2011, the Partnership completed a public offering of 1,874,500 common units at a price of $39.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands. Total proceeds from the sale of the 1,874,500 common units, net of underwriters' discounts, commissions and offering expenses were $70,330. The Partnership's general partner contributed $1,505 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. The net proceeds were used to reduce the outstanding balance under its revolving credit facility.

(13) Income Taxes

Because its income is taxed directly to its partners, the operations of a partnership are generally not subject to income taxes, except as discussed below. Effective January 1, 2007, the Partnership became subject to the Texas margin tax, which is considered a state income tax, and is included in Income tax expense on the consolidated statements of operations.

The Partnership's taxable subsidiary, Woodlawn, is subject to income taxes due to its corporate structure. Income tax expense related to Woodlawn is recorded in discontinued operations. A current state income tax expense of $3 and $5, related to the operation of the subsidiary, were recorded for the three and six months ended June 30, 2012 and $7 and $12 for the three and six months ended 2011, respectively. In connection with the Woodlawn acquisition, the Partnership also established deferred income taxes of $8,964 associated with book and tax basis differences of the acquired assets and liabilities. The basis differences are primarily related to property, plant and equipment.

A deferred tax benefit related to the Woodlawn basis differences of $152 and $321 was recorded for the three and six months ended June 30, 2012 and $29 and $32 for the three and six months ended June 30, 2011, respectively. A deferred tax liability of $7,336 and $7,657 related to the basis differences existed at June 30, 2012 and December 31, 2011, respectively.

Since the tax base on the Texas margin tax is derived from an income-based measure, the margin tax is construed as an income tax and, therefore, the recognition of deferred taxes applies to the margin tax. The impact on deferred taxes as a result of this provision is immaterial. State income taxes attributable to the Texas margin tax of $307 and $572 were recorded in continuing operations current income tax expense for the three and six months ended June 30, 2012 and $223 and $444 for the three and six months ended June 30, 2011, respectively.

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The components of income tax expense (benefit) from operations recorded for the three and six months ended June 30, 2012 and 2011 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Current:				
Federal	$ 4	$ 29	$ 4	$ 29
State	310	230	577	456
	314	259	581	485
Deferred:				
Federal	(152)	(29)	(321)	(32)
Total income tax expense (benefit)	$ 162	$ 230	$ 260	$ 453

Total income tax expense (benefit) was allocated to continuing and discontinued operations as follows:

Income tax expense (benefit) from continuing operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Current:				
State	$307	$223	$572	$444
Total income tax expense (benefit) from continuing operations	$307	$223	$572	$444

Income tax expense (benefit) from discontinued operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Current:				
Federal	$ 4	$ 29	$ 4	$ 29
State	3	7	5	12
	7	36	9	41
Deferred:				
Federal	(152)	(29)	(321)	(32)
Total income tax expense (benefit) from discontinued operations	$ (145)	$ 7	$ (312)	$ 9

(14) Commitments and Contingencies

From time to time, the Partnership is subject to various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Partnership.

On May 2, 2008, the Partnership received a copy of a petition filed in the District Court of Gregg County, Texas by Scott D. Martin (the "Plaintiff") against Ruben S. Martin, III (the "Defendant") with respect to certain matters relating to Martin Resource Management. In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment adverse to the Defendant which contained monetary damages and specific performance components (the "Judgment"). The Defendant appealed the Judgment. On November 3, 2010, the Court of Appeals, Sixth Appellate District of Texas at Texarkana, issued an opinion on the appeal overturning the Judgment. The Appellate Court's opinion rendered a take-nothing judgment against the Plaintiff and found in favor of the Defendant. The Supreme Court of Texas denied the Plaintiff's petition for review and therefore the opinion of the Sixth Appellate District of Texas at Texarkana has become final.

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On September 5, 2008, the Plaintiff and one of his affiliated partnerships (the “SDM Plaintiffs”), on behalf of themselves and derivatively on behalf of Martin Resource Management, filed suit in a Harris County, Texas district court (the “Harris County Litigation”) against Martin Resource Management, the Defendant, Robert Bondurant, Donald R. Neumeyer and Wesley M. Skelton, in their capacities as directors of Martin Resource Management (the “MRMC Director Defendants”), as well as 35 other officers and employees of Martin Resource Management (the “Other MRMC Defendants”). In addition to their respective positions with Martin Resource Management, Robert Bondurant, Donald Neumeyer and Wesley Skelton are officers of the Partnership’s general partner. The Partnership is not a party to this lawsuit, and it does not assert any claims (i) against the Partnership, (ii) concerning the Partnership’s governance or operations, or (iii) against the MRMC Director Defendants or other MRMC Defendants with respect to their service to the Partnership.

The SDM Plaintiffs allege, among other things, that the MRMC Director Defendants have breached their fiduciary duties owed to Martin Resource Management and the SDM Plaintiffs, entrenched their control of Martin Resource Management and diluted the ownership position of the SDM Plaintiffs and certain other minority shareholders in Martin Resource Management, and engaged in acts of unjust enrichment, excessive compensation, waste, fraud and conspiracy with respect to Martin Resource Management. The SDM Plaintiffs seek, among other things, to rescind the June 2008 issuance by Martin Resource Management of shares of its common stock under its 2007 Long-Term Incentive Plan to the Other MRMC Defendants, remove the MRMC Director Defendants as officers and directors of Martin Resource Management, prohibit the Defendant, Wesley M. Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Trust (the “ESOT”), and place all of the Martin Resource Management common shares owned or controlled by the Defendant in a constructive trust that prohibits him from voting those shares. The SDM Plaintiffs have amended their Petition to eliminate their claims regarding rescission of the issue by Martin Resource Management of shares of its common stock to the MRMC Employee Stock Ownership Plan. The case was abated in July 2009 during the pendency of a mandamus proceeding in the Texas Supreme Court. The Supreme Court denied mandamus relief on November 20, 2009. This lawsuit was amended to add the ESOT as a party and was subsequently removed to Federal Court by the ESOT. This lawsuit was remanded from Federal Court to the State District Court. The trial was previously set for August of 2012 but has been removed from the trial docket. The trial is nonetheless stayed pending the outcome of procedural matters pending in the appellate courts.

The lawsuits described above are in addition to (i) a separate lawsuit filed in July 2008 in a Gregg County, Texas district court by the daughters of the Defendant against Scott Martin, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that he has engaged in self-dealing in his capacity as a trustee under the trust, which holds shares of Martin Resource Management common stock, and has breached his fiduciary duties owed to the plaintiffs, who are beneficiaries of such trust, and (ii) a separate lawsuit filed in October 2008 in the United States District Court for the Eastern District of Texas by Angela Jones Alexander against the Defendant and Karen Yost in their capacities as a former trustee and a trustee, respectively, of the R.S. Martin Jr. Children Trust No. One (f/b/o Angela Santi Jones), which holds shares of Martin Resource Management common stock, which suit alleges, among other things that the Defendant and Karen Yost breached fiduciary duties owed to Angela Jones Alexander, who is the beneficiary of such trust, and seeks to remove Karen Yost as the trustee of such trust. With respect to the lawsuit described in (i) above, the Partnership has been informed that the Plaintiff has resigned as a trustee of the Ruben S. Martin, III Dynasty Trust. With respect to the lawsuit described in (ii) above, Angela Jones Alexander amended her claims to include her grandmother, Margaret Martin, as a defendant, but subsequently dropped her claims against Mrs. Martin. Additionally, all claims pertaining to Karen Yost have been resolved. All claims pertaining to Defendant have been preliminarily resolved, as the court, on February 9, 2011, issued an order that granted the parties' Joint Motion for Administrative Closure. With respect to the lawsuit referenced in (i) above, the case was tried in October 2009 and the jury returned a verdict in favor of the Defendant's daughters against Scott Martin in the amount of $4,900. On December 22, 2009, the court entered a judgment, reflecting an amount consistent with the verdict and additionally awarded attorneys' fees and interest. On January 7, 2010, the court modified its original judgment and awarded the Defendant's daughters approximately $2,700 in damages and attorneys' fees, plus interest. Scott Martin has appealed the judgment. On March 20, 2012, the Court of Appeals, Sixth Appellate District of Texas at Texarkana, issued an opinion on the appeal overturning the Judgment. While the Appellate Court found that there was sufficient evidence to support the jury's finding that a breach of fiduciary duty occurred, it found insufficient evidence to support any damages and therefore rendered a take-nothing judgment against the daughters of the Defendant. A motion for rehearing at the Appellate Court was overruled on April 26, 2012. The Defendant's daughters have indicated they will appeal the Appellate Court's ruling.

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On September 24, 2008, Martin Resource Management removed Plaintiff as a director of the general partner of the Partnership. Such action was taken as a result of the collective effect of Plaintiff's then recent activities, which the board of directors of Martin Resource Management determined was detrimental to both Martin Resource Management and the Partnership. The Plaintiff does not serve on any committees of the board of directors of the Partnership's general partner. This position on the board of directors was filled on July 26, 2010, by Charles Henry "Hank" Still.

On February 22, 2010, as a result of the Harris County Litigation being derivative in nature, Martin Resource Management formed a special committee of its board of directors and designated such committee as the Martin Resource Management authority for the purpose of assessing, analyzing and monitoring the Harris County Litigation and any other related litigation and making any and all determinations in respect of such litigation on behalf of Martin Resource Management. Such authorization includes, but is not limited to, reviewing the merits of the litigation, assessing whether to pursue claims or counterclaims against various persons or entities, assess whether to appoint or retain experts or disinterested persons to make determinations in respect of such litigation, and advising and directing Martin Resource Management's general counsel and outside legal counsel with respect to such litigation. The special committee consists of Robert Bondurant, Donald R. Neumeyer and Wesley M. Skelton.

On May 4, 2010, the Partnership received a copy of a petition filed in a new case with the District Clerk of Gregg County, Texas by Martin Resource Management against the Plaintiff and others with respect to certain matters relating to Martin Resource Management ("the Gregg County Matter"). As noted above, the Plaintiff was a former director of Martin Resource Management. The lawsuit alleges that the Plaintiff with help from others breached the fiduciary duties the Plaintiff owed to Martin Resource Management. The Partnership is not a party to the lawsuit, and the lawsuit does not assert any claims (i) against the Partnership, (ii) concerning the Partnership's governance or operations, or (iii) against the Plaintiff with respect to his service as an officer or former director of the general partner of the Partnership. With respect to this lawsuit, the case was tried in January 2012 and the jury returned a verdict in favor of Martin Resource Management against Scott D. Martin for breach of fiduciary duty and awarded an amount of $1,800. The court entered a judgment in favor of Martin Resource Management in the amount awarded by the jury plus interest. Scott D. Martin is appealing this judgment.

Additionally, on July 11, 2011, Scott D. Martin sued Martin Resource Management in State District Court in Harris County, Texas, alleging that it tortiously interfered with his rights under an existing insurance policy. A motion to transfer this case was granted and this case is currently pending in the 188th District Court of Gregg County, Texas. .

On June 22, 2012, the Partnership received from Scott D. Martin a demand that the Partnership indemnify him for legal fees and damages adjudged against him in the Gregg County Matter. He followed this up with an additional demand that the Partnership indemnify him for legal fees and expenses he paid in defending the lawsuit brought in Gregg County, Texas by the daughters of the Defendant. On June 25, 2012, the Partnership filed a petition in the District Court of Gregg County, Texas against Scott D. Martin, seeking a declaratory judgment regarding the Partnership's obligations to indemnify Scott D. Martin.

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(15) Consolidating Financial Statements

In connection with the Partnership’s filing of a shelf registration statement on Form S-3 with the Securities and Exchange Commission (the “Registration Statement”), Martin Operating Partnership L.P. (the “Operating Partnership”), the Partnership’s wholly-owned subsidiary, has issued in the past, and may issue in the future, unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time under the Registration Statement. If issued, the guarantees will be full, irrevocable and unconditional. In addition, the Operating Partnership may also issue senior or subordinated debt securities under the Registration Statement which, if issued, will be fully, irrevocably and unconditionally guaranteed by the Partnership. The Partnership does not provide separate financial statements of the Operating Partnership because the Partnership has no independent assets or operations, the guarantees are full and unconditional, and the other subsidiary of the Partnership is minor. There are no significant restrictions on the ability of the Partnership or the Operating Partnership to obtain funds from any of their respective subsidiaries by dividend or loan.

(16) Subsequent Events

On July 31, 2012, the Partnership completed the sale of its East Texas and Northwest Louisiana natural gas gathering and processing assets owned by Prism Gas to CenterPoint, as described in Note 4 for approximately $275,000 excluding any transaction costs and purchase price adjustments. . The asset sale includes the Partnership’s 50% operating interest in Waskom. A subsidiary of CenterPoint currently owns the other 50% percent interest.

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Item 2.Management's Discussion and Analysis of Financial Condition and Results of Operations

References in this quarterly report on Form 10-Q to "Martin Resource Management" refers to Martin Resource Management Corporation and its subsidiaries, unless the context otherwise requires. You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated and condensed financial statements and the notes thereto included elsewhere in this quarterly report.

Forward-Looking Statements

This quarterly report on Form 10-Q includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this quarterly report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue", or similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Item 1A. Risk Factors" of our Form 10-K for the year ended December 31, 2011, filed with the Securities and Exchange Commission (the "SEC") on March 5, 2012, and in this report.

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum and by-products;
- Natural gas services;
- Sulfur and sulfur-based products gathering, processing, marketing, manufacturing and distribution; and
- Marine transportation services for petroleum products and by-products.

The petroleum products and by-products we collect, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We operate primarily in the Gulf Coast region of the United States. This region is a major hub for petroleum refining, natural gas gathering and processing and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management, a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource

Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified and capitalized on the needs of producers and purchasers of hydrocarbon products and by-products and other bulk liquids. Martin Resource Management owns an approximate 28.0% limited partnership interest in us. Furthermore, it owns and controls our general partner, which owns a 2.0% general partner interest in us and all of our incentive distribution rights.

Martin Resource Management has operated our business since 2002. Martin Resource Management began operating our natural gas services business in the 1950s and our sulfur business in the 1960s. It began our marine transportation business in the late 1980s. It entered into our fertilizer and terminalling and storage businesses in the early 1990s. In recent years, Martin Resource Management has increased the size of our asset base through expansions and strategic acquisitions.

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Recent Developments

We believe one of the rationales driving investment in master limited partnerships, including us, is the opportunity for distribution growth offered by the partnerships. Such distribution growth is a function of having access to liquidity in the financial markets used for incremental capital investment (development projects and acquisitions) to grow distributable cash flow. Growth opportunities can be constrained by a lack of liquidity or access to the financial markets. During 2011 and thus far in 2012, the financial markets were available to us. As such, we were able to issue equity in February 2011 and January 2012 for the purpose of reducing outstanding indebtedness under our credit facility. Our credit facility is our primary source of liquidity and was refinanced in April 2011. Additionally we upsized our credit facility in April 2011, December 2011, and May 2012.

Conditions in our industry continue to be challenging in 2012. For example:

Coupled with the general decline in drilling activity are the federal government's enhanced safety regulations and inspection requirements as it relates to deep-water drilling in the Gulf of Mexico. These enhanced safety regulations and inspection requirements of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) continue to provide uncertainty surrounding the requirements for and pace of issuance of permits on the Gulf of Mexico Outer Continental Shelf (OCS). Although permits began to be issued by the BOEMRE again during first quarter 2011, they have not been approved in a timely manner consistent with pre-BP/Macondo spill levels.

There has been a decline in the demand for certain marine transportation services based on decreased refinery production resulting in an oversupply of equipment.

Despite the industry challenges we have faced, we are positioning ourselves for continued growth. In particular:

We continue to adjust our business strategy to focus on maximizing our liquidity, maintaining a stable asset base, and improving the profitability of our assets by increasing their utilization while controlling costs. Over the past year we have had access to the capital markets and have appropriate levels of liquidity and operating cash flows to adequately fund our growth. Our goal over the next two years will be to increase growth capital expenditures primarily in our Terminalling and Storage and Sulfur Services segments.

We continue to evaluate opportunities to enter into interest rate and commodity hedging transactions. We believe these transactions can beneficially remove risks associated with interest rate and commodity price volatility.

During 2011 and the first part of 2012, we have experienced positive changing market dynamics in our Terminalling and Storage and Marine Transportation segments including activity associated with the rapidly developing basins such as the Eagle Ford shale in South Texas.

On June 18, 2012, we and a subsidiary of CenterPoint Energy Inc. (NYSE: CNP), ("CenterPoint") entered into a definitive agreement under which CenterPoint would acquire our East Texas and Northwest Louisiana natural gas gathering and processing assets owned by Prism Gas Systems 1, L.P., a wholly-owned subsidiary of us, and other natural gas gathering and processing assets also owned by us, for cash in a transaction valued at approximately $275,000 excluding any transaction costs and purchase price adjustments. The asset sale includes our 50% operating interest in Waskom Gas Processing Company. A subsidiary of CenterPoint currently owns the other 50% percent interest. The sale was completed on July 31, 2012.

Additionally, we have reached agreement with a private investor group to sell our interest in Matagorda Offshore Gathering System and Panther Interstate Pipeline Energy LLC for $2.0 million. These assets, along with the assets sold to CenterPoint are collectively referred to as the "Prism Assets". This sale is expected to be completed in the third quarter of 2012.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based on the historical consolidated and condensed financial statements included elsewhere herein. We prepared these financial statements in conformity with generally accepted accounting principles. The preparation of these financial statements required us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We based our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Our results may differ from these estimates. Currently, we believe that our accounting policies do not require us to make estimates using assumptions about matters that are highly uncertain. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include the amount of the allowance for doubtful accounts receivable and the determination of the fair value of our reporting units under Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 350 related to goodwill. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2011, and there have been no material changes to these policies through June 30, 2012.

Our Relationship with Martin Resource Management

Martin Resource Management is engaged in the following principal business activities:

- providing land transportation of various liquids using a fleet of trucks and road vehicles and road trailers;
- distributing fuel oil, asphalt, sulfuric acid, marine fuel and other liquids;
- providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Mississippi and Texas;
- operating a small crude oil gathering business in Stephens, Arkansas;
- operating a lube oil processing facility in Smackover, Arkansas;
- operating an underground NGL storage facility in Arcadia, Louisiana;
- supplying employees and services for the operation of our business; and
- operating, solely for our account, our asphalt facilities in Omaha, Nebraska, Port Neches, Texas and South Houston, Texas.

We are and will continue to be closely affiliated with Martin Resource Management as a result of the following relationships.

Ownership

Martin Resource Management owns an approximate 28.0% limited partnership interest and a 2% general partnership interest in us and all of our incentive distribution rights.

Management

Martin Resource Management directs our business operations through its ownership and control of our general partner. We benefit from our relationship with Martin Resource Management through access to a significant pool of management expertise and established relationships throughout the energy industry. We do not have employees. Martin Resource Management employees are responsible for conducting our business and operating our assets on our behalf.

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Related Party Agreements

We are a party to an omnibus agreement with Martin Resource Management. The omnibus agreement requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. We reimbursed Martin Resource Management for $27.3 million of direct costs and expenses for the three months ended June 30, 2012 compared to $20.9 million for the three months ended June 30, 2011. We reimbursed Martin Resource Management for $51.0 million of direct costs and expenses for the six months ended June 30, 2012 compared to $40.4 million for the six months ended June 30, 2011. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. Effective October 1, 2011 through September 30, 2012, the Conflicts Committee of the board of directors of our general partner (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $6.6 million. We reimbursed Martin Resource Management for $1.6 and $1.0 million of indirect expenses for the three months ended June 30, 2012 and 2011, respectively. We reimbursed Martin Resource Management for $3.3 and $2.1 million of indirect expenses for the six months ended June 30, 2012 and 2011, respectively. These indirect expenses covered the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. The omnibus agreement also contains significant non-compete provisions and indemnity obligations. Martin Resource Management also licenses certain of its trademarks and trade names to us under the omnibus agreement.

In addition to the omnibus agreement, we and Martin Resource Management have entered into various other agreements including, but not limited to, a motor carrier agreement, terminal services agreements, marine transportation agreements and other agreements for the provision of various goods and services. Pursuant to the terms of the omnibus agreement, we are prohibited from entering into certain material agreements with Martin Resource Management without the approval of the Conflicts Committee.

For a more comprehensive discussion concerning the omnibus agreement and the other agreements that we have entered into with Martin Resource Management, please refer to "Item 13. Certain Relationships and Related Transactions – Agreements" set forth in our annual report on Form 10-K for the year ended December 31, 2011, filed with the SEC on March 5, 2012.

Commercial

We have been and anticipate that we will continue to be both a significant customer and supplier of products and services offered by Martin Resource Management. Our motor carrier agreement with Martin Resource Management provides us with access to Martin Resource Management's fleet of road vehicles and road trailers to provide land transportation in the areas served by Martin Resource Management. Our ability to utilize Martin Resource Management's land transportation operations is currently a key component of our integrated distribution network.

We also use the underground storage facilities owned by Martin Resource Management in our natural gas services operations. We lease an underground storage facility from Martin Resource Management in Arcadia, Louisiana with a storage capacity of 2.4 million barrels. Our use of this storage facility gives us greater flexibility in our operations by allowing us to store a sufficient supply of product during times of decreased demand for use when demand increases.

In the aggregate, our purchases of land transportation services, NGL storage services, sulfuric acid and lube oil product purchases and sulfur services payroll reimbursements from Martin Resource Management accounted for approximately 5% and 3% of our total cost of products sold during the three months ended June 30, 2012 and 2011, respectively and approximately 4% and 3% of our total cost of products sold for the six months ended June 30, 2012 and 2011, respectively. We also purchase marine fuel from Martin Resource Management, which we account for as an operating expense.

Correspondingly, Martin Resource Management is one of our significant customers. It primarily uses our terminalling, marine transportation and NGL distribution services for its operations. We provide terminalling and storage services under a terminal services agreement. We provide marine transportation services to Martin Resource Management under a charter agreement on a spot-contract basis at applicable market rates. Our sales to Martin Resource Management accounted for approximately 7% and 8% of our total revenues for the three months ended June 30, 2012 and 2011, respectively. Our sales to Martin Resource Management accounted for approximately 7% and 9% of our total revenues for the six months ended June 30, 2012 and 2011, respectively. We provide terminalling and storage and marine transportation services to Midstream Fuel Service LLC and Midstream Fuel LLC provides terminal services to us to handle lubricants, greases and drilling fluids.

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For a more comprehensive discussion concerning the agreements that we have entered into with Martin Resource Management, please refer to "Item 13. Certain Relationships and Related Transactions – Agreements" set forth in our annual report on Form 10-K for the year ended December 31, 2011, filed with the SEC on March 5, 2012.

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or to our management, as appropriate. If the board of directors is involved in the approval process, it determines whether to refer the matter to the Conflicts Committee, as constituted under our limited partnership agreement. Certain related party transactions are required to be submitted to the Conflicts Committee. If a matter is referred to the Conflicts Committee, it obtains information regarding the proposed transaction from management and determines whether to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers such advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Results of Operations

The results of operations for the three and six months ended June 30, 2012 and 2011 have been derived from our consolidated and condensed financial statements.

We evaluate segment performance on the basis of operating income, which is derived by subtracting cost of products sold, operating expenses, selling, general and administrative expenses, and depreciation and amortization expense from revenues. The following table sets forth our operating revenues and operating income by segment for the three months ended June 30, 2012 and 2011. The results of operations for the first three months of the year are not necessarily indicative of the results of operations which might be expected for the entire year.

The natural gas services segment information below excludes the discontinued operations of the Prism Assets for all periods.

	Operating Revenues	Revenues Intersegment Eliminations	Operating Revenues after Eliminations	Operating Income (loss)	Operating Income Intersegment Eliminations	Operating Income (loss) after Eliminations
	(In thousands)					
Three months ended June 30, 2012						
Terminalling and storage	$41,430	$ (1,176)	$ 40,254	$4,998	$ (654)	$ 4,344
Natural gas services	164,817	—	164,817	(417)	384	(33)
Sulfur services	67,093	—	67,093	12,278	1,142	13,420
Marine transportation	21,466	(752)	20,714	2,150	(872)	1,278
Indirect selling, general and administrative	—	—	—	(2,349)	—	(2,349)
Total	$294,806	$ (1,928)	$ 292,878	$16,660	$ —	$ 16,660
Three months ended June 30, 2011						

Terminalling and storage	$39,766	$ (1,068)	$ 38,698	$3,123	$ (172)	$ 2,951
Natural gas services	127,050	—	127,050	(283)	243	(40)
Sulfur services	76,933	—	76,933	10,102	1,884	11,986
Marine transportation	19,351	(1,975)	17,376	(1,011)	(1,955)	(2,966)
Indirect selling, general and administrative	—	—	—	(1,762)	—	(1,762)
Total	$263,100	$ (3,043)	$ 260,057	$10,169	$ —	$ 10,169
Six months ended June 30, 2012						
Terminalling and storage	$84,464	$ (2,351)	$ 82,113	$8,734	$ (1,308)	$ 7,426
Natural gas services	336,928	—	336,928	2,426	761	3,187
Sulfur services	141,645	—	141,645	24,813	2,234	27,047
Marine transportation	43,033	(1,457)	41,576	1,538	(1,687)	(149)
Indirect selling, general and administrative	—	—	—	(4,767)	—	(4,767)
Total	$606,070	$ (3,808)	$ 602,262	$32,744	$ —	$ 32,744
Six months ended June 30, 2011						
Terminalling and storage	$77,412	$ (2,046)	$ 75,366	$6,340	$ (221)	$ 6,119
Natural gas services	264,205	—	264,205	2,986	448	3,434
Sulfur services	136,691	—	136,691	18,129	3,768	21,897
Marine transportation	40,790	(4,015)	36,775	(252)	(3,995)	(4,247)
Indirect selling, general and administrative	—	—	—	(3,580)	—	(3,580)
Total	$519,098	$ (6,061)	$ 513,037	$23,623	$ —	$ 23,623

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Our results of operations are discussed on a comparative basis below. There are certain items of income and expense which we do not allocate on a segment basis. These items, including equity in earnings (loss) of unconsolidated entities, interest expense, and indirect selling, general and administrative expenses, are discussed after the comparative discussion of our results within each segment.

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

Our total revenues before eliminations were $294.8 million for the three months ended June 30, 2012, compared to $263.1 million for the three months ended June 30, 2011, an increase of $31.7 million, or 12%. Our operating income before eliminations was $16.7 million for the three months ended June 30, 2012, compared to $10.2 million for the three months ended June 30, 2011, an increase of $6.5 million, or 64%.

The results of operations are described in greater detail on a segment basis below.

Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Three Months Ended June 30,	
	2012	2011
	(In thousands)	
Revenues:		
Services	$ 22,222	$ 20,375
Products	19,208	19,391
Total revenues	41,430	39,766
Cost of products sold	17,890	18,290
Operating expenses	13,922	12,939
Selling, general and administrative expenses	51	92
Depreciation and amortization	4,944	4,745
	4,623	3,700
Other operating income (loss)	375	(577)
Operating income	$ 4,998	$ 3,123

Revenues. Our terminalling and storage revenues increased $1.7 million, or 4%, for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. Of the increase, $1.8 million is related to new terminalling assets commissioned in the second quarter of 2012, offset by a $0.1 million decrease in product revenues.

Cost of products sold. Our cost of products sold remained relatively flat for the three months ended June 30, 2012 compared to the three months ended June 30, 2011.

Operating Expenses. Operating expenses increased $1.0 million, or 8%, for the three months ended June 30, 2012 as compared to the same period of 2011. Of the increase, $0.8 million relates to increased repair and maintenance charges incurred at our Neches and Stanolind facilities for channel dredging and road repairs. The balance of the increase primarily relates to increased operating expenses at our Cross facilities.

Selling, general and administrative expenses. Selling, general and administrative expenses remained relatively flat for the three months ended June 30, 2012 compared to the three months ended June 30, 2011.

Depreciation and amortization. Depreciation and amortization increased $0.2 million, or 4%, for the three months ended June 30, 2012 compared to the three months ended June 30, 2011 resulting from capital expenditures made during the past twelve months.

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Other operating income. Other operating income of $0.4 million for the three months ended June 30, 2012 consisted of the final indemnity payment related to the sale of our Mont Belvieu facility in 2009. Other operating income for the three months ended June 30, 2011includes a loss of $0.7 million on the disposition of certain property, plant and equipment at our terminal located in Corpus Christi, TX. The disposition was executed to facilitate the construction of a new crude terminal adjacent to our existing facility. The loss was offset by business interruption insurance recoveries of $0.1 million received during the second quarter of 2011.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Three Months Ended June 30,	
	2012	2011
	(In thousands)	
Revenues	$ 164,817	$ 127,050
Cost of products sold	163,427	125,891
Operating expenses	804	776
Selling, general and administrative expenses	859	522
Depreciation and amortization	144	144
	(417)	(283)
Other operating income	—	—
Operating loss	$ (417)	$ (283)
NGLs Volumes (Bbls)	2,436	1,547
Equity in earnings (loss) of unconsolidated entities	$ (745)	$ 153

Revenues. Our natural gas services revenues increased $37.8 million, or 30% for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. NGL sales volumes for the three months of 2012 increased 57% compared to the same period of 2011. Our NGL average sales price per barrel for the three months ended June 30, 2012, decreased $14.45, or 18% compared to the same period of 2011.

Cost of products sold. Our cost of products sold increased $37.5 million, or 30%, for the three months ended June 30, 2012, compared to the same period of 2011. The percentage increase in NGL cost of products sold was slightly higher than our percentage increase in NGL revenues, resulting in decreased margins of $0.18 per barrel.

Operating expenses. Operating expenses remained consistent for the three months ended June 30, 2012, as compared to the same period for 2011.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.3 million, or 65%, for the three months ended June 30, 2012, as compared to the same period for 2011. This is primarily due to an increase in the reserve of an uncollectible customer receivable of $0.2 million and increased wages and burden of $0.1 million.

Depreciation and amortization. Depreciation and amortization remained consistent for the three months ended June 30, 2012, as compared to the same period for 2011.

Equity in earnings of unconsolidated entities. Equity in earnings (loss) of unconsolidated entities was $(0.7) million and $0.2 million for the six months ended June 30, 2012 and 2011, respectively, a decrease of $0.9 million. This decrease is primarily related to our share of an adjustment associated with unrecoverable base gas which migrated beyond the gas reservoir related to our investment in Redbird Gas Storage LLC ("Redbird") during second quarter 2012.

In summary, our natural gas services operating income decreased $0.1 million, or 13%, for the three months ended June 30, 2012, compared to the same period of 2011.

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Sulfur Services Segment

The following table summarizes our results of operations in our sulfur segment.

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011
	(In thousands)	
Revenues:		
Services	$ 2,925	$ 2,850
Products	64,168	74,083
Total revenues	67,093	76,933
Cost of products sold	47,440	59,983
Operating expenses	4,614	4,966
Selling, general and administrative expenses	982	857
Depreciation and amortization	1,782	1,700
	12,275	9,427
Other operating income	3	675
Operating income	$ 12,278	$ 10,102
Sulfur (long tons)	328.0	339.6
Fertilizer (long tons)	83.6	69.4
Sulfur services volumes (long tons)	411.6	409.0

Revenues. Our total sulfur services revenues decreased $9.9 million, or 13%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. Services revenue increased $0.1 million, or 3% for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. The decrease in products revenue was primarily a result of a decline in our average sales price of 14%.

Cost of products sold. Our cost of products sold decreased $12.5 million, or 21%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. The percentage decrease in sulfur services cost of products sold was slightly higher than our percentage decrease in sulfur services revenues, resulting in an increase in our margin per ton of 18%. This decrease is also related to a decline in the market price of our sulfur products.

Operating expenses. Our operating expenses decreased $0.4 million, or 8%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This was primarily a result of decreased outside towing expenses of $0.2 million.

Selling, general, and administrative expenses. Selling, general, and administrative expenses increased $0.1 million, or 11%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This increase is related to an increase of $0.1 million in overhead allocation expense.

Depreciation and amortization. Depreciation and amortization expense increased $0.1 million, or 6%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011.

Other operating income. Other operating income decreased $0.7 million for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This decrease relates to business interruption insurance recoveries from Hurricane Ike that were reimbursed in 2011.

In summary, our sulfur operating income increased $2.2 million, or 22%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011.

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Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

	Three Months Ended June 30,	
	2012	2011
	(In thousands)	
Revenues	$ 21,466	$ 19,351
Operating expenses	16,033	16,505
Selling, general and administrative expenses	362	518
Depreciation and amortization	2,921	3,339
	2,150	(1,011)
Other operating income	-	—
Operating income (loss)	$ 2,150	$ (1,011)

Revenues. Our marine transportation revenues increased $2.1 million, or 11%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This increase was primarily a result of an increase in our offshore marine operations somewhat offset by a decrease in our inland marine operations. Our offshore revenues increased $3.5 million primarily due to increased utilization of the offshore fleet in 2012 of $2.7 million due to increased demand for our two offshore tows which operate in the spot market and an increase in ancillary charges of $0.8 million. Our inland marine operations decreased $1.4 million, of which $0.6 million is attributed to decreased utilization of the inland fleet and $0.8 million in decreased ancillary charges, primarily related to fuel.

Operating expenses. Operating expenses decreased $0.5 million, or 3%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This decrease in operating costs is primarily due to a decrease in outside towing expense of $0.8 million, decreased barge lease expense of $0.3 million, and decreased operating supplies expense of $0.2 million. These decreases were partially offset by increases in wages and burden of $0.3 million, increased Marine Jones-Act claims expense of $0.1 million, increased repairs and maintenance expense of $0.2 million, and increased fuel expense of $0.2 million. During both quarters ended June 30, 2012 and 2011, respectively, operating expenses were somewhat higher than normalized levels. This was due to a higher than expected expenses associated with the dry docking of one of our inland vessels during the second quarter of 2012. For 2011, we saw increased barge cleaning expense associated with the vessels being utilized in the BP oil spill cleanup efforts.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased $0.2 million, or 30%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This decrease was primarily related to decreased software costs of $0.1 million.

Depreciation and Amortization. Depreciation and amortization decreased $0.4 million, or 13%, for the three months ended June 30, 2012, compared to the three months ended June 30, 2011. This decrease was primarily a result of a reduction in depreciation from disposal of equipment made in the last twelve months somewhat offset by capital expenditures made in the last twelve months.

In summary, our marine transportation operating income increased $3.1 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011.

Six Months Ended June 30, 2012 Compared to the Six Months Ended June 30, 2011

Our total revenues before eliminations were $606.1 million for the six months ended June 30, 2012 compared to $519.1 million for the six months ended June 30, 2011, an increase of $87.0 million, or 17%. Our operating income before eliminations was $32.7 million for the six months ended June 30, 2012 compared to $23.6 million for the six months ended June 30, 2011, an increase of $9.1 million, or 39%.

The results of operations are described in greater detail on a segment basis below.

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Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In thousands)	
Revenues:		
Services	$ 43,583	$ 39,476
Products	40,881	37,936
Total revenues	84,464	77,412
Cost of products sold	38,430	35,780
Operating expenses	27,967	25,254
Selling, general and administrative expenses	61	176
Depreciation and amortization	9,667	9,285
	8,339	6,917
Other operating income (loss)	395	(577)
Operating income	$ 8,734	$ 6,340

Revenues. Our terminalling and storage revenues increased $7.1 million, or 9%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. Of the increase in total revenues, $4.1 million is attributable to services revenue and $3.0 million pertains to product revenues. The increase in services revenue is primarily related to certain terminalling assets commissioned during the six months of 2012. Of the increase in product revenues, $6.7 million was due to the conversion of a consigned product delivery agreement with one of our customers during December 2011. This increase was offset by decreased revenues of $3.7 million from reduced sales volumes.

Cost of products sold. Our cost of products sold increased $2.7 million, or 7%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. Of this increase, $6.3 million was primarily due to the conversion of a consigned product delivery agreement with one of our customers during December 2011. The increase was offset by a $3.6 million decrease in cost of sales from reduced sales volumes.

Operating expenses.   Operating expenses increased $2.7 million, or 11%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. Of this increase, $2.6 million was due primarily to increased operating expenses associated certain terminalling assets commissioned during the six months of 2012.

Selling, general and administrative expenses. Selling, general and administrative expenses remained relatively flat for the six month period ending June 30, 2012 as compared to the same period of 2011.

Depreciation and amortization. Depreciation and amortization increased $0.4 million, or 4%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The balance of the increase was a result of capital expenditures made during the past twelve months.

Other operating income.   Other operating income of $0.4 million for the six months ended June 30, 2012 consisted of the final indemnity payment related to the sale of our Mont Belvieu facility in 2009. Other operating income for the six months ended June 30, 2011includes a loss of $0.7 million on the disposition of certain property, plant and equipment at our terminal located in Corpus Christi, TX. The disposition was executed to facilitate the construction of a new crude terminal adjacent to our existing facility. The loss was offset primarily by business interruption insurance recoveries of $0.1 million received during the second quarter of 2011.

In summary, our terminalling and storage operating income increased $2.4 million, or 38%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Six Months Ended June 30,	
	2012	2011
	(In thousands)	
Revenues	$ 336,928	$ 264,205
Cost of products sold	331,003	258,374
Operating expenses	1,756	1,487
Selling, general and administrative expenses	1,456	1,071
Depreciation and amortization	287	287
	2,426	2,986
Other operating income	—	—
Operating income	$ 2,426	$ 2,986
NGLs Volumes (Bbls)	4,733	3,376
Equity in earnings (loss) of unconsolidated entities	$ (363)	$ 153

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Revenues. Our natural gas services revenues increased $72.7 million, or 28% for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. NGL sales volumes for the six months of 2012 increased 40% compared to the same period of 2011. Our NGL average sales price per barrel for the six months ended June 30, 2012, decreased $7.08, or 9% compared to the same period of 2011.

Cost of products sold. Our cost of products sold increased $72.6 million, or 28%, for the six months ended June 30, 2012, compared to the same period of 2011. The percentage increase in NGL cost of products sold was slightly higher than our percentage increase in NGL revenues, resulting in decreased margins of $0.48 per barrel.

Operating expenses. Operating expenses increased $0.3 million, or 18%, for the six months ended June 30, 2012, as compared to the same period for 2011. This is primarily related to increased wages and burden of $0.1 million and increased pipeline maintenance expenses of $0.1 million.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.4 million, or 36%, for the six months ended June 30, 2012, as compared to the same period for 2011. This is primarily due to an increase in the reserve of an uncollectible customer receivable of $0.2 million, increased wages and burden of $0.1 million, and increased property tax expense of $0.1 million.

Depreciation and amortization. Depreciation and amortization remained consistent for the six months ended June 30, 2012, as compared to the same period for 2011.

Equity in earnings of unconsolidated entities. Equity in earnings (loss) of unconsolidated entities was $(0.4) million and $0.2 million for the six months ended June 30, 2012 and 2011, respectively, a decrease of $0.6 million. This decrease is primarily related to our share of an adjustment associated with unrecoverable base gas which migrated beyond the gas reservoir related to our investment in Redbird during second quarter 2012, offset by a full period of earnings this year, as Redbird was acquired in May, 2011.

In summary, our natural gas services operating income decreased $0.6 million, or 19%, for the six months ended June 30, 2012, compared to the same period of 2011.

Sulfur Services Segment

The following table summarizes our results of operations in our sulfur services segment.

	Six Months Ended June 30, 2012	2011
	(In thousands)	
Revenues:		
Services	$ 5,851	$ 5,700
Products	135,794	130,991
Total revenues	141,645	136,691
Cost of products sold	102,491	104,515
Operating expenses	8,807	9,657
Selling, general and administrative expenses	1,937	1,743
Depreciation and amortization	3,575	3,322
	24,835	17,454
Other operating income (loss)	(22)	675

Operating income	$	24,813	$	18,129
Sulfur (long tons)		636.2		688.5
Fertilizer (long tons)		177.5		147.0
Sulfur services volumes (long tons)		813.7		835.5

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Revenues. Our total sulfur services revenues increased $4.9 million, or 4%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. Service revenue accounted for $0.2 million, while product sales accounted for the remaining $4.7 million. The service revenue relates to an increase in a base fee for 2012. The increase in product revenue increase was primarily a result of a 4% increase in our average sales price. The sales price increase was related to an increased market price for our sulfur products.

Cost of products sold. Our cost of products sold decreased $2.0 million, or 2%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The percentage decrease in sulfur services cost of products sold was slightly lower than our percentage decrease in sulfur services revenues, resulting in an increase in our margin per ton of 29%. This decrease is also related to a decline in the market price of our sulfur products.

Operating expenses. Our operating expenses decreased $0.9 million, or 9%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. This decrease was a result of decreased outside towing expenses of $1.1 million being partially offset by an increase in fuel costs of $0.2 million related to our marine transportation expenses.

Selling, general and administrative expenses. Selling, general, and administrative expenses increased $0.2 million, or 12%, for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This increase is related to an increase of $0.2 million in overhead allocation expense.

Depreciation and amortization. Depreciation and amortization expense increased $0.3 million, or 9%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. This increase is a result of capital expenditures made during the past twelve months.

Other operating income. Other operating income decreased $0.7 million for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This decrease relates to business interruption insurance recoveries from Hurricane Ike that were reimbursed in 2011.

In summary, our sulfur services operating income increased $6.7 million, or 37%, for the six months ended June 30, 2012 compared to the six months ended June 30, 2011.

Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

	Six Months Ended June 30,	
	2012	2011
	(In thousands)	
Revenues	$ 43,033	$ 40,790
Operating expenses	34,747	33,531
Selling, general and administrative expenses	786	907
Depreciation and amortization	5,962	6,604
	1,538	(252)
Other operating income (loss)	—	—
Operating income (loss)	$ 1,538	$ (252)

Revenues. Our marine transportation revenues increased $2.2 million, or 5%, for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This increase was primarily a result of an increase in our offshore marine operations, offset by a decrease in our inland marine operations. Our offshore revenues increased $3.8 million primarily due to increased utilization of the offshore fleet in 2012 of $3.3 million due to increased demand for our two offshore tows which operate in the spot market and an increase in ancillary charges of $0.6 million. Our inland marine operations decreased $1.6 million, of which $1.9 million is attributed to decreased utilization of the inland fleet offset by $0.3 million in increased ancillary charges, primarily related to fuel.

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Operating expenses. Operating expenses increased $1.2 million, or 4%, for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This increase in operating costs is primarily due to an increase in fuel expense of $1.2 million, increased Marine Jones-Act claims expense of $0.3 million, and increased wages and burden expense of $0.7 million. These increases were offset by a decrease in outside towing expense of $1.0 million. During both periods ended June 30, 2012 and 2011, respectively, operating expenses were somewhat higher than normalized levels. This was due to a higher than expected expenses associated with the dry docking of one of our inland vessels during 2012. For 2011, we saw increased barge cleaning expense associated with the vessels being utilized in the BP oil spill cleanup efforts.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased $0.1 million, or 13%, for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This decrease was primarily related to decreased software costs of $0.1 million.

Depreciation and Amortization. Depreciation and amortization decreased $0.6 million, or 10%, for the six months ended June 30, 2012, compared to the six months ended June 30, 2011. This decrease was primarily a result of disposal of equipment made in the last twelve months offset by capital expenditures made in the last twelve months.

In summary, our marine transportation operating income increased $1.8 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011.

Equity in Earnings of Unconsolidated Entities

For the three and six months ended June 30, 2012, equity in earnings of unconsolidated entities relates to our unconsolidated interests in Redbird, Caliber Gathering System, LLC and Pecos Valley Producer Services LLC. For the three and six months ended June 30, 2011, equity in earnings of unconsolidated entities relates to our unconsolidated interest in Redbird.

Equity in earnings (loss) of unconsolidated entities was $(0.7) million and $0.2 million for the three months ended June 30, 2012 and 2011, respectively, a decrease of $0.9 million. This decrease is primarily related to Redbird's share of a base gas liability adjustment during second quarter 2012.

Equity in earnings (loss) of unconsolidated entities was $(0.4) million for the six months ended June 30, 2012 compared to $0.2 million for the six months ended June 30, 2011, a decrease of $0.6 million. This decrease is primarily related to Redbird's share of a base gas liability adjustment during second quarter 2012.

Interest Expense

Our interest expense for all operations was $8.3 million for the three months ended June 30, 2012, compared to $4.4 million for the three months ended June 30, 2012, an increase of $3.9 million, or 88%. This increase was primarily due to the interest rate swaps on our senior notes that contributed to decreases in interest expense related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps in the second quarter of 2011. These swaps were terminated during third quarter 2011.

Our interest expense for all operations was $15.5 million for the six months ended June 30, 2012, compared to $12.8 million for the six months ended June 30, 2012, an increase of $2.7 million, or 21%. This increase was primarily due to the interest rate swaps on our senior notes that contributed to decreases in interest expense related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps in the six months ended June 30, 2011. These swaps were terminated during third quarter 2011.

In conjunction with the redemption of our senior notes, we incurred a debt prepayment premium in the amount of $2.2 million for the three and six months ending June 30, 2012.

Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses were $1.6 million for the three months ended June 30, 2012 compared to $1.0 million for the three months ended June 30, 2011, an increase of $0.6 million, or 58% primarily due to an increase in allocated overhead expenses from Martin Resource Management. Indirect selling, general and administrative expenses were $3.3 million for the six months ended June 30, 2012 compared to $2.1 million for the six months ended June 30, 2011, an increase of $1.2 million, or 58% primarily due to an increase in allocated overhead expenses from Martin Resource Management.

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Martin Resource Management allocated to us a portion of its indirect selling, general and administrative expenses for services such as accounting, treasury, clerical billing, information technology, administration of insurance, engineering, general office expense and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. This allocation is based on the percentage of time spent by Martin Resource Management personnel that provide such centralized services. Generally accepted accounting principles also permit other methods for allocation of these expenses, such as basing the allocation on the percentage of revenues contributed by a segment. The allocation of these expenses between Martin Resource Management and us is subject to a number of judgments and estimates, regardless of the method used. We can provide no assurances that our method of allocation, in the past or in the future, is or will be the most accurate or appropriate method of allocating these expenses. Other methods could result in a higher allocation of selling, general and administrative expense to us, which would reduce our net income.

In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. Effective October 1, 2011 through September 30, 2012, the Conflicts Committee of the board of directors of our general partner (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $6.6 million. We reimbursed Martin Resource Management for $1.6 and $1.0 million of indirect expenses for the three months ended June 30, 2012 and 2011, respectively. We reimbursed Martin Resource Management for $3.3 and $2.1 million of indirect expenses for the three months ended June 30, 2012 and 2011, respectively. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Liquidity and Capital Resources

General

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations and access to debt and equity markets, both public and private. During 2012 and 2011, we completed several transactions that have improved our liquidity position. In July 2012, we completed the sale of certain gas gathering and processing assets for approximately $275.0 million. In January 2012, we received net proceeds of $91.4 million from a public offering of common units. In February 2011, we received net proceeds of $70.3 million from a public offering of common units. Additionally, we made certain strategic amendments to our credit facility which provides for a maximum borrowing capacity of $400 million under our revolving credit facility.

As a result of these financing activities, discussed in further detail below, management believes that expenditures for our current capital projects will be funded with cash flows from operations, current cash balances and our current borrowing capacity under the expanded revolving credit facility. However, it may be necessary to raise additional funds to finance our future capital requirements.

Our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will also depend upon our future operating performance, which is subject to certain risks. Please read "Item 1A. Risk Factors" of our Form 10-K for the year ended December 31, 2011, filed with the SEC on March 5, 2012, as well as our updated risk factors contained in "Item 1A. Risk Factors" set forth elsewhere herein, for a discussion of such risks.

Debt Financing Activities

On May 24, 2012, we redeemed $25.0 million of the Senior Notes from various holders using proceeds of our January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under our revolving credit facility.

On May 10, 2012, we increased the maximum amount of borrowings and letters of credit available under our revolving credit facility from $375.0 million to $400.0 million.

On December 5, 2011, we increased the maximum amount of borrowings and letters of credit available under our revolving credit facility from $350.0 million to $375.0 million.

On September 7, 2011, we amended our revolving credit facility to (1) increase the maximum amount of investments made in permitted joint ventures to $50.0 million, and (2) increase the maximum amount of investments made in Redbird and Cardinal to $120.0 million.

On April 15, 2011, we amended our credit facility to (i) increase the maximum amount of borrowings and letters of credit under the Credit Agreement from $275.0 million to $350.0 million, (ii) extend the maturity date of all amounts outstanding under the Credit Agreement from March 15, 2013 to April 15, 2016, (iii) decrease the applicable interest rate margin on committed revolver loans under the Credit Agreement as described in more detail below, (iv) adjust the financial covenants as described in more detail below, (v) increase the maximum allowable amount of additional outstanding indebtedness of the borrower and the Partnership and certain of its subsidiaries as described in more detail below, and (vi) adjust the commitment fee incurred on the unused portion of the loan facility as described in more detail below.

Equity Offerings

On January 25, 2012, we completed a public offering of 2,645,000 common units at a price of $36.15 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 2,645,000 common units, net of underwriters' discounts, commissions and offering expenses were $91.4 million. Our general partner contributed $2.0 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. On January 25, 2012, all of the net proceeds were used to reduce our outstanding indebtedness.

On February 9, 2011, we completed a public offering of 1,874,500 common units at a price of $39.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 1,874,500 common units, net of underwriters' discounts, commissions and offering expenses were $70.3 million. Our general partner contributed $1.5 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. On February 9, 2011, we made a $65.0 million payment to reduce the outstanding balance under our revolving credit facility.

Due to the foregoing, we believe that cash generated from operations and our borrowing capacity under our credit facility will be sufficient to meet our working capital requirements, anticipated maintenance capital expenditures and scheduled debt payments in 2013.

Finally, our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will depend upon our future operating performance, which is subject to certain risks. Please read "Item 1A. Risk Factors" of our Form 10-K for the year ended December 31, 2011, filed with the SEC on March 5, 2012, as well as our updated risk factors contained in "Item 1A. Risk Factors" set forth elsewhere herein, for a discussion of such risks.

Cash Flows and Capital Expenditures

For the six months ended June 30, 2012, cash decreased $0.2 million as a result of $17.1 million provided by operating activities ($10.2 million from continuing operating activities and $6.9 million from discontinued operating activities), $63.8 million used in investing activities ($61.8 million from continuing investing activities and $2.0 million from discontinued investing activities) and $46.5 million provided by financing activities. For the six months ended June 30, 2011, cash decreased $11.3 million as a result of $30.1 million provided by operating activities ($20.4 million from continuing operating activities and $9.6 million from discontinued operating activities), $113.6 million used in investing activities ($107.7 million from continuing investing activities and $5.9 million from discontinued investing activities), and $72.2 million provided by financing activities.

For the six months ended June 30, 2012, our cash flows used in continuing investing activities of $61.8 million consisted of capital expenditures, payments for plant turnaround costs, return of investments from unconsolidated entities and contributions to unconsolidated entities. For the six months ended June 30, 2012, our cash flows used in discontinued investing activities of $2.0 million consisted of capital expenditures, return of investments from unconsolidated entities and contributions to unconsolidated entities. For the six months ended June 30, 2011, our cash flows used in continuing investing activities of $107.7 million consisted of capital expenditures, payments for turnaround costs, investments in other long-term assets, return of investments from unconsolidated entities and contributions to unconsolidated entities. For the six months ended June 30, 2011, our cash flows used in discontinued investing activities of $5.9 million consisted of capital expenditures, return of investments from unconsolidated entities and contributions to unconsolidated entities.

Generally, our capital expenditure requirements have consisted, and we expect that our capital requirements will continue to consist, of:

- maintenance capital expenditures, which are capital expenditures made to replace assets to maintain our existing operations and to extend the useful lives of our assets; and

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expansion capital expenditures, which are capital expenditures made to grow our business, to expand and upgrade our existing terminalling, marine transportation, storage and manufacturing facilities, and to construct new terminalling facilities, plants, storage facilities and new marine transportation assets.

For the six months ended June 30, 2012 and 2011, our capital expenditures for property and equipment in continuing activities were $45.6 million and $29.5 million, respectively. For the six months ended June 30, 2012 and 2011, our capital expenditures for property and equipment in discontinued activities were $1.0 million and $0.7 million, respectively.

As to each period:

For the six months ended June 30, 2012, we spent $43.3 million for expansion capital expenditures and $2.3 million for maintenance capital expenditures related to continuing operations. Our expansion capital expenditures were made in connection with construction projects associated with our terminalling and sulfur services segments. Our maintenance capital expenditures were primarily made in our sulfur services segment for routine maintenance on the facilities as well as marine transportation segment dry dockings of our vessels pursuant to the United States Coast Guard requirements. For the six months ended June 30, 2012, we spent $0.5 million for expansion capital expenditures and $0.5 million for maintenance capital expenditures related to discontinued operations.

For the six months ended June 30, 2011, we spent $21.1 million for expansion capital expenditures and $8.4 million for maintenance capital expenditures related to continuing operations. Our expansion capital expenditures were made in connection with construction projects associated with our terminalling and sulfur services segments. Our maintenance capital expenditures were primarily made in our sulfur services segment for routine maintenance on the facilities as well as marine transportation segment dry dockings of our vessels pursuant to the United States Coast Guard requirements. For the six months ended June 30, 2011, we spent $0.2 million for expansion capital expenditures and $0.5 million for maintenance capital expenditures related to discontinued operations.

For the six months ended June 30, 2012, our financing activities consisted of cash distributions paid to common and subordinated unitholders of $38.9 million, payments of long term debt to financial lenders of $217.0 million, payments of notes payable and capital lease obligations of $6.5 million, borrowings of long-term debt under our credit facility of $216 million, payments of debt issuance costs of $0.2 million, proceeds from a public offering of $91.4 million, purchase of treasury stock of $0.2 million and general partner contributions of $1.9 million.

For the six months ended June 30, 2011, our financing activities consisted of cash distributions paid to common and subordinated unitholders of $31.4 million, payments of long-term debt to financial lenders of $301.5 million, payments of notes payable and capital lease obligations of $0.5 million, borrowings of long-term debt under our credit facility of $357.5 million, excess purchase price over carrying value of acquired assets of $19.7 million, payments of debt issuance costs of $3.4 million, proceeds from a public offering of $70.3 million, purchase of treasury stock of $0.6 million and general partner contributions of $1.5 million.

With respect to continuing investing activities, we made contributions to unconsolidated entities for operations of $17.3 million and $0 during the six months ended June 30, 2012 and 2011, respectively. We made initial investments in unconsolidated entities of $0.8 million and $59.3 million during the six months ended June 30, 2012 and 2011, respectively. Additionally, we received distributions from unconsolidated entities of $4.3 million and $0 during the six months ended June 30, 2012 and 2011, respectively.

With respect to discontinued investing activities, we made contributions to unconsolidated entities for operations of $1.3 million and $6.5 million during the six months ended June 30, 2012 and 2011, respectively. Additionally, we received distributions from unconsolidated entities of $0.3 million and $1.3 million during the six months ended June

30, 2012 and 2011, respectively.

The net investment in unconsolidated entities includes $2.9 million and $3.5 million of expansion capital expenditures in the six months ended June 30, 2012 and 2011, respectively.

With respect to discontinued operating activities, we received distributions in-kind from unconsolidated entities of $5.6 million and $7.0 million during the six months ended June 30, 2012 and 2011, respectively.

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Capital Resources

Historically, we have generally satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and borrowings. We expect our primary sources of funds for short-term liquidity will be cash flows from operations and borrowings under our credit facility.

As of June 30, 2012, we had $453.1 million of outstanding indebtedness, consisting of outstanding borrowings of $173.2 million (net of unamortized discount) under our Senior Notes, $274.0 million under our revolving credit facility, and $5.9 million under capital lease obligations.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2012, is as follows (dollars in thousands):

		Payments due by period			
Type of Obligation	Total Obligation	Less than One Year	1-3 Years	3-5 Years	Due Thereafter
Revolving credit facility	$274,000	$—	$—	$274,000	$—
Senior unsecured notes	173,235	—	—	—	173,235
Capital leases including current maturities	5,941	206	596	5,139	—
Non-competition agreements	100	50	50	—	—
Throughput commitment	50,725	3,972	9,903	10,549	26,301
Operating leases	49,927	10,350	24,789	8,383	6,405
Interest expense: [1]					
Revolving credit facility	34,810	9,187	18,374	7,249	—
Senior unsecured notes	90,598	15,531	31,062	31,062	12,943
Capital leases	3,581	929	1,737	915	—
Total contractual cash obligations	$682,917	$40,225	$86,511	$337,297	$218,884

[1]Interest commitments are estimated using our current interest rates for the respective credit agreements over their remaining terms.

Letter of Credit. At June 30, 2012, we had outstanding irrevocable letters of credit in the amount of $0.1 million, which were issued under our revolving credit facility.

Off Balance Sheet Arrangements. We do not have any off-balance sheet financing arrangements.

Description of Our Long-Term Debt

Senior Notes

In March 2010, we and Martin Midstream Finance Corp. ("FinCo"), a subsidiary of us (collectively, the "Issuers"), entered into (i) a Purchase Agreement, dated as of March 23, 2010 (the "Purchase Agreement"), by and among the Issuers, certain subsidiary guarantors (the "Guarantors") and Wells Fargo Securities, LLC, RBC Capital Markets Corporation and UBS Securities LLC, as representatives of a group of initial purchasers (collectively, the "Initial Purchasers"), (ii) an Indenture, dated as of March 26, 2010 (the "Indenture"), among the Issuers, the Guarantors and Wells Fargo Bank, National Association, as trustee (the "Trustee") and (iii) a Registration Rights Agreement, dated as of March 26, 2010 (the "Registration Rights Agreement"), among the Issuers, the Guarantors and the Initial Purchasers, in connection with a private placement to eligible purchasers of $200 million in aggregate principal amount of the Issuers' 8.875% senior unsecured notes due 2018 (the “Senior Notes”). We completed the aforementioned Senior Notes offering on March 26, 2010 and received proceeds of approximately $197.2 million, after deducting initial purchaser discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility.

In connection with the issuance of the Senior Notes, all “non-issuer” wholly-owned subsidiaries issued full, irrevocable, and unconditional guarantees of the Senior Notes. We do not provide separate financial statements of the operating partnership because it has no independent assets or operations, the guarantees are full and unconditional, and our other subsidiary is minor.

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Indenture

Interest and Maturity. On March 26, 2010, the Issuers issued the Senior Notes pursuant to the Indenture in a transaction exempt from registration requirements under the Securities Act. The Senior Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Senior Notes will mature on April 1, 2018. The interest payment dates are April 1 and October 1.

Optional Redemption. Prior to April 1, 2013, the Issuers have the option on any one or more occasions to redeem up to 35% of the aggregate principal amount of the Senior Notes issued under the Indenture at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date of the Senior Notes with the proceeds of certain equity offerings. Prior to April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Senior Notes at the redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. On or after April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Senior Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on April 1, 2014, 102.219% for the 12-month period beginning on April 1, 2015 and 100.00% for the 12-month period beginning on April 1, 2016, and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the Senior Notes.

On April 24, 2012 we notified the Trustee of our intention to exercise a partial redemption of the our Senior Notes pursuant to the Indenture. On May 24, 2012, we redeemed $25.0 million of the Senior Notes from various holders using proceeds of our January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under our revolving credit facility.

Certain Covenants. The Indenture restricts our ability and the ability of certain of our subsidiaries to: (i) sell assets including equity interests in its subsidiaries; (ii) pay distributions on, redeem or repurchase its units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of its assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; (x) enter into sale and leaseback transactions; or (xi) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of these covenants will terminate.

Events of Default. The Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the Senior Notes; (ii) default in payment when due of the principal of, or premium, if any, on the Senior Notes; (iii) our failure to comply with certain covenants relating to asset sales, repurchases of the Senior Notes upon a change of control and mergers or consolidations; (iv) our failure, for 180 days after notice, to comply with its reporting obligations under the Securities Exchange Act of 1934; (v) our failure, for 60 days after notice, to comply with any of the other agreements in the Indenture; (vi) default under any mortgage, indenture or instrument governing any indebtedness for money borrowed or guaranteed by us or any of our restricted subsidiaries, whether such indebtedness or guarantee now exists or is created after the date of the Indenture, if such default: (a) is caused by a payment default; or (b) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of the indebtedness, together with the principal amount of any other such indebtedness under which there has been a payment default or acceleration of maturity, aggregates $20 million or more, subject to a cure provision; (vii) our or any of our restricted subsidiaries failure to pay final judgments aggregating in excess of $20 million, which judgments are not paid, discharged or stayed for a period of 60 days; (viii) except as permitted by the Indenture, any subsidiary guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force or effect, or any Guarantor, or any person acting on behalf of any Guarantor, denies or disaffirms its obligations under its subsidiary guarantee; and (ix) certain events of bankruptcy, insolvency or reorganization described in the Indenture with respect to the Issuers or any of our restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary of us. Upon a continuing Event of Default, the Trustee, by notice to the Issuers, or the holders of at least 25% in principal amount of the then outstanding Senior Notes, by notice to the Issuers and the Trustee, may declare the Senior Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Issuers, any restricted subsidiary of us that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of us, will automatically cause the Senior Notes to become due and payable.

Registration Rights Agreement. Under the Registration Rights Agreement, the Issuers and the Guarantors filed with the SEC a registration statement to exchange the Senior Notes for substantially identical notes that are registered under the Securities Act. We exchanged the Senior Notes for registered 8.875% senior unsecured notes due April 2018.

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Credit Facility

On November 10, 2005, we entered into a $225.0 million multi-bank credit facility, which has subsequently been amended including most recently on September 7, 2011, when we amended our credit facility to, (1) increase the maximum amount of investments made in permitted joint ventures to $50.0 million, and (2) increase the maximum amount of investments made in Redbird and Cardinal to $120.0 million. Effective May 10, 2012, we increased the maximum amount of borrowings and letters of credit available under our revolving credit facility from $375.0 million to $400.0 million.

As of June 30, 2012, we had approximately $274.0 million outstanding under the revolving credit facility and $0.1 million of letters of credit issued, leaving approximately $125.9 million available under our credit facility for future revolving credit borrowings and letters of credit.

The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. During the current fiscal year, draws on our credit facility have ranged from a low of $175.0 million to a high of $298.0 million.

The credit facility is guaranteed by substantially all of our subsidiaries. Obligations under the credit facility are secured by first priority liens on substantially all of our assets and those of the guarantors, including, without limitation, inventory, accounts receivable, bank accounts, marine vessels, equipment, fixed assets and the interests in our subsidiaries and certain of our equity method investees.

We may prepay all amounts outstanding under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, equity issuances and debt incurrences. We expect to use the proceeds from our disposition of the Prism Assets to pay down outstanding indebtedness. This transaction will not impact our ability to borrow the maximum $400.0 million available under our revolving credit facility in the future.

Indebtedness under the credit facility bears interest, at our option, at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent’s prime rate) plus an applicable margin. We pay a per annum fee on all letters of credit issued under the credit facility, and we pay a commitment fee which ranges from 0.375% to 0.50% per annum on the unused revolving credit availability under the credit facility. The letter of credit fee and the applicable margins for our interest rate vary quarterly based on our leverage ratio (as defined in the new credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letters of Credit
Less than 2.25 to 1.00	1.00 %	2.00 %	2.00 %
Greater than or equal to 2.25 to 1.00 and less than 3.00 to 1.00	1.25 %	2.25 %	2.25 %
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.50 %	2.50 %	2.50 %
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.75 %	2.75 %	2.75 %
Greater than or equal to 4.00 to 1.00	2.00 %	3.00 %	3.00 %
Greater than or equal to 4.50 to 1.00	2.25 %	3.25 %	3.25 %

The applicable margin for existing LIBOR borrowings is 3.00%. Effective July 1, 2012, the applicable margin for existing LIBOR borrowings remained at 3.00%. Effective October 1, 2012, the applicable margin for existing LIBOR borrowings will remain at 3.00%.

The credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The maximum permitted leverage ratio is 5.00 to 1.00. The maximum permitted senior leverage ratio (as defined in the new credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.25 to 1.00. The minimum consolidated interest coverage ratio (as defined in the new credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 2.75 to 1.00.

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In addition, the credit facility contains various covenants that, among other restrictions, limit our and our subsidiaries' ability to:

- grant or assume liens;
- make investments (including investments in our joint ventures) and acquisitions;
- enter into certain types of hedging agreements;
- incur or assume indebtedness;
- sell, transfer, assign or convey assets;
- repurchase our equity, make distributions and certain other restricted payments, but the credit facility permits us to make quarterly distributions to unitholders so long as no default or event of default exists under the credit facility;
- change the nature of our business;
- engage in transactions with affiliates;
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement and our material agreements;
- make capital expenditures; and
- permit our joint ventures to incur indebtedness or grant certain liens.

Each of the following will be an event of default under the credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation, or covenant in the credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- our or any of our subsidiaries' default under other indebtedness that exceeds a threshold amount;
- bankruptcy or other insolvency events involving us or any of our subsidiaries;
- judgments against us or any of our subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or any of our subsidiaries, in excess of a threshold amount;
- a change in control (as defined in the credit facility);

the termination of any material agreement or certain other events with respect to material agreements;

the invalidity of any of the loan documents or the failure of any of the collateral documents to create a lien on the collateral; and

any of our joint ventures incurs debt or liens in excess of a threshold amount.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls our general partner, or if Ruben Martin is not the chief executive officer of our general partner and a successor acceptable to the administrative agent and lenders providing more than 50% of the commitments under our credit facility is not appointed, the lenders under our credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, either a bankruptcy event with respect to Martin Resource Management or a judgment with respect to Martin Resource Management could independently result in an event of default under our credit facility if it is deemed to have a material adverse effect on us.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to us or any of our subsidiaries, all indebtedness under our credit facility will immediately become due and payable. If any other event of default exists under our credit facility, the lenders may terminate their commitments to lend us money, accelerate the maturity of the indebtedness outstanding under the credit facility and exercise other rights and remedies. In addition, if any event of default exists under our credit facility, the lenders may commence foreclosure or other actions against the collateral. Any event of default and corresponding acceleration of outstanding balances under our credit facility could require us to refinance such indebtedness on unfavorable terms and would have a material adverse effect on our financial condition and results of operations as well as our ability to make distributions to unitholders.

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If any default occurs under our credit facility, or if we are unable to make any of the representations and warranties in the credit facility, we will be unable to borrow funds or have letters of credit issued under our credit facility.

As of August 3, 2012, our outstanding indebtedness includes $39.0 million under our credit facility.

We are subject to interest rate risk on our credit facility and may enter into interest rate swaps to reduce this risk.

Effective September 2010, we entered into an interest rate swap that swapped $40 million of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap was not accounted for using hedge accounting. This swap was scheduled to mature in April 2018, but was terminated in August 2011.

Effective September 2010, we entered into an interest rate swap that swapped $60 million of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap was not accounted for using hedge accounting. This swap was scheduled to mature in April 2018, but was terminated in August 2011.

Seasonality

A substantial portion of our revenues are dependent on sales prices of products, particularly NGLs and fertilizers, which fluctuate in part based on winter and spring weather conditions. The demand for NGLs is strongest during the winter heating season. The demand for fertilizers is strongest during the early spring planting season. However, our terminalling and storage and marine transportation businesses and the molten sulfur business are typically not impacted by seasonal fluctuations. We expect to derive a majority of our net income from our terminalling and storage, sulfur and marine transportation businesses. Therefore, we do not expect that our overall net income will be impacted by seasonality factors. However, extraordinary weather events, such as hurricanes, have in the past, and could in the future, impact our terminalling and storage and marine transportation businesses. For example, Hurricanes Katrina and Rita in the third quarter of 2005 adversely impacted operating expenses and the four hurricanes that impacted the Gulf of Mexico and Florida in the third quarter of 2004 adversely impacted our terminalling and storage and marine transportation business's revenues.

Impact of Inflation

Inflation did not have a material impact on our results of operations for the three and six months ended June 30, 2012 and 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the costs of labor and supplies. In the future, increasing energy prices could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses which could adversely affect net income. We cannot assure you that we will be able to pass along increased operating expenses to our customers.

Environmental Matters

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We incurred no material environmental costs, liabilities or expenditures to mitigate or eliminate environmental contamination during the three and six months ended June 30, 2012 or 2011.

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Item 3.Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk. We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Under our hedging policy, we monitor and manage the commodity market risk associated with the commodity risk exposure of Prism Gas Systems I, L.P. ("Prism Gas"). In addition, we are focusing on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

We use derivatives to manage the risk of commodity price fluctuations. These outstanding contracts expose us to credit loss in the event of nonperformance by the counterparties to the agreements. We have incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement; establish a maximum credit limit threshold pursuant to our hedging policy; and monitor the appropriateness of these limits on an ongoing basis. We have agreements with three counterparties containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by us if the value of derivatives is a liability to us. As of June 30, 2012, we have no cash collateral deposits posted with counterparties.

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of gathering, processing and sales activities. Our exposure to these fluctuations is primarily in the gas processing component of our business. Gathering and processing revenues are earned under various contractual arrangements with gas producers. Gathering revenues are generated through a combination of fixed-fee and index-related arrangements. Processing revenues are generated primarily through contracts which provide for processing on percent-of-liquids and percent-of-proceeds bases.

1) Percent-of-liquids contracts: Under these contracts, we receive a fee in the form of a percentage of the NGLs recovered, and the producer bears all of the cost of natural gas shrink. Therefore, margins increase during periods of high NGL prices and decrease during periods of low NGL prices.

2) Percent-of-proceeds contracts: Under these contracts, we generally gather and process natural gas on behalf of certain producers, sell the resulting residue gas and NGLs at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGLs to the producer and sell the volumes kept to third parties at market prices. Under these types of contracts, revenues and gross margins increase as natural gas prices and NGL prices increase, and revenues and gross margins decrease as natural gas and NGL prices decrease.

Market risk associated with gas processing margins by contract type, and gathering and transportation margins as a percent of total gross margin remained consistent for the three and six months ended June 30, 2012 and 2011, as our contract mix and percent of volumes associated with those contracts did not differ materially.

Due to the sale of the Prism assets during July 2012, the aggregate effect of a hypothetical $1.00/MMbtu increase or decrease in the natural gas price index will not have a significant impact on our annual gross margin. Additionally, the aggregate effect of a hypothetical $10.00/Bbl increase or decrease in the crude oil price index will not have a significant impact on our annual gross margin.

We will continue to manage our risks associated with market fluctuations, and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that we will be able to do so or that the terms thereof will be similar to our existing hedging arrangements.

The relevant payment indices for our various commodity contracts are as follows:

- Natural gas contracts - monthly posting for ANR Pipeline Co. - Louisiana as posted in Platts Inside FERC’s Gas Market Report;
- Crude oil contracts - WTI NYMEX average for the month of the daily closing prices; and
- Natural gasoline contracts - Mt. Belvieu Non-TET average monthly postings as reported by the Oil Price Information Service (OPIS).

Hedging Arrangements in Place
As of June 30, 2012

Period	Underlying	Notional Volume	Commodity Price We Pay	Commodity Price We Receive	Fair Value Asset (In Thousands)	Fair Value Liability (In Thousands)
July 2012	Natural Gasoline	1,000 (BBL)	Index	$ 2.340/Gal	$ 29	$ —
July 2012	Crude Oil	2,000 (BBL)	Index	$ 88.63/bbl	7	—
July 2012	Natural Gasoline	1,000 (BBL)	Index	$ 90.20/bbl	5	—
					$ 41	$ —

Our principal customers with respect to Prism Gas' natural gas gathering and processing are large, natural gas marketing services, oil and gas producers and industrial end-users. In addition, substantially all of our natural gas and NGL sales are made at market-based prices. Our standard gas and NGL sales contracts contain adequate assurance provisions which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to us.

Interest Rate Risk. We are exposed to changes in interest rates as a result of our credit facility, which had a weighted-average interest rate of 3.35% as of June 30, 2012. As of August 3, 2012, we had total indebtedness outstanding under our credit facility of $39.0 million, all of which was unhedged floating rate debt. Based on the amount of unhedged floating rate debt owed by us on June 30, 2012, the impact of a 1% increase in interest rates on this amount of debt would result in an increase in interest expense and a corresponding decrease in net income of approximately $2.7 million annually.

Historically, we have managed a portion of our interest rate risk on a portion of our long-term debt with interest rate swaps, which reduced our exposure to changes in interest rates by converting variable interest rates to fixed interest rates on our Credit Facility and fixed interest rates to variable interest rates on our Senior Notes. During the third quarter of 2011, we terminated all of our interest rate swaps on our Senior Notes.

We are not exposed to changes in interest rates with respect to our Senior Notes as these obligations are fixed rate. The estimated fair value of the Senior Notes was approximately $177.4 million as of June 30, 2012, based on market prices of similar debt at June 30, 2012. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in approximately an $4.9 million decrease in fair value of our long-term debt at June 30, 2012.

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of our general partner, carried out an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner concluded that our disclosure controls and procedures were effective, as of the end of the period covered by this report, to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms.

There were no changes in our internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION

Item 1.Legal Proceedings

From time to time, we are subject to certain legal proceedings claims and disputes that arise in the ordinary course of our business. Although we cannot predict the outcomes of these legal proceedings, we do not believe these actions, in the aggregate, will have a material adverse impact on our financial position, results of operations or liquidity.

Item 1A.Risk Factors

There have been no material changes to the risk factors disclosed in our annual report on Form 10-K filed with the SEC on March 5, 2012.

Item 5.Other Information

Certain Other Information. On May 2, 2008, we received a copy of a petition filed in the District Court of Gregg County, Texas by Scott D. Martin (the "Plaintiff") against Ruben S. Martin, III (the "Defendant") with respect to certain matters relating to Martin Resource Management. In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment adverse to the Defendant which contained monetary damages and specific performance components (the "Judgment"). The Defendant appealed the Judgment. On November 3, 2010, the Court of Appeals, Sixth Appellate District of Texas at Texarkana, issued an opinion on the appeal overturning the Judgment. The Appellate Court's opinion rendered a take-nothing judgment against the Plaintiff and found in favor of the Defendant. The Supreme Court of Texas denied the Plaintiff's petition for review and therefore the opinion of the Sixth Appellate District of Texas at Texarkana has become final.

On September 5, 2008, the Plaintiff and one of his affiliated partnerships (the "SDM Plaintiffs"), on behalf of themselves and derivatively on behalf of Martin Resource Management, filed suit in a Harris County, Texas district court (the "Harris County Litigation") against Martin Resource Management, the Defendant, Robert Bondurant, Donald R. Neumeyer and Wesley M. Skelton, in their capacities as directors of Martin Resource Management (the "MRMC Director Defendants"), as well as 35 other officers and employees of Martin Resource Management (the "Other MRMC Defendants"). In addition to their respective positions with Martin Resource Management, Robert Bondurant, Donald Neumeyer and Wesley Skelton are officers of our general partner. We are not a party to this lawsuit, and it does not assert any claims (i) against us, (ii) concerning our governance or operations, or (iii) against the MRMC Director Defendants or other MRMC Defendants with respect to their service to us.

The SDM Plaintiffs allege, among other things, that the MRMC Director Defendants have breached their fiduciary duties owed to Martin Resource Management and the SDM Plaintiffs, entrenched their control of Martin Resource Management and diluted the ownership position of the SDM Plaintiffs and certain other minority shareholders in Martin Resource Management, and engaged in acts of unjust enrichment, excessive compensation, waste, fraud and conspiracy with respect to Martin Resource Management. The SDM Plaintiffs seek, among other things, to rescind the June 2008 issuance by Martin Resource Management of shares of its common stock under its 2007 Long-Term Incentive Plan to the Other MRMC Defendants, remove the MRMC Director Defendants as officers and directors of Martin Resource Management, prohibit the Defendant, Wesley M. Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Trust (the "ESOT"), and place all of the Martin Resource Management common shares owned or controlled by the Defendant in a constructive trust that prohibits him from voting those shares. The SDM Plaintiffs have amended their Petition to eliminate their claims regarding rescission of the issue by Martin Resource Management of shares of its common stock to the MRMC Employee Stock Ownership Plan. The case was abated in July 2009 during the pendency of a mandamus proceeding in the Texas Supreme Court. The Supreme Court denied mandamus relief on November 20, 2009. This lawsuit was amended to add the ESOT as a party and was subsequently removed to Federal Court by the ESOT. This lawsuit was remanded from Federal Court to the State District Court. The trial was previously set for August 2012 but has been removed from the trial docket. The trial is nonetheless stayed pending the outcome of procedural matters pending in the appellate courts.

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The lawsuits described above are in addition to (i) a separate lawsuit filed in July 2008 in a Gregg County, Texas district court by the daughters of the Defendant against Scott Martin, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that he has engaged in self-dealing in his capacity as a trustee under the trust, which holds shares of Martin Resource Management common stock, and has breached his fiduciary duties owed to the plaintiffs, who are beneficiaries of such trust, and (ii) a separate lawsuit filed in October 2008 in the United States District Court for the Eastern District of Texas by Angela Jones Alexander against the Defendant and Karen Yost in their capacities as a former trustee and a trustee, respectively, of the R.S. Martin Jr. Children Trust No. One (f/b/o Angela Santi Jones), which holds shares of Martin Resource Management common stock, which suit alleges, among other things that the Defendant and Karen Yost breached fiduciary duties owed to Angela Jones Alexander, who is the beneficiary of such trust, and seeks to remove Karen Yost as the trustee of such trust. With respect to the lawsuit described in (i) above, we have been informed that the Plaintiff has resigned as a trustee of the Ruben S. Martin, III Dynasty Trust. With respect to the lawsuit described in (ii) above, Angela Jones Alexander amended her claims to include her grandmother, Margaret Martin, as a defendant, but subsequently dropped her claims against Mrs. Martin. Additionally, all claims pertaining to Karen Yost have been resolved. All claims pertaining to Defendant have been preliminarily resolved, as the court, on February 9, 2011, issued an order that granted the parties' Joint Motion for Administrative Closure. With respect to the lawsuit referenced in (i) above, the case was tried in October 2009 and the jury returned a verdict in favor of the Defendant's daughters against Scott Martin in the amount of $4,900. On December 22, 2009, the court entered a judgment, reflecting an amount consistent with the verdict and additionally awarded attorneys' fees and interest. On January 7, 2010, the court modified its original judgment and awarded the Defendant's daughters approximately $2,700 in damages and attorneys' fees, plus interest. Scott Martin has appealed the judgment. On March 20, 2012, the Court of Appeals, Sixth Appellate District of Texas at Texarkana, issued an opinion on the appeal overturning the Judgment. While the Appellate Court found that there was sufficient evidence to support the jury's finding that a breach of fiduciary duty occurred, it found insufficient evidence to support any damages and therefore rendered a take-nothing judgment against the daughters of the Defendant. A motion for rehearing at the Appellate Court was overruled on April 26, 2012. The Defendant's daughters have indicated they will appeal the Appellate Court's ruling.

On September 24, 2008, Martin Resource Management removed Plaintiff as a director of the general partner of the Partnership. Such action was taken as a result of the collective effect of Plaintiff's then recent activities, which the board of directors of Martin Resource Management determined was detrimental to both Martin Resource Management and the Partnership. The Plaintiff does not serve on any committees of the board of directors of our general partner. The position on the board of directors of the Partnership's general partner vacated by the Plaintiff may be filled in accordance with the existing procedures for replacement of a departing director utilizing the Nominations Committee of the board of directors of the general partner of the Partnership. This position on the board of directors has been filled as of July 26, 2010, by Charles Henry "Hank" Still.

On February 22, 2010, as a result of the Harris County Litigation being derivative in nature, Martin Resource Management formed a special committee of its board of directors and designated such committee as the Martin Resource Management authority for the purpose of assessing, analyzing and monitoring the Harris County Litigation and any other related litigation and making any and all determinations in respect of such litigation on behalf of Martin Resource Management. Such authorization includes, but is not limited to, reviewing the merits of the litigation, assessing whether to pursue claims or counterclaims against various persons or entities, assess whether to appoint or retain experts or disinterested persons to make determinations in respect of such litigation, and advising and directing Martin Resource Management's general counsel and outside legal counsel with respect to such litigation. The special committee consists of Robert Bondurant, Donald R. Neumeyer and Wesley M. Skelton.

On May 4, 2010, we received a copy of a petition filed in a new case with the District Clerk of Gregg County, Texas by Martin Resource Management against the Plaintiff and others with respect to certain matters relating to Martin Resource Management ("the "Gregg County Matter"). As noted above, the Plaintiff was a former director of Martin

Resource Management. The lawsuit alleges that the Plaintiff with help from others breached the fiduciary duties the Plaintiff owed to Martin Resource Management. We are not a party to the lawsuit, and the lawsuit does not assert any claims (i) against the Partnership, (ii) concerning our governance or operations, or (iii) against the Plaintiff with respect to his service as an officer or former director of the general partner of the Partnership. With respect to this lawsuit, the case was tried in January 2012 and the jury returned a verdict in favor of Martin Resource Management against Scott D. Martin for breach of fiduciary duty and awarded an amount of $1,800. The court entered a judgment in favor or Martin Resource Management in the amount awarded by the jury plus interest. Scott D. Martin is appealing this judgment.

Additionally, on July 11, 2011, Scott D. Martin sued Martin Resource Management in State District Court in Harris County, Texas, alleging that it tortiously interfered with his rights under an existing insurance policy. A motion to transfer this case was granted and this case is currently pending in 188th District Court of Gregg County, Texas.

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On June 22, 2012, we received from Scott D. Martin a demand that we indemnify him for legal fees and damages adjudged against him in the Gregg County Matter. He followed this up with an additional demand that we indemnify him for legal fees and expenses he paid in defending the lawsuit brought in Gregg County, Texas by the daughters of the Defendant. On June 25, 2012, we filed a petition in the District Court of Gregg County, Texas against Scott D. Martin, seeking a declaratory judgment regarding the Partnership's obligations to indemnify Scott D. Martin.

Item 6.Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report and is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this Report to be signed on its behalf by the undersigned thereunto duly authorized.

Martin Midstream Partners L.P.

By: Martin Midstream GP LLC
It's General Partner

Date: August 6, 2012

By: /s/ Ruben S. Martin
Ruben S. Martin
President and Chief
Executive Officer

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INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
3.1	Certificate of Limited Partnership of Martin Midstream Partners L.P. (the "Partnership"), dated June 21, 2002 (filed as Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.2	Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of November 25, 2009 (filed as Exhibit 10.1 to the Partnership's Amendment to Current Report on Form 8-K/A, filed January 19, 2010, and incorporated herein by reference).
3.3	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of the Partnership dated January 31, 2011 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K , filed February 1, 2011, and incorporated herein by reference.
3.4	Certificate of Limited Partnership of Martin Operating Partnership L.P. (the "Operating Partnership"), dated June 21, 2002 (filed as Exhibit 3.3 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.5	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated November 6, 2002 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed November 19, 2002, and incorporated herein by reference).
3.6	Certificate of Formation of Martin Midstream GP LLC (the "General Partner"), dated June 21, 2002 (filed as Exhibit 3.5 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.7	Limited Liability Company Agreement of the General Partner, dated June 21, 2002 (filed as Exhibit 3.6 to the Partnership's Registration Statement on Form S-1 (Reg. No. 33-91706), filed July 1, 2002, and incorporated herein by reference).
3.8	Certificate of Formation of Martin Operating GP LLC (the "Operating General Partner"), dated June 21, 2002 (filed as Exhibit 3.7 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.9	Limited Liability Company Agreement of the Operating General Partner, dated June 21, 2002 (filed as Exhibit 3.8 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
4.1	Specimen Unit Certificate for Common Units (contained in Exhibit 3.2).
4.2	Specimen Unit Certificate for Subordinated Units (filed as Exhibit 4.2 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-91706), filed October 25, 2002, and incorporated herein by reference).
4.3	Indenture, dated as of March 26, 2010, by and among the Partnership, Martin Midstream Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K, filed March 26, 2010, and incorporated herein by reference).
4.4	Registration Rights Agreement, dated as of March 26, 2010, by and among the Partnership, Martin Midstream Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (filed as Exhibit 4.2 to the Partnership's Current Report on Form 8-K, filed March 26, 2010, and incorporated herein by reference).
10.1	Commitment Increase and Joinder Agreement dated May 10, 2012 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed May 10, 2012 and incorporated herein by reference).
31.1*	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the

	SEC and shall not be deemed to be “filed.”
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be “filed.”

* Filed or furnished herewith