MARTIN MIDSTREAM PARTNERS LP
Form 10-Q
August 09, 2011

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, 2011

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 (State or other jurisdiction of incorporation or organization)	05-0527861 (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 9, 2011 was 19,582,332. The number of the registrant's subordinated units outstanding at August 9, 2011 was 889,444.

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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, 2011 (Unaudited)	December 31, 2010 (Audited)
Assets		
Cash	$ 67	$ 11,380
Accounts and other receivables, less allowance for doubtful accounts of $2,705 and $2,528, respectively	99,119	95,276
Product exchange receivables	16,641	9,099
Inventories	63,560	52,616
Due from affiliates	19,122	6,437
Fair value of derivatives	2,258	2,142
Other current assets	1,209	2,784
Total current assets	201,976	179,734
Property, plant and equipment, at cost	677,785	632,456
Accumulated depreciation	(219,291)	(200,276)
Property, plant and equipment, net	458,494	432,180
Goodwill	37,268	37,268
Investment in unconsolidated entities	160,898	98,217
Fair value of derivatives	39	—
Deferred debt costs	14,531	13,497
Other assets, net	25,073	24,582
	$ 898,279	$ 785,478
Liabilities and Partners' Capital		
Current portion of capital lease obligations	$ 1,173	$ 1,121
Trade and other accounts payable	90,685	82,837
Product exchange payables	27,609	22,353
Due to affiliates	17,227	6,957
Income taxes payable	601	811
Fair value of derivatives	387	282
Other accrued liabilities	9,669	10,034
Total current liabilities	147,351	124,395
Long-term debt and capital leases, less current maturities	428,442	372,862
Deferred income taxes	7,782	8,213
Fair value of derivatives	2,603	4,100
Other long-term obligations	1,753	1,102
Total liabilities	587,931	510,672
Partners' capital	309,728	273,387

Accumulated other comprehensive income	620	1,419
Total partners’ capital	310,348	274,806
Commitments and contingencies		
	$ 898,279	$ 785,478

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,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues:				
Terminalling and storage *	$19,327	$16,664	$37,450	$32,705
Marine transportation *	17,376	18,113	36,775	35,990
Sulfur services	2,850	—	5,700	—
Product sales: *				
Natural gas services	159,198	124,784	326,409	290,013
Sulfur services	74,083	42,878	130,991	77,287
Terminalling and storage	19,371	9,505	37,916	18,625
	252,652	177,167	495,316	385,925
Total revenues	292,205	211,944	575,241	454,620
Costs and expenses:				
Cost of products sold: (excluding depreciation and amortization)				
Natural gas services *	153,417	119,282	311,621	276,946
Sulfur services *	59,892	31,615	104,334	56,350
Terminalling and storage	17,395	8,962	33,955	17,408
	230,704	159,859	449,910	350,704
Expenses:				
Operating expenses *	34,712	28,102	69,061	57,297
Selling, general and administrative *	5,012	4,838	10,040	10,108
Depreciation and amortization	11,309	9,986	22,251	19,891
Total costs and expenses	281,737	202,785	551,262	438,000
Other operating income	98	(57)	98	45
Operating income	10,566	9,102	24,077	16,665
Other income (expense):				
Equity in earnings of unconsolidated entities	2,793	2,342	5,169	4,518
Interest expense	(4,403)	(8,194)	(12,805)	(16,197)
Other, net	44	23	104	83
Total other income (expense)	(1,566)	(5,829)	(7,532)	(11,596)
Net income before taxes	9,000	3,273	16,545	5,069
Income tax benefit (expense)	(230)	(198)	(453)	(223)
Net income	$8,770	$3,075	$16,092	$4,846
General partner’s interest in net income	$1,415	$969	$2,644	$1,832
Limited partners’ interest in net income	$7,078	$1,829	$12,894	$2,460

Net income per limited partner unit - basic and diluted	$0.37	$0.10	$0.67	$0.14
Weighted average limited partner units - basic	19,158,507	17,702,321	19,162,963	17,702,442
Weighted average limited partner units - diluted	19,158,901	17,703,945	19,163,960	17,704,293

See accompanying notes to consolidated and condensed financial statements.

*Related Party Transactions Included Above

Revenues:				
Terminalling and storage	$12,897	$11,593	$25,835	$22,287
Marine transportation	6,306	6,920	12,871	12,980
Product Sales	3,321	3,074	8,721	3,382
Costs and expenses:				
Cost of products sold: (excluding depreciation and amortization)				
Natural gas services	25,754	22,662	48,959	41,368
Sulfur services	4,492	3,919	8,645	7,236
Expenses:				
Operating expenses	13,702	12,309	25,744	23,771
Selling, general and administrative	2,893	3,634	5,924	5,436

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

	Partners' Capital						
	Common Units	Amount	Subordinated Units	Amount	General Partner Amount	Accumulated Other Comprehensive Income (Loss)	Total
Balances – January 1, 2010	16,057,832	$245,683	889,444	$16,613	$4,731	$ (2,076)	$264,951
Net income	—	3,014	—	—	1,832	—	4,846
Recognition of beneficial conversion feature	—	(554)	—	554	—	—	—
Follow-on public offering	1,650,000	50,530	—	—	—	—	50,530
General partner contribution	—	—	—	—	1,089	—	1,089
Cash distributions	—	(25,324)	—	—	(2,350)	—	(27,674)
Unit-based compensation	3,000	38	—	—	—	—	38
Purchase of treasury units	(3,000)	(92)	—	—	—	—	(92)
Adjustment in fair value of derivatives	—	—	—	—	—	3,452	3,452
Balances – June 30, 2010	17,707,832	$273,295	889,444	$17,167	$5,302	$ 1,376	$297,140
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)
Distribution to parent	—	(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

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,	
	2011	2010	2011	2010
Net income	$8,770	$3,075	$16,092	$4,846
Changes in fair values of commodity cash flow hedges	843	246	(65)	745
Commodity cash flow hedging gains (losses) reclassified to earnings	(318)	(268)	(752)	(386)
Changes in fair value of interest rate cash flow hedges	—	—	—	(241)
Interest rate cash flow hedging losses reclassified to earnings	—	963	18	3,334
Comprehensive income	$9,295	$4,016	$15,293	$8,298

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, 2011	2010
Cash flows from operating activities:		
Net income	$16,092	$4,846
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	22,251	19,891
Amortization of deferred debt issuance costs	2,390	2,663
Amortization of debt discount	175	93
Deferred taxes	(32)	(289)
(Gain) loss on sale of property, plant and equipment	714	(45)
Equity in earnings of unconsolidated entities	(5,169)	(4,518)
Distributions in-kind from equity investments	7,034	4,531
Non-cash mark-to-market on derivatives	(2,346)	(2,650)
Other	96	38
Change in current assets and liabilities, excluding effects of acquisitions and dispositions:		
Accounts and other receivables	(3,843)	8,013
Product exchange receivables	(7,542)	677
Inventories	(10,944)	(13,647)
Due from affiliates	(12,685)	(7,385)
Other current assets	1,176	(1,183)
Trade and other accounts payable	7,848	(4,223)
Product exchange payables	5,257	8,295
Due to affiliates	10,270	392
Income taxes payable	(210)	(63)
Other accrued liabilities	(365)	3,400
Change in other non-current assets and liabilities	(92)	(3,864)
Net cash provided by operating activities	30,075	14,972
Cash flows from investing activities:		
Payments for property, plant and equipment	(30,169)	(7,716)
Acquisitions	(16,815)	—
Payments for plant turnaround costs	(2,044)	(1,062)
Proceeds from sale of property, plant and equipment	—	968
Investment in unconsolidated entities	(59,319)	(20,110)
Return of investments from unconsolidated entities	1,285	740
Distributions from (contributions to) unconsolidated entities for operations	(6,512)	881
Net cash used in investing activities	(113,574)	(26,299)
Cash flows from financing activities:		
Payments of long-term debt	(301,500)	(331,693)
Payments of notes payable and capital lease obligations	(543)	(49)
Proceeds from long-term debt	357,500	330,682
Net proceeds from follow on offering	70,330	50,530
General partner contribution	1,505	1,089
Distribution to parent	(19,685)	—

Payments of debt issuance costs	(3,424)	(7,327)
Purchase of treasury units	(582)	(92)
Cash distributions paid	(31,415)	(27,674)
Net cash provided by financing activities	72,186	15,466
Net increase (decrease) in cash	(11,313)	4,139
Cash at beginning of period	11,380	5,956
Cash at end of period	$ 67	$ 10,095

See accompanying notes to consolidated and condensed financial statements.

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MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2011
(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, 2010, filed with the Securities and Exchange Commission (the “SEC”) on March 2, 2011.

(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 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.

In May 2010, the Partnership issued 1,000 restricted common units to each of its three independent, non-employee directors under its long-term incentive plan from treasury shares purchased by the Partnership in the open market for $92. These units vest in 25% increments beginning in January 2011 and will be fully vested in January 2014.

The cost resulting from share-based payment transactions was $59 and $11 for the three months ended June 30, 2011 and 2010, respectively, and $96 and $38 for the six months ended June 30, 2011 and 2010, 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.

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(Unaudited)

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, 2011 and 2010 the general partner received $1,265 and $926, respectively, in incentive distributions. For the six months ended June 30, 2011 and 2010, the general partner received $2,370 and $1,771, respectively, in incentive distributions.

(d) Net Income per Unit

The Partnership follows the provisions of 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 and six months ended June 30, 2011 and 2010, 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 months and six months ended June 30, 2011 and 2010, 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.

The following table reconciles net income to limited partners' interest in net income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income attributable to Martin Midstream Partners L.P.	$8,770	$3,075	$16,092	$4,846
Less general partner's interest in net income:				
Distributions payable on behalf of IDRs	1,265	926	2,370	1,771
Distributions payable on behalf of general partner interest	345	304	655	580

Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	(195)	(261)	(381)	(519)
Less beneficial conversion feature	277	277	554	554
Limited partners' interest in net income	$7,078	$1,829	$12,894	$2,460

The weighted average units outstanding for basic net income per unit were 19,158,507 and 19,162,963 for the three months and six months ended June 30, 2011, respectively, and 17,702,321 and 17,702,442 for the three months and six months ended June 30, 2010, respectively. For diluted net income per unit, the weighted average units outstanding were increased by 394 and 997 for the three and six months ended June 30, 2011, respectively, and 1,624 and 1,851 for the three and six months ended June 30, 2010, respectively, due to the dilutive effect of restricted units granted under the Partnership's long-term incentive plan.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2011
(Unaudited)

(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 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, which for the Partnership means January 1, 2012. As this new guidance only requires enhanced disclosure, adoption will 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 is a natural gas storage joint venture formed with Martin Resource Management to invest in Cardinal Gas Storage Partners LLC ("Cardinal"), that is focused on the development, construction, operation and management of natural gas storage facilities across North America. 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 loan facility.

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 loan 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, 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. The impact on first quarter depreciation expense as a result of the finalization of the purchase price allocation is accounted for retrospectively and was a reduction of $241.

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(Dollars in thousands, except where otherwise indicated)
June 30, 2011
(Unaudited)

Harrison Gathering System

On January 15, 2010, the Partnership, through its wholly-owned subsidiary, Prism Gas Systems I LP (“Prism Gas”), as 50% owner and the operator of Waskom Gas Processing Company (“Waskom”), through Waskom’s wholly-owned subsidiary Waskom Midstream LLC, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Gathering System. The Partnership’s share of the acquisition cost was approximately $20,000 and was recorded as an investment in an unconsolidated entity.

(4) Inventories

Components of inventories at June 30, 2011 and December 31, 2010, were as follows:

	June 30, 2011	December 31, 2010
Natural gas liquids	$24,331	$19,775
Sulfur	14,917	15,933
Sulfur Based Products	9,816	9,027
Lubricants	11,867	5,267
Other	2,629	2,614
	$63,560	$52,616

(5) Investments in Unconsolidated Entities and Joint Ventures

The Partnership owns all of the unconsolidated Class B equity interests in Redbird. Prism Gas owns an unconsolidated 50% interest in Waskom, the Matagorda Gathering System (“Matagorda”) and Panther Interstate Pipeline Energy LLC (“PIPE”). As a result, these assets are accounted for by the equity method.

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, 2011 and 2010, respectively, and has been recorded as a reduction of equity in earnings of unconsolidated entities. The remaining unamortized excess investment relating to property and equipment was $8,606 and $8,903 at June 30, 2011 and December 31, 2010, 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, 2011 or 2010.

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.

Activity related to these investment accounts for the six months ended June 30, 2011 and 2010 is as follows:

	Waskom	PIPE	Matagorda	Redbird	Total
Investment in unconsolidated entities, December 31, 2010	$93,768	$1,311	$3,138	—	$98,217
Distributions in kind	(7,034)	—	—	—	(7,034)
Contributions to unconsolidated entities:					
Cash contributions (See Note 3)	—	—	—	59,319	59,319
Contributions to unconsolidated entities for operations	6,342	—	170	—	6,512
Return of investments	(1,200)	—	(85)	—	(1,285)
Equity in earnings:					
Equity in earnings (losses) from operations	5,287	(21)	47	153	5,466
Amortization of excess investment	(275)	(8)	(14)	—	(297)
Investment in unconsolidated entities, June 30, 2011	$96,888	$1,282	$3,256	$59,472	$160,898

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NOTES TO CONSOLIDATED AND CONDENSED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)
June 30, 2011
(Unaudited)

	Waskom	PIPE	Matagorda	Redbird	Total
Investment in unconsolidated entities, December 31, 2009	$75,844	$1,401	$3,337	—	$80,582
Distributions in kind	(4,531)	—	—	—	(4,531)
Contributions to unconsolidated entities:					
Cash contributions (See Note 3)	20,110	—	—	—	20,110
Contributions to unconsolidated entities for operations	(881)	—	—	—	(881)
Return of investments	(500)	(30)	(210)	—	(740)
Equity in earnings:					
Equity in earnings (losses) from operations	4,857	(166)	124	—	4,815
Amortization of excess investment	(275)	(8)	(14)	—	(297)
Investment in unconsolidated entities, June 30, 2010	$94,624	$1,197	$3,237	$—	$99,058

Select 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
2011						
Waskom	$134,249	$114,300	$34,072	$5,672	$65,578	$10,574
	As of December 31					
2010						
Waskom	$128,250	$108,669	$32,154	$5,123	$60,808	$9,714

As of June 30, 2011 and December 31, 2010, the amount of the Partnership's consolidated retained earnings that represents undistributed earnings related to the unconsolidated equity-method investees is $44,239 and $36,964, 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, 2011 and December 31, 2010, the Partnership's interest in cash of the unconsolidated equity-method investees was $930 and $1,145, respectively.

(6) 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.

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. As a result of its effectiveness assessment at June 30, 2011, the Partnership believes certain hedge contracts will continue to be effective in offsetting changes in cash flow or fair value attributable to the hedged risk.

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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.

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. The Partnership has entered into hedging transactions through 2012 to protect a portion of its commodity 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. The number of 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 and 2010, 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.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2011 (all gas quantities are expressed in British Thermal Units, crude oil and natural gas liquids are expressed in barrels). As of June 30, 2011, the remaining term of the contracts extend no later than December 2012, with no single contract longer than one year. For the three months and six months ended June 30, 2011 and 2010, 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.

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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 $91.20 settled against WTI NYMEX average monthly closings	July 2011 to December 2011	(56)
Total commodity swaps not designated as hedging instruments				$ (56)
Cash Flow Hedges:				
Natural Gas Swap	10,000 Mmbtu	Fixed price of $6.1250 settled against IF_ANR_LA first of the month posting	July 2011 to December 2011	102
Natural Gas Swap	20,000 Mmbtu	Fixed price of $4.3225 settled against IF_ANR_LA first of the month posting	July 2011 to December 2011	(12)
Natural Gasoline Swap	2,000 BBL	Fixed price of $87.10 settled against WTI NYMEX average monthly closings	July 2011 to December 2011	(105)
Natural Gasoline Swap	1,000 BBL	Fixed price of $88.85 settled against WTI NYMEX average monthly closings	July 2011 to December 2011	(42)
Natural Gasoline Swap	1,000 BBL	Fixed price of $2.383 settled against Mont Belvieu Non-TET OPIS Average	July 2011 to December 2011	81
Crude Oil Swap	1,000 BBL	Fixed price of $101.90 settled against WTI NYMEX average monthly closings	July 2011 to December 2011	36
Natural Gas Swap	10,000 Mmbtu	Fixed price of $4.8700 settled against IF_ANR_LA first of the month posting	January 2012 to December 2012	10

Natural Gas Swap	20,000 Mmbtu	Fixed price of $4.9600 settled against IF_ANR_LA first of the month posting	January 2012 to December 2012		42
Natural Gasoline Swap	1,000 BBL	Fixed price of $90.20 settled against WTI NYMEX average monthly closings	January 2012 to December 2012		(111)
Natural Gasoline Swap	1,000 BBL	Fixed price of $2.340 settled against Mont Belvieu Non-TET OPIS Average	January 2012 to December 2012		64
Crude Oil Swap	2,000 BBL	Fixed price of $88.63 settled against WTI NYMEX average monthly closings	January 2012 to December 2012		(258)
Total commodity swaps designated as hedging instruments				$	(193)
Total net fair value of commodity derivatives				$	(249)

Based on estimated volumes, as of June 30, 2011, the Partnership had hedged approximately 47% and 35% of its commodity risk by volume for 2011 and 2012, respectively. The Partnership anticipates entering into additional commodity derivatives on an ongoing basis to manage its risks associated with these market fluctuations and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that the Partnership will be able to do so or that the terms thereof will be similar to the Partnership's existing hedging arrangements.

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, 2011. 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.

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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, has established a maximum credit limit threshold pursuant to its hedging policy, and monitors the appropriateness of these limits on an ongoing basis. The Partnership has agreements with four 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 the Partnership if the value of derivatives is a liability to the Partnership. As of June 30, 2011, the Partnership has no cash collateral deposits posted with counterparties.

The Partnership's 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 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, 2011 and 2010, net gains on swap hedge contracts increased crude revenue by $357 and $256, respectively. For the six months ended June 30, 2011 and 2010, net gains on swap hedge contracts increased crude revenue by $297 and $253, respectively. As of June 30, 2011 an unrealized derivative fair value gain of $147, related to current and terminated cash flow hedges of crude oil price risk, was recorded in AOCI. Fair value gains of $404 and fair value losses of $257 are expected to be reclassified into earnings in 2011 and 2012, respectively. The actual reclassification to earnings for contracts remaining in effect will be based on mark-to-market prices at the contract settlement date or for those terminated contracts based on the recorded values at June 30, 2011, 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. For the three months ended June 30, 2011 and 2010, net gains on swap hedge contracts increased gas revenue by $69 and $192, respectively. For the six months ended June 30, 2011 and 2010, net gains on swap hedge contracts increased gas revenue $143 and $257, respectively. As of June 30, 2011 an unrealized derivative fair value gain of $131 related to cash flow hedges of natural gas was recorded in AOCI. Fair value gains of $81 and $50 are expected to be reclassified into earnings in 2011 and 2012, respectively. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, 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, 2011 and 2010, net gains on swap hedge contracts increased natural gas liquids revenue by $60 and $226, respectively. For the six months ended June 30, 2011 and 2010, net gains and losses on swap hedge contracts increased or decreased natural gas liquids revenue $222 and $189, respectively. As of June 30, 2011 an unrealized derivative fair value gain of $342 related to cash flow hedges of natural gas was recorded in AOCI. Fair value gains of $383 and fair value losses of $41 are expected to be reclassified into earnings in 2011 and 2012, respectively. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, 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.

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(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 and term loan credit facilities. 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.

The Partnership has entered into interest rate swap agreements with an aggregate notional amount of $100,000 to hedge its exposure to changes in the fair value of Senior Notes as described in Note 10. The Partnership believes the interest rate hedge contracts will be effective in offsetting changes in fair value attributable to the hedged risk; however, the contracts were not designated as fair value hedges and therefore, are not receiving hedge accounting but being marked to market through earnings.

Under the following swap agreements, the Partnership pays a floating rate of interest and receives a fixed rate based on a three-month U.S. Dollar LIBOR rate to match the fixed rate of the Senior Notes:

Date of Hedge	Notional Amount	Paying Floating Rate	Receiving Fixed Rate	Maturity Date
September 2010	$ 40,000	3 Month LIBOR	2.3150 %	April 2018
September 2010	$ 60,000	3 Month LIBOR	2.3150 %	April 2018

In March 2010, in connection with a pay down of the Partnership's revolving credit facility, the Partnership terminated all of its existing cash flow hedge agreements with an aggregate notional amount of $140,000, which it had entered to hedge its exposure to increases in the benchmark interest rate underlying its variable rate revolving and term loan credit facilities. Termination fees of $3,850 were paid on early extinguishment of all interest rate swap agreements in March 2010. The amounts remaining in AOCI were reclassified into interest expense over the original term of the terminated interest rate derivatives.

The Partnership recognized decreases 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. The Partnership recognized increases in interest expense of $963 and $3,524 for the three and six months ended June 30, 2010, 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.

(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, 2011	December 31, 2010	Balance Sheet Location	June 30, 2011	December 31, 2010
Derivatives designated as hedging instruments						
	Current:			Current:		
Interest rate contracts	Fair value of derivatives	$ —	$ —	Fair value of derivatives	$ —	$ —

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Fair Values of Derivative Instruments in the Consolidated Balance Sheet

	Derivative Assets	Fair Values		Derivative Liabilities	Fair Values	
	Balance Sheet Location	June 30, 2011	December 31, 2010	Balance Sheet Location	June 30, 2011	December 31, 2010
Commodity contracts	Fair value of derivatives	296	201	Fair value of derivatives	331	230
		296	201		331	230
	Non-current:			Non-current:		
Interest rate contracts	Fair value of derivatives	—	—	Fair value of derivatives	—	—
Commodity contracts	Fair value of derivatives	39	—	Fair value of derivatives	197	171
		39	—		197	171
Total derivatives designated as hedging instruments		$ 335	$ 201		$ 528	$ 401
Derivatives not designated as hedging instruments						
	Current:			Current:		
Interest rate contracts	Fair value of derivatives	$ 1,962	$ 1,941	Fair value of derivatives	$ —	$ —
Commodity contracts	Fair value of derivatives	—	—	Fair value of derivatives	56	51
		1,962	1,941		56	51
	Non-current:			Non-current:		
Interest rate contracts	Fair value of derivatives	—	—	Fair value of derivatives	2,406	3,930
		—	—		—	—

Commodity contracts	Fair value of derivatives			Fair value of derivatives		
		—	—		2,406	3,930
Total derivatives not designated as hedging instruments		$ 1,962	$ 1,941		$ 2,462	$ 3,981

Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Three Months Ended June 30, 2011 and 2010

	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	
	2011	2010		2011	2010		2011	2010
Derivatives designated as hedging instruments								
Interest rate contracts	$ —	$ —	Interest Expense	$ —	$ (963)	Interest Expense	$ —	$ —

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Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Three Months Ended June 30, 2011 and 2010

	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	
Commodity contracts	843	246	Natural Gas Services Revenues	329	223	Natural Gas Services Revenues	(11)	45
Total derivatives designated as hedging instruments	$ 843	$ 246		$ 329	$ (740)		$ (11)	$ 45

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives 2011	2010
Derivatives not designated as hedging instruments			
Interest rate contracts	Interest Expense	$ 3,167	$ —
Commodity contracts	Natural Gas Services Revenues	167	406
Total derivatives not designated as hedging instruments		$ 3,334	$ 406

Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Six Months Ended June 30, 2011 and 2010

Effective Portion		Ineffective Portion and Amount Excluded from Effectiveness Testing
Amount of Gain or	Amount of Gain or	Amount of Gain or

	(Loss) Recognized in OCI on Derivatives		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	(Loss) Reclassified from Accumulated OCI into Income		Location of Gain or (Loss) Recognized in Income on Derivatives	(Loss) Recognized in Income on Derivatives	
	2011	2010		2011	2010		2011	2010
Derivatives designated as hedging instruments								
Interest rate contracts	$ —	$ (241)	Interest Expense	$ (18)	$ (3,334)	Interest Expense	$ —	$ —
Commodity contracts	(65)	745	Natural Gas Services Revenues	763	337	Natural Gas Services Revenues	(11)	49
Total derivatives designated as hedging instruments	$ (65)	$ 504		$ 745	$ (2,997)		$ (11)	$ 49

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Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Six Months Ended June 30, 2011 and 2010

	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

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives 2011	2010
Derivatives not designated as hedging instruments			
Interest rate contracts	Interest Expense	$ 2,553	$ (190)
Commodity contracts	Natural Gas Services Revenues	(90)	312
Total derivatives not designated as hedging instruments		$ 2,463	$ 122

Amounts expected to be reclassified into earnings for the subsequent twelve-month period are losses of $0 for interest rate cash flow hedges and gains of $751 for commodity cash flow hedges.

(7) 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 6 for further information on the Partnership's derivative instruments and hedging activities.

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The following items are measured at fair value on a recurring basis subject to the disclosure requirements of ASC 820 at June 30, 2011:

		Fair Value Measurements at Reporting Date Using		
Description	June 30, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Interest rate derivatives	$1,962	$—	$1,962	$ —
Natural gas derivatives	154	—	154	—
Crude oil derivatives	36	—	36	—
Natural gas liquids derivatives	145	—	145	—
Total assets	$2,297	$—	$2,297	$ —
Liabilities				
Interest rate derivatives	$(2,406)	$—	$(2,406)	$ —
Natural gas derivatives	(12)	—	(12)	—
Crude oil derivatives	(314)	—	(314)	—
Natural gas liquids derivatives	(258)	—	(258)	—
Total liabilities	$(2,990)	$—	$(2,990)	$ —

The following items are measured at fair value on a recurring basis subject to the disclosure requirements of ASC 820 at December 31, 2010:

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Interest rate derivatives	$1,941	$—	$1,941	$ —

Natural gas derivatives	201	—	201	—
Total assets	$2,142	$—	$2,142	$ —
Liabilities				
Interest rate derivatives	$3,930	$—	$3,930	$ —
Natural gas derivatives	28	—	28	—
Crude oil derivatives	177	—	177	—
Natural gas liquids derivatives	247	—	247	—
Total liabilities	$4,382	$—	$4,382	$ —

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:

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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 because of the short maturity of these instruments.

Long-term debt including current installments — The carrying amount of the revolving and term loan facilities approximates fair value due to the debt having a variable interest rate.

The estimated fair value of the Senior Notes was approximately $217,022 and $216,366 based on market prices of similar debt at June 30, 2011 and December 31, 2010, respectively.

(8) Related Party Transactions

As of June 30, 2011, Martin Resource Management owns 5,703,823 of the Partnership's common units and 889,444 subordinated units collectively representing approximately 32.2% 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, 2011, of approximately 32.2% 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 our 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 our general partner, 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.

This restriction does not apply to:

the ownership and/or operation on our behalf of any asset or group of assets owned by us or our affiliates;

any business operated by Martin Resource Management, including the following:

- o providing land transportation of various liquids;
- o distributing fuel oil, sulfuric acid, marine fuel and other liquids;

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o providing marine bunkering and other shore-based marine services in Alabama, Florida, Louisiana Mississippi and Texas;

o operating a small crude oil gathering business in Stephens, Arkansas;

o operating an underground NGL storage facility in Arcadia, Louisiana;

o building and marketing sulfur processing equipment; and

o 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 million 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 us with corporate staff, support services, and administrative services necessary to operate our business. 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. 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, 2010, through September 30, 2011, the Conflicts Committee of the board of directors of our general partner (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $4,168. We reimbursed Martin Resource Management for $1,042 and $916 of indirect expenses for the three months ended June 30, 2011 and 2010, respectively. We reimbursed Martin Resource Management for $2,084 and $1,833 of indirect expenses for the six months ended June 30, 2011 and 2010, 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 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 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 our general partner.

Related Party Transactions. The omnibus agreement prohibits us from entering into any material agreement with Martin Resource Management without the prior approval of the conflicts committee of our 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.

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License Provisions. Under the omnibus agreement, Martin Resource Management has granted us 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 our general partner if such amendment would adversely affect the unitholders. The omnibus agreement was amended on November 24, 2009, to permit us to provide refining services to Martin Resource Management. Such amendment was approved by the conflicts committee of our 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 our 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 us 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 anytime 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 to 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.

Cross Marine Charter Agreements. Cross entered into four marine charter agreements with the Partnership effective March 1, 2007. 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.

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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 we charge 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. We are party to an agreement under which we process crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts for Cross. The Tolling Agreement has a 12 year term which expires November 24, 2021. Under this Tolling Agreement, Martin Resource Management agreed to refine a minimum of 6,500 barrels per day of crude oil at the refinery at a fixed price per barrel. Any additional barrels are refined 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, and which is not consumed by the Partnership’s internal operations. This agreement, which was amended and restated in August 2008, 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.

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,	
	2011	2010	2011	2010
Revenues:				
Terminalling and storage	$12,897	$11,593	$25,835	$22,287
Marine transportation	6,306	6,920	12,871	12,980
Product sales:				
Natural gas services	1,583	1,470	3,786	1,531
Sulfur services	1,635	1,553	4,821	1,739
Terminalling and storage	103	51	114	112
	3,321	3,074	8,721	3,382
	$22,524	$21,587	$47,427	$38,649

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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	$25,754	$22,662	$48,959	$41,368
Sulfur services	4,492	3,919	8,645	7,236
Terminalling and storage	83	123	138	223
	$30,329	$26,704	$57,742	$48,827

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

Expenses:				
Operating expenses				
Marine transportation	$6,793	$6,609	$12,781	$12,853
Natural gas services	567	797	1,175	1,129
Sulfur services	1,658	1,492	2,902	2,509
Terminalling and storage	4,684	3,411	8,886	7,280
	$13,702	$12,309	$25,744	$23,771

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	$15	$—	$30	$—
Natural gas services	1,197	2,124	2,529	2,392
Sulfur services	639	594	1,281	1,211
Indirect overhead allocation, net of reimbursement	1,042	916	2,084	1,833
	$2,893	$3,634	$5,924	$5,436

(9) 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.

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, 2010 filed with the SEC on March 2, 2011. The Partnership evaluates the performance of its reportable segments based on operating income. There is no allocation of administrative expenses or interest expense.

	Operating Revenues	Intersegment Revenues Eliminations	Operating Revenues	Depreciation and Amortization	Operating Income (loss) after	Capital Expenditures

			after Eliminations		eliminations	
Three months ended June 30, 2011						
Terminalling and storage	$39,766	$ (1,068)	$ 38,698	$ 4,745	$ 2,951	$ 5,706

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	Operating Revenues	Intersegment Revenues Eliminations	Operating Revenues after Eliminations	Depreciation and Amortization	Operating Income (loss) after eliminations	Capital Expenditures
Natural gas services	159,198	—	159,198	1,525	357	486
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	$295,248	$ (3,043)	$ 292,205	$ 11,309	$ 10,566	$ 15,296
Three months ended June 30, 2010						
Terminalling and storage	$27,244	$ (1,075)	$ 26,169	$ 4,145	$ 3,823	$ 1,621
Natural gas services	124,784	—	124,784	1,198	(72)	425
Sulfur services	42,878	—	42,878	1,523	6,131	895
Marine transportation	19,200	(1,087)	18,113	3,120	451	1,267
Indirect selling, general and administrative	—	—	—	—	(1,231)	—
Total	$214,106	$ (2,162)	$ 211,944	$ 9,986	$ 9,102	$ 4,208
Six months ended June 30, 2011						
Terminalling and storage	$77,412	$ (2,046)	$ 75,366	$ 9,285	$ 6,119	$ 9,909
Natural gas services	326,409	—	326,409	3,040	3,888	1,001
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	$581,302	$ (6,061)	$ 575,241	$ 22,251	$ 24,077	$ 30,170
Six months ended June 30, 2010						
Terminalling and storage	$53,586	$ (2,256)	$ 51,330	$ 8,156	$ 6,428	$ 3,441
Natural gas services	290,013	—	290,013	2,389	2,635	770
Sulfur services	77,287	—	77,287	3,046	10,471	2,189
Marine transportation	38,198	(2,208)	35,990	6,300	161	1,316
Indirect selling, general and administrative	—	—	—	—	(3,030)	—
Total	$459,084	$ (4,464)	$ 454,620	$ 19,891	$ 16,665	$ 7,716

The following table reconciles operating income to net income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Operating income	$10,566	$9,102	$24,077	$16,665
Equity in earnings of unconsolidated entities	2,793	2,342	5,169	4,518
Interest expense	(4,403)	(8,194)	(12,805)	(16,197)
Other, net	44	23	104	83
Income tax benefit (expense)	(230)	(198)	(453)	(223)
Net income	$8,770	$3,075	$16,092	$4,846

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Total assets by segment are as follows:

	June 30, 2011	December 31, 2010
Total assets:		
Terminalling and storage	$219,905	$188,234
Natural gas services	375,273	314,815
Sulfur services	153,035	138,224
Marine transportation	150,066	144,205
Total assets	$898,279	$785,478

(10) Long-Term Debt and Capital Leases

At June 30, 2011 and December 31, 2010, long-term debt consisted of the following:

	June 30, 2011	December 31, 2010
** $200,000 Senior Notes, 8.875% interest, net of unamortized discount of $2,368 and $2,543, respectively, issued March 2010 and due April 2018, unsecured	$197,632	$197,457
*** $350,000 Revolving loan facility at variable interest rate (2.79%* weighted average at June 30, 2011), 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	219,000	163,000
$7,114 Note payable to bank, interest rate at 7.50%, maturity date of January 2017, secured by equipment	6,869	7,354
Capital lease obligations	6,114	6,172
Total long-term debt and capital lease obligations	429,615	373,983
Less current installments	1,173	1,121
Long-term debt and capital lease obligations, net of current installments	$428,442	$372,862

* 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 2.50%. Effective July 1, 2011, the applicable margin for existing LIBOR borrowings remained at 2.50%. Effective October 1, 2011, the applicable margin for existing LIBOR borrowings will remain at 2.50%.

** 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 is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

** 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 is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

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*** Effective October 2008, the Partnership entered into a cash flow hedge that swapped $40,000 of floating rate to fixed rate. The fixed rate cost was 2.820% plus the Partnership's applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 2.580% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in October 2010, but were terminated in March 2010.

*** Effective January 2008, the Partnership entered into a cash flow hedge that swapped $25,000 of floating rate to fixed rate. The fixed rate cost was 3.400% plus the Partnership's applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 3.050% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges matured in January 2010.

*** Effective September 2007, the Partnership entered into a cash flow hedge that swapped $25,000 of floating rate to fixed rate. The fixed rate cost was 4.605% plus the Partnership's applicable LIBOR borrowing spread. Effective March 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 4.305% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in September 2010, but were terminated in March 2010.

*** Effective November 2006, the Partnership entered into an interest rate swap that swapped $30,000 of floating rate to fixed rate. The fixed rate cost was 4.765% plus the Partnership's applicable LIBOR borrowing spread. This cash flow hedge matured in March 2010.

*** Effective March 2006, the Partnership entered into a cash flow hedge that swapped $75,000 of floating rate to fixed rate. The fixed rate cost was 5.25% plus the Partnership's applicable LIBOR borrowing spread. Effective February 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 5.10% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in November 2010, but were terminated in March 2010.

(a) Senior Notes

In March 2010, the Partnership and Martin Midstream Finance Corp. ("FinCo"), a subsidiary of the Partnership (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 $200,000 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 $197,200, after deducting initial purchasers' 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 of the Partnership issued full, irrevocable, and unconditional guarantees of the Senior Notes. As discussed in Note 14, 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.

Indenture. 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.

Interest and Maturity. The Senior Notes will mature on April 1, 2018. The interest payment dates are April 1 and October 1.

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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 twelve-month period beginning on April 1, 2015 and 100.00% for the twelve-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.

Certain Covenants. The Indenture restricts the Partnership's ability and the ability of certain of its 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) failure by the Partnership to comply with certain covenants relating to asset sales, repurchases of the Senior Notes upon a change of control and mergers or consolidations; (iv) failure by the Partnership for 180 days after notice to comply with its reporting obligations under the Securities Exchange Act of 1934; (v) failure by the Partnership 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 the Partnership or any of its 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 $20,000 or more, subject to a cure provision; (vii) failure by the Partnership or any of its restricted subsidiaries to pay final judgments aggregating in excess of $20,000, 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 the Partnership's restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary of the Partnership. 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 the Partnership that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of the Partnership, 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 with respect to an offer to exchange the Senior Notes for substantially identical notes that are registered under the Securities Act. The Partnership exchanged the Senior Notes for registered 8.875% senior unsecured notes due April 2018.

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(b) Credit Facility

On November 10, 2005, the Partnership entered into a $225,000 multi-bank credit facility, which has subsequently been amended including most recently on April 15, 2011, when the Partnership amended its revolving credit facility to (1) increase the maximum amount of borrowings and letters of credit under the Credit Agreement from $275,000 to $350,000, (2) extend the maturity date of all amounts outstanding under the Credit Agreement from March 15, 2013 to April 15, 2016, (3) decrease the applicable interest rate margin on committed revolver loans under the Credit Agreement, (4) adjust the financial covenants, and (5) increase the maximum allowable amount of additional outstanding indebtedness of the borrower and the Partnership and certain of its subsidiaries in an amount not to exceed $35,000.

Under the amended and restated credit facility, as of June 30, 2011, the Partnership had $219,000 outstanding under the revolving credit facility. As of June 30, 2011, irrevocable letters of credit issued under the Partnership's credit facility totaled $120. As of June 30, 2011, the Partnership had $130,880 available under its revolving credit facility. 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 the Partnership's credit facility ranged from a low of $135,000 to a high of $234,000.

The Partnership's obligations under the credit facility are secured by substantially all of the Partnership's assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in its operating subsidiaries and equity method investees. The Partnership may prepay all amounts outstanding under this facility at any time without penalty.

In addition, the credit facility contains various covenants, which, among other things, limit the Partnership's ability to: (i) incur indebtedness; (ii) grant certain liens; (iii) merge or consolidate unless it is the survivor; (iv) sell all or substantially all of its assets; (v) make certain acquisitions; (vi) make certain investments; (vii) make certain capital expenditures; (viii) make distributions other than from available cash; (ix) create obligations for some lease payments; (x) engage in transactions with affiliates; (xi) engage in other types of business; and (xii) incur indebtedness or grant certain liens through its joint ventures.

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. The Partnership was in compliance with the covenants contained in the credit facility as of June 30, 2011.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls the Partnership's general partner, or if Ruben Martin is not the chief executive officer of our general partner or 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 the Partnership's credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, an event of default by Martin Resource Management under its credit facility could independently result in an event of default under the Partnership's credit facility if it is deemed to have a material adverse effect on the Partnership. Any event of default and corresponding acceleration of outstanding balances under the Partnership's credit facility could require the Partnership to refinance such indebtedness on unfavorable terms and would have a material adverse effect on the Partnership's financial condition and results of operations as well as its ability to make distributions to unitholders.

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The Partnership is required to make certain prepayments under the credit facility. If the Partnership receives greater than $15,000 from the incurrence of indebtedness other than under the credit facility, it must prepay indebtedness under the credit facility with all such proceeds in excess of $15,000. The Partnership must prepay revolving loans under the credit facility with the net cash proceeds from any issuance of its equity. The Partnership must also prepay indebtedness under the credit facility with the proceeds of certain asset dispositions. Other than these mandatory prepayments, the credit facility requires interest only payments on a quarterly basis until maturity. All outstanding principal and unpaid interest must be paid by April 15, 2016. The credit facility contains customary events of default, including, without limitation, payment defaults, cross-defaults to other material indebtedness, bankruptcy-related defaults, change of control defaults and litigation-related defaults.

The Partnership paid cash interest in the amount of $1,610 and $1,269 for the three months ended June 30, 2011 and 2010, respectively and $3,848 and $10,998 for the six months ended June 30, 2011 and 2010, respectively. Capitalized interest was $151 and $30 for the three months ended June 30, 2011 and 2010, respectively, and $245 and $55 for the six months ended June 30, 2011 and 2010, respectively. In March 2010, the Partnership terminated all of its interest rate swaps resulting in termination fees of $3,850.

(11) Equity Offering

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 $70,329. 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. On February 9, 2011, the Partnership made a $65,500 payment to reduce the outstanding balance under its revolving credit facility.

On February 8, 2010, the Partnership completed a public offering of 1,650,000 common units at a price of $32.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). The common units sold in the offering were registered under the Securities Act pursuant to the Partnership's existing shelf registration statement. Following this offering, the common units represented a 93.3% limited partnership interest in the Partnership. Total proceeds from the sale of the 1,650,000 common units, net of underwriters' discounts, commissions and offering expenses were $50,530. The Partnership's general partner contributed $1,089 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. On February 8, 2010, the Partnership made a $45,000 payment to reduce the outstanding balance under its revolving credit facility.

(12) Income Taxes

The operations of a partnership are generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the Texas margin tax as described below. Woodlawn, a subsidiary of the Partnership, is subject to income taxes due to its corporate structure. A current federal income tax expense of $29 and $29, related to the operation of the subsidiary were recorded for the three and six months ended June 30, 2011 and $0 and $0 for the three and six months ended June 30, 2010, respectively. State income taxes attributable to the Texas margin tax incurred by the subsidiary were $6 and $11 for the three and six months ended June 30, 2011 and $5 and $10 for the three and six months ended June 30, 2010, 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 $29 and $32 was recorded for the three and six months ended June 30, 2011, respectively, and $141 and $289 was recorded for the three and six months ended June 30, 2010, respectively. A deferred tax liability of $7,782 and $8,213 related to the basis differences existed at June 30, 2011 and at December 31, 2010, respectively.

In 2006, the Texas Governor signed into law a Texas margin tax (H.B. No. 3) which restructures the state business tax by replacing the taxable capital and earned surplus components of the current franchise tax with a new "taxable margin" component. 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 new 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 $230 and $456 were recorded in current income tax expense for the three and six months ended June 30, 2011 and $339 and $512 for the three and six months ended June 30, 2010, respectively.

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An income tax receivable of $331 (which is included in other current assets) existed at both June 30, 2011 and December 31, 2010.

The components of income tax expense (benefit) from operations recorded for the three and six months ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Current:				
Federal	$29	$—	$29	$—
State	230	339	456	512
	259	339	485	512
Deferred:				
Federal	(29)	(141)	(32)	(289)
	$230	$198	$453	$223

(13) 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 (the “Court”) by Scott D. Martin (the “Plaintiff”) against Ruben S. Martin, III (the “Defendant”) with respect to certain matters relating to Martin Resource Management. The Defendant is an executive officer of Martin Resource Management and the Partnership’s general partner, the Defendant is a director of both Martin Resource Management and the Partnership’s general partner, and the Plaintiff is a former director of Martin Resource Management and the Partnership’s general partner. The lawsuit alleged that the Defendant breached a settlement agreement with the Plaintiff concerning certain Martin Resource Management matters and that the Defendant breached fiduciary duties allegedly owed to the Plaintiff in connection with their respective ownership and other positions with Martin Resource Management. Prior to the trial of this lawsuit, the Plaintiff dropped his claims against the Defendant relating to the breach of fiduciary duty allegations. 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 Defendant with respect to his service as an officer or director of the Partnership’s general partner.

In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment (the “Judgment”) with respect to the lawsuit as further described below. In connection with the Judgment, the Defendant has advised us that he has filed a motion for new trial, a motion for judgment notwithstanding the verdict and a notice of appeal. In addition, on June 22, 2009, the Plaintiff filed a notice of appeal with the Court indicating his intent to appeal the Judgment and in fact, has done so. The Defendant has further advised the Partnership that on June 30, 2009, he posted a cash deposit in lieu of a bond and the judge has ruled that as a result of such deposit, the enforcement of any of the provisions in the Judgment is stayed until the matter is resolved on appeal.

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The Judgment awarded the Plaintiff monetary damages in the approximate amount of $3,200, attorney's fees of approximately $1,600 and interest. In addition, the Judgment grants specific performance and provides that the Defendant is to (i) transfer one share of his Martin Resource Management common stock to the Plaintiff, (ii) take such actions, including the voting of any Martin Resource Management shares which the Defendant owns, controls or otherwise has the power to vote, as are necessary to change the composition of the board of directors of Martin Resource Management from the current five-person board consisting of the Defendant, Randy Tauscher, Wes Skelton, Don Neumeyer, and Bob Bondurant (executive officers of Martin Resource Management and our general partner) to a four-person board to consist of the Defendant and his designee and the Plaintiff and his designee, and (iii) take such actions as are necessary to change the trustees of the Martin Resource Management Employee Stock Ownership Trust (the "MRMC ESOP Trust") to just the Defendant and the Plaintiff. The Judgment is directed solely at the Defendant and is not binding on any other officer, director or shareholder of Martin Resource Management or any trustee of a trust owning Martin Resource Management shares. The Judgment with respect to (ii) above terminated on February 17, 2010, and with respect to (iii) above on the 30th day after the election by the Martin Resource Management shareholders of the first successor Martin Resource Management board after February 17, 2010. However, any enforcement of the Judgment was stayed pending resolution of the appeal relating to it. In 2010, the Martin Resource Management board of directors removed Ruben S. Martin III and Scott D. Martin as trustees of the MRMC Employee Stock Ownership Plan and appointed the current trustees, Melanie Mathews, Johnnie Murry, Gina Patterson and Wesley M. Skelton. An election of the Board of Directors of Martin Resource Management occurred on June 18, 2010, whereby the current board of directors was elected.

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 specifically reversed the Judgment and rendered a take-nothing judgment against the Plaintiff and in favor of the Defendant. The Plaintiff petitioned the Supreme Court of Texas to hear his appeal from the Appellate Court. On June 17, 2011, the Supreme Court of Texas denied the Plaintiff's petition for review. The Plaintiff filed a request for rehearing which was denied by the Supreme Court of Texas on August 5, 2011.

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 Defendants, Wesley M. Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Plan (the "ESOP"), 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 ESOP as a party and was subsequently removed to Federal Court by the ESOP. This lawsuit is now pending under Cause No. 4:11-CV-01882 in the United States District Court, Southern District of Texas, Houston Division.

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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 the Plaintiff, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that the Plaintiff 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, and 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 the plaintiff, 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 the Plaintiff 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, including interest and attorneys' fees. The Plaintiff has appealed the judgment and such appeal is still pending.

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. 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, assessing 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. As noted above, the Plaintiff was a former director of Martin Resource Management. The lawsuit alleges that the Plaintiff and others (i) willfully and intentionally interfered with existing Martin Resource Management contracts and the prospective business relationships of Martin Resource Management and (ii) published disparaging statements to third-parties with business relationships with Martin Resource Management, which constituted slander and business disparagement. 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. Additionally, on July 11, 2011, Scott D. Martin sued Martin Resource Management in State District Court in Harris County, Texas alleging that it tortuously interfered with his rights under an existing insurance policy.

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(14) Consolidating Financial Statements

In connection with the Partnership's shelf registration statement on Form S-3 (the "Registration Statement"), Martin Operating Partnership L.P. (the "Operating Partnership"), the Partnership's wholly-owned subsidiary, and its subsidiaries has issued in the past, and may issue in the future, additional 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. The guarantees issued in the past are 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.

(15) Subsequent Event

On August 5, 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 payment of $2,800 upon cancellation of these swap agreements.

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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, 2010, filed with the Securities and Exchange Commission (the "SEC") on March 2, 2011, 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 31.6% 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 for several years. 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

Global financial markets and economic conditions have significantly improved over the last year. One of the features driving investment in master limited partnerships, including us, has been 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 are not as constrained by a lack of liquidity in the financial markets as they were before. During much of 2010 and into 2011, the financial markets were available to us. As such, we were able to issue senior unsecured long-term debt in the first quarter 2010 and equity in both the first and third quarters of 2010. Additionally, we were able to issue equity in February 2011 for the purpose of reducing outstanding indebtedness under our credit facility.

Conditions in our industry continue to be challenging in 2011. For example:

The general decline in drilling activity by gas producers in our areas of operations in Northeast Texas continues which began during the fourth quarter of 2008 as a result of the global economic crisis. Several gas producers in our areas of operation have substantially reduced drilling activity as compared to their drilling levels before the crisis.

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. On October 12, 2010, the United States Government lifted the moratorium on deep water permitting and drilling. Although these enhanced safety regulations and inspection requirements of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) have continued to provide uncertainty surrounding the requirements for and pace of issuance of permits on the Gulf of Mexico Outer Continental Shelf (OCS), permits began to be issued by the BOEMRE again during first quarter 2011.

There has been a decline in the demand for marine transportation services based on decreased refinery production resulting in an oversupply of equipment. This was partially offset in 2010 by the marine transportation services required in the efforts to clean up the BP oil spill in the Gulf of Mexico. 2011 continues to be a challenge for marine transportation services based on these industry conditions.

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

We adjusted our business strategy for 2010 and 2011 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 across all segments, primarily in our Terminalling and Storage segment.

We continue to evaluate opportunities to enter into commodity hedging transactions to further reduce our commodity price risk.

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. However, we have described below the critical accounting policies that we believe could impact our consolidated and condensed financial statements most significantly.

You should also read Note 1, "General" in Notes to Consolidated and Condensed Financial Statements contained in this quarterly report and the "Significant Accounting Policies" note in the consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 2, 2011, in conjunction with this Management's Discussion and Analysis of Financial Condition and Results of Operations. Some of the more significant estimates in these financial statements include the amount of the allowance for doubtful accounts receivable and the determination of the fair value of our reporting units under ASC 350 related to intangibles-goodwill and other.

Derivatives

All derivatives and hedging instruments are included on the balance sheet as an asset or 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 other comprehensive income until such time as the hedged item is recognized in earnings. Our hedging policy allows us to use hedge accounting for financial transactions that are designated as hedges. Derivative instruments not designated as hedges or hedges that become ineffective are marked to market with all market value adjustments being recorded in the consolidated statements of operations. As of June 30, 2011, we have designated a portion of our derivative instruments as qualifying cash flow hedges. Fair value changes for these hedges have been recorded in other comprehensive income as a component of partners' capital.

Product Exchanges

We enter into product exchange agreements with third parties whereby we agree to exchange natural gas liquids ("NGLs") and sulfur with third parties. We record the balance of exchange products due to other companies under these agreements at quoted market product prices and the balance of exchange products due from other companies at the lower of cost or market. Cost is determined using the first-in, first-out method.

Revenue Recognition

Revenue for our four operating segments is recognized as follows:

Terminalling and storage. Revenue is recognized for storage contracts based on the contracted monthly tank fixed fee. For throughput contracts, revenue is recognized based on the volume moved through our terminals at the contracted rate. For our tolling agreement, revenue is recognized based on the contracted monthly reservation fee and throughput volumes moved through the facility. When lubricants and drilling fluids are sold by truck, revenue is recognized upon delivering product to the customers as title to the product transfers when the customer physically receives the product.

Natural gas services. Natural gas gathering and processing revenues are recognized when title passes or service is performed. NGL distribution revenue is recognized when product is delivered by truck to our NGL customers, which occurs when the customer physically receives the product. When product is sold in storage, or by pipeline, we recognize NGL distribution revenue when the customer receives the product from either the storage facility or pipeline.

Sulfur services. Revenue from sulfur product sales is recognized when the customer takes title to the product. Revenue from sulfur services is recognized as deliveries are made during each monthly period.

Marine transportation. Revenue is recognized for contracted trips upon completion of the particular trip. For time charters, revenue is recognized based on a per day rate.

Equity Method Investments

We use the equity method of accounting for investments in unconsolidated entities where the ability to exercise significant influence over such entities exists. Investments in unconsolidated entities consist of capital contributions and advances plus our share of accumulated earnings as of the entities' latest fiscal year-ends, less capital withdrawals and distributions. Investments in excess of the underlying net assets of equity method investees, specifically identifiable to property, plant and equipment, are amortized over the useful life of the related assets. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. This goodwill is not subject to amortization and is accounted for as a component of the investment. Equity method investments are subject to impairment evaluation. No portion of the net income from these entities is included in our operating income.

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We own an unconsolidated 50% of the ownership interests in Waskom Gas Processing Company ("Waskom"), Matagorda Offshore Gathering System ("Matagorda") and Panther Interstate Pipeline Energy LLC ("PIPE"). We own all of the unconsolidated Class B equity interests in Redbird Gas Storage LLC ("Redbird"). Each of these interests is accounted for under the equity method of accounting.

Goodwill

Goodwill is subject to a fair-value based impairment test on an annual basis. We are required to identify our reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets. We are required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeds the fair value of the reporting unit; we would be required to perform the second step of the impairment test, as this is an indication that the reporting unit goodwill may be impaired.

All four of our "reporting units", terminalling and storage, natural gas services, sulfur services and marine transportation, contain goodwill.

We performed the annual impairment test as of September 30, 2010, and we determined that the fair value in each reporting unit based on the weighted average of three valuation techniques: (i) the discounted cash flow method, (ii) the guideline public company method, and (iii) the guideline transaction method.

Significant changes in these estimates and assumptions could materially affect the determination of fair value for each reporting unit which could give rise to future impairment. Changes to these estimates and assumptions can include, but may not be limited to, varying commodity prices, volume changes and operating costs due to market conditions and/or alternative providers of services.

Environmental Liabilities and Litigation

We have not historically experienced circumstances requiring us to account for environmental remediation obligations. If such circumstances arise, we would estimate remediation obligations utilizing a remediation feasibility study and any other related environmental studies that we may elect to perform. We would record changes to our estimated environmental liability as circumstances change or events occur, such as the issuance of revised orders by governmental bodies or court or other judicial orders and our evaluation of the likelihood and amount of the related eventual liability.

Because the outcomes of both contingent liabilities and litigation are difficult to predict, when accounting for these situations, significant management judgment is required. Amounts paid for contingent liabilities and litigation have not had a materially adverse effect on our operations or financial condition and we do not anticipate they will in the future.

Allowance for Doubtful Accounts

In evaluating the collectability of our accounts receivable, we assess a number of factors, including a specific customer's ability to meet its financial obligations to us, the length of time the receivable has been past due and historical collection experience. Based on these assessments, we record specific and general reserves for bad debts to reduce the related receivables to the amount we ultimately expect to collect from customers.

Our management closely monitors potentially uncollectible accounts. Estimates of uncollectible amounts are revised each period, and changes are recorded in the period they become known. If there is a deterioration of a major customer's creditworthiness or actual defaults are higher than the historical experience, management's estimates of the recoverability of amounts due us could potentially be adversely affected. These charges have not had a materially adverse effect on our operations or financial condition.

Asset Retirement Obligation

We recognize and measure our asset and conditional asset retirement obligations and the associated asset retirement cost upon acquisition of the related asset and based upon the estimate of the cost to settle the obligation at its anticipated future date. The obligation is accreted to its estimated future value and the asset retirement cost is depreciated over the estimated life of the asset.

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Estimates of future asset retirement obligations include significant management judgment and are based on projected future retirement costs. Such costs could differ significantly when they are incurred. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates due to surface repair, labor and material costs, revisions to estimated inflation rates and changes in the estimated timing of abandonment. For example, the Company does not have access to natural gas reserves information related to our gathering systems to estimate when abandonment will occur.

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, Florida, 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 31.6% 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.

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 $22.4 million of direct costs and expenses for the three months ended June 30, 2011 compared to $21.1 million for the three months ended June 30, 2010. We reimbursed Martin Resource Management for $43.6 million of direct costs and expenses for the six months ended June 30, 2011 compared to $39.8 million for the six months ended June 30, 2010. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

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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, 2010 through September 30, 2011, the Conflicts Committee of the board of directors of our general partner (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $4.2 million. We reimbursed Martin Resource Management for $1.0 and $0.9 million of indirect expenses for the three months ended June 30, 2011 and 2010, respectively. We reimbursed Martin Resource Management for $2.1 and $1.8 million of indirect expenses for the six months ended June 30, 2011 and 2010, 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. The agreements include, but are not limited to, a motor carrier agreement, a terminal services agreement, a marine transportation agreement, a product storage agreement, a product supply agreement, and a Purchaser Use Easement, Ingress-Egress Easement and Utility Facilities Easement. 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, 2010, filed with the SEC on March 2, 2011.

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 11% and 13% of our total cost of products sold during the three months ended June 30, 2011 and 2010, respectively and approximately 10% of our total cost of products sold for both the six months ended June 30, 2011 and 2010. 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 8% and 10% of our total revenues for the three months ended June 30, 2011 and 2010, respectively. Our sales to Martin Resource Management accounted for approximately 10% and 9% of our total revenues for the three months ended June 30, 2011 and 2010, respectively. We provide terminalling, 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.

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, 2010, filed with the SEC on March 2, 2011.

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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, 2011 and 2010 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 and six months ended June 30, 2011 and 2010. The results of operations for the first six months of the year are not necessarily indicative of the results of operations which might be expected for the entire year.

	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, 2011						
Terminalling and storage	$39,766	$ (1,068)	$ 38,698	$3,123	$ (172)	$ 2,951
Natural gas services	159,198	—	159,198	114	243	357
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	$295,248	$ (3,043)	$ 292,205	$10,566	$ —	$ 10,566
Three months ended June 30, 2010						
Terminalling and storage	$27,244	$ (1,075)	$ 26,169	$4,368	$ (545)	$ 3,823
Natural gas services	124,784	—	124,784	(346)	274	(72)
Sulfur services	42,878	—	42,878	4,773	1,358	6,131
Marine transportation	19,200	(1,087)	18,113	1,538	(1,087)	451
Indirect selling, general and administrative	—	—	—	(1,231)	—	(1,231)
Total	$214,106	$ (2,162)	$ 211,944	$9,102	$ —	$ 9,102

Six months ended June 30, 2011						
Terminalling and storage	$77,412	$ (2,046)	$ 75,366	$6,340	$ (221)	$ 6,119
Natural gas services	326,409	—	326,406	3,440	448	3,888
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	$581,302	$ (6,061)	$ 575,241	$24,077	$ —	$ 24,077
Six months ended June 30, 2010						
Terminalling and storage	$53,586	$ (2,256)	$ 51,330	$7,677	$ (1,249)	$ 6,428
Natural gas services	290,013	—	290,013	1,949	686	2,635
Sulfur services	77,287	—	77,287	7,700	2,771	10,471
Marine transportation	38,198	(2,208)	35,990	2,369	(2,208)	161
Indirect selling, general and administrative	—	—	—	(3,030)	—	(3,030)
Total	$459,084	$ (4,464)	$ 454,620	$16,665	$ —	$ 16,665

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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, 2011 Compared to the Three Months Ended June 30, 2010

Our total revenues before eliminations were $295.2 million for the three months ended June 30, 2011 compared to $214.1 million for the three months ended June 30, 2010, an increase of $81.1 million, or 38%. Our operating income before eliminations was $10.6 million for the three months ended June 30, 2011 compared to $9.1 million for the three months ended June 30, 2010, an increase of $1.5 million, or 16%.

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, 2011	Three Months Ended June 30, 2010
	(In thousands)	
Revenues:		
Services	$20,375	$17,739
Products	19,391	9,505
Total revenues	39,766	27,244
Cost of products sold	18,290	8,962
Operating expenses	12,939	9,767
Selling, general and administrative expenses	92	2
Depreciation and amortization	4,745	4,145
	3,700	4,368
Other operating income	(577)	—
Operating income	$3,123	$4,368

Revenues. Our terminalling and storage revenues increased $12.5 million, or 46%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Of the increase in total revenues, $2.6 million is attributable to services revenue and $9.9 million pertains to product revenues. The increase in services revenue is primarily related to the acquisition of certain terminalling assets from Martin Resource Management in February 2011. Of the increase in product revenues, $7.7 million was due to the conversion of a consigned product delivery agreement with one of our customers during September 2010. The remaining $2.2 million increase was due to increases in average selling prices at our Mega Lubricant facility.

Cost of products sold. Our cost of products sold increased $9.3 million, or 104%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Of this increase, $6.8 million was primarily due to the conversion of a consigned product delivery agreement with one of our customers during September 2010. The remaining increase was due to an increase in our average purchase price of products at our Mega Lubricants facility.

Operating expenses. Operating expenses increased $3.2 million, or 33%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Of this increase, $1.6 million was due primarily to operating expenses associated with the acquisition of certain terminalling assets from Martin Resource Management in the first quarter of 2011. The remaining balance of $1.6 million pertains to increases in various areas of operations and additional labor and burden costs.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.1 million, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. This increase was primarily due to legal fees associated with the acquisition of certain terminalling assets from Martin Resource Management in the first quarter of 2011.

Depreciation and amortization. Depreciation and amortization increased $0.6 million, or 15%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Of the increase $0.2 million relates to additional depreciation expense associated with the acquisition of certain terminalling assets from Martin Resource Mangement in the first quarter of 2011. The balance of the increase was a result of capital expenditures made in the past twelve months.

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Other operating income. 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 quarter.

In summary, our terminalling and storage operating income decreased $1.3 million, or 29%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

Natural Gas Services Segment

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

	Three Months Ended June 30,	
	2011	2010
	(In thousands)	
Revenues:		
NGLs	$146,487	$111,265
Natural gas	10,920	11,785
Non-cash mark-to-market adjustment of commodity derivatives	642	470
Gain (loss) on cash settlements of commodity derivatives	(156)	205
Other operating fees	1,305	1,059
Total revenues	159,198	124,784
Cost of products sold:		
NGLs	143,259	108,031
Natural gas	10,401	11,525
Total cost of products sold	153,660	119,556
Operating expenses	2,116	2,001
Selling, general and administrative expenses	1,783	2,375
Depreciation and amortization	1,525	1,198
	114	(346)
Other operating income	—	—
Operating income (loss)	$114	$(346)
NGLs Volumes (Bbls)	2,193	2,254
Natural Gas Volumes (Mmbtu)	2,684	2,978
Information above does not include activities relating to Waskom, PIPE, Matagorda and Redbird investments.		
Equity in Earnings of Unconsolidated Entities	$2,793	$2,342
Waskom:		
Plant Inlet Volumes (Mmcf/d)	286	281
Frac Volumes (Bbls/d)	9,058	10,847

Revenues. Our natural gas services revenues increased $34.4 million, or 28% for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

For the three months ended June 30, 2011, NGL revenues increased $35.2 million, or 32% and natural gas revenues decreased $0.9 million, or 7%. The increase in NGL revenues is primarily due to increased sales prices, offset by a decrease in NGL sales volumes. Our NGL average sales price per barrel increased $17.34 or 35%. Additionally, NGL sales volumes for the three months ended June 30, 2011 decreased 3% compared to the same period of 2010. Our natural gas average sales price per Mmbtu increased $0.11, or 3% compared to the same period of 2010. Our natural gas sales volumes decreased 10% compared to the same period of 2010.

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Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the three months ended June 30, 2011, 40% of our total natural gas volumes and 43% of our total NGL volumes were hedged as compared to 44% and 38%, respectively, in 2010. The impact of price risk management and marketing activities increased total natural gas and NGL revenues $0.5 million for the second quarter of 2011 compared to $0.7 million in the same period of 2010. Of the $0.5 million increase, $0.6 million was attributable to a non-cash mark-to-market adjustments made to our derivative contracts and $0.1 million is related to losses recognized on cash settlements of our derivative contracts.

Costs of products sold. Our cost of products sold increased $34.1 million, or 29%, for the three months ended June 30, 2011 compared to the same period of 2010. Of the increase, $35.2 million relates to NGLs and a decrease of $1.1 million relates to natural gas. The increase in NGL cost of products sold was consistent with our increase in NGL revenues as our NGL margins remained consistent. The decrease relating to natural gas cost of products sold was more than the decrease in natural gas revenues which caused our Mmbtu margins to increase by 121%.

Operating expenses. Operating expenses increased $0.1 million, or 6%, for the three months ended June 30, 2011 compared to the same period of 2010 as a result of the acquisition of the Darco gathering system in November 2010.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased $0.6 million, or 25%, for the three months ended June 30, 2011 compared to the same period of 2010 primarily due to the write-off of an uncollectible customer receivable of $0.6 million during 2010.

Depreciation and amortization. Depreciation and amortization increased $0.3 million, or 27% compared to the same period of 2010 primarily due to increased amortization expense related to contracts associated with the Darco acquisition of $0.2 million as well as certain capital projects being placed in service of $0.1 million.

In summary, our natural gas services operating income increased $0.5 million, or 133%, for the three months ended June 30, 2011 compared to the same period of 2010.

Equity in earnings of unconsolidated entities. Equity in earnings of unconsolidated entities was $2.8 million and $2.3 million for the three months ended June 30, 2011 and 2010, respectively, an increase of $0.5 million, or 19%. This increase is primarily a result of increased commodity prices of $0.3 million and earnings related to the Partnership's investment in Redbird of $0.2 million.

Sulfur Services Segment

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

	Three Months Ended June 30,	
	2011	2010
	(In thousands)	
Revenues:		
Services	$2,850	$—
Products	74,083	42,878
Total revenues	76,933	42,878
Cost of products sold	59,983	31,705
Operating expenses	4,966	4,000

Selling, general and administrative expenses	857	877
Depreciation and amortization	1,700	1,523
	9,427	4,773
Other operating income	675	—
Operating income	$10,102	$4,473
Sulfur (long tons)	339.6	278.3
Fertilizer (long tons)	69.4	72.7
Sulfur Services Volumes (long tons)	409.0	351.0

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Revenues. Our sulfur services revenues increased $34.1 million, or 79%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Service revenue accounted for $2.9 million, while product sales accounted for the remaining $31.2 million. The service revenue relates to a new contract that began on January 1, 2011. The increase in product revenue increase was primarily a result of a 17% increase in our volumes sold and an average sales price increase of 48%. The sales price increase was related to an increased market price for our sulfur products.

Cost of products sold. Our cost of products sold increased $28.3 million, or 89%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. Our margin per ton increased by 8%. This increase is also related to the market price of our sulfur products.

Operating expenses. Our operating expenses increased $1.0 million, or 25%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. This increase was a result of increased outside towing expenses of $0.6 million and increased fuel costs of $0.3 million related to our marine transportation expenses.

Selling, general, and administrative expenses. Our selling, general and administrative expenses remained consistent for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

Depreciation and amortization. Depreciation and amortization expense increased $0.2 million, or 13%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

Other operating income. Other Operating income of $0.7 million for the three months ended June 30, 2011 is related to business interruption insurance recoveries from Hurricane Ike.

In summary, our sulfur services operating income increased $5.6 million, or 126%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

Marine Transportation Segment

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

	Three Months Ended June 30,	
	2011	2010
	(In thousands)	
Revenues	$19,351	$19,200
Operating expenses	16,505	14,132
Selling, general and administrative expenses	518	353
Depreciation and amortization	3,339	3,120
	(1,011)	1,595
Other operating income (loss)	—	(57)
Operating income (loss)	$(1,011)	$1,538

Revenues. Our marine transportation revenues increased $0.2 million, or 1%, for the three months ended June 30, 2011, compared to the three months ended June 30, 2010. Our inland marine operations revenues increased $2.2 million, primarily due to increases in ancillary charges of $1.3 million. The remaining $0.9 million increase is related to increased utilization of the inland fleet through the utilization of new leased equipment and increases in contract rates. Our offshore revenues decreased $2.0 million due to decreased utilization of the offshore fleet of $1.9 million and a decrease in ancillary charges of $0.2 million.

Operating expenses. Operating expenses increased $2.4 million, or 17%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010, primarily as a result of an increase in fuel costs of $1.0 million, outside towing expense of $0.9 million, and repairs and maintenance expense of $0.2 million.

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Selling, general and administrative expenses. Selling, general and administrative expenses increased $0.2 million for the three months ended June 30, 2011 compared to the three months ended June 30, 2010 primarily as a result of increased supply costs of $0.1 million and consulting fees of $0.1 million.

Depreciation and amortization. Depreciation and amortization increased $0.2 million, or 7%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010. This increase was primarily a result of capital expenditures made in the last twelve months.

In summary, our marine transportation operating income decreased $2.5 million, or 166%, for the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

Six Months Ended June 30, 2011 Compared to the Six Months Ended June 30, 2010

Our total revenues before eliminations were $581.3 million for the six months ended June 30, 2011 compared to $459.1 million for the six months ended June 30, 2010, an increase of $122.2 million, or 27%. Our operating income before eliminations was $24.1 million for the six months ended June 30, 2011 compared to $16.7 million for the six months ended June 30, 2010, an increase of $7.4 million, or 44%.

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.

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Revenues:		
Services	$39,476	$34,961
Products	37,936	18,625
Total revenues	77,412	53,586
Cost of products sold	35,780	17,408
Operating expenses	25,254	20,284
Selling, general and administrative expenses	176	61
Depreciation and amortization	9,285	8,156
	6,917	7,677
Other operating income	(577)	—
Operating income	$6,340	$7,677

Revenues. Our terminalling and storage revenues increased $23.8 million, or 44%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Of the increase in total revenues, $4.5 million is attributable to services revenue and $19.3 million pertains to product revenues. The increase in services revenue is primarily related to the acquisition of certain terminalling assets from Martin Resource Management in February 2011. Of the increase in product revenues, $14.0 million was due to the conversion of a consigned product delivery agreement with one of our customers during September 2010. The remaining $4.3 million increase was due to increases in average selling prices at our Mega Lubricant facility.

Cost of products sold. Our cost of products sold increased $18.4 million, or 106%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Of this increase, $13.5 million was primarily due to the conversion of a consigned product delivery agreement with one of our customers during September 2010. The remaining increase was due to an increase in our average purchase price of products at our Mega Lubricants facility.

Operating expenses. Operating expenses increased $5.0 million, or 24%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Of this increase, $2.6 million was due primarily to operating expenses associated with the acquisition of certain terminalling assets from Martin Resource Mangement in the first quarter of 2011. The remaining balance of $2.4 million pertains to increases in various areas of operations in addition to labor and burden costs.

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Selling, general and administrative expenses. Selling, general and administrative expenses inceased $0.1 million, or 189% for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. This increase was primarily due to legal fees associated with the acquisition of certain terminalling assets from Martin Resource Management in the first quarter of 2011.

Depreciation and amortization. Depreciation and amortization increased $1.1 million, or 14%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Of the increase $0.7 million relates to additional depreciation expense associated with the acquisition of certain terminalling assets from Martin Resource Mangement in the first quarter of 2011. The balance of the increase was a result of capital expenditures made during the past twelve months.

Other operating income. 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 quarter.

In summary, our terminalling and storage operating income decreased $1.3 million, or 17%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Natural Gas Services Segment

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Revenues:		
NGLs	$301,787	$264,276
Natural gas	20,936	22,780
Non-cash mark-to-market adjustment of commodity derivatives	819	418
Gain (loss) on cash settlements of commodity derivatives	(156)	282
Other operating fees	3,023	2,257
Total revenues	326,409	290,013
Cost of products sold:		
NGLs	291,848	255,314
Natural gas	20,121	22,318
Total cost of products sold	312,069	277,632
Operating expenses	4,226	3,767
Selling, general and administrative expenses	3,634	4,276
Depreciation and amortization	3,040	2,389
	3,440	1,949
Other operating income	—	—
Operating income (loss)	$3,440	$1,949
NGLs Volumes (Bbls)	4,678	5,124
Natural Gas Volumes (Mmbtu)	5,304	5,009

Information above does not include activities relating to Waskom, PIPE, Matagorda and Redbird investments.

Equity in Earnings of Unconsolidated Entities	$5,169	$4,518
Waskom:		
Plant Inlet Volumes (Mmcf/d)	279	264
Frac Volumes (Bbls/d)	9,043	9,626

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Revenues. Our natural gas services revenues increased $36.4 million, or 13%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

For the six months ended June 30, 2011, NGL revenues increased $37.5 million, or 14%, and natural gas revenues decreased $1.8 million, or 8%. The increase in NGL revenues is primarily due to increased commodity prices, offset by decreases in sales volumes. Our NGL average sales price per barrel increased $12.94 or 25% and NGL sales volumes for the first six months of 2011 decreased by 9%. The decrease in natural gas revenues is primarily related to a decrease in sales price, offset by an increase in sales volumes. Our natural gas average sales price per Mmbtu decreased $0.60, or 13% compared to the same period of 2010. Natural gas volumes increased 6% compared to the same period of 2010.

Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the six months ended June 30, 2011, 40% of our total natural gas volumes and 43% of our total NGL volumes were hedged as compared to 44% and 38%, respectively, in 2010. The impact of price risk management and marketing activities increased total natural gas and NGL revenues $0.7 million for the six months of 2011 and 2010, respectively. Of the $0.7 million increase, $0.8 million was attributable to a non-cash mark-to-market adjustments made to our derivative contracts and $0.1 million is related to losses recognized on cash settlements of our derivative contracts.

Costs of products sold. Our cost of products sold increased $34.4 million, or 12%, for the six months ended June 30, 2011 compared to the same period of 2010. Of the increase, $36.6 million relates to NGLs and a decrease of $2.2 million relates to natural gas. The increase in NGL cost of products sold is less than our increase in NGL revenues as our NGL margins increased by $0.35 per barrel, or 20%. The percentage decrease relating to natural gas cost of products sold was greater than the percentage decrease in natural gas revenues which caused our Mmbtu margins to increase by 67%.

Operating expenses. Operating expenses increased $0.5 million, or 12%, for the six months ended June 30, 2011 compared to the same period of 2010 as a result of the acquisition of the Darco gathering system in November 2010 of $0.3 million and increased repairs and maintenance expense of $0.1 million.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased $0.6 million, or 15%, for the six months ended June 30, 2011 compared to the same period of 2010 primarily due to the write-off of an uncollectible customer receivable during 2010.

Depreciation and amortization. Depreciation and amortization increased $0.7 million, or 27%, for the six months ended June 30, 2011 compared to the same period of 2010 due to increased amortization expense related to contracts associated with the Darco acquisition of $0.4 million as well as certain capital projects being placed in service of $0.3 million.

In summary, our natural gas services operating income increased $1.5 million, or 76%, for the six months ended June 30, 2011 compared to the same period of 2010.

Equity in earnings of unconsolidated entities. Equity in earnings of unconsolidated entities was $5.2 million and $4.5 million for the six months ended June 30, 2011 and 2010, respectively, an increase of $0.7 million, or 11%. This increase is primarily a result of higher commodity prices of $0.5 million and earnings related to the Partnership's investment in Redbird of $0.2 million.

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Sulfur Services Segment

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

	Six Months Ended June 30,	
	2011	2010
	(In thousands)	
Revenues:		
Services	$5,700	$—
Products	130,991	77,287
Total revenues	136,691	77,287
Cost of products sold	104,515	56,531
Operating expenses	9,657	8,236
Selling, general and administrative expenses	1,743	1,774
Depreciation and amortization	3,322	3,046
	17,454	7,700
Other operating income	675	—
Operating income	$18,129	$7,700
Sulfur (long tons)	688.5	584.7
Fertilizer (long tons)	147.0	140.7
Sulfur Services Volumes (long tons)	835.5	725.4

Revenues. Our sulfur services revenues increased $59.4 million, or 77%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Service revenue accounted for $5.7 million, while product sales accounted for the remaining $53.7 million. The service revenue relates to a new contract that began on January 1, 2011. The increase in product revenue increase was primarily a result of a 15% increase in our volumes sold and an average sales price increase of 47%. The sales price increase was related to an increased market price for our sulfur products.

Cost of products sold. Our cost of products sold increased $48.0 million, or 85%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. Our margin per ton increased by 11%. This increase is also related to the market price of our sulfur products.

Operating expenses. Our operating expenses increased $1.5 million, or 18%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. This increase was a result of increased outside towing expenses of $1.0 million and increased fuel costs of $0.3 million related to our marine transportation expenses.

Selling, general and administrative expenses. Our selling, general and administrative expenses remained consistent for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Depreciation and amortization. Depreciation and amortization expense increased $0.3 million, or 17%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Other operating income. Other Operating income of $0.7 million for the six months ended June 30, 2011 is related to business interruption insurance recoveries from Hurricane Ike.

In summary, our sulfur services operating income increased $10.4 million, or 135%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Marine Transportation Segment

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

	Six Months Ended June 30,	
	2011	2010
	(In thousands)	
Revenues	$40,790	$38,198
Operating expenses	33,531	28,607
Selling, general and administrative expenses	907	967
Depreciation and amortization	6,604	6,300
	(252)	2,324
Other operating income (loss)	—	45
Operating income (loss)	$(252)	$2,369

Revenues. Our marine transportation revenues increased $2.6 million, or 7%, for the six months ended June 30, 2011, compared to the six months ended June 30, 2010. Our inland marine operations revenues increased $4.9 million, of which $3.0 million is attributed to increased utilization of the inland fleet through the utilization of new leased equipment and increases in contract rates. The remaining $1.8 million of the increase is due to an increase in ancillary charges. Our offshore revenues decreased $2.3 million primarily due to decreased utilization of the offshore fleet in 2011 ($3.2 million), offset by an increase in ancillary charges ($0.7 million).

Operating expenses. Operating expenses increased $4.9 million, or 17%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010, primarily as a result of increased outside towing expenses of $2.1 million, increased fuel costs of $1.6 million, increased repairs and maintenance expense of $0.6 million, and increased wages and burden costs of $0.5 million.

Selling, general and administrative expenses. Selling, general and administrative expenses remained consistent for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Depreciation and amortization. Depreciation and amortization increased $0.3 million, or 5%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. This increase was primarily a result of capital expenditures made in the last twelve months.

In summary, our marine transportation operating income decreased $2.6 million, or 111%, for the six months ended June 30, 2011 compared to the six months ended June 30, 2010.

Equity in Earnings of Unconsolidated Entities

We own an unconsolidated 50% of the ownership interests in Waskom Gas Processing Company (“Waskom”), Matagorda Offshore Gathering System (“Matagorda”) and Panther Interstate Pipeline Energy LLC (“PIPE”). We own all of the unconsolidated Class B equity interests in Redbird Gas Storage LLC (“Redbird”). Each of these interests is accounted for under the equity method of accounting.

On January 15, 2010, Waskom, through its wholly owned subsidiary Waskom Midstream, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Gathering System. Our share of the acquisition cost was approximately $20 million and was recorded as an investment in an unconsolidated entity.

For the three months ended June 30, 2011 and 2010 equity in earnings of unconsolidated entities relates to our unconsolidated interests in Waskom, Matagorda, PIPE, and Redbird for the period after May 31, 2011.

Equity in earnings of unconsolidated entities was $2.8 million and $2.3 million for the three months ended June 30, 2011 and 2010, respectively, an increase of $0.5 million. This increase is related to earnings received from Waskom, Matagorda, PIPE, and Redbird for the period after May 31, 2011. This increase is primarily a result of increased commodity prices.

Equity in earnings of unconsolidated entities was $5.2 million for the six months ended June 30, 2011 compared to $4.5 million for the six months ended June 30, 2010, an increase of $0.7 million. This increase is related to earnings received from Waskom, Matagorda, PIPE, and Redbird for the period after May 31, 2011. This increase is primarily a result of increased commodity prices

Interest Expense

Our interest expense for all operations was $4.3 million for the three months ended June 30, 2011, compared to the $8.2 million for the three months ended June 30, 2010, a decrease of $3.9 million, or 47%. This decrease was primarily due to decreases in interest expense related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps.

Our interest expense for all operations was $12.7 million for the six months ended June 30, 2011, compared to the $16.2 million for the six months ended June 30, 2010, a decrease of $3.5 million, or 22%. This decrease was primarily due to the termination of all our interest rate swaps at a cost of $3.8 million during first quarter 2010, decreases in interest expense related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps, offset by increases due to the issuance of our senior notes at the end of the first quarter 2010.

Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses were $1.8 million for the three months ended June 30, 2011 compared to $1.2 million for the three months ended June 30, 2010, an increase of $0.6 million, or 50%. Indirect selling, general and administrative expenses were $3.6 million for the six months ended June 30, 2011 compared to $3.0 million for the six months ended June 30, 2010, an increase of $0.6 million, or 20%.

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, 2010 through September 30, 2011, the Conflicts Committee of the board of directors of our general partner (the "Conflicts Committee") approved an annual reimbursement amount for indirect expenses of $4.2 million. We reimbursed Martin Resource Management for $1.0 and $0.9 million of indirect expenses for the three months ended June 30, 2011 and 2010, respectively. We reimbursed Martin Resource Management for $2.1 and $1.8 million of indirect expenses for the six months ended June 30, 2011 and 2010, respectively. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Liquidity and Capital Resources

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 2010 and 2011, we completed several transactions that have improved our liquidity position. In February 2011, we received net proceeds of $70.3 million from a public offering of common units. In March 2010, we received net proceeds of $197.2 million from a private placement of senior notes and $50.5 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 $350 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, 2010, filed with the SEC on March 2, 2011, 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 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.

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Effective March 26, 2010, we amended our credit facility to (i) decrease the size of our aggregate facility from $350.0 million to $275.0 million, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit us to invest up to $40.0 million in our joint ventures, (v) eliminate the covenant that limits our ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit our ability to make future acquisitions, and (viii) adjust the financial covenants. For a more detailed discussion regarding our credit facility, see “Description of Our Long-Term Debt—Credit Facility” within this Item.

On March 26, 2010, we completed a private placement of $200.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 to qualified institutional buyers under Rule 144A. We received proceeds of approximately $197.2 million, after deducting initial purchasers’ discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership’s revolving credit facility. For a more detailed discussion regarding the notes offering, see “Description of Our Long-Term Debt—Senior Notes” within this Item.

Equity Offerings

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 $65.5 million payment to reduce the outstanding balance under our revolving credit facility.

On February 8, 2010, we completed a public offering of approximately 1.65 million common units, representing limited partner interests in us at a purchase price of $32.35 per common unit. In connection with the public offering of units, on February 3, 2010, we entered into an underwriting agreement with UBS Securities LLC, RBC Capital Markets Corporation and Wells Fargo Securities, LLC, as representatives for the several underwriters parties thereto. The common units sold in the offering were registered under the Securities Act pursuant to our existing shelf registration statement. Following this offering, the common units represented a 93.3% limited partnership interest in us. We received net proceeds of approximately $50.5 million after payment of underwriters’ discounts, commissions and offering expenses. Our general partner contributed $1.1 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. On February 8, 2010, the Partnership made a $45.0 million payment to reduce the outstanding balance under its revolving credit facility.

Cash Flows and Capital Expenditures

For the six months ended June 30, 2011, cash decreased $11.3 million as a result of $30.1 million provided by operating activities, $113.6 million used in investing activities and $72.2 million provided by financing activities. For the six months ended June 30, 2010 cash increased $4.1 million as a result of $14.9 million provided by operating activities, $26.3 million used in investing activities and $15.5 million provided by financing activities.

For the six months ended June 30, 2011, the cash used in our investing activities of $113.6 million consisted of capital expenditures, acquisitions, plant turnaround costs, return of investments from unconsolidated entities and investments in and distributions from unconsolidated entities. For the six months ended June 30, 2010, the cash used in our investing activities of $26.3 million consisted of capital expenditures, proceeds from sale of property, plant and equipment, plant turnaround costs, return of investments from unconsolidated entities and investments in and distributions from 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

- 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.

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For the six months ended June 30, 2011 and 2010, our capital expenditures for property and equipment were $30.2 million and $7.7 million, respectively.

As to each period:

For the six months ended June 30, 2011, we spent $21.2 million for expansion and $9.0 million for maintenance. 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 in the marine transportation segment for dry dockings of our vessels pursuant to the United States Coast Guard requirements.

For the six months ended June 30, 2010, we spent $5.4 million for expansion and $2.3 million for maintenance. 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 in the marine transportation segment for dry dockings of our vessels pursuant to the United States Coast Guard requirements.

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, cash distributions to our parent 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.

For the six months ended June 30, 2010, our financing activities consisted of cash distributions paid to common and subordinated unitholders of $27.7 million, payments of long-term debt to financial lenders of $331.6 million, payments of notes payable and capital lease obligations of $0.1 million, borrowings of long-term debt under our credit facility of $330.6 million, payments of debt issuance costs of $7.3 million, proceeds from a public offering of $50.5 million, purchase of treasury stock of $0.1 million and general partner contributions of $1.1 million.

We made net investments in (received distributions from) unconsolidated entities of $6.5 million and $(0.9) million during the six months ended June 30, 2011 and 2010, respectively. The net investment in unconsolidated entities includes $3.5 million and $1.0 million of expansion capital expenditures in the six months ended June 30, 2011 and 2010, respectively.

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, 2011, we had $429.6 million of outstanding indebtedness, consisting of outstanding borrowings of $197.6 million (net of unamortized discount) under our Senior Notes, $219.0 million under our revolving credit facility, notes payable of $6.9 million and $6.1 million under capital lease obligations. As of June 30, 2011, we had $130.9 million of available borrowing capacity under our revolving credit facility.

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Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2011 is as follows (dollars in thousands):

		Payment due by period			
Type of Obligation	Total Obligation	Less than One Year	1-3 Years	3-5 Years	Due Thereafter
Long-Term Debt					
Revolving credit facility	$ 219,000	$ —	$ —	$ 219,000	$ —
Senior unsecured notes	197,632	—	—	—	197,632
Note payable	6,869	1,020	2,304	2,677	859
Capital leases including current maturities	6,114	144	429	671	4,870
Non-competition agreements	150	50	100	—	—
Throughput commitment	64,025	2,214	11,203	12,598	38,010
Operating leases	50,679	12,119	21,479	9,839	7,242
Interest expense: [1]					
Revolving credit facility	29,223	6,102	12,204	10,917	—
Senior unsecured notes	119,813	17,750	35,500	35,500	31,063
Note payable	1,561	481	715	343	22
Capital leases	4,591	961	1,836	1,665	129
Total contractual cash obligations	$ 699,657	$ 40,850	$ 85,770	$ 293,210	$ 279,827

(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, 2011, 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 the Partnership has no independent assets or operations, the guarantees are full and unconditional, and our other subsidiary is minor.

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 twelve-month period beginning on April 1, 2015 and 100.00% for the twelve-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.

Certain Covenants. The Indenture restricts our ability and the ability of certain of its 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 with respect to an offer to exchange the Senior Notes for substantially identical notes that are registered under the Securities Act. The Partnership exchanged the Senior Notes for registered 8.875% senior unsecured notes due April 2018.

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 April 15, 2011, when we amended our credit facility to, (1) increase the maximum amount of borrowings and letters of credit under the Credit Agreement from $275 million to $350 million, (2) extend the maturity date of all amounts outstanding under the Credit Agreement from March 15, 2013 to April 15, 2016, (3) decrease the applicable interest rate margin on committed revolver loans under the Credit Agreement, (4) adjust the financial covenants, and (5) increase the maximum allowable amount of additional outstanding indebtedness of the borrower and us and certain of its subsidiaries.

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As of June 30, 2011, we had approximately $219.0 million outstanding under the revolving credit facility and $0.1 million of letters of credit issued, leaving approximately $130.9 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 $135.0 million to a high of $234.0 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. Prepayments as a result of asset sales and debt incurrences require a mandatory reduction of the lenders' commitments under the credit facility equal to 25% of the corresponding mandatory prepayment, but in no event will such prepayments cause the lenders' commitments under the credit facility to be less than $250.0 million. Prepayments as a result of equity issuances do not require any reduction of the lenders' commitments under the credit facility.

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	Letter of Credit Fees
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 %

As of June 30, 2011, based on our leverage ratio the applicable margin for existing Eurodollar Rate borrowings is 2.50%. Effective July 1, 2011, the applicable margin for Eurodollar Rate borrowings will remain at 2.50%.   Effective October 1, 2011, the applicable margin for Eurodollar Rate borrowings will remain at 2.50%.

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 there under 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.

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 8, 2011, our outstanding indebtedness includes $219 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.

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Effective September 2010, we entered into an interest rate swap that swapped $40,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

Effective September 2010, we entered into an interest rate swap that swapped $60,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

Effective October 2008, we entered into an interest rate swap that swapped $40.0 million of floating rate to fixed rate. The fixed rate cost was 2.820% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 2.580% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in October 2010, but were terminated in March 2010.

Effective January 2008, we entered into an interest rate swap that swapped $25.0 million of floating rate to fixed rate. The fixed rate cost was 3.400% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 3.050% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps matured in January 2010.

Effective September 2007, we entered into an interest rate swap that swapped $25.0 million of floating rate to fixed rate. The fixed rate cost was 4.605% plus our applicable LIBOR borrowing spread. Effective March 2009, we entered into two subsequent swaps to lower our effective fixed rate to 4.305% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in September 2010, but were terminated in March 2010.

Effective November 2006, we entered into an interest rate swap that swapped $30.0 million of floating rate to fixed rate. The fixed rate cost was 4.765% plus our applicable LIBOR borrowing spread. This interest rate swap, which matured in March 2010, was not accounted for using hedge accounting.

Effective March 2006, we entered into an interest rate swap that swapped $75.0 million of floating rate to fixed rate. The fixed rate cost was 5.25% plus our applicable LIBOR borrowing spread. Effective February 2009, we entered into two subsequent swaps to lower our effective fixed rate to 5.10% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in November 2010, but were terminated in March 2010.

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.

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Impact of Inflation

Inflation did not have a material impact on our results of operations for the three months ended June 30, 2011 and 2010. 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 months ended June 30, 2011 or 2010.

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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 five 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, 2011, 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 decease.

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 months ended June 30, 2011 and 2010, as our contract mix and percent of volumes associated with those contracts did not differ materially.

The aggregate effect of a hypothetical $1.00/MMbtu increase or decrease in the natural gas price index would result in an approximate annual gross margin change of $0.1 million. In addition, the aggregate effect of a hypothetical $10.00/Bbl increase or decrease in the crude oil price index would result in an approximate annual gross margin change of $0.3 million.

Prism Gas has entered into hedging transactions through 2012 to protect a portion of its commodity exposure from these contracts. These hedging arrangements are in the form of swaps for crude oil, natural gas and natural gasoline.

Based on estimated volumes, as of June 30, 2011, we had hedged approximately 47% and 35% of our commodity risk by volume for 2011 and 2012, respectively. We anticipate entering into additional commodity derivatives on an ongoing basis to manage our risks associated with these 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.

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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, 2011

Period	Underlying	Notional Volume	Commodity Price We Receive	Commodity Price We Pay	Fair Value Asset (In Thousands)	Fair Value Liability (In Thousands)
July 2011-December 2011	Natural Gas	60,000 (Mmbtu)	Index	$6.125/Mmbtu	102	—
July 2011-December 2011	Natural Gas	120,000 (Mmbtu)	Index	$4.3225/Mmbtu	—	(12)
July 2011-December 2011	Crude Oil	12,000 (BBL)	Index	$91.20/Bbl	—	(56)
July 2011-December 2011	Crude Oil	6,000 (BBL)	Index	$101.90/Bbl	36	—
July 2011-December 2011	Natural Gasoline	12,000 (BBL)	Index	$87.10/Bbl	—	(105)
July 2011-December 2011	Natural Gasoline	6,000 (BBL)	Index	$88.85/Bbl	—	(42)
July 2011-December 2011	Natural Gasoline	6,000 (BBL)	Index	$2.383/Gl	81	—
January 2012-December 2012	Natural Gas	120,000 (Mmbtu)	Index	$4.870/Mmbtu	10	—
January 2012-December 2012	Natural Gas	240,000 (Mmbtu)	Index	$4.960/Mmbtu	42	—
January 2012-December 2012	Crude Oil	48,000 (BBL)	Index	$88.63/Bbl	—	(258)
January 2012-December 2012	Natural Gasoline	12,000 (BBL)	Index	$90.20/Bbl	—	(111)
			Index	$2.340/Gl	64	—

January 2012-December 2012	Natural Gasoline	12,000 (BBL)				
			$	335	$	(584)

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 2.79% as of June 30, 2011. As of August 8, 2011, we had total indebtedness outstanding under our credit facility of $219 million, all of which was unhedged floating rate debt. Based on the amount of unhedged floating rate debt owed by us on June 30, 2011, 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 $2.3 million annually.

Historically, we have managed a portion of our interest rate risk on our revolving credit facility with interest rate swaps, which reduced our exposure to changes in interest rates by converting variable interest rates to fixed interest rates. During the first six months of 2011, we terminated all of our interest rate swaps on our revolving credit facility.

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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 $217.0 million as of June 30, 2011, based on market prices of similar debt at June 30, 2011. 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 a $10.0 million decrease in fair value of our long-term debt at June 30, 2011.

We have entered into interest rate swap agreements to adjust the interest we pay from fixed rate to floating rate on our Senior Notes due in April 2018. Pursuant to the terms of these interest rate swap agreements, we pay a variable rate interest payment based on the three-month LIBOR and receive a fixed rate. The net difference to be paid or received from the counterparties under the interest rate swap agreement is settled quarterly and is recognized as an adjustment to interest expense. The risk associated with these interest rate swaps exposes us to an increase in interest rates which would result in an increase in interest expense and a corresponding decrease in net income.

At June 30, 2011, we are party to interest rate swap agreements as shown below:

Interest Rate Swaps
As of June 30, 2011

Date of Swap	Bank	Maturity	Notional Amount	Interest Rate We Pay	Interest Rate We Receive	Fair Value Asset (In Thousands)	Fair Value Liability (In Thousands)
September 2010	SunTrust	April 2018	$ 60,000	3 MO LIBOR	2.3150%	$ 1,177	$ 1,445
September 2010	RBS	April 2018	$ 40,000	3 MO LIBOR	2.3150%	785	961
						$ 1,962	$ 2,406

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 2, 2011.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer purchases of equity securities

Period	Total number of units purchased	Average price paid per unit	Total number of units purchased as part of publicly announced plans or programs	Maximum number of units that may yet be purchased under the plans or programs
May 1, 2011 to May 31, 2011[1]	5,750	$ 40.82	—	—

1 Our general partner purchased our common units and subsequently granted them to our independent directors as part of their annual director compensation.

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 (the "Court") by Scott D. Martin (the "Plaintiff") against Ruben S. Martin, III (the "Defendant") with respect to certain matters relating to Martin Resource Management. The Defendant is an executive officer of Martin Resource Management and our general partner, the Defendant is a director of both Martin Resource Management and our general partner, and the Plaintiff is a former director of Martin Resource Management and our general partner. The lawsuit alleged that the Defendant breached a settlement agreement with the Plaintiff concerning certain Martin Resource Management matters and that the Defendant breached fiduciary duties allegedly owed to the Plaintiff in connection with their respective ownership and other positions with Martin Resource Management. Prior to the trial of this lawsuit, the Plaintiff dropped his claims against the Defendant relating to the breach of fiduciary duty allegations. We are not a party to the lawsuit and the lawsuit does not assert any claims (i) against us, (ii) concerning our governance or operations, or (iii) against the Defendant with respect to his service as an officer or director of our general partner.

In May 2009, the lawsuit went to trial and on June 18, 2009, the Court entered a judgment (the "Judgment") with respect to the lawsuit as further described below. In connection with the Judgment, the Defendant has advised us that he has filed a motion for new trial, a motion for judgment notwithstanding the verdict and a notice of appeal. In addition, on

June 22, 2009, the Plaintiff filed a notice of appeal with the Court indicating his intent to appeal the Judgment and in fact, has done so. The Defendant has further advised us that on June 30, 2009, he posted a cash deposit in lieu of a bond and the judge has ruled that as a result of such deposit, the enforcement of any of the provisions in the Judgment is stayed until the matter is resolved on appeal.

The Judgment awarded the Plaintiff monetary damages in the approximate amount of $3,200, attorney's fees of approximately $1,600 and interest. In addition, the Judgment grants specific performance and provides that the Defendant is to (i) transfer one share of his Martin Resource Management common stock to the Plaintiff, (ii) take such actions, including the voting of any Martin Resource Management shares which the Defendant owns, controls or otherwise has the power to vote, as are necessary to change the composition of the board of directors of Martin Resource Management from the current five-person board consisting of the Defendant, Randy Tauscher, Wes Skelton, Don Neumeyer, and Bob Bondurant (executive officers of Martin Resource Management and our general partner) to a four-person board to consist of the Defendant and his designee and the Plaintiff and his designee, and (iii) take such actions as are necessary to change the trustees of the Martin Resource Management Employee Stock Ownership Trust (the "MRMC ESOP Trust") to just the Defendant and the Plaintiff. The Judgment is directed solely at the Defendant and is not binding on any other officer, director or shareholder of Martin Resource Management or any trustee of a trust owning Martin Resource Management shares. The Judgment with respect to (ii) above terminated on February 17, 2010, and with respect to (iii) above on the 30th day after the election by the Martin Resource Management shareholders of the first successor Martin Resource Management board after February 17, 2010. However, any enforcement of the Judgment was stayed pending resolution of the appeal relating to it. In 2010, the Martin Resource Management board of directors removed Ruben S. Martin III and Scott D. Martin as trustees of the MRMC Employee Stock Ownership Plan and appointed the current trustees, Melanie Mathews, Johnnie Murry, Gina Patterson and Wesley M. Skelton. An election of the Board of Directors of Martin Resource Management occurred on June 18, 2010, whereby the current board of directors was elected.

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 specifically reversed the Judgment and rendered a take-nothing judgment against the Plaintiff and in favor of the Defendant. The Plaintiff petitioned the Supreme Court of Texas to hear his appeal from the Appellate Court. On June 17, 2011, the Supreme Court of Texas denied the Plaintiff's petition for review. The Plaintiff filed a request for rehearing which was denied by the Supreme Court of Texas on August 5, 2011.

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 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 Defendants, Wesley M. Skelton and Robert Bondurant from serving as trustees of the MRMC Employee Stock Ownership Plan (the "ESOP"),, 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 ESOP as a party and was subsequently removed to Federal Court by the ESOP. This lawsuit is now pending under Cause No. 4:11-CV-01882 in the United States District Court, Southern District of Texas, Houston Division.

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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 the Plaintiff, both individually and in his capacity as trustee of the Ruben S. Martin, III Dynasty Trust, which suit alleges, among other things, that the Plaintiff 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, and 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 the plaintiff, 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 has amended her claims to include her grandmother, Margaret Martin, as a defendant. 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 the Plaintiff in the amount of $4.9 million. 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 $2.7 million in damages, including interest and attorneys' fees. The Plaintiff has appealed the judgment and such appeal is still pending.

On September 24, 2008, Martin Resource Management removed Plaintiff as a director of our general partner. 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 were detrimental to both Martin Resource Management and us. 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 our 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 our general partner. 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, assessing 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 Court by Martin Resource Management against the Plaintiff and others with respect to certain matters relating to Martin Resource Management. As noted above, the Plaintiff was a director of Martin Resource Management. The lawsuit alleges that the Plaintiff and others (i) willfully and intentionally interfered with existing Martin Resource Management contracts and the prospective business relationships of Martin Resource Management and (ii) published disparaging statements to third-parties with business relationships with Martin Resource Management, which constituted slander and business disparagement. We are not a party to the lawsuit, and the lawsuit does not assert any claims (i) against us, (ii) concerning our governance or operations or (iii) against the Plaintiff with respect to his service as an officer or former director of our general partner. Additionally, on July 11, 2011, Scott D. Martin sued Martin Resource Management in State District Court in Harris County, Texas alleging that it tortuously interfered with his rights under an existing insurance policy.

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
Its General Partner

Date: August 9, 2011

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).
10.1	Seventh Amendment to Second Amended and Restated Credit Agreement, dated as of April 15, 2011, among Martin Operating Partnership L.P., the Partnership, Martin Operating GP LLC, Prism Gas Systems I, L.P., Prism Gas Systems GP, L.L.C., Prism Gulf Coast Systems, L.L.C., McLeod Gas Gathering and Processing Company, L.L.C., Woodlawn Pipeline Co., Inc., Prism Liquids Pipeline, LLC, the financial institutions party to the Credit Agreement and Royal Bank of Canada, as administrative agent and collateral agent (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed April 21, 2011, 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.”

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101	Interactive Data: the following financial information from Martin Midstream Partners L.P.'s Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2011, formatted in Extensible Business Reporting Language: (1) the Consolidated Balance Sheets; (2) the Consolidated Statements of Income; (3) the Consolidated Statements of Cash Flows; (4) the Consolidated Statements of Capital; (5) the Consolidated Statements of Other Comprehensive Income; and (6) the Notes to Consolidated Financial Statements, tagged as blocks of text.

* Filed or furnished herewith