UNIVERSAL DISPLAY CORP \PA\
Form 10-Q
August 09, 2010

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

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2010

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________ to ___________

Commission File Number 1-12031

UNIVERSAL DISPLAY CORPORATION
(Exact name of registrant as specified in its charter)

Pennsylvania (State or other jurisdiction of incorporation or organization)	23-2372688 (I.R.S. Employer Identification No.)
375 Phillips Boulevard Ewing, New Jersey (Address of principal executive offices)	08618 (Zip Code)

Registrant’s telephone number, including area code: (609) 671-0980

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

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

As of August 2, 2010, the registrant had outstanding 38,190,299 shares of common stock.

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

UNIVERSAL DISPLAY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,754,285	$22,701,126
Short-term investments	54,338,639	41,172,955
Accounts receivable	3,885,380	3,344,255
Other current assets	456,068	411,240
Total current assets	70,434,372	67,629,576
PROPERTY AND EQUIPMENT, net of accumulated depreciation of $16,606,630 and $15,788,490	10,248,341	11,048,763
ACQUIRED TECHNOLOGY, net of accumulated amortization of $16,563,982 and $15,716,446	386,736	1,234,272
OTHER ASSETS	270,932	227,276
TOTAL ASSETS	$81,340,381	$80,139,887
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$1,747,143	$1,275,695
Accrued expenses	4,378,779	5,238,870
Deferred license fees	4,028,487	6,047,467
Deferred revenue	864,881	1,403,927
Total current liabilities	11,019,290	13,965,959
DEFERRED LICENSE FEES	3,105,933	2,826,237
STOCK WARRANT LIABILITY	5,589,350	3,720,165
RETIREMENT PLAN BENEFIT LIABILITY	5,807,038	—
Total liabilities	25,521,611	20,512,361
COMMITMENTS AND CONTINGENCIES (Note 10)		
SHAREHOLDERS' EQUITY:		
Preferred Stock, par value $0.01 per share, 5,000,000 shares authorized, 200,000 shares of Series A Nonconvertible Preferred Stock issued and outstanding (liquidation value of $7.50 per share or $1,500,000)	2,000	2,000
	381,971	368,184

Common Stock, par value $0.01 per share, 100,000,000 and 50,000,000 shares authorized, 38,197,078 and 36,818,440 shares issued and outstanding at June 30, 2010 and December 31, 2009, respectively		
Additional paid-in capital	265,437,511	256,340,530
Accumulated deficit	(204,523,131)	(197,108,705)
Accumulated other comprehensive (loss) income	(5,479,581)	25,517
Total shareholders' equity	55,818,770	59,627,526
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$81,340,381	$80,139,887

The accompanying notes are an integral part of these consolidated statements.

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UNIVERSAL DISPLAY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended June 30, 2010	2009
REVENUE:		
Commercial revenue	$1,951,892	$1,239,056
Developmental revenue	6,494,937	1,717,298
Total revenue	8,446,829	2,956,354
OPERATING EXPENSES:		
Cost of chemicals sold	1,017,416	318,191
Research and development	4,701,508	5,324,695
Selling, general and administrative	3,624,582	2,715,071
Patent costs	843,907	823,729
Royalty and license expense	168,560	85,431
Total operating expenses	10,355,973	9,267,117
Operating loss	(1,909,144)	(6,310,763)
INTEREST INCOME	61,125	188,593
INTEREST EXPENSE	(5,648)	(298)
LOSS ON STOCK WARRANT LIABILITY	(2,582,428)	(292,710)
NET LOSS	$(4,436,095	

	June 30, 2012	2011	For the Six Months Ended June 30, 2012	2011
	(In thousands)		(In thousands)	
Net income (loss)	$ 65,662	$ (7,651)	$ 117,585	$ (3,450)
Other comprehensive income (loss):				
Cash flow hedges:				
Cash flow hedge loss reclassified to net income (loss)	53,229	27,430	96,031	46,944
Change in fair value of cash flow hedges	20,166	(14,051)	(152,888)	(142,775)
Defined benefit pension and retiree health benefit plans	133	61	268	122
Total other comprehensive income (loss)	73,528	13,440	(56,589)	(95,709)
Comprehensive income (loss) attributable to partners capital	$ 139,190	$ 5,789	$ 60,996	$ (99,159)

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	Accumulated Other Comprehensive Income (Loss)	Partners Capital		
		General Partner	Limited Partners	Total
	(In thousands)			
Balance at December 31, 2011	$ 38,527	$ 23,902	$ 666,471	$ 728,900
Other comprehensive loss	(56,589)			(56,589)
Net income		3,971	113,614	117,585
Units repurchased for phantom unit grants			(2,110)	(2,110)
Issuance of phantom units			1,648	1,648
Amortization of vested phantom units			864	864
Proceeds from public offering of common units, net			146,597	146,597
Contributions from Calumet GP, LLC		3,122		3,122
Distributions to partners		(1,951)	(56,367)	(58,318)
Balance at June 30, 2012	$ (18,062)	$ 29,044	$ 870,717	$ 881,699

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Six Months Ended June 30,	
	2012	2011
	(In thousands)	
Operating activities		
Net income (loss)	$ 117,585	$ (3,450)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation and amortization	39,286	28,964
Amortization of turnaround costs	7,161	5,746
Non-cash interest expense	2,759	1,655
Non-cash debt extinguishment costs		14,401
Provision for doubtful accounts	267	255
Unrealized (gain) loss on derivative instruments	(10,764)	3,541
Non-cash equity based compensation	1,875	1,963
Other non-cash activities	813	(1,625)
Changes in assets and liabilities:		
Accounts receivable	(31,815)	(48,479)
Inventories	(4,828)	(111,555)
Prepaid expenses and other current assets	(2,856)	(1,747)
Derivative activity	(590)	5,699
Turnaround costs	(14,141)	(7,501)
Deposits	(5,775)	(12,735)
Accounts payable	(57,872)	58,145
Accrued interest payable	(152)	4,689
Accrued salaries, wages and benefits	(718)	383
Taxes payable	2,072	1,186
Other liabilities	2,389	(9,473)
Pension and postretirement benefit obligations	(142)	(620)
Net cash provided by (used in) operating activities	44,554	(70,558)
Investing activities		
Additions to property, plant and equipment	(22,456)	(20,635)
Proceeds from insurance recoveries equipment		1,942
Acquisitions of TruSouth and Missouri	(46,402)	
Change in restricted cash	(263,313)	
Proceeds from sale of property, plant and equipment	1,913	130
Net cash used in investing activities	(330,258)	(18,563)
Financing activities		
Proceeds from borrowings revolving credit facility	1,055,168	692,543
Repayments of borrowings revolving credit facility	(1,055,168)	(675,285)
Repayments of borrowings term loan credit facility		(367,385)
Payments on capital lease obligations	(881)	(534)
Proceeds from public offering of common units, net	146,597	92,290
Proceeds from senior notes offering	270,187	400,000
Debt issuance costs	(7,483)	(17,582)
Contributions from Calumet GP, LLC	3,122	1,970
Common units repurchased for vested phantom unit grants	(2,110)	(620)
Distributions to partners	(58,318)	(36,258)
Net cash provided by financing activities	351,114	89,139

Net increase in cash and cash equivalents		65,410		18
Cash and cash equivalents at beginning of period		64		37
Cash and cash equivalents at end of period	$	65,474	$	55
Supplemental disclosure of noncash financing and investing activities				
Equipment acquired under capital lease	$	4,255	$	

See accompanying notes to unaudited condensed consolidated financial statements.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(dollars in thousands)

1. Description of the Business

Calumet Specialty Products Partners, L.P. (the Company) is a Delaware limited partnership. The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of June 30, 2012, the Company had 57,529,778 limited partner common units and 1,174,077 general partner equivalent units. The general partner owns 2% of the Company and all of the incentive distribution rights (as defined in the Company s partnership agreement), while the remaining 98% is owned by limited partners. The general partner employs all employees and the limited partnership reimburses the general partner for all expenses. The Company is engaged in the production and marketing of crude oil-based specialty lubricating oils, white mineral oils, solvents, petrolatums, asphalt, waxes and fuel and fuel related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company owns facilities located in Shreveport, Louisiana (Shreveport and TruSouth); Superior, Wisconsin (Superior); Princeton, Louisiana (Princeton); Cotton Valley, Louisiana (Cotton Valley); Karns City, Pennsylvania (Karns City); Dickinson, Texas (Dickinson); Louisiana, Missouri (Missouri) and Houston, Texas (Royal Purple) and terminals located in Burnham, Illinois (Burnham); Rhinelander, Wisconsin (Rhinelander); Crookston, Minnesota (Crookston) and Proctor, Minnesota (Duluth).

The unaudited condensed consolidated financial statements of the Company as of June 30, 2012 and for the three and six months ended June 30, 2012 and 2011 included herein have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Certain information and disclosures normally included in the consolidated financial statements prepared in accordance with generally accepted accounting principles (GAAP) in the United States of America (the U.S.) have been condensed or omitted pursuant to such rules and regulations, although the Company believes that the following disclosures are adequate to make the information presented not misleading. These unaudited condensed consolidated financial statements reflect all adjustments that, in the opinion of management, are necessary to present fairly the results of operations for the interim periods presented. All adjustments are of a normal nature, unless otherwise disclosed. The results of operations for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. These unaudited condensed consolidated financial statements should be read in conjunction with the Company s 2011 Annual Report.

2. New and Recently Adopted Accounting Pronouncements

In July 2012, the FASB issued ASU No. 2012-02, *Intangibles (Topic 350) Testing Indefinite-Lived Intangible Assets for Impairment* (ASU 2012-02). ASU 2012-02 permits an entity to first assess qualitative factors to determine if it is more likely than not that the fair value of an indefinite-lived intangible asset is more than its carrying amount. If based on its qualitative assessment an entity concludes it is more likely than not that the fair value of an indefinite-lived intangible asset exceeds its carrying amount, quantitative impairment testing is not required. However, if an entity concludes otherwise, quantitative impairment testing is required. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted. The Company is in the process of evaluating the impact of the adoption of ASU 2012-02 on its financial statements.

In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011-11 will require entities to disclose information about offsetting and related arrangements to enable financial statement users to understand the effect of such arrangements on the balance sheet. Entities are required to disclose both gross information and net information about financial instruments and derivative instruments that are either offset in the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. ASU 2011-11 is effective for the first reporting period (including interim periods) beginning after January 1, 2013 and should be applied retrospectively for any period presented. The Company is in the process of evaluating the impact of the adoption of ASU 2011-11 on its financial stat ements.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* (ASU 2011-05), which amends current comprehensive income guidance. This accounting update eliminates the option to present the components of other comprehensive income (loss) as part of the statement of partners capital. Instead, the Company must report comprehensive income in either a single continuous statement of comprehensive income (loss) which contains two sections, net income and other comprehensive income (loss), or in two separate but consecutive statements. In December 2011, the FASB issued ASU No. 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* (ASU 2011-12), which indefinitely defers the requirement in ASU 2011-05 to present reclassification adjustments out of accumulated other comprehensive income (loss) by component in both the statement in which net income is presented and the statement in which other comprehensive income (loss) is presented. During the deferral period, the existing requirements in U.S. GAAP for the presentation of reclassification adjustments must continue to be followed. Amendments to ASU 2011-05, as superseded by ASU 2011-12, are effective for fiscal years (including interim periods) beginning after December 15, 2011 and are to be applied retrospectively, with early adoption permitted. The Company elected to present the components of comprehensive loss in two separate but consecutive financial statements, which is illustrated in the unaudited condensed consolidated statements of operations and the unaudited condensed consolidated statements of comprehensive income (loss).

In May 2011, the FASB issued ASU No. 2011-04, *Amendments to Achieve Common Fair Value Measurements and Disclosure Requirements in U.S. GAAP and IFRS* (ASU 2011-04). ASU 2011-04 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the FASB s intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. ASU 2011-04 is effective for the first reporting period (including interim periods) beginning after December 15, 2011. The adoption of ASU 2011-04 did not have a material impact on the Company s unaudited condensed consolidated financial statements.

3. Acquisitions

Superior Acquisition

On September 30, 2011, the Company completed the acquisition of the Superior, Wisconsin refinery and associated operating assets and inventories and related business of Murphy Oil Corporation (Murphy Oil) for aggregate consideration of approximately $413,173 (Superior Acquisition). The Superior Acquisition was financed by a combination of (i) net proceeds of $193,538 from the Company s September 2011 public offering of common units (including the general partner s contribution and excluding the over-allotment option exercised), (ii) net proceeds of $180,296 from the Company s September 2011 private placement of 9 3/8% senior notes due May 1, 2019 and (iii) borrowings under the Company s revolving credit facility.

The allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows:

	Allocation of Purchase Price
Inventories	$ 183,602
Prepaid expenses and other current assets	5,845
Property, plant and equipment	239,478
Accrued salaries, wages and benefits	(775)
Pension and postretirement benefit obligations	(14,977)
Total purchase price	$ 413,173

Missouri Acquisition

On January 3, 2012, the Company completed the acquisition of the aviation and refrigerant lubricants business (a polyolester based synthetic lubricants business) of Hercules Incorporated, a subsidiary of Ashland, Inc., and a manufacturing facility located in Louisiana, Missouri (Missouri Acquisition) for aggregate consideration of approximately $19,575. The Missouri Acquisition was financed with borrowings under the Company s revolving credit facility and cash on hand. The Company believes the Missouri Acquisition will provide greater diversity to its specialty products segment. The assets acquired have been included in the condensed consolidated balance sheets and results have been included in the unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Missouri Acquisition, during the three and six months ended June 30, 2012, the Company incurred acquisition costs of approximately $25 and $505, respectively, which are reflected in selling, general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $1,478 of goodwill as a result of this acquisition, all of which was recorded within the Company s specialty products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company s strategic platform for expansion in its specialty products segment. The allocation of the aggregate purchase price to assets acquired is as follows:

	Allocation of Purchase Price
Inventories	$ 2,775

Property, plant and equipment		9,955
Goodwill		1,478
Other intangible assets		5,367
Total purchase price	$	19,575

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The component of the intangible asset listed in the table above as of January 3, 2012, based upon a third party appraisal, was as follows:

	Amount	Life
Customer relationships	$ 5,367	20

TruSouth Acquisition

On January 6, 2012, the Company completed the acquisition of all of the outstanding membership interests of TruSouth Oil, LLC, a specialty petroleum packaging and distribution company located in Shreveport, Louisiana (TruSouth Acquisition) for aggregate consideration of approximately $26,827. The TruSouth Acquisition was financed with borrowings under the Company s revolving credit facility. Immediately prior to its acquisition by the Company, TruSouth was owned in part by affiliates of the Company s general partner. The Company believes the TruSouth Acquisition will provide greater diversity to its specialty products segment. The assets acquired and liabilities assumed have been included in the condensed consolidated balance sheets and results have been included in the unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the TruSouth Acquisition, during the three and six months ended June 30, 2012, the Company incurred acquisition costs of $25 and $179, respectively, which are reflected in selling, general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $637 of goodwill as a result of this acquisition, all of which was recorded within the Company s specialty products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company s strategic platform for expansion in its specialty products segment. The allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows:

	Allocation of Purchase Price
Accounts receivable	$ 4,972
Inventories	7,976
Prepaid expenses and other current assets	272
Property, plant and equipment	17,682
Goodwill	637
Other intangible assets	2,545
Accounts payable	(2,672)
Accrued salaries, wages and benefits	(151)
Other current liabilities	(918)
Long-term debt	(3,516)
Total purchase price, net of cash acquired	$ 26,827

The components of intangible assets listed in the table above as of January 6, 2012, based upon a third party appraisal, were as follows:

	Amount	Life
Customer relationships	$ 1,775	15
Tradenames	675	9
Non-competition agreements	95	2
Total	$ 2,545	
Weighted average amortization period		13

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Results of Sales and Earnings

The following financial information reflects the results of sales and operating income of the Superior, Missouri and TruSouth Acquisitions that are included in the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2012:

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Sales	$ 331,336	$ 685,158
Operating income	28,159	48,531

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the unaudited condensed consolidated results of operations of the Company as if the Superior, Missouri and TruSouth Acquisitions had taken place on January 1, 2011.

	Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
Sales	$ 1,162,330	$ 2,060,473
Net income	662	7,229
Limited partners interest net income per unit basic and diluted	$ 0.01	$ 0.14

The Company s historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Superior, Missouri and TruSouth Acquisitions. This unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the pro forma events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

For the three months ended June 30, 2011 the unaudited pro forma financial information reflects adjustments to increase interest expense by $10,243 as a result of the issuance of the 2019 Notes (defined below), amending and restating the revolving credit facility, additional borrowings under the revolving credit facility to fund portions of the Superior, Missouri and TruSouth Acquisitions and the repayment of borrowings under the prior term loan from the net proceeds of the 2019 Notes issued in April 2011. Additionally, the unaudited pro forma financial information reflects adjustments to increase depreciation expense by $216 as a result of the addition of fixed assets related to the Superior Acquisition at their estimated fair value, as well as adjustments to eliminate the income tax expense attributable to the Superior Acquisition of $6,702.

For the six month ended June 30, 2011 the unaudited pro forma financial information reflects adjustments to increase interest expense by $20,490 as a result of the issuance of the 2019 Notes, amending and restating the revolving credit facility, additional borrowings under the revolving credit facility to fund a portion of the Superior, Missouri and TruSouth Acquisitions and the repayment of borrowings under the prior term loan from the net proceeds of the 2019 Notes issued in April 2011. Additionally, the unaudited pro forma financial information reflects adjustments to increase depreciation expense by $431 as a result of the addition of fixed assets related to the Superior Acquisition at their estimated fair value, as well as adjustments to eliminate the income tax expense attributable to the Superior Acquisition of $11,170.

Fair Value Measurements of Acquisitions

The fair value of the property, plant and equipment and intangible assets are based upon the discounted cash flow method that involves inputs that are not observable in the market (Level 3). Goodwill assigned represents the amount of consideration transferred in excess of the fair value assigned to individual assets acquired and liabilities assumed.

4. Inventories

The Company uses the last-in, first-out (LIFO) method of valuing inventory. An actual valuation of inventory under the LIFO method can be made only at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management s estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market value.

Inventories consist of the following:

	June 30 , 2012	December 31, 2011
Raw materials	$ 112,584	$ 105,802
Work in process	95,523	91,763
Finished goods	305,212	300,175
	$ 513,319	$ 497,740

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The replacement cost of these inventories, based on current market values, would have been $27,053 and $87,635 higher as of June 30, 2012 and December 31, 2011, respectively.

5. Commitments and Contingencies

From time to time, the Company is a party to certain claims and litigation incidental to its business, including claims made by various taxation and regulatory authorities, such as the U.S. Environmental Protection Agency (EPA), the Louisiana Department of Environmental Quality (LDEQ), the Wisconsin Department of Natural Resources (WDNR), the Internal Revenue Service, various state and local departments of revenue and the federal Occupational Safety and Health Administration (OSHA), as the result of audits or reviews of the Company s business. In addition, the Company has property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to the Company.

Environmental

The Company operates crude oil and specialty hydrocarbon refining and terminal operations, which are subject to stringent and complex federal, state, regional and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations can impose obligations that are applicable to the Company s operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company may release materials into the environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, requiring the application of specific health and safety criteria addressing worker protection and imposing substantial liabilities for pollution resulting from its operations. Certain of these laws impose joint and several, strict liability for costs required to remediate and restore sites where petroleum hydrocarbons, wastes, or other materials have been released or disposed.

In connection with the Superior Acquisition, the Company became a party to an existing consent decree (Consent Decree) with the EPA and WDNR that applies, in part, to its Superior refinery. Under the Consent Decree, the Company will have to complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the facility to the EPA and WDNR. The Company currently estimates costs of approximately $4,300 to make known equipment upgrades and conduct other discrete tasks in compliance with the Consent Decree. Failure to perform required tasks under the Consent Decree could result in the imposition of stipulated penalties, which could be significant. In addition, the Company may have to pursue certain additional environmental and safety-related projects at the Superior refinery including, but not limited to: (i) installing process equipment pursuant to applicable EPA fuel content regulations; (ii) purchasing emission credits on an interim basis until such time as any process equipment that may be required under the EPA fuel content regulations is installed and operational; (iii) performing monitoring of historical contamination at the facility; (iv) upgrading treatment equipment or possibly pursuing other remedies, as necessary, to satisfy new effluent discharge limits under a federal Clean Water Act permit renewal that is pending and (v) pursuing various voluntary programs at the Superior refinery, including removing asbestos-containing materials or enhancing process safety or other maintenance practices. Completion of these additional projects would result in the Company incurring additional costs, which could be substantial. For the three and six months ended June 30, 2012, the Company incurred approximately $886 and $1,429, respectively, of costs related to installing process equipment pursuant to the EPA fuel content regulations.

On June 29, 2012, the EPA issued a Finding of Violation/Notice of Violation to the Company s Superior refinery. This finding is in response to information provided to the EPA by the Company in response to an information request. The EPA alleges that the efficiency of the flares at the Superior refinery is lower than regulatory requirements. The Company is contesting the allegations and is currently awaiting an informal conference with the EPA. The Company does not believe that the resolution of these allegations will have a material adverse effect on the Company s financial results or operations.

In addition, the Company is indemnified by Murphy Oil for specified environmental liabilities including: (i) certain obligations arising out of the Consent Decree (including payment of a civil penalty required under the Consent Decree), (ii) certain liabilities arising in connection with Murphy Oil s transport of certain wastes and other materials to specified offsite real properties for disposal or recycling prior to the Superior Acquisition and (iii) certain liabilities for certain third party actions, suits or proceedings alleging exposure, prior to the Superior Acquisition, of an individual to wastes or other materials at the specified on-site real property, which wastes or other materials were spilled, released, emitted or discharged by Murphy Oil. The Company is also indemnified by Murphy Oil for two years following the Superior Acquisition for liabilities arising from breaches of certain environmental representations and warranties made by Murphy Oil, subject to a maximum liability of $22,000, for which the Company is required to contribute up to the first $6,600.

On December 23, 2010, the Company entered into a settlement agreement with the LDEQ under LDEQ s Small Refinery and Single Site Refinery Initiative, covering the Shreveport, Princeton and Cotton Valley refineries. This settlement agreement became effective on January 31, 2012. The settlement agreement, termed the Global Settlement, resolved alleged violations of the federal Clean Air Act and federal Clean Water Act regulations prior to December 31, 2010. The Company made a $1,000 payment to

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the LDEQ and agreed to complete beneficial environmental programs and implement emissions reduction projects at the Company s Shreveport, Cotton Valley and Princeton refineries on an agreed-upon schedule. During the three and six months ended June 30, 2012, the Company incurred approximately $1,089 and $2,172, respectively, of expenditures and estimates additional expenditures of approximately $4,000 to $8,000 of capital expenditures and expenditures related to additional personnel and environmental studies over the next four years as a result of the implementation of these requirements. This agreement also fully settles the alleged environmental and permit violations at the Company s Shreveport, Cotton Valley and Princeton refineries and stipulates that no further civil penalties over alleged past violations at those refineries will be pursued by the LDEQ. The required investments are expected to include projects resulting in (i) nitrogen oxide and sulfur dioxide emission reductions from heaters and boilers and the application of New Source Performance Standards for sulfur recovery plants and flaring devices, (ii) control of incidents related to acid gas flaring, tail gas and hydrocarbon flaring, (iii) electrical reliability improvements to reduce flaring, (iv) flare refurbishment at the Shreveport refinery, (v) enhancement of the Benzene Waste National Emissions Standards for Hazardous Air Pollutants programs and the Leak Detection and Repair programs at the Company s Shreveport, Princeton and Cotton Valley refineries and (vi) Title V audits and targeted audits of certain regulatory compliance programs. During negotiations with the LDEQ, the Company voluntarily initiated projects for certain of these requirements prior to completing the Global Settlement with the LDEQ, and currently anticipates completion of these projects over the next four years. These capital investment requirements will be incorporated into the Company s annual capital expenditures budget and the Company does not expect any additional capital expenditures as a result of the required audits or required operational changes included in the Global Settlement to have a material adverse effect on the Company s financial results or operations. The terms of this settlement agreement were deemed final and effective on January 31, 2012 upon the concurrence of the Louisiana Attorney General.

Voluntary remediation of subsurface contamination is in process at each of the Company s refinery sites. The remedial projects are being overseen by the appropriate state agencies. Based on current investigative and remedial activities, the Company believes that the groundwater contamination at these refineries can be controlled or remedied without having a material adverse effect on the Company s financial condition. However, such costs are often unpredictable and, therefore, there can be no assurance that the future costs will not become material. The Company incurred approximately $13 of such capital expenditures at its Cotton Valley refinery during the three and six months ended June 30, 2012. The Company incurred approximately $57 and $261, respectively, of such capital expenditures at its Cotton Valley refinery during the three and six months ended June 30, 2011.

The Company is indemnified by Shell Oil Company, as successor to Pennzoil-Quaker State Company and Atlas Processing Company, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company s acquisition of the facility. The indemnity is unlimited in amount and duration, but requires the Company to contribute up to $1,000 of the first $5,000 of indemnified costs for certain of the specified environmental liabilities.

Occupational Health and Safety

The Company is subject to various laws and regulations relating to occupational health and safety, including OSHA and comparable state laws. These laws and regulations strictly govern the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in the Company s operations and that this information be provided to employees, contractors, state and local government authorities and customers. The Company maintains safety and training programs as part of its ongoing efforts to ensure compliance with applicable laws and regulations. The Company has implemented an internal program of inspection designed to monitor and enforce compliance with worker safety requirements as well as a quality system that meets the requirements of the ISO-9001-2008 Standard. The integrity of the Company s ISO-9001-2008 Standard certification is maintained through surveillance audits by its registrar at regular intervals designed to ensure adherence to the standards. The Company s compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures.

The Company has completed studies to assess the adequacy of its process safety management practices at its Shreveport refinery with respect to certain consensus codes and standards. During the three and six months ended June 30, 2012, the Company incurred approximately $48 and $302, respectively, of capital expenditures and expects to incur between $1,000 and $4,000 of capital expenditures during the remainder of 2012 and in 2013 to address OSHA compliance issues identified in these studies. The Company expects these capital expenditures will enhance its equipment such that the equipment maintains compliance with applicable consensus codes and standards.

In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery s process safety management program under OSHA s National Emphasis Program. On March 14, 2011, OSHA issued a Citation and Notification of Penalty (the Cotton Valley Citation) to the Company as a result of the Cotton Valley inspection, which included a proposed penalty amount of $208. The Company has contested the Cotton Valley Citation and associated penalties and is currently in negotiations with OSHA to reach a settlement allowing an extended abatement period for a new refinery flare system study and for completion of facility site modifications, including relocation and hardening of structures.

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Labor Matters

The Company has employees covered by various collective bargaining agreements. The Superior collective bargaining agreement expired on July 1, 2012 but has been indefinitely extended for a rolling 21 day period. The Missouri collective bargaining agreement was ratified on May 1, 2012 and will expire on April 30, 2014.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued to domestic vendors. As of June 30, 2012 and December 31, 2011, the Company had outstanding standby letters of credit of $175,560 and $230,040, respectively, under its senior secured revolving credit facility (the revolving credit facility). Refer to Note 6 for additional information regarding the revolving credit facility. The maximum amount of letters of credit the Company could issue at June 30, 2012 and December 31, 2011 under its revolving credit facility is subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $680,000, which is the greater of (i) $400,000 and (ii) 80% of revolver commitments ($850,000 at June 30, 2012 and December 31, 2011) in effect.

As of June 30, 2012 and December 31, 2011, the Company had availability to issue letters of credit of $388,459 and $340,715, respectively, under its revolving credit facility. As discussed in Note 7, as of June 30, 2012 and December 31, 2011 the outstanding standby letters of credit issued under the revolving credit facility included a $25,000 letter of credit issued to a hedging counterparty to support a portion of its fuel products hedging program.

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6. Long-Term Debt

Long-term debt consisted of the following:

	June 30, 2012	December 31, 2011
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments monthly, borrowings due June 2016	$	$
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019, effective interest rate of 9.90% for the six months ended June 30, 2012	600,000	600,000
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 9.625% for the six months ended June 30, 2012	275,000	
Capital lease obligations, at various interest rates, interest and principal payments monthly through January 2027	5,905	786
Less unamortized discount on 2019 Notes issued in September 2011 and 2020 Notes	(17,877)	(13,696)
Total long-term debt	863,028	587,090
Less current portion of long-term debt	773	551
	$ 862,255	$ 586,539

9 5/8% Senior Notes

On June 29, 2012, in connection with the Royal Purple Acquisition (defined below), the Company issued and sold $275,000 in aggregate principal amount of 9 5/8% of senior notes due August 1, 2020 (the 2020 Notes) in a private placement pursuant to Rule 144A under the Securities Act of 1933, as amended (the Securities Act), to eligible purchasers at a discounted price of 98.25 percent of par. The 2020 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 Company received net proceeds of $262,704, net of discount, underwriters fees and expenses. The net proceeds (before expenses) of $263,313 from the sale of the 2020 Notes were deposited into an escrow account pending completion of the Royal Purple Acquisition and released from the escrow account at the closing of the Royal Purple Acquisition on July 3, 2012. As of June 30, 2012, net proceeds (before expenses) were included in restricted cash on the consolidated condensed balance sheets. Refer to Note 14 for additional information regarding the Royal Purple Acquisition.

Interest on the 2020 Notes is paid semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2013. The 2020 Notes will mature on August 1, 2020, unless redeemed prior to maturity. The 2020 Notes are jointly and severally guaranteed on a senior unsecured basis by all of the Company s current operating subsidiaries and certain of the Company s future operating subsidiaries, with the exception of Calumet Finance Corp. (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company s indebtedness, including the 2020 Notes). The operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indenture governing the 2020 Notes.

At any time prior to August 1, 2015, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.625% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2020 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 120 days of the date of the closing of such public or private equity offering.

On and after August 1, 2016, the Company may on any one or more occasions redeem all or a part of the 2020 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2020 Notes, if redeemed during the twelve-month period beginning on August 1 of the years indicated below:

Year	**Percentage**
2016	104.813%
2017	102.406%
2018 and at any time thereafter	100.000%

Prior to August 1, 2016, the Company may on any one or more occasions redeem all or part of the 2020 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indenture governing the 2020 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

The indenture governing the 2020 Notes contains covenants that, among other things, restrict the Company s ability and the ability of certain of the Company s subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company s common 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 the Company s restricted subsidiaries to the Company; (vii) consolidate, merge or transfer all or substantially all of the Company s assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2020 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default or Event of Default, each as defined in the indenture governing the 2020 Notes, has occurred and is continuing, many of these covenants will be suspended.

Upon the occurrence of certain change of control events, each holder of the 2020 Notes will have the right to require that the Company repurchase all or a portion of such holder s 2020 Notes in cash at a purchase price equal to 101% of the principal amount thereof, plus any accrued and unpaid interest to the date of repurchase.

On June 29, 2012, in connection with the issuance and sale of the 2020 Notes, the Company entered into a registration rights agreement (the Registration Rights Agreement) with the initial purchasers of the 2020 Notes obligating the Company to use reasonable best efforts to file an exchange registration statement with the SEC, so that holders of the 2020 Notes can offer to exchange the 2020 Notes for registered notes having substantially the same terms as the 2020 Notes and evidencing the same indebtedness as the 2020 Notes. The Company must use reasonable best efforts to cause the exchange offer registration statement to become effective by June 28, 2013 and remain effective until 180 days after the closing of the exchange. Additionally, the Company has agreed to commence the exchange offer promptly after the exchange offer registration statement is declared effective by the SEC and use reasonable best efforts to complete the exchange offer not later than 60 days after such effective date. Under certain circumstances, in lieu of a registered exchange offer, the Company must use reasonable best efforts to file a shelf registration statement for the resale of the 2020 Notes. If the Company fails to satisfy these obligations on a timely basis, the annual interest borne by the 2020 Notes will be increased by up to 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective.

9 3/8% Senior Notes

On April 21, 2011, in connection with the restructuring of the majority of its outstanding long-term debt, the Company issued and sold $400,000 in aggregate principal amount of 9 3/8% of senior notes due May 1, 2019 (the 2019 Notes issued in April 2011) in a private placement pursuant to Rule 144A under the Securities Act to eligible purchasers at par. The 2019 Notes issued in April 2011 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 Company received proceeds of $388,999 net of underwriters fees and expenses, which the Company used to repay in full borrowings outstanding under its prior term loan, as well as all accrued interest and fees, and for general partnership purposes.

On September 19, 2011, in connection with the Superior Acquisition, the Company issued and sold $200,000 in aggregate principal amount of 9 3/8% of senior notes due May 1, 2019 (the 2019 Notes issued in September 2011) in a private placement pursuant to Rule 144A under the Securities Act to eligible purchasers at a discounted price of 93 percent of par. The 2019 Notes issued in September 2011 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 Company received proceeds of $180,296 net of discount, underwriters fees and expenses, which the Company used to fund a portion of the purchase price of the Superior Acquisition. Because the terms of the 2019 Notes issued in September 2011 are substantially identical to the terms of the 2019 Notes issued in April 2011, in this Quarterly Report, the Company collectively refers to the 2019 Notes issued in April 2011 and the 2019 Notes issued in September 2011 as the 2019 Notes.

Interest on the 2019 Notes is paid semiannually in arrears on May 1 and November 1 of each year, beginning on November 1, 2011. The 2019 Notes will mature on May 1, 2019, unless redeemed prior to maturity. The 2019 Notes are jointly and severally guaranteed on a senior unsecured basis by all of the Company s current operating subsidiaries and certain of the Company s future operating subsidiaries, with the exception of Calumet Finance Corp. (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company s indebtedness, including the 2019 Notes). The operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indentures governing the 2019 Notes.

The indentures governing the 2019 Notes contain covenants that, among other things, restrict the Company s ability and the ability of certain of the Company s subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company s common 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 the Company s restricted subsidiaries to the Company; (vii) consolidate, merge or transfer all or substantially all of the Company s assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default or Event of Default, each as defined in the indentures governing the 2019 Notes, has occurred and is continuing, many of these covenants will be suspended.

Amended and Restated Senior Secured Revolving Credit Facility

The Company has an $850,000 senior secured revolving credit facility, which is its primary source of liquidity for cash needs in excess of cash generated from operations. The revolving credit facility matures in June 2016 and currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at the Company s option. As of June 30, 2012, the margin was 125 basis points for prime and 250 basis points for LIBOR; however, the margin can fluctuate quarterly based on the Company s average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter.

In addition to paying interest monthly on outstanding borrowings under the revolving credit facility, the Company is required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to 0.375% to 0.50% per annum depending on the average daily available unused borrowing capacity. The Company also pays a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

The borrowing capacity at June 30, 2012 under the revolving credit facility was $564,019. As of June 30, 2012, the Company had no outstanding borrowings under the revolving credit facility, leaving $388,459 available for additional borrowings based on specified availability limitations. Lenders under the revolving credit facility have a first priority lien on the Company s cash, accounts receivable, inventory and certain other personal property.

The revolving credit facility contains various covenants that limit, among other things, the Company s ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates and enter into a merger, consolidation or sale of assets. Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company s availability under the revolving credit facility falls below the greater of (i) 12.5% of the lesser of (a) the Borrowing Base (as defined in the revolving credit agreement) (without giving effect to the LC Reserve (as defined in the revolving credit agreement)) and (b) the credit agreement commitments then in effect and (ii) $46,364, (as increased, upon the effectiveness of the increase in the maximum availability under the revolving credit facility, by the same percentage as the percentage increase in the revolving credit agreement commitments), then the Company will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0.

Capital Lease Obligations

In connection with the TruSouth Acquisition, the Company acquired $5,771 of capital leases for a building and equipment.

Maturities of Long-term Debt

As of June 30, 2012, maturities of the Company s long-term debt are as follows:

Year	**Maturity**
2012	$ 393
2013	771
2014	423
2015	303
2016	328
Thereafter	878,687
Total	$ 880,905

7. Derivatives

The Company utilizes derivative instruments to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas, the sale of fuel products and interest payments. The Company employs various hedging strategies, which are further discussed below. The Company does not hold or issue derivative instruments for trading purposes.

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The Company recognizes all derivative instruments at their fair values (see Note 8) as either current assets or current liabilities on the condensed consolidated balance sheets. Fair value includes any premiums paid or received and unrealized gains and losses. Fair value does not include any amounts receivable from or payable to counterparties, or collateral provided to counterparties. Derivative asset and liability amounts with the same counterparty are netted against each other for financial reporting purposes. The Company s financial results are subject to the possibility that changes in a derivative s fair value could result in significant ineffectiveness and potentially no longer qualify it for hedge accounting. The Company recorded the following derivative assets and liabilities at their fair values as of June 30, 2012 and December 31, 2011:

	Derivative Assets		Derivative Liabilities	
	June 30, 2012	December 31, 2011	June 30, 2012	December 31, 2011
Derivative instruments designated as hedges:				
Fuel products segment:				
Crude oil swaps	$ (19,019)	$ 83,919	$ (40,557)	$ 56,041
Gasoline swaps	5,152	(20,605)	7,227	(1,596)
Diesel swaps	8,624	(4,561)	(12,156)	(22,586)
Jet fuel swaps	8,167	1,077	1,335	(72,537)
Total derivative instruments designated as hedges	2,924	59,830	(44,151)	(40,678)
Derivative instruments not designated as hedges:				
Fuel products segment:				
Crude oil swaps	(4,901)		(5,082)	
Gasoline swaps	4,464			
Diesel swaps	13,239		5,051	
Jet fuel swaps			(480)	
Specialty products segment:				
Crude oil swaps			584	
Natural gas swaps (1)	(777)	(1,328)	(1,308)	(1,892)
Interest rate swaps: (2)			(145)	(1,011)
Total derivative instruments not designated as hedges	12,025	(1,328)	(1,380)	(2,903)
Total derivative instruments	$ 14,949	$ 58,502	$ (45,531)	$ (43,581)

(1) The Company enters into natural gas swaps to economically hedge its exposures to price risk related to these commodities in its specialty products segment. The Company has not designated these derivative instruments as cash flow hedges.

(2) The Company refinanced a significant majority of its long-term debt in April 2011 and, as a result, all of its interest rate swaps that were designated as cash flow hedges for the interest payments under the previous term loan facility are no longer designated as cash flow hedges.

The Company accounts for certain derivatives hedging purchases of crude oil, sales of gasoline, diesel and jet fuel and the payment of interest as cash flow hedges. The derivatives hedging sales and purchases are recorded to sales and cost of sales, respectively, in the unaudited condensed consolidated statements of operations upon recording the related hedged transaction in sales or cost of sales. The derivatives designated as hedging payments of interest are recorded in interest expense in the unaudited condensed consolidated statements of operations upon payment of interest. The Company assesses, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

To the extent a derivative instrument designated as a hedge is determined to be effective as a cash flow hedge of an exposure to changes in the fair value of a future transaction, the change in fair value of the derivative is deferred in accumulated other comprehensive income (loss), a component of partners capital in the condensed consolidated balance sheets, until the underlying transaction hedged is recognized in the unaudited condensed consolidated statements of operations. Hedge accounting is discontinued when it is determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative instrument no longer qualifies as an effective cash flow hedge, the derivative instrument is subject to the mark-to-market method of accounting prospectively. Changes in the mark-to-market fair value of the derivative instrument are recorded to unrealized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Unrealized gains and losses related to discontinued cash flow hedges that were previously accumulated in accumulated other comprehensive income (loss) will remain in accumulated other comprehensive income (loss) until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, at which time, associated deferred amounts in accumulated other comprehensive income (loss) are immediately recognized in unrealized gain (loss) on derivative instruments.

Effective January 1, 2012, hedge accounting was discontinued prospectively for certain crude oil derivative instruments when it was determined that they were no longer highly effective in offsetting changes in the cash flows associated with crude oil purchases at the Company s Superior refinery due to the volatility in crude oil pricing differentials between heavy crude oil and NYMEX WTI. The discontinuance of hedge accounting on these crude oil derivative instruments has caused the Company to recognize derivative gains of $13,975 and derivative losses of $67,770 in realized gain (loss) on derivative instruments and unrealized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three months ended June 30, 2012. The discontinuance of hedge accounting on these crude oil derivative instruments caused the Company to recognize derivative gains of $41,154 and derivative losses of $38,472 in realized gain (loss) on derivative instruments and unrealized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the six months ended June 30, 2012.

Effective April 1, 2012, hedge accounting was discontinued prospectively for certain gasoline and diesel derivative instruments associated with gasoline and diesel sales at the Company s Superior refinery. The Company voluntarily discontinued hedge accounting on these gasoline and diesel fuel products derivative instruments because the associated crack spread crude oil derivatives no longer qualified for hedge accounting. The discontinuance of hedge accounting on these gasoline and diesel derivative instruments has caused the Company to recognize derivative gains of $13,273 and $80,691 in realized gain (loss) on derivative instruments and unrealized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2012.

The amount reclassified from accumulated other comprehensive income (loss) into earnings, as a result of the discontinuance of hedge accounting for certain jet fuel products derivative instruments because it was no longer probable that the original forecasted transaction would occur by the end of the originally specified time period, has caused the Company to recognize derivative losses of $1,068 and $480 in realized gain (loss) on derivative instruments and unrealized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2012.

For derivative instruments not designated as cash flow hedges and the portion of any cash flow hedge that is determined to be ineffective, the change in fair value of the asset or liability for the period is recorded to unrealized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Upon the settlement of a derivative not designated as a cash flow hedge, the gain or loss at settlement is recorded to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Ineffectiveness is inherent in the hedging of crude oil and fuel products. Due to the volatility in the markets for crude oil and fuel products, the Company is unable to predict the amount of ineffectiveness each period, which has the potential for the future loss of hedge accounting, determined on a derivative by derivative basis or in the aggregate for a specific commodity. Ineffectiveness has resulted, and the loss of hedge accounting has resulted, in increased volatility in the Company s financial results. However, even though certain derivative instruments may not qualify for hedge accounting, the Company intends to continue to utilize such instruments as management believes such derivative instruments continue to provide the Company with the opportunity to more effectively stabilize cash flows.

The Company recorded the following amounts in its condensed consolidated balance sheets, unaudited condensed consolidated statements of operations, unaudited condensed consolidated statements of other comprehensive income (loss) and its unaudited condensed consolidated statements of partners capital as of, and for the three months ended, June 30, 2012 and 2011 related to its derivative instruments that were designated as cash flow hedges:

	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion)			**Amount of (Gain) Loss Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Loss) (Effective Portion)**		**Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion)**		
	Three Months Ended June 30,		**Location of (Gain) Loss**	**Three Months Ended June 30,**		**Location of**	**Three Months Ended June 30,**	
Type of Derivative	**2012**	**2011**		**2012**	**2011**	**Gain (Loss)**	**2012**	**2011**
Fuel products segment:								
Crude oil swaps	$ (131,590)	$ (75,758)	Cost of sales	$ (13,407)	$ (41,998)	Unrealized/ Realized	$ (11,703)	$ (1,716)
Gasoline swaps	18,102	1,374	Sales	22,898	12,576	Unrealized/ Realized	3,421	(878)
Diesel swaps	47,399	27,530	Sales	16,236	25,074	Unrealized/ Realized	759	19

Jet fuel swaps	86,255	31,169	Sales	25,008	29,113	Unrealized/ Realized	6,233	(1,128)
Jet fuel collars			Sales			Unrealized/ Realized		
Specialty products segment:								
Crude oil swaps			Cost of sales	2,494	2,665	Unrealized/ Realized		
Natural gas swaps			Cost of sales			Unrealized/ Realized		
Interest rate swaps:		1,634	Interest expense			Unrealized/ Realized		
Total	$ 20,166	$ (14,051)		$ 53,229	$ 27,430		$ (1,290)	$ (3,703)

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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations and its unaudited condensed consolidated statements of partners capital for the three months ended June 30, 2012 and 2011 related to its derivative instruments not designated as cash flow hedges.

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Three Months Ended June 30, 2012	2011	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Three Months Ended June 30, 2012	2011
Fuel products segment:				
Crude oil swaps	$ (7,780)	$	$ (81,862)	$
Gasoline swaps	11,391		39,817	
Diesel swaps	5,184		40,874	
Jet fuel swaps	(1,068)		(480)	
Jet fuel collars				
Specialty products segment:				
Crude oil swaps			584	
Natural gas swaps	(2,050)		2,607	
Interest rate swaps:	(140)	(553)	151	(1,238)
Total	$ 5,537	$ (553)	$ 1,691	$ (1,238)

The Company recorded the following amounts in its condensed consolidated balance sheets, unaudited condensed consolidated statements of operations, unaudited condensed consolidated statements of other comprehensive income (loss) and its unaudited condensed consolidated statements of partners capital as of, and for the six months ended, June 30, 2012 and 2011 related to its derivative instruments that were designated as cash flow hedges:

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion) Six Months Ended June 30, 2012	2011	Location of (Gain) Loss	Amount of (Gain) Loss Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Loss) (Effective Portion) Six Months Ended June 30, 2012	2011	Location of Gain (Loss)	Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion) Six Months Ended June 30, 2012	2011
Fuel products segment:								
Crude oil swaps	$ (98,900)	$ 61,188	Cost of sales	$ (34,610)	$ (61,099)	Unrealized/ Realized	$ 49,926	$ (497)
Gasoline swaps	(40,165)	(17,736)	Sales	39,204	18,815	Unrealized/ Realized	(15,318)	(1,339)
Diesel swaps	(21,431)	(68,792)	Sales	22,841	43,187	Unrealized/ Realized	(1,840)	(538)
Jet fuel swaps	7,608	(119,414)	Sales	68,610	42,674	Unrealized/ Realized	1,891	(1,604)
Jet fuel collars			Sales			Unrealized/ Realized		
Specialty products segment:								
Crude oil swaps			Cost of sales	(14)	2,665	Unrealized/ Realized		
Natural gas swaps			Cost of sales			Unrealized/ Realized		

Interest rate swaps:		1,979	Interest expense		702	Unrealized/ Realized		
Total	$ (152,888)	$ (142,775)		$ 96,031	$ 46,944		$ 34,659	$ (3,978)

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations and its unaudited condensed consolidated statements of partners capital for the six months ended June 30, 2012 and 2011 related to its derivative instruments not designated as cash flow hedges.

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Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Six Months Ended June 30, 2012	2011	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Six Months Ended June 30, 2012	2011
Fuel products segment:				
Crude oil swaps	$ (7,353)	$	$ (80,165)	$
Gasoline swaps	11,391		39,817	
Diesel swaps	5,184		40,874	
Jet fuel swaps	(1,068)		(480)	
Jet fuel collars		(562)		543
Specialty products segment:				
Crude oil swaps		932	584	(662)
Natural gas swaps	(3,450)		1,135	
Interest rate swaps:	(589)	(752)	867	(1,046)
Total	$ 4,115	$ (382)	$ 2,632	$ (1,165)

The cash flow impact of the Company s derivative activities is classified primarily as a component of net income (loss) in the operating activities section in the unaudited condensed consolidated statements of cash flows.

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company s credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of June 30, 2012 and December 31, 2011, the Company had three counterparties, in which the derivatives held were net assets, totaling $14,949 and $58,502, respectively. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least Baa2 and BBB by Moody s and S&P, respectively. In the event of default, the Company would potentially be subject to losses on derivative instruments with mark to market gains. The Company requires collateral from its counterparties when the fair value of the derivatives exceeds agreed upon thresholds in its master derivative contracts with these counterparties. No such collateral was held by the Company as of June 30, 2012 or December 31, 2011. The Company s contracts with these counterparties allow for netting of derivative instruments executed under each contract. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in deposits, on the Company s condensed consolidated balance sheets and not netted against derivative assets or liabilities. As of June 30, 2012 and December 31, 2011, the Company had provided its counterparties with no collateral above a $25,000 letter of credit provided to one counterparty to support crack spread hedging. For financial reporting purposes, the Company does not offset the collateral provided to a counterparty against the fair value of its obligation to that counterparty. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability.

Certain of the Company s outstanding derivative instruments are subject to credit support agreements with the applicable counterparties which contain provisions setting certain credit thresholds above which the Company may be required to post agreed-upon collateral, such as cash or letters of credit, with the counterparty to the extent that the Company s mark-to-market net liability, if any, on all outstanding derivatives exceeds the credit threshold amount per such credit support agreement. In certain cases, the Company s credit threshold is dependent upon the Company s maintenance of certain corporate credit ratings with Moody s and S&P. In the event that the Company s corporate credit rating was lowered below its current level by either Moody s or S&P, such counterparties would have the right to reduce the applicable threshold to zero and demand full collateralization of the Company s net liability position on outstanding derivative instruments. As of June 30, 2012 and December 31, 2011, there was a net asset of $1,941 and $3,561, respectively, associated with the Company s outstanding derivative instruments subject to such requirements. In addition, the majority of the credit support agreements covering the Company s outstanding derivative instruments also contain a general provision stating that if the Company experiences a material adverse change in its business, in the reasonable discretion of the counterparty, the Company s credit threshold could be lowered by such counterparty. The Company does not expect that it will experience a material adverse change in its business.

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The effective portion of the cash flow hedges classified in accumulated other comprehensive loss is $9,763 as of June 30, 2012. The effective portion of the cash flow hedges classified in accumulated other comprehensive income was $47,094 as of December 31, 2011. Absent a change in the fair market value of the underlying transactions, the following other comprehensive income (loss) at June 30, 2012 will be reclassified to earnings by December 31, 2014 with balances being recognized as follows:

Year	Accumulated Other Comprehensive Income (Loss)
2012	$ (26,239)
2013	15,723
2014	753
Total	$ (9,763)

Based on fair values as of June 30, 2012, the Company expects to reclassify $16,253 of net losses on derivative instruments from accumulated other comprehensive loss to earnings during the next twelve months due to actual crude oil purchases and gasoline, diesel and jet fuel sales. However, the amounts actually realized will be dependent on the fair values as of the dates of settlement.

Crude Oil Swap and Collar Contracts Specialty Products Segment

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. Historically, the Company has utilized combinations of options and swaps to manage crude oil price risk and volatility of cash flows in its specialty products segment. These derivatives may be designated as cash flow hedges of the future purchase of crude oil if they meet the hedge criteria. The company s general policy is to enter into crude oil derivative contracts that mitigate the Company s exposure to price risk associated with crude oil purchases related to specialty products production (for up to 70% of expected purchases). The Company may execute derivative contracts for up to two years forward. As of June 30, 2012, the Company had the following crude oil derivatives related to future crude oil purchases in its specialty products segment, none of which are designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Calendar Year 2013	200,000	548	$ 84.75
Totals	200,000		
Average price			$ 84.75

As of December 31, 2011, the Company did not have any crude oil derivatives related to future crude oil purchases in its specialty products segment.

Natural Gas Swap Contracts

Natural gas purchases comprise a significant component of the Company s cost of sales; therefore, changes in the price of natural gas also significantly affect its profitability and cash flows. The Company utilizes swap contracts to manage natural gas price risk and volatility of cash flows. The Company s policy is generally to enter into natural gas derivative contracts to hedge no more than 75% of its anticipated natural gas requirement for a period no greater than three years forward. At June 30, 2012, the Company had the following natural gas derivatives related to natural gas purchases in its specialty products segment, none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu

Third Quarter 2012	1,200,000	$ 4.03
Fourth Quarter 2012	600,000	4.08
Totals	1,800,000	
Average price		$ 4.05

At December 31, 2011, the Company had the following natural gas derivatives related to natural gas purchases in its specialty products segment, none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2012	1,200,000	$ 3.90
Second Quarter 2012	1,200,000	3.93
Third Quarter 2012	1,200,000	4.03
Fourth Quarter 2012	600,000	4.08
Totals	4,200,000	
Average price		$ 3.97

Crude Oil Contracts Fuel Products Segment

Crude Oil Swap Contracts

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. The Company utilizes swap contracts to manage crude oil price risk and volatility of cash flows in its fuel products segment. The Company s policy is generally to enter into crude oil swap contracts for a period no greater than five years forward and for no more than 75% of crude oil purchases used in fuels production. At June 30, 2012, the Company had the following derivatives related to crude oil purchases in its fuel products segment, all of which are designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Third Quarter 2012	1,472,000	16,000	$ 86.23
Fourth Quarter 2012	1,242,000	13,500	90.50
Calendar Year 2013	5,328,000	14,597	99.03
Calendar Year 2014	1,910,000	5,233	88.25
Totals	9,952,000		
Average price			$ 94.00

At June 30, 2012, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Third Quarter 2012	1,380,000	15,000	$ 83.35
Fourth Quarter 2012	1,380,000	15,000	83.35
Calendar Year 2013	1,821,000	4,989	98.72
Totals	4,581,000		
Average price			$ 89.46

At December 31, 2011, the Company had the following derivatives related to crude oil purchases in its fuel products segment, all of which are designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)

First Quarter 2012	2,866,500	31,500	$ 85.34
Second Quarter 2012	2,775,500	30,500	84.83
Third Quarter 2012	2,852,000	31,000	84.83
Fourth Quarter 2012	2,622,000	28,500	86.73
Calendar Year 2013	4,420,000	12,110	97.93
Calendar Year 2014	1,000,000	2,740	90.55
Totals	16,536,000		
Average price			$ 89.07

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Crude Oil Basis Swap Contracts

In April, 2012 the Company entered into a crude oil basis swaps to mitigate the risk of future changes in pricing differentials between Canadian heavy crude oil and NYMEX WTI crude oil. At June 30, 2012, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as cash flow hedges.

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Calendar Year 2013	730,000	2,000	$ (23.75)
Totals	730,000		
Average price			$ (23.75)

At December 31, 2011, the Company had no derivatives related to crude oil basis swaps in its fuel products segment.

Fuel Products Swap Contracts

The Company is exposed to fluctuations in the prices of gasoline, diesel and jet fuel. The Company utilizes swap contracts to manage diesel, gasoline and jet fuel price risk and volatility of cash flows in its fuel products segment. The Company s policy is generally to enter into diesel, jet fuel and gasoline swap contracts for a period no longer than five years forward and for no more than 75% of forecasted fuel sales.

Diesel Swap Contracts

At June 30, 2012, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2012	690,000	7,500	$ 98.96
Fourth Quarter 2012	506,000	5,500	105.41
Calendar Year 2013	1,926,000	5,277	121.78
Calendar Year 2014	910,000	2,493	111.15
Totals	4,032,000		
Average price			$ 113.42

At June 30, 2012, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, none of which are designated as cash flow hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2012	460,000	5,000	$ 115.27
Fourth Quarter 2012	460,000	5,000	115.27
Calendar Year 2013	1,456,000	3,989	127.20

Totals	2,376,000	
Average price		$ 122.58

At December 31, 2011, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

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Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2012	546,000	6,000	$ 118.07
Second Quarter 2012	819,000	9,000	110.09
Third Quarter 2012	1,150,000	12,500	105.48
Fourth Quarter 2012	966,000	10,500	110.11
Calendar Year 2013	1,831,000	5,016	123.20
Totals	5,312,000		
Average price			$ 114.44

Jet Fuel Swap Contracts

At June 30, 2012, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2012	754,000	8,196	$ 99.80
Fourth Quarter 2012	736,000	8,000	104.79
Calendar Year 2013	2,498,000	6,844	127.09
Calendar Year 2014	1,000,000	2,740	115.56
Totals	4,988,000		
Average price			$ 117.37

At June 30, 2012, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, none of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2012	28,000	304	$ 99.12
Totals	28,000		
Average price			$ 99.12

At December 31, 2011, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2012	1,274,000	14,000	$ 97.97
Second Quarter 2012	1,046,500	11,500	98.47
Third Quarter 2012	782,000	8,500	99.78
Fourth Quarter 2012	736,000	8,000	104.79

Calendar Year 2013	2,044,000	5,600	125.13
Calendar Year 2014	1,000,000	2,740	115.56
Totals	6,882,500		
Average price			$ 109.60

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Gasoline Swap Contracts

At June 30, 2012, the Company had the following derivatives related to gasoline sales in its fuel products segment, all of which are designated as cash flow hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Calendar Year 2013	904,000	2,477	$ 114.75
Totals	904,000		
Average price			$ 114.75

At June 30, 2012, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as cash flow hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2012	920,000	10,000	$ 102.48
Fourth Quarter 2012	920,000	10,000	102.48
Calendar Year 2013	365,000	1,000	105.50
Totals	2,205,000		
Average price			$ 102.98

At December 31, 2011, the Company had the following derivatives related to gasoline sales in its fuel products segment, all of which are designated as cash flow hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2012	1,046,500	11,500	$ 100.72
Second Quarter 2012	910,000	10,000	102.48
Third Quarter 2012	920,000	10,000	102.48
Fourth Quarter 2012	920,000	10,000	102.48
Calendar Year 2013	545,000	1,4293	107.11
Totals	4,341,500		
Average price			$ 102.63

Interest Rate Swap Contracts

The Company s profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates. The primary purpose of the Company s interest rate risk management activities is to hedge its exposure to changes in interest rates. Historically, the Company s policy has been to enter into interest rate swap agreements to hedge up to 75% of its interest rate risk related to variable rate debt. With the issuances of the 2019 Notes and 2020 Notes, which constitute fixed rate debt, the Company does not expect to enter into additional hedges (beyond those listed below) to fix its interest rates. The following table summarizes the Company s outstanding interest rate swaps as of June 30, 2012:

Interest Rate Swap Contract	Effective Date	Maturity Date	Notional Amount	Swap Contract	Weighted Average Fixed Rate
2006 Swap (1)	June 9, 2006	December 10, 2012	$ 19,975	3 Month LIBOR	5.44%
2006 Swap (1)	December 10, 2007	December 10, 2012	$ 19,975	3 Month LIBOR plus 1.98% spread	5.44%

(1) Due to the repayment of $19,000 of the outstanding balance of the Company s then existing term loan facility in August 2007 and subsequent refinancing of the remaining term loan balance, this interest rate swap contract was not designated as a cash flow hedge of the future payment of interest. The entire change in the fair value of this interest rate swap was recorded to unrealized loss on derivative instruments in the consolidated statements of operations. In the first quarter of 2008, the Company fixed its unrealized loss on this interest rate swap derivative instrument by entering into an offsetting interest rate swap expiring December 2012, which is not designated as a cash flow hedge. The notional amount is based upon a fixed schedule set forth in the confirmation, and the amount disclosed is the notional amount as of June 30, 2012.

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8. Fair Value Measurements

The Company uses a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. Observable inputs are from sources independent of the Company. Unobservable inputs reflect the Company s assumptions about the factors market participants would use in valuing the asset or liability developed based upon the best information available in the circumstances. These tiers include the following:

Level 1 inputs include observable unadjusted quoted prices in active markets for identical assets or liabilities

Level 2 inputs include other than quoted prices in active markets that are either directly or indirectly observable

Level 3 inputs include unobservable inputs in which little or no market data exists; therefore requiring an entity to develop its own assumptions

In determining fair value, the Company uses various valuation techniques and prioritizes the use of observable inputs. The availability of observable inputs varies from instrument to instrument and depends on a variety of factors including the type of instrument, whether the instrument is actively traded and other characteristics particular to the instrument. For many financial instruments, pricing inputs are readily observable in the market, the valuation methodology used is widely accepted by market participants and the valuation does not require significant management judgment. For other financial instruments, pricing inputs are less observable in the marketplace and may require management judgment.

Recurring Fair Value Measurements

Derivative Assets and Liabilities

Derivative instruments are reported in the accompanying unaudited condensed consolidated financial statements at fair value. The Company s derivative instruments consist of over-the-counter (OTC) contracts, which are not traded on a public exchange. Substantially all of the Company s derivative instruments are with counterparties that have long-term credit ratings of at least Baa2 and BBB by Moody s and S&P, respectively.

To estimate the fair values of the Company s derivative instruments, the Company uses the market approach. Under this approach, the fair values of the Company s derivative instruments for crude oil, gasoline, diesel, jet fuel, natural gas and interest rates are determined primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Generally, the Company obtains this data through surveying its counterparties and performing various analytical tests to validate the data. In situations where the Company obtains inputs via quotes from its counterparties, it verifies the reasonableness of these quotes via similar quotes from another counterparty as of each date for which financial statements are prepared. The Company also includes an adjustment for non-performance risk in the recognized measure of fair value of all of the Company s derivative instruments. The adjustment reflects the full credit default spread (CDS) applied to a net exposure by counterparty. When the Company is in a net asset position, it uses its counterparty s CDS, or a peer group s estimated CDS when a CDS for the counterparty is not available. The Company uses its own peer group s estimated CDS when it is in a net liability position. As a result of applying the applicable CDS at June 30, 2012, the Company s asset was reduced by $183 and the liability was reduced by approximately $1,301. As a result of applying the CDS at December 31, 2011, the Company s asset was reduced by $1,297 and the liability was reduced by approximately $165.

Based on the use of various unobservable inputs, principally non-performance risk and unobservable inputs in forward years for crude oil, gasoline, jet fuel, diesel and natural gas, the Company has categorized these derivative instruments as Level 3. Significant increases (decreases) in any of those unobservable inputs in isolation would result in a significantly lower (higher) fair value measurement. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative instruments it holds. See Note 7 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value using quoted market prices in the accompanying unaudited condensed consolidated financial statements. The Company s investments associated with its Pension Plan (as such term is hereinafter defined) primarily consist of (i) cash and cash equivalents, (ii) mutual funds that are publicly traded and (iii) a commingled fund. The mutual funds are publicly traded and market prices are readily available; thus, these investments are categorized as Level 1. The commingled fund is categorized as Level 2 because inputs used in its valuation are not quoted prices in active markets that are indirectly observable and is valued at the net asset value of shares held by the Pension Plan at quarter end.

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Hierarchy of Recurring Fair Value Measurements

The Company s recurring assets and liabilities measured at fair value at June 30, 2012 and December 31, 2011 were as follows:

	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Cash and cash equivalents	$ 65,474	$	$	$ 65,474	$ 64	$	$	$ 64
Derivative assets:								
Crude oil swaps			(23,920)	(23,920)			83,919	83,919
Gasoline swaps			9,616	9,616			(20,605)	(20,605)
Diesel swaps			21,863	21,863			(4,561)	(4,561)
Jet fuel swaps			8,167	8,167			1,077	1,077
Natural gas swaps			(777)	(777)			(1,328)	(1,328)
Total derivative assets			14,949	14,949			58,502	58,502
Restricted cash	263,313			263,313				
Pension plan investments	34,616	2,593		37,209	33,580	2,462		36,042
Total recurring assets at fair value	$ 363,403	$ 2,593	$ 14,949	$ 380,945	$ 33,644	$ 2,462	$ 58,502	$ 94,608
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$	$	$ (45,055)	(45,055)	$	$	$ 56,041	$ 56,041
Gasoline swaps			7,227	7,227			(1,596)	(1,596)
Diesel swaps			(7,105)	(7,105)			(22,586)	(22,586)
Jet fuel swaps			855	855			(72,537)	(72,537)
Natural gas swaps			(1,308)	(1,308)			(1,892)	(1,892)
Interest rate swaps			(145)	(145)			(1,011)	(1,011)
Total derivative liabilities			(45,531)	(45,531)			(43,581)	(43,581)
Total recurring liabilities at fair value	$	$	$ (45,531)	$ (45,531)	$	$	$ (43,581)	$ (43,581)

The table below sets forth a summary of net changes in fair value of the Company s Level 3 financial assets and liabilities for the six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,	
	2012	2011
Fair value at January 1,	$ 14,921	$ (32,814)
Realized (gain) loss on derivative instruments	(30,642)	1,984
Unrealized gain (loss) on derivative instruments	10,764	(3,541)
Change in fair value of cash flow hedges	(152,888)	(142,775)
Settlements	127,263	39,261
Transfers in (out) of Level 3		
Fair value at June 30,	$ (30,582)	$ (137,885)
Total gain (loss) included in net income attributable to changes in unrealized gain (loss) relating to financial assets and liabilities held as of	$ 10,764	$ (3,541)

June 30,

All settlements from derivative instruments that are deemed effective and were designated as cash flow hedges are included in sales for gasoline, diesel and jet fuel derivatives, cost of sales for crude oil and natural gas derivatives, and interest expense for interest rate derivatives in the unaudited condensed consolidated financial statements of operations in the period that the hedged cash flow occurs. Any ineffectiveness associated with these derivative instruments are recorded in earnings in realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. All settlements from derivative instruments not designated as cash flow hedges are recorded in realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. See Note 7 for further information on derivative instruments.

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Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of impairment. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. Refer to Note 3 for the fair values of assets acquired and liabilities assumed in connection with the Missouri and TruSouth Acquisitions.

The Company reviews for goodwill impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable. The fair value of the reporting units is determined using the income approach. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation and risks associated with the reporting unit. These assets would generally be classified within Level 3, in the event that the Company were required to measure and record such assets at fair value within its unaudited condensed consolidated financial statements.

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including definite-lived intangible assets and property plant and equipment, when events or circumstances warrant such a review. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved and these assets would generally be classified within Level 3, in the event that the Company were required to measure and record such assets at fair value within its unaudited condensed consolidated financial statements.

Estimated Fair Value of Financial Instruments

Cash

The carrying values of cash and cash equivalents, including restricted cash, are considered to be representative of their respective fair values, due to the short maturity of these instruments.

Debt

The estimated fair value of long-term debt at June 30, 2012 consists primarily of the 2019 Notes and 2020 Notes. The estimated fair value of long-term debt at December 31, 2011 consists primarily of the 2019 Notes and borrowings under the revolving credit facility. The fair value of the Company s 2019 Notes and 2020 Notes were based upon using quoted market prices in an active market and are classified as Level 1. The carrying value of borrowings, if any, under the Company s revolving credit facility approximates its fair value as determined by discounted cash flows and is classified as Level 3. Capital lease obligations approximate their fair value as determined by discounted cash flows and are classified as Level 3.

The Company s carrying and estimated fair value of the Company s financial instruments, carried at adjusted historical cost, at June 30, 2012 and December 31, 2011 were as follows:

	June 30, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:				
2019 Notes	$ 608,996	$ 586,936	$ 591,750	$ 586,304
2020 Notes	279,813	270,187		
Capital lease and other obligations	5,905	5,905	786	786

9. Partners Capital

On May 8, 2012, the Company completed a public offering of its common units in which it sold 6,000,000 common units to the underwriters of the offering at a price to the public of $25.50 per common unit. The proceeds received by the Company from this offering (net of underwriting discounts, commissions and expenses but before its general partner s capital contribution) were $146,597 and were used to repay borrowings under its revolving credit facility. Underwriting discounts totaled $6,180. The Company s general partner contributed $3,122 to maintain its 2% general partner interest.

The Company s distribution policy is defined in its partnership agreement. For the three months ended June 30, 2012 and 2011, the Company made distributions of $30,119 and $19,311, respectively, to its partners. For the six months ended June 30, 2012 and 2011, the Company made distributions of $58,318 and $36,258, respectively, to its partners.

For the three months ended June 30, 2012 and 2011 the general partner was allocated $1,096 and $0, respectively, in incentive distribution rights. For the six months ended June 30, 2012 and 2011 the general partner was allocated $1,619 and $0, respectively, in incentive distribution rights.

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10. Unit-Based Compensation

A summary of the Company s nonvested phantom units as of June 30, 2012 and the changes during the six months ended June 30, 2012 is presented below:

Nonvested Phantom Units	Grant	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2011	325,096	$ 20.82
Granted	100,661	23.78
Vested	(86,236)	22.49
Forfeited	(14,909)	21.78
Nonvested at June 30, 2012	324,612	$ 21.25

For the three months ended June 30, 2012 and 2011, compensation expense of $720 and $653, respectively, was recognized in the unaudited condensed consolidated statements of operations related to vested phantom unit grants. For the six months ended June 30, 2012 and 2011, compensation expense of $864 and $1,282, respectively, was recognized in the unaudited condensed consolidated statements of operations related to vested phantom unit grants. As of June 30, 2012 and 2011, there was a total of $6,897 and $1,929, respectively, of unrecognized compensation costs related to nonvested phantom unit grants. These costs are expected to be recognized over a weighted-average period of approximately three years.

11. Employee Benefit Plans

The components of net periodic pension and other post retirement benefits cost (credit) for the three months ended June 30, 2012 and 2011 were as follows:

	For the Three Months Ended June 30, 2012		2011	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	$ 225	$ 131	$ 25	$
Interest cost	621	89	333	4
Expected return on assets	(597)		(265)	
Amortization of net (gain) loss	143	(1)	70	
Prior service credit		(9)		(9)
Net periodic benefit cost (credit)	$ 392	$ 210	$ 163	$ (5)

The components of net periodic pension and other post retirement benefits cost (credit) for the six months ended June 30, 2012 and 2011 were as follows:

	For the Six Months Ended June 30, 2012		2011	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits

Service cost	$ 450	$ 262	$ 49	$
Interest cost	1,243	178	666	9
Expected return on assets	(1,195)		(529)	
Amortization of net (gain) loss	287	(2)	140	(1)
Prior service credit		(18)		(18)
Net periodic benefit cost (credit)	$ 785	$ 420	$ 326	$ (10)

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At June 30, 2012, the Company s investments associated with its non-contributory defined benefit plans (the Pension Plan) primarily consist of (i) cash and cash equivalents, (ii) mutual funds that are publicly traded and (iii) a commingled fund. The mutual funds are publicly traded and market prices of the mutual funds are readily available; thus, these investments are categorized as Level 1. The commingled fund is categorized as Level 2 because inputs used in its valuation are not quoted prices in active markets that are indirectly observable and is valued at the net asset value of the shares held by the Pension Plan at quarter end. The Company s Pension Plan assets measured at fair value at June 30, 2012 and December 31, 2011 were as follows:

	June 30, 2012 Pension Assets		December 31, 2011 Pension Assets	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$ 22,490	$	$ 22,243	$
Equity	4,375		4,000	
Foreign equities	717		691	
Commingled fund		2,593		2,462
Fixed income	7,034		6,646	
	$ 34,616	$ 2,593	$ 33,580	$ 2,462

12. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands, except unit data)			
Numerator for basic and diluted earnings per limited partner unit:				
Net income (loss)	$ 65,662	$ (7,651)	$ 117,585	$ (3,450)
General partner s interest in net income (loss)	1,314	(153)	2,352	(69)
General partner s incentive distribution rights	1,096		1,619	
Nonvested share based payments	377		685	
Net income (loss) available to limited partners	$ 62,875	$ (7,498)	$ 112,929	$ (3,381)
Denominator:				
Basic weighted average limited partner units outstanding	55,028	39,886	53,354	38,373
Effect of dilutive securities:				
Participating securities phantom units	46		26	
Diluted weighted average limited partner units outstanding	55,074	39,886	53,380	38,373
Limited partners interest basic net income (loss) per unit	$ 1.14	$ (0.19)	$ 2.12	$ (0.09)
Limited partners interest diluted net income (loss) per unit	$ 1.14	$ (0.19)	$ 2.12	$ (0.09)

13. Segments and Related Information

a. Segment Reporting

The Company has two reportable segments: Specialty Products and Fuel Products. The Specialty Products segment produces a variety of lubricating oils, solvents, waxes and asphalt and other by-products. These products are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. The Fuel Products segment produces a variety of fuel and fuel-related products including gasoline, diesel, jet fuel and heavy fuel oils. The results of the operations from such assets acquired as a result of the Superior Acquisition have been included in the both segments since the date of acquisition, September 30, 2011. The results of operations from such assets acquired as a result of the Missouri and TruSouth Acquisitions have been included in the specialty products segment since their dates of acquisition, January 3, 2012 and January 6, 2012, respectively.

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The accounting policies of the segments are the same as those described in the summary of significant accounting policies as disclosed in Note 2 Summary of Significant Accounting Policies in Part II Item 8 Financial Statements and Supplementary Data of the Company s 2011 Annual Report except that the Company evaluates segment performance based on operating income (loss). The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. Reportable segment information is as follows:

Three Months Ended June 30, 2012	**Specialty Products**	**Fuel Products**	**Combined Segments**	**Eliminations**	**Consolidated Total**
Sales:					
External customers	$ 572,409	$ 514,587	$ 1,086,996	$	$ 1,086,996
Intersegment sales	287,374	13,051	300,425	(300,425)	
Total sales	$ 859,783	$ 527,638	$ 1,387,421	$ (300,425)	$ 1,086,996
Depreciation and amortization	18,656	4,645	23,301		23,301
Operating income	49,949	28,510	78,459		78,459
Reconciling items to net income:					
Interest expense					(18,392)
Gain on derivative instruments					5,938
Other					(4)
Income tax expense					(339)
Net income					$ 65,662
Capital expenditures	$ 10,718	$ 2,003	$ 12,721	$	$ 12,721

Three Months Ended June 30, 2011	**Specialty Products**	**Fuel Products**	**Combined Segments**	**Eliminations**	**Consolidated Total**
Sales:					
External customers	$ 466,414	$ 267,356	$ 733,770	$	$ 733,770
Intersegment sales	291,351	15,272	306,623	(306,623)	
Total sales	$ 757,765	$ 282,628	$ 1,040,393	$ (306,623)	$ 733,770
Depreciation and amortization	17,065		17,065		17,065
Operating income (loss)	35,485	(12,074)	23,411		23,411
Reconciling items to net loss:					
Interest expense					(10,544)
Debt extinguishment costs					(15,130)
Loss on derivative instruments					(5,494)
Other					274
Income tax expense					(168)
Net loss					$ (7,651)
Capital expenditures	$ 14,069	$	$ 14,069	$	$ 14,069

Six Months Ended June 30, 2012	**Specialty Products**	**Fuel Products**	**Combined Segments**	**Eliminations**	**Consolidated Total**
Sales:					
External customers	$ 1,134,904	$ 1,121,678	$ 2,256,582	$	$ 2,256,582
Intersegment sales	597,071	22,238	619,309	(619,309)	

Total sales	$ 1,731,975	$ 1,143,916	$ 2,875,891	$ (619,309)	$ 2,256,582
Depreciation and amortization	37,350	9,097	46,447		46,447
Operating income	78,643	34,830	113,473		113,473
Reconciling items to net income:					
Interest expense					(36,976)
Gain on derivative instruments					41,406
Other					114
Income tax expense					(432)
Net income					$ 117,585
Capital expenditures	$ 18,260	$ 4,196	$ 22,456	$	$ 22,456

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Six Months Ended June 30, 2011	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$ 863,516	$ 475,494	$ 1,339,010	$	$ 1,339,010
Intersegment sales	507,428	18,907	526,335	(526,335)	
Total sales	$ 1,370,944	$ 494,401	$ 1,865,345	$ (526,335)	$ 1,339,010
Depreciation and amortization	34,710		34,710		34,710
Operating income (loss)	51,955	(16,390)	35,565		35,565
Reconciling items to net loss:					
Interest expense					(18,025)
Debt extinguishment costs					(15,130)
Loss on derivative instruments					(5,525)
Other					103
Income tax expense					(438)
Net loss					$ (3,450)
Capital expenditures	$ 20,635	$	$ 20,635	$	$ 20,635

	June 30, 2012	December 31, 2011
Segment assets:		
Specialty products	$ 1,582,410	$ 1,159,040
Fuel products	528,748	573,018
Total assets	$ 2,111,158	$ 1,732,058

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and six months ended June 30, 2012 and 2011. All of the Company s long-lived assets are domestically located.

c. Product Information

The Company offers specialty products primarily in five general categories consisting of lubricating oils, solvents, waxes, fuels and asphalt and other by-products. Fuel products primarily consist of gasoline, diesel, jet fuel and heavy fuel oils and other. The following table sets forth the major product category sales:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Specialty products:				
Lubricating oils	$ 297,984	$ 246,448	$ 610,732	$ 455,499
Solvents	122,783	135,642	257,579	253,978
Waxes	34,792	33,874	71,942	68,181
Fuels	2,482	592	5,482	1,423
Asphalt and other by-products	114,368	49,858	189,169	84,435
Total	$ 572,409	$ 466,414	$ 1,134,904	$ 863,516
Fuel products:				
Gasoline	244,936	127,452	538,328	223,233

Diesel	199,320	91,611	440,034	173,764
Jet fuel	42,292	40,686	88,197	67,460
Heavy fuel oils and other	28,039	7,607	55,119	11,037
Total	$ 514,587	$ 267,356	$ 1,121,678	$ 475,494
Consolidated sales	$ 1,086,996	$ 733,770	$ 2,256,582	$ 1,339,010

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d. Major Customers

During the three and six months ended June 30, 2012 and 2011, the Company had no customer that represented 10% or greater of consolidated sales.

14. Subsequent Events

On July 3, 2012, the Company completed the acquisition of all the membership interests of Royal Purple, LLC (Royal Purple) for aggregate consideration of approximately $332,679, excluding certain purchase price adjustments (Royal Purple Acquisition). Royal Purple is a formulator and marketer of premium industrial and consumer lubricants across several large markets including oil and gas, chemicals and refining, power generation, manufacturing and transportation, food and drug manufacturing and automotive aftermarket. The Royal Purple Acquisition was financed with the net proceeds, net of discount, underwriters fees and expenses, of $262,704 from the Company s 2020 Notes offering and cash on hand.

The Royal Purple Acquisition purchase price allocation has not yet been finalized due to the timing of the closing of the acquisition. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained.

On July 20, 2012, the Company declared a quarterly cash distribution of $0.59 per unit on all outstanding units, or approximately $35,890 in aggregate, for the quarter ended June 30, 2012. The distribution will be paid on August 14, 2012 to unitholders of record as of the close of business on August 3, 2012. This quarterly distribution of $0.59 per unit equates to $2.36 per unit, or approximately $143,560 in aggregate on an annualized basis.

The fair value of the Company s derivatives decreased by approximately $36,000 subsequent to June 30, 2012 to a net liability of approximately $67,000. The fair value of the Company s long-term debt, excluding capital leases, has increased by approximately $16,000 subsequent to June 30, 2012.

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

The historical consolidated financial statements included in this Quarterly Report reflect all of the assets, liabilities and results of operations of Calumet Specialty Products Partners, L.P. (Calumet, the Company, we, our, us). The following discussion analyzes the financial condition and results of operations of the Company for the three and six months ended June 30, 2012 and 2011. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Calumet in conjunction with our 2011 Annual Report and the historical unaudited condensed consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana and own plants primarily located in Louisiana, Wisconsin and Pennsylvania. We own and lease additional facilities, primarily related to production and distribution of specialty products throughout the U.S. Our business is organized into two segments: specialty products and fuel products. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums, asphalt and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel and heavy fuel oils. In connection with our production of specialty products and fuel products, we also produce asphalt and a limited number of other by-products.

Second Quarter 2012 Update

For the three months ended June 30, 2012 and 2011, 42.1% and 51.5%, respectively, of our sales volume and 68.8% and 115.3%, respectively, of our gross profit was generated from our specialty products segment while, for the same periods, 57.9% and 48.5%, respectively, of our sales volume and 31.2% and (15.3)%, respectively, of our gross profit was generated from our fuel products segment.

We continued to see strength in product demand in our specialty products segment in the second quarter of 2012. We noted a 24.7% increase in barrels of specialty products sold for the quarter ended June 30, 2012 compared to the same period in 2011, including the impact of incremental sales in the second quarter of 2012 from the Superior Acquisition, which closed on September 30, 2011. Excluding incremental sales volume associated with the Superior, TruSouth and Missouri Acquisitions, our specialty products sales volume decreased 1.9% primarily due to the April 28, 2012 shutdown by ExxonMobil of a crude oil pipeline serving the Shreveport refinery for a portion of its crude oil requirements. Our specialty products segment generated a gross profit margin of 15.5% for the three months ended June 30, 2012, as compared to a gross profit margin of 12.5% in the same period of 2011, as specialty products sales pricing remained fairly constant throughout the second quarter of 2012 while crude oil prices decreased significantly during the quarter.

Higher sales and production volume in our fuel products segment during the second quarter of 2012 allowed us to take advantage of higher market crack spreads. We noted an 82.9% increase in barrels of fuel products sold in the second quarter of 2012 compared to the same period in 2011, driven primarily by incremental fuel products sales from the Superior refinery partially offset by lower production at our Shreveport refinery due to the April 28, 2012 shutdown by ExxonMobil of a crude oil pipeline serving the refinery for a portion of its crude oil requirements. Historically, the barrels of crude oil received from this pipeline have been among the most expensive barrels run by our Shreveport refinery. As a result of the ExxonMobil pipeline shutdown, our Shreveport refinery run rates decreased by an average of approximately 4,500 bpd for the second quarter of 2012 compared to the first quarter of 2012. We expect these decreased run rates will remain in effect until the ExxonMobil pipeline service is restored or our ability to receive crude oil by rail, from other suppliers, at our Shreveport refinery is expanded, which is anticipated to be completed in the fourth quarter of 2012. The fuel products segment generated a gross profit margin of 7.8% during the second quarter of 2012 compared to a loss of 2.9% in the same period of 2011. Also improving gross profit were lower realized losses on our derivative instruments as outlined in the table below. During the second quarter of 2012, we entered into additional derivative instruments due to the strength in forward crack spreads, adding 1.6 million barrels of derivatives for calendar years 2012 through 2014 at an average of $24.89 per barrel.

During the second quarter of 2012, Bakken crude oil and Canadian heavy crude oil differentials to NYMEX WTI averaged $19.78 per barrel below NYMEX WTI. In addition to the benefit from the Bakken crude oil and Canadian heavy crude oil differentials, our Superior refinery fuel products sales benefited from Group 3 diesel prices improving from an average of $1.94 below U.S. Gulf Coast diesel prices in the first quarter of 2012 to an average of $0.19 above U.S. Gulf Coast diesel prices during the second quarter of 2012. As we have not executed any basis trades to lock in this differential during the second quarter of 2012, we benefited from the inversion of this differential during the second quarter of 2012 compared to the first quarter of 2012. Alternatively, we currently use U.S. Gulf Coast fuel products swaps to hedge our Group 3 fuel selling price exposure.

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On July 3, 2012, we completed the acquisition of all the membership interests of Royal Purple, LLC (Royal Purple) for aggregate consideration of approximately $332.7 million, excluding certain purchase price adjustments (Royal Purple Acquisition). Royal Purple is a formulator and marketer of premium industrial and consumer lubricants across several large markets including oil and gas, chemicals and refining, power generation, manufacturing and transportation, food and drug manufacturing and automotive aftermarket. The Royal Purple Acquisition was financed with the net proceeds (net of discount, underwriters fees and expenses) of $262.7 million from our June 2012 private placement of 9 5/8% senior notes due August 1, 2020 and cash on hand. We intend to continue to pursue strategic acquisitions to enhance our existing assets.

We generated $27.5 million in cash flow from operations during the second quarter of 2012. We generated distributable cash flow (as defined below in Non-GAAP Financial Measures) of $94.9 million and $25.4 million for the second quarter of 2012 and 2011, respectively, and paid distributions of $30.1 million to our unitholders in the second quarter of 2012, an increase of $10.8 million over the same period in the prior year. We plan to continue focusing our efforts on generating positive cash flows from operations which we expect will be used to (i) improve our liquidity position, (ii) pay quarterly distributions to our unitholders, (iii) service our debt obligations and (iv) provide funding for general partnership purposes.

Key Performance Measures

Our sales and net income are principally affected by the price of crude oil, demand for specialty and fuel products, prevailing crack spreads for fuel products, the price of natural gas used as fuel in our operations and our results from derivative instrument activities.

Our primary raw materials are crude oil and other specialty feedstocks and our primary outputs are specialty petroleum and fuel products. The prices of crude oil, specialty products and fuel products are subject to fluctuations in response to changes in supply, demand, market uncertainties and a variety of additional factors beyond our control. We monitor these risks and enter into financial derivatives designed to mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically hedge our cash flow exposure to commodity price risk so that we can meet our cash distribution, debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please read Part I Item 3 Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk. As of June 30, 2012, we have derivative instruments for approximately 14.5 million barrels of fuel products through December 2014 at an average refining margin of $23.37 per barrel with average refining margins ranging from a low of $18.12 per barrel in 2012 to a high of $26.50 per barrel in 2013. Please refer to Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements and Part I Item 3 Quantitative and Qualitative Disclosures About Market Risk Existing Commodity Derivative Instruments and Interest Rate Risk and Commodity Price Risk for detailed information regarding our derivative instruments.

Our management uses several financial and operational measurements to analyze our performance. These measurements include the following:

- sales volumes;
- production yields; and
- specialty products and fuel products gross profit.

Sales volumes. We view the volumes of specialty products and fuel products sold as an important measure of our ability to effectively utilize our refining assets. Our ability to meet the demands of our customers is driven by the volumes of crude oil and feedstocks that we run at our facilities. Higher volumes improve profitability both through the spreading of fixed costs over greater volumes and the additional gross profit achieved on the incremental volumes.

Production yields. In order to maximize our gross profit and minimize lower margin by-products, we seek the optimal product mix for each barrel of crude oil we refine, which we refer to as production yield.

Specialty products and fuel products gross profit. Specialty products and fuel products gross profit are important measures of our ability to maximize the profitability of our specialty products and fuel products segments. We define specialty products and fuel products gross profit as sales less the cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and processing materials. We use specialty products and fuel products gross profit as indicators of our ability to manage our business during periods of crude oil and natural gas price fluctuations, as the prices of our specialty products and fuel products generally do not change immediately with changes in the price of crude oil and natural gas. The increase in selling prices typically lags behind the rising costs of crude oil feedstocks for specialty products. Other than plant fuel, production-related expenses generally remain stable across broad ranges of throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.

Our fuel products segment gross profit may differ from a standard U.S. Gulf Coast and a Group 3 2/1/1 or 3/2/1 market crack spread due to many factors, including derivative activities to hedge both our fuel products segment revenues and the cost of crude oil reflected in gross profit, our fuel products mix as shown in our production table being different than the ratios used to calculate such market crack spreads, the allocation of by-product (primarily asphalt) losses to the fuel products segment, operating costs including fixed costs and actual crude oil costs differing from market indices and our local market pricing differentials for fuel products in the Shreveport, Louisiana and Superior, Wisconsin vicinities as compared to U.S. Gulf Coast and Group 3 postings, respectively.

In addition to the foregoing measures, we also monitor our selling, general and administrative expenditures, substantially all of which are incurred through our general partner.

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Results of Operations for the Three and Six Months Ended June 30, 2012 and 2011

Production Volume. The following table sets forth information about our combined operations. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks such as ethanol and biodiesel in our fuel products segment. The table includes the results of operations at our Superior refinery commencing October 1, 2011. The table also includes the results of operations at our Missouri facility commencing January 3, 2012 and TruSouth facility commencing January 6, 2012 except that our TruSouth operations are not included in total feedstock runs or total facility production in the table as these packaging operations are not related to our refining operations.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
		(In bpd)			(In bpd)	
Total sales volume (1)	91,198	59,648	52.9%	94,357	56,619	66.7%
Total feedstock runs (2)	89,775	61,853	45.1%	93,990	58,986	59.3%
Facility production: (3)						
Specialty products:						
Lubricating oils	15,524	14,141	9.8%	15,102	13,961	8.2%
Solvents	10,189	11,051	(7.8)%	9,658	10,592	(8.8)%
Waxes	1,234	1,204	2.5%	1,255	1,133	10.8%
Fuels	914	435	110.1%	680	533	27.6%
Asphalt and other by-products	15,310	8,961	70.9%	15,648	8,495	84.2%
Total	43,171	35,792	20.6%	42,343	34,714	22.0%
Fuel products:						
Gasoline	20,582	10,266	100.5%	22,742	9,619	136.4%
Diesel	20,176	11,424	76.6%	21,648	11,095	95.1%
Jet fuel	5,251	5,429	(3.3)%	5,353	4,303	24.4%
Heavy fuel oils and other	2,816	1,065	164.4%	3,118	812	284.0%
Total	48,825	28,184	73.2%	52,861	25,829	104.7%
Total facility production (3)	91,996	63,976	43.8%	95,204	60,543	57.3%

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements and sales of inventories. Total sales volume includes the sale of purchased fuel product blendstocks such as ethanol and biodiesel in our fuel products segment sales. The increase in total sales volume for the three and six months ended June 30, 2012 compared to the same periods in 2011 is due primarily to incremental sales of fuel products and asphalt subsequent to the Superior Acquisition on September 30, 2011, as well as increased sales volumes of lubricating oils.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. The increase in the total feedstock runs for the three and six months ended June 30, 2012 compared to the same periods in 2011 is due primarily to incremental feedstock runs from the Superior refinery partially offset by decreased run rates at our Shreveport refinery during the second quarter of 2012 due to the ExxonMobil pipeline serving this refinery being shut down since April 28, 2012.

(3) Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities, pursuant to supply and/or processing agreements, including such agreements with LyondellBasell. The difference between total facility production and total feedstock runs is primarily a result of the time lag between

the input of feedstock and production of finished products and volume loss. The increase in total facility production for three and six months ended June 30, 2012 compared to the same periods in 2011 is due primarily to the operational items discussed above in footnote 2 of this table.

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The following table reflects our consolidated results of operations and includes the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with GAAP, please read Non-GAAP Financial Measures.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Sales	$ 1,086,996	$ 733,770	$ 2,256,582	$ 1,339,010
Cost of sales	958,188	683,205	2,043,530	1,241,581
Gross profit	128,808	50,565	213,052	97,429
Operating costs and expenses:				
Selling, general and administrative	22,046	10,467	40,188	20,995
Transportation	24,957	22,691	52,499	45,766
Taxes other than income taxes	1,918	1,203	3,648	2,563
Insurance recoveries		(7,910)		(8,698)
Other	1,428	703	3,244	1,238
Operating income	78,459	23,411	113,473	35,565
Other income (expense):				
Interest expense	(18,392)	(10,544)	(36,976)	(18,025)
Debt extinguishment costs		(15,130)		(15,130)
Realized gain (loss) on derivative instruments	21,218	(2,370)	30,642	(1,984)
Unrealized gain (loss) on derivative instruments	(15,280)	(3,124)	10,764	(3,541)
Other	(4)	274	114	103
Total other income (expense)	(12,458)	(30,894)	4,544	(38,577)
Net income (loss) before income taxes	66,001	(7,483)	118,017	(3,012)
Income tax expense	339	168	432	438
Net income (loss)	$ 65,662	$ (7,651)	$ 117,585	$ (3,450)
EBITDA	$ 104,055	$ 32,723	$ 194,279	$ 59,107
Adjusted EBITDA	$ 122,307	$ 40,841	$ 191,961	$ 75,494
Distributable Cash Flow	$ 94,854	$ 25,367	$ 134,030	$ 43,589

Non-GAAP Financial Measures

We include in this Quarterly Report the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow, and provide reconciliations of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP.

EBITDA, Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;

- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

We believe that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions. We believe that excluding these transactions allows investors to meaningfully trend and analyze the performance of our core cash operations.

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We define EBITDA for any period as net income (loss) plus interest expense (including debt issuance and extinguishment costs), income taxes and depreciation and amortization.

We define Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense; (b) income taxes; (c) depreciation and amortization; (d) unrealized losses from mark to market accounting for hedging activities; (e) realized gains under derivative instruments excluded from the determination of net income (loss); (f) non-cash equity based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (g) debt refinancing fees, premiums and penalties and (h) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

We define Distributable Cash Flow for any period as Adjusted EBITDA less replacement capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense) and income tax expense. Distributable Cash Flow is used by us, our investors and analysts to analyze our ability to pay distributions.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report have been updated to reflect the calculation of Consolidated Cash Flow contained in the indentures governing our 2019 Notes and 2020 Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2019 Notes and 2020 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report for prior periods have been updated to reflect the use of the new calculations. Please refer to Liquidity and Capital Resources within this item for additional details regarding the covenants governing our debt instruments.

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EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income (loss), net cash provided by (used in) operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA, Adjusted EBITDA and Distributable Cash Flow do not reflect our obligations for the payment of income taxes, interest expense or other obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of the measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner. The following tables present a reconciliation of both net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow, and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by (used in) operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Reconciliation of Net Income (Loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income (loss)	$ 65,662	$ (7,651)	$ 117,585	$ (3,450)
Add:				
Interest expense	18,392	10,544	36,976	18,025
Debt extinguishment costs		15,130		15,130
Depreciation and amortization	19,662	14,532	39,286	28,964
Income tax expense	339	168	432	438
EBITDA	$ 104,055	$ 32,723	$ 194,279	$ 59,107
Add:				
Unrealized (gain) loss on derivatives	$ 15,280	$ 3,124	$ (10,764)	$ 3,541
Realized gain (loss) on derivatives, not included in net income (loss)	(1,950)	1,394	(590)	5,137
Amortization of turnaround costs	3,639	2,533	7,161	5,746
Non-cash equity based compensation and other non-cash items	1,283	1,067	1,875	1,963
Adjusted EBITDA	$ 122,307	$ 40,841	$ 191,961	$ 75,494
Less:				
Replacement capital expenditures (1)	$ 3,900	$ 3,505	$ 9,141	$ 7,596
Cash interest expense (2)	17,006	9,887	34,217	16,370
Turnaround costs	6,208	1,914	14,141	7,501
Income tax expense	339	168	432	438
Distributable Cash Flow	$ 94,854	$ 25,367	$ 134,030	$ 43,589

(1) Replacement capital expenditures are defined as those capital expenditures, which do not increase operating capacity or reduce operating costs and exclude turnaround costs.
(2) Represents consolidated interest expense less non-cash interest expense.

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	Six Months Ended June 30, 2012	2011
	(In thousands)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by (used in) operating activities:		
Distributable Cash Flow	$ 134,030	$ 43,589
Add:		
Replacement capital expenditures (1)	9,141	7,596
Cash interest expense (2)	34,217	16,370
Turnaround costs	14,141	7,501
Income tax expense	432	438
Adjusted EBITDA	$ 191,961	$ 75,494
Less:		
Unrealized (gain) loss on derivative instruments	(10,764)	3,541
Realized gain (loss) on derivatives, not included in net income (loss)	(590)	5,137
Amortization of turnaround costs	7,161	5,746
Non-cash equity based compensation and other non-cash items	1,875	1,963
EBITDA	$ 194,279	$ 59,107
Add:		
Unrealized (gain) loss on derivative instruments	(10,764)	3,541
Cash interest expense (2)	(34,217)	(16,370)
Non-cash equity based compensation and other non-cash items	1,875	1,963
Amortization of turnaround costs	7,161	5,746
Income tax expense	(432)	(438)
Provision for doubtful accounts	267	255
Debt extinguishment costs		(729)
Changes in assets and liabilities:		
Accounts receivable	(31,815)	(48,479)
Inventories	(4,828)	(111,555)
Other current assets	(8,631)	(14,482)
Turnaround costs	(14,141)	(7,501)
Derivative activity	(590)	5,699
Accounts payable	(57,872)	58,145
Other liabilities	3,591	(3,215)
Other, including changes in noncurrent liabilities	671	(2,245)
Net cash provided by (used in) operating activities	$ 44,554	$ (70,558)

(1) Replacement capital expenditures are defined as those capital expenditures, which do not increase operating capacity or reduce operating costs and exclude turnaround costs.

(2) Represents consolidated interest expense less non-cash interest expense.

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Changes in Results of Operations for the Three Months Ended June 30, 2012 and 2011

Sales. Sales increased $353.2 million, or 48.1%, to $1,087.0 million in the three months ended June 30, 2012 from $733.8 million in the same period in 2011. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended June 30,		
	2012	**2011**	**% Change**
	(Dollars in thousands, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 297,984	$ 246,448	20.9%
Solvents	122,783	135,642	(9.5)%
Waxes	34,792	33,874	2.7%
Fuels (1)	2,482	592	319.3%
Asphalt and by-products (2)	114,368	49,858	129.4%
Total specialty products	$ 572,409	$ 466,414	22.7%
Total specialty products sales volume (in barrels)	3,490,000	2,798,000	24.7%
Average specialty products sales price per barrel	$ 164.01	$ 166.70	(1.6)%
Fuel products:			
Gasoline	$ 267,833	$ 140,028	91.3%
Diesel	233,946	138,389	69.0%
Jet fuel	48,911	48,095	1.7%
Heavy oils and other (3)	28,039	7,607	268.6%
Hedging activities loss	(64,142)	(66,763)	(3.9)%
Total fuel products	$ 514,587	$ 267,356	92.5%
Total fuel products sales volume (in barrels)	4,809,000	2,630,000	82.9%
Average fuel products sales price per barrel (excluding hedging activities)	$ 120.34	$ 127.04	(5.3)%
Average fuel products sales price per barrel (including hedging activities)	$ 107.00	$ 101.66	5.3%
Total sales	$ 1,086,996	$ 733,770	48.1%
Total sales volume (in barrels)	8,299,000	5,428,000	52.9%

(1) Represents fuels produced in connection with the production of specialty products at the Princeton, Cotton Valley and TruSouth facilities.
(2) Represents asphalt and by-products produced in connection with the production of specialty products at the Shreveport, Superior, Princeton and Cotton Valley refineries.
(3) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport and Superior refineries.

Specialty products segment sales for the three months ended June 30, 2012 increased $106.0 million, or 22.7%, primarily as a result of an increase in sales volume of 24.7% as compared to the same period in 2011. The increase in sales volume is due primarily to incremental asphalt sales volume associated with the Superior Acquisition, which closed on September 30, 2011, and an increase in lubricating oils sales volume driven by a 9.8% increase in production volume. The specialty products average selling price per barrel decreased $2.69, or 1.6%, in response to an 8.8% decrease in the average cost of crude oil per barrel for the second quarter of 2012 as compared to the same period in 2011. Excluding incremental volumes from the Superior, TruSouth and Missouri Acquisitions, the specialty products average sales price per barrel increased 4.1% and our sales volume decreased 1.9% quarter over quarter primarily due to decreased run rates at our Shreveport refinery due to the ExxonMobil pipeline serving this refinery being shut down since April 28, 2012.

Fuel products segment sales for the three months ended June 30, 2012 increased $247.2 million, or 92.5%, due primarily to increased sales volume, as a result of the incremental fuel products sales volume from the Superior Acquisition and a $2.6 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges partially offset by a decrease in the fuel products average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) of $6.70, or 5.3%. The decrease in the average selling price per barrel of 5.3% (excluding hedging activities) compares to a 14.6% decrease in the average price of crude oil per barrel. Excluding incremental fuel products sales volume associated with the Superior Acquisition, our fuel products sales volume decreased 2.7% in the second quarter of 2012 as compared to the same period in 2011 primarily as a result of decreased run rates at our Shreveport refinery due to the ExxonMobil pipeline serving this refinery being shut down since April 28, 2012. Please see Gross Profit below for discussion of the net impact of our crude oil and fuel products derivative instruments.

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Gross Profit. Gross profit increased $78.2 million, or 154.7%, to $128.8 million in the three months ended June 30, 2012 from $50.6 million in the same period in 2011. Gross profit for our specialty products and fuel products segments was as follows:

	Three Months Ended June 30,		
	2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$ 88,618	$ 58,308	52.0%
Percentage of sales	15.5%	12.5%	
Specialty products gross profit per barrel	$ 25.39	$ 20.84	21.8%
Fuel products:			
Gross profit excluding hedging activities	$ 90,925	$ 17,022	434.2%
Hedging activities	$ (50,735)	$ (24,765)	104.9%
Gross profit	$ 40,190	$ (7,743)	619.0%
Percentage of sales	7.8%	(2.9)%	
Fuel products gross profit per barrel (excluding hedging activities)	$ 18.91	$ 6.47	192.3%
Fuel products gross profit per barrel (including hedging activities)	$ 8.36	$ (2.94)	384.4%
Total gross profit	$ 128,808	$ 50,565	154.7%
Percentage of sales	11.8%	6.9%	

The increase in specialty products segment gross profit of $30.3 million quarter over quarter was due primarily to a 24.7% increase in sales volume and an 8.8% decrease in the average cost of crude oil per barrel, partially offset by a 1.6% decrease in the average selling price per barrel, as discussed above. Excluding incremental volumes from the Superior, TruSouth and Missouri Acquisitions, the specialty products average sales price per barrel increased 4.1% quarter over quarter.

The increase in fuel products segment gross profit of $47.9 million quarter over quarter was due primarily to an 82.9% increase in sales volume, mostly as a result of the Superior Acquisition, a 14.6% decrease in the average cost of crude oil per barrel, partially offset by a 5.3% decrease in the average sales price per barrel (excluding the impact of realized hedging losses reflected in sales) and increased realized losses on derivatives of $26.0 million. Due to the extremely volatile nature of the pricing differentials between NYMEX WTI and Canadian heavy and Bakken crude oils during 2012, our NYMEX WTI crude oil swap contracts entered into to hedge the purchase of crude oil at our Superior refinery as part of our crack spread hedging program were no longer closely correlated and we were required, under GAAP, to discontinue hedge accounting on these derivatives as of January 1, 2012. Effective April 1, 2012, we also voluntarily discontinued hedge accounting for our fuel products swap contracts entered into to hedge fuel products sales at our Superior refinery. Primarily as a result of discontinuing hedge accounting on these derivative instruments, we recorded a gain of $21.2 million to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations for the three months ended June 30, 2012. The effective portion of realized gains or losses on crude oil and fuel products derivatives, under hedge accounting are recorded to cost of sales and sales, respectively. Total loss on settled derivative instruments reflected in gross profit, as discussed above, and realized gain (loss) on derivative instruments was $32.0 million for the second quarter of 2012, an increased loss of $2.2 million quarter over quarter.

Selling, general and administrative. Selling, general and administrative expenses increased $11.6 million, or 110.6%, to $22.0 million in the three months ended June 30, 2012 from $10.5 million in the same period in 2011. This increase was primarily due to additional employee compensation costs from the Superior, Missouri and TruSouth Acquisitions with no similar expenses in the comparable period in the prior year, increased professional fees of $2.5 million, increased advertising expenses of $2.1 million and increased incentive compensation expenses of $1.4 million.

Transportation. Transportation expenses increased $2.3 million, or 10.0%, to $25.0 million in the three months ended June 30, 2012 from $22.7 million in the same period in 2011. This increase is due primarily to incremental transportation expenses related to sales from the Superior Acquisition, increased sales volume of lubricating oils, as well as higher freight rates.

Insurance recoveries. Insurance recoveries were $7.9 million for the three months ended June 30, 2011. The gain was related to a claim settled in the second quarter of 2011 with insurers related to the failure of an environmental operating unit at the Shreveport refinery in the first quarter of 2010.

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Interest expense. Interest expense increased $7.8 million, or 74.4%, to $18.4 million in the three months ended June 30, 2012 from $10.5 million in the three months ended June 30, 2011, due primarily to a higher interest rate associated with the 2019 Notes as compared to the prior term loan that was repaid in full and extinguished in connection with the issuance of the 2019 Notes, as well as additional outstanding long-term debt in the form of 2019 Notes issued to partially fund the Superior Acquisition.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the three months ended June 30, 2012 and 2011.

	Three Months Ended June 30, 2012	2011
Derivative loss reflected in sales	$ (64,142)	$ (66,763)
Derivative gain reflected in cost of sales	10,913	39,333
Derivative loss reflected in gross profit	$ (53,229)	$ (27,430)
Realized gain (loss) on derivative instruments	$ 21,218	$ (2,370)
Unrealized loss on derivative instruments	(15,280)	(3,124)
Total derivative loss on unaudited condensed consolidated statements of operations	$ (47,291)	$ (32,924)
Total loss on derivative settlements	$ (33,962)	$ (28,404)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments increased $23.6 million to a gain of $21.2 million in the three months ended June 30, 2012 from a loss of $2.4 million for the three months ended June 30, 2011. The change was due primarily to an increased realized gain of approximately $27.2 million related to the settlement of derivative instruments which were not reflected in gross profit because of the loss of hedge accounting in 2012 on Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated as well as the discontinuance of hedge accounting for fuel products hedges related to the Superior refinery.

Unrealized gain (loss) on derivative instruments. Unrealized loss on derivative instruments increased $12.2 million, to $15.3 million in the three months ended June 30, 2012 from $3.1 million in the three months ended June 30, 2011. The change was due primarily to increased loss ineffectiveness of approximately $15.1 million and increased unrealized loss of approximately $14.1 million related to crude oil derivative instruments not designated as cash flow hedges in our fuel products segment. Partially offsetting this increased unrealized loss was an increased unrealized gain of approximately $12.9 million due primarily to the discontinuance of hedge accounting in 2012 for fuel products hedges related to the Superior refinery, as well as the loss of hedge accounting on Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated.

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Changes in Results of Operations for the Six Months Ended June 30, 2012 and 2011

Sales. Sales increased $917.6 million, or 68.5%, to $2,256.6 million in the six months ended June 30, 2012 from $1,339.0 million in the same period in 2011. Sales for each of our principal product categories in these periods were as follows:

	Six Months Ended June 30, 2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 610,732	$ 455,499	34.1%
Solvents	257,579	253,978	1.4%
Waxes	71,942	68,181	5.5%
Fuels (1)	5,482	1,423	285.2%
Asphalt and other by-products (2)	189,169	84,435	124.0%
Total specialty products	$ 1,134,904	$ 863,516	31.4%
Total specialty products sales volume (in barrels)	6,917,000	5,446,000	27.0%
Average specialty products sales price per barrel	$ 164.07	$ 158.56	3.5%
Fuel products:			
Gasoline	$ 577,531	$ 242,048	138.6%
Diesel	512,992	249,284	105.8%
Jet fuel	106,691	77,801	37.1%
Heavy oils and other (3)	55,119	11,037	399.4%
Hedging activities loss	(130,655)	(104,676)	24.8%
Total fuel products	$ 1,121,678	$ 475,494	135.9%
Total fuel products sales volume (in barrels)	10,256,000	4,802,000	113.6%
Average fuel products sales price per barrel (excluding hedging activities)	$ 122.11	$ 120.82	1.1%
Average fuel products sales price per barrel (including hedging activities)	$ 109.37	$ 99.02	10.5%
Total sales	$ 2,256,582	$ 1,339,010	68.5%
Total sales volume (in barrels)	17,173,000	10,248,000	67.6%

(1) Represents fuels produced in connection with the production of specialty products at the Princeton, Cotton Valley and TruSouth facilities.

(2) Represents asphalt and other by-products produced in connection with the production of specialty products at the Shreveport, Superior, Princeton and Cotton Valley refineries.

(3) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport and Superior refineries.

Specialty products segment sales for the six months ended June 30, 2012 increased $271.4 million, or 31.4%, primarily as a result of an increase in sales volume of 27.0% as compared to the same period in 2011. The increase is due primarily to incremental asphalt sales volume associated with the Superior Acquisition, which closed on September 30, 2011, and an increase in lubricating oil sales volume driven by an 8.2% increase in production volume. The specialty products average selling price per barrel increased $5.51, or 3.5%, relative to a 0.7% increase in the average cost of crude oil per barrel for the six months ended June 30, 2012 as compared to the same period in 2011. Excluding incremental sales volume associated with the Superior, TruSouth and Missouri Acquisitions, our specialty products sales volume increased 6.4% as a result of an increase in lubricating oil sales volume driven by increased production and the specialty products average sales price per barrel increased 7.3% compared to same period in 2011.

Fuel products segment sales for the six months ended June 30, 2012 increased $646.2 million, or 135.9%, due primarily to increased sales volume, as a result of the incremental fuel products sales volume from the Superior Acquisition. The fuels products average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) increased $1.29, or 1.1%. The increase in the average selling price per barrel of 1.1% (excluding hedging activities) compares to a 5.2% decrease in the average price of crude oil per barrel. Also impacting fuel product sales was a $26.0 million increase in realized derivative losses recorded in sales on our fuel products cash flow hedges. Excluding incremental fuel products sales volume associated with the Superior Acquisition, our fuel products sales volume increased 11.5% for the six months ended June 30, 2012 as compared to the same period in 2011 primarily due to the planned turnaround at our Shreveport refinery in the first quarter of 2011 partially offset by decreased run rates at our Shreveport refinery due to the ExxonMobil pipeline serving this refinery being shut down since April 28, 2012. Please see Gross Profit below for discussion of the net impact of our crude oil and fuel products derivative instruments.

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Gross Profit. Gross profit increased $115.6 million, or 118.7%, to $213.1 million in the six months ended June 30, 2012 from $97.4 million in the same period in 2011. Gross profit for our specialty products and fuel products segments was as follows:

	Six Months Ended June 30, 2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$ 155,087	$ 106,199	46.0%
Percentage of sales	13.7%	12.3%	
Specialty products gross profit per barrel	$ 22.42	$ 19.50	15.0%
Fuel products:			
Gross profit excluding hedging activities	$ 154,010	$ 34,807	342.5%
Hedging activities	$ (96,045)	$ (43,577)	120.4%
Gross profit (loss)	$ 57,965	$ (8,770)	760.9%
Percentage of sales	5.2%	(1.8)%	
Fuel products gross profit per barrel (excluding hedging activities)	$ 15.02	$ 7.25	107.2%
Fuel products gross profit per barrel (including hedging activities)	$ 5.65	$ (1.83)	408.7%
Total gross profit	$ 213,052	$ 97,429	118.7%
Percentage of sales	9.4%	7.3%	

The increase in specialty products segment gross profit of $48.9 million for the six months ended June 30, 2012 compared to the same period in 2011 was due primarily to a 27.0% increase in sales volume and a 3.5% increase in the average selling price per barrel as discussed above, partially offset by a 0.7% increase in the average cost of crude oil per barrel. Excluding incremental volumes from the Superior, TruSouth and Missouri Acquisitions, the specialty products average sales price per barrel increased 7.3% compared to same period in 2011.

The increase in fuel products segment gross profit of $66.7 million for the six months ended June 30, 2012 compared to the same period in 2011 was due primarily to a 113.6% increase in sales volume, mostly as a result of the Superior Acquisition, a 1.1% increase in the average sales price per barrel (excluding the impact of those realized hedging losses reflected in sales), a 5.2% decrease in the average cost of crude oil per barrel, partially offset by increased realized losses on derivatives of $52.5 million. Due to the extremely volatile nature of the pricing differentials between NYMEX WTI and Canadian heavy and Bakken crude oils during 2012, our NYMEX WTI crude oil swap contracts entered into to hedge the purchase of crude oil at our Superior refinery as part of our crack spread hedging program were no longer closely correlated and we were required, under GAAP, to discontinue hedge accounting on these derivatives as of January 1, 2012. Effective April 1, 2012, we also discontinued hedge accounting for our fuel products swap contracts entered into to hedge fuel products sales at our Superior refinery. Primarily as a result of discontinuing hedge accounting on these derivative instruments, we recorded a gain of $30.6 million to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations for the six months ended June 30, 2012. The effective portion of realized gains or losses on crude oil and fuel products derivatives, under hedge accounting are recorded to cost of sales and sales, respectively. Our fuel products segment gross profit for the six months ended June 30, 2012 does not reflect any impacts of our derivative instruments related to the Superior refinery. Total loss on settled derivative instruments reflected in gross profit, as discussed above, and realized gain (loss) on derivative instruments was $65.4 million for the six months ended June 30, 2012, an increased loss of $17.2 million period over period.

Selling, general and administrative. Selling, general and administrative expenses increased $19.2 million, or 91.4%, to $40.2 million in the six months ended June 30, 2012 from $21.0 million in the same period in 2011. This increase was primarily due to additional employee compensation costs from the Superior, Missouri and TruSouth Acquisitions, with no similar expenses in the comparable period in the prior year, increased professional fees of $5.2 million, increased advertising expenses of $2.6 million and increased incentive compensation costs of $2.0 million.

Transportation. Transportation expenses increased $6.7 million, or 14.7%, to $52.5 million in the six months ended June 30, 2012 from $45.8 million in the same period in 2011. This increase is due primarily to incremental transportation expenses related to sales from the Superior Acquisition, increased sales volume of lubricating oils, as well as higher freight rates.

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Insurance recoveries. Insurance recoveries were $8.7 million for the six months ended June 30, 2011. The gain was related to a claim settled in the second quarter of 2011 with insurers related to the failure of an environmental operating unit at the Shreveport refinery in the first quarter of 2010.

Interest expense. Interest expense increased $19.0 million, or 105.1%, to $37.0 million in the six months ended June 30, 2012 from $18.0 million in the six months ended June 30, 2011, due primarily to a higher interest rate associated with the 2019 Notes as compared to the prior term loan that was repaid in full and extinguished in connection with the issuance of the 2019 Notes, as well as additional outstanding long-term debt in the form of 2019 Notes issued to partially fund the Superior Acquisition.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the six months ended June 30, 2012 and 2011.

	Six Months Ended June 30,	
	2012	**2011**
Derivative loss reflected in sales	$ (130,655)	$ (104,676)
Derivative gain reflected in cost of sales	34,624	58,434
Derivative loss reflected in gross profit	$ (96,031)	$ (46,242)
Realized gain (loss) on derivative instruments	$ 30,642	$ (1,984)
Unrealized gain (loss) on derivative instruments	10,764	(3,541)
Derivative loss reflected in interest expense		(702)
Total derivative loss on unaudited condensed consolidated statements of operations	$ (54,625)	$ (52,469)
Total loss on derivative settlements	$ (65,979)	$ (43,788)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments increased $32.6 million to a gain of $30.6 million in the six months ended June 30, 2012 from a loss of $2.0 million for the six months ended June 30, 2011. The change was due primarily to an increased realized gain of approximately $54.4 million related to the settlement of derivative instruments which were not reflected in gross profit because of the loss of hedge accounting in 2012 on Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated as well as the discontinuance of hedge accounting for fuel products hedges related to the Superior refinery. Partially offsetting this increased realized gain was an increased realized loss due to ineffectiveness of approximately $17.1 million related to settlements.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments increased $14.3 million, to a gain of $10.8 million gain in the six months ended June 30, 2012 from a loss of $3.5 million loss in the six months ended June 30, 2011. The change was due primarily to an increased unrealized gain of approximately $42.2 million due primarily to the loss of hedge accounting on the discontinuance of hedge accounting in 2012 for fuel products hedges related to the Superior refinery, as well as Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated. Partially offsetting this increased unrealized gain was an increased unrealized loss of approximately $17.1 million of loss ineffectiveness and increased unrealized loss of approximately $14.1 million related to crude oil derivatives not designated as cash flow hedges in our fuel products segment.

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Liquidity and Capital Resources

General

The following should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources included under Part I Item 7 in our 2011 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 6 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements for additional discussion related to long-term debt.

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity offerings, proceeds from notes offerings and bank borrowings. Principal uses of cash have included capital expenditures, acquisitions, distributions to our unitholders and general partner and debt service. We expect that our principal uses of cash in the future will be for distributions to our limited partners and general partner, debt service, replacement and environmental capital expenditures, capital expenditures related to internal growth projects and acquisitions from third parties or affiliates. We expect to fund future capital expenditures with current cash flow from operations and borrowings under our revolving credit facility. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Cash Flows from Operating, Investing and Financing Activities

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity to meet our financial commitments, debt service obligations and anticipated capital expenditures. However, we are subject to business and operational risks that could materially adversely affect our cash flows. A material decrease in our cash flow from operations including a significant, sudden decrease in crude oil prices would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially our ability to comply with the covenants under our credit facilities. A significant, sudden increase in crude oil prices, if sustained, would likely result in increased working capital requirements which would be funded by borrowings under our revolving credit facility.

The following table summarizes our primary sources and uses of cash in each of the periods presented:

	Six Months Ended June 30,	
	2012	**2011**
	(In thousands)	
Net cash provided by (used in) operating activities	$ 44,554	$ (70,558)
Net cash used in investing activities	(330,258)	(18,563)
Net cash provided by financing activities	351,114	89,139
Net increase in cash and cash equivalents	$ 65,410	$ 18

Operating Activities. Operating activities provided cash of $44.6 million during the six months ended June 30, 2012 compared to using cash of $70.6 million during the same period in 2011. The increase in cash provided by operating activities is due primarily to increased net income of $121.0 million partially offset by a slight increase in working capital requirements during the six months ended June 30, 2012 compared to the same period in 2011.

Investing Activities. Cash used in investing activities increased to $330.3 million during the six months ended June 30, 2012 compared to $18.6 million during the six months ended June 30, 2011. The increase is due primarily to the net proceeds before expenses of $263.3 from the sale of the 2020 Notes that were deposited into an escrow account pending completion of the Royal Purple Acquisition and were subsequently released from the escrow account at the closing of the Royal Purple Acquisition on July 3, 2012. Additionally, we closed on the Missouri and TruSouth Acquisitions in January 2012 with a combined purchase price of $46.4 million, with no similar acquisitions in the same period in 2011.

Financing Activities. Financing activities provided cash of $351.1 million in the six months ended June 30, 2012 compared to $89.1 million during the six months ended June 30, 2011. This change is due primarily to the increased net proceeds from the public offering of common units (including the general partner s contribution) of $55.5 million, the repayment of the senior secured first lien term facility in April 2011 of $367.4 million partially offset by decreased net proceeds from the private placement of senior notes of $126.3 million and increased distributions to our unitholders of $22.1 million.

On May 8, 2012, we completed a public offering of our common units in which we sold 6,000,000 common units to the underwriters of the offering at a price to the public of $25.50 per common unit. The proceeds received by us from this offering (net of underwriting discounts, commissions and expenses but before our general partner s capital contribution) were $146.6 million and were used to repay borrowings under our revolving credit facility. Underwriting discounts totaled $6.2 million. Our general partner contributed $3.1 million to maintain its 2% general partner interest.

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On July 20, 2012, we declared a quarterly cash distribution of $0.59 per unit on all outstanding units, or approximately $35.9 million in aggregate, for the quarter ended June 30, 2012. The distribution will be paid on August 14, 2012 to unitholders of record as of the close of business on August 3, 2012. This quarterly distribution of $0.59 per unit equates to $2.36 per unit, or approximately $143.6 million in aggregate on an annualized basis.

Capital Expenditures

Our capital expenditure requirements consist of capital improvement expenditures, replacement capital expenditures and environmental capital expenditures. Capital improvement expenditures include expenditures to acquire assets to grow our business, to expand existing facilities, such as projects that increase operating capacity, or to reduce operating costs. Replacement capital expenditures replace worn out or obsolete equipment or parts. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations.

The following table sets forth our capital improvement expenditures, replacement capital expenditures and environmental capital expenditures in each of the periods shown.

	Six Months Ended June 30, 2012	2011
	(In thousands)	
Capital improvement expenditures	$ 13,315	$ 13,039
Replacement capital expenditures	2,855	5,873
Environmental capital expenditures	6,286	1,723
Total	$ 22,456	$ 20,635

We anticipate that future capital expenditure requirements will be provided primarily through cash flow from operations and available borrowings under our revolving credit facility. Our capital improvement expenditures have increased during the six months ended June 30, 2012 as compared to the same period in 2011 due primarily to incremental expenditures at our Superior refinery related to our crude oil rail loading project. Our environmental capital expenditures have increased during the six months ended June 30, 2012 as compared to the same period in 2011 due primarily to expenditures related to the Global Settlement with the LDEQ and OSHA compliance issues. Please read Note 5 of Part I Item 1 Financial Statements Commitments and Contingencies Environmental for additional information on the Global Settlement and OSHA compliance issues.

We estimate our replacement and environmental capital expenditures will be approximately $26.0 million for the remainder of 2012. These estimated amounts for 2012 include a portion of the $4.0 million to $8.0 million in environmental projects to be spent over the next four years as required by our settlement with the LDEQ under the Small Refinery and Single Site Refining Initiative. Please read Note 5 of Part I Item 1 Financial Statements Commitments and Contingencies Environmental for additional information.

Additionally, we anticipate future turnaround spending requirements will be approximately $5.0 million for the remainder of 2012 and between $45.0 million and $50.0 million in 2013. We expect these expenditures will be funded primarily through cash flow from operations and borrowings under our revolving credit facility.

Debt and Credit Facilities

As of June 30, 2012, our primary debt and credit instruments consist of:

- an $850.0 million senior secured revolving credit facility maturing in June 2016, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $680.0 million, which is the greater of (i) $400.0 million and (ii) 80% of revolver commitments in effect;

- $600.0 million of 9 3/8% senior notes due 2019 (2019 Notes) and

$275.0 million of 9 5/8% senior notes due 2020 (2020 Notes).

As of June 30, 2012, we believe we were in compliance with all covenants under the debt instruments in place at June 30, 2012 and have adequate liquidity to conduct our business.

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Short Term Liquidity

As of June 30, 2012, our principal sources of short-term liquidity were (i) our revolving credit facility and (ii) cash flow from operations. The loan commitments under our revolving credit facility can be used to fund borrowings for general partnership purposes, capital expenditures, distributions to our unitholders and acquisitions.

Borrowings under the revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of Eligible Accounts Receivable and Eligible Inventory (as defined in the revolving credit agreement). As such, the borrowing base can fluctuate based on changes in selling prices of our products and our current material costs, primarily the cost of crude oil. On June 30, 2012, we had availability on our revolving credit facility of $388.4 million, based on a $564.0 million borrowing base, $175.6 million in outstanding standby letters of credit and no outstanding borrowings. The borrowing base cannot exceed the revolving credit facility commitments then in effect. The lender group under our revolving credit facility is comprised of a syndicate of thirteen lenders with total commitments of $850.0 million. The lenders have a first priority lien on our cash, accounts receivable, inventory and certain other personal property.

Amounts outstanding under our revolving credit facility fluctuate materially during each quarter due to normal changes in working capital, payments of quarterly distributions to unitholders and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supplies on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended June 30, 2012 were $173.8 million. Nonetheless, our availability on our revolving credit facility during the peak borrowing days of a quarter has been ample to support our operations and service upcoming requirements. During the quarter ended June 30, 2012, availability for additional borrowings under our revolving credit facility was approximately $238.7 million at its lowest point. We believe that we will continue to have sufficient cash flow from operations and borrowing availability under our revolving credit facility to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures.

The revolving credit facility currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option. As of June 30, 2012, this margin was 125 basis points for prime and 250 basis points for LIBOR; however, the margin can fluctuate quarterly based on our average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter.

In addition to paying interest on outstanding borrowings under the revolving credit facility, we are required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to 0.375% to 0.50% per annum depending on the average daily available unused borrowing capacity. We also pay a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

Our revolving credit facility contains various covenants that limit, among other things, our ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates; and enter into a merger, consolidation or sale of assets. The revolving credit facility generally permits us to make cash distributions to our unitholders as long as immediately after giving effect to such a cash distribution we have availability under the revolving credit facility at least equal to the greater of (i) 15% of the lesser of (a) the Borrowing Base (as defined in the revolving credit agreement) without giving effect to the LC Reserve (as defined in the credit agreement) and (b) the revolving credit facility commitments then in effect and (ii) $45.0 million. Further, the revolving credit facility contains one springing financial covenant which provides that only if our availability under the revolving credit facility falls below the greater of (i) 12.5% of the lesser of (a) the Borrowing Base (as defined in the credit agreement) (without giving effect to the LC Reserve (as defined in the revolving credit agreement)) and (b) the credit agreement commitments then in effect and (ii) $46.4 million, (as increased, upon the effectiveness of the increase in the maximum availability under our revolving credit facility, by the same percentage as the percentage increase in our revolving credit agreement commitments), we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the credit agreement) of at least 1.0 to 1.0.

If an event of default exists under the revolving credit facility, the lenders will be able to accelerate the maturity of the credit facility and exercise other rights and remedies. An event of default includes, among other things, the nonpayment of principal, interest, fees or other amounts; failure of any representation or warranty to be true and correct when made or confirmed; failure to perform or observe covenants in the revolving credit facility or other loan documents, subject, in limited circumstances, to certain grace periods; cross-defaults in other indebtedness if the effect of such default is to cause, or permit the holders of such indebtedness to cause, the acceleration of such indebtedness under any material agreement; bankruptcy or insolvency events; monetary judgment defaults; asserted invalidity of the loan documentation; and a change of control over us.

Long-Term Financing

In addition to our principal sources of short-term liquidity listed above, we can meet our cash requirements (other than distributions of cash from operations to our common unitholders) through issuing long-term notes or additional common units.

From time to time we issue long-term debt securities, often referred to as our senior notes. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations. As of June 30, 2012, we had $600.0 million in 2019 Notes and $275.0 million in 2020 Notes outstanding. As of December 31, 2011, we had $600.0 million in 2019 Notes outstanding.

The indentures governing the 2019 and 2020 Notes contain covenants that, among other things, restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company s common 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 our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2019 or 2020 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default or Event of Default, each as defined in the indentures governing the 2019 or 2020 Notes, has occurred and is continuing, many of these covenants will be suspended.

To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives.

We are subject, however, to conditions in the equity and debt markets for our common units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our common units and/or senior notes in the future. If we are unable or unwilling to issue additional common units, we may be required to either restrict capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. For additional information regarding our 2020 Notes, see Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements. For additional information regarding our 2019 Notes, see Note 7 Long-Term Debt in Part II Item 8 Financial Statements and Supplementary Data of our 2011 Annual Report.

Master Derivative Contracts

Under our credit support arrangements, our payment obligations under all of our master derivatives contracts for commodity hedging generally are secured by a first priority lien on our and our subsidiaries real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). We have also issued to one counterparty a $25.0 million standby letter of credit under the revolving credit facility. In the event that such counterparty s exposure to us exceeds $200.0 million, we will be required to post additional collateral support in the form of either cash or letters of credit with the party to enter into additional crack spread hedges. We had no additional letters of credit or cash margin posted with any hedging counterparty as of June 30, 2012. Our master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on our operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements. For financial reporting purposes, we do not offset the collateral provided to a counterparty against the fair value of our obligation to that counterparty. Any outstanding collateral is released to us upon settlement of the related derivative instrument liability.

The fair value of our derivatives decreased by approximately $36.0 million subsequent to June 30, 2012 to a net liability of approximately $67.0 million. All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads to significantly impact our liquidity.

Additionally, we have a collateral sharing agreement (the Collateral Trust Agreement) which governs how secured hedging counterparties will share collateral pledged as security for the payment obligations owed by us to secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $100.0 million the extent to which forward purchase contracts for physical commodities would be covered by, and secured under, the Collateral Trust Agreement. There is no such limit on financially settled derivative instruments used for commodity hedging. Subject to certain conditions set forth in the Collateral Trust Agreement, we have the ability to add secured hedging counterparties thereto.

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of June 30, 2012 at current maturities and reflects only those line items that have materially changed since December 31, 2011:

	Payments Due by Period (In thousands)				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Operating activities:					
Interest on long-term debt at contractual rates (1)	$ 621,848	$ 90,518	$ 174,705	$ 170,281	$ 186,344
Operating lease obligations (2)	79,546	23,195	29,197	13,521	13,633
Letters of credit (3)	175,560	175,560			
Purchase commitments (4)	1,467,846	1,177,097	290,749		
Financing activities:					
Capital lease obligations	5,905	773	963	657	3,512
Long-term debt obligations, excluding capital lease obligations	875,000				875,000
Total obligations	$ 3,225,705	$ 1,467,143	$ 495,614	$ 184,459	$ 1,078,489

(1) Interest on long-term debt at contractual rates and maturities relates primarily to our 2019 and 2020 Notes, revolving credit facility fees and capital lease obligations.
(2) We have various operating leases primarily for the use of land, storage tanks, compressor stations, railcars, equipment, precious metals and office facilities that extend through June 2026.
(3) Letters of credit primarily supporting crude oil purchases, precious metals leasing and hedging activities.
(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil and other feedstocks and finished products for resale from various suppliers based on current market prices at the time of delivery.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with ConocoPhillips related to the LVT unit at its Lake Charles, Louisiana refinery (the LVT Feedstock Agreement). Pursuant to the LVT Feedstock Agreement, ConocoPhillips is obligated to supply a minimum quantity (the Base Volume) of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, we expect to purchase $69.3 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of June 30, 2012. This amount is not included in the table above. If the Base Volume is not supplied at any point during the first five years of the ten year term, a penalty for each gallon of shortfall must be paid to us as liquidated damages.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2012 and 2013, for which we have not contractually committed, refer to Capital Expenditures above.

Off-Balance Sheet Arrangements

As of June 30, 2012, we had approximately $79.5 million in operating lease commitments. We did not enter into any material off-balance sheet debt or operating lease transactions during the quarter.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Part I Item 7 of our 2011 Annual Report.

Recent Accounting Pronouncements

For additional discussion regarding recent accounting pronouncements, see Note 2 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Part I Item 7A in our 2011 Annual Report and Item 3 of our Quarterly Report on Form 10-Q for the three months ended March 31, 2012 (the 2012 First Quarterly Report). There have been no material changes in that information other than as discussed below. Also, see Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements in this Quarterly Report for additional discussion related to derivative instruments and hedging activities.

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Commodity Price Risk

Holding all other variables constant, we expect a $1 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of June 30, 2012:

	In millions
Crude oil swaps	$ 14.7
Crude oil basis swaps	$ 0.7
Diesel swaps	$ (6.4)
Jet fuel swaps	$ (5.0)
Gasoline swaps	$ (3.1)
Natural gas swaps	$ 1.8

Interest Rate Risk

Our profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates. The primary purpose of our interest rate risk management activities is to hedge our exposure to changes in interest rates. Historically, our policy has been to enter into interest rate swap agreements to hedge up to 75% of our interest rate risk related to variable rate debt. With the issuances of our 2019 and 2020 Notes, which constitute fixed rate debt, we do not expect to enter into additional hedges to fix our interest rates.

We are exposed to market risk from fluctuations in interest rates. As of June 30, 2012, we had no borrowings of variable rate debt outstanding under our revolving credit facility. Holding other variables constant (such as debt levels), a one hundred basis point change in interest rates on our variable rate debt as of June 30, 2012 would not have an impact on net income and cash flows for 2012.

Existing Commodity Derivative Instruments

We are also subject to the risk that the crude oil and fuel products derivatives we use to hedge against fuel products crack spread volatility do not provide adequate protection against volatility. All of the crude oil derivatives in our hedge portfolio are based on the market price of NYMEX WTI and the fuel products derivatives are all based on U.S. Gulf Coast market prices. In recent periods, the spread between NYMEX WTI and other crude oil indices (specifically LLS and Brent on which a portion of our crude oil purchases are based) has widened, which has led to more of our crude oil hedges not being as effective. To the extent the spread between NYMEX WTI and the other crude oil indices stays at current levels or continues to widen, our hedges could continue to become less effective and not provide adequate protection against crude oil price volatility. Refer to Part I Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations Second Quarter 2012 Update for discussion on the discontinuance of hedge accounting related to crude oil, diesel and gasoline derivatives related to crack spread hedging at our Superior refinery.

Fuel Products Segment

The following table provides a summary of the implied crack spreads for the crude oil, diesel, jet fuel and gasoline swaps as of June 30, 2012 disclosed in Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements .

Crude Oil and Fuel Products Swap Contracts by Expiration Dates	**Barrels**	**BPD**	**Implied Crack Spread ($/Bbl)**
Third Quarter 2012	2,852,000	31,000	$ 18.12
Fourth Quarter 2012	2,622,000	28,500	19.20
Calendar Year 2013	7,149,000	19,586	26.50
Calendar Year 2014	1,910,000	5,233	25.22
Totals	14,533,000		
Average price			$ 23.37

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Specialty Products Segment

The following table provides a summary of our crude oil derivatives related to crude oil purchases in our specialty products segment as of June 30, 2012, which we disclose in Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements, none of which were designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Calendar Year 2013	200,000	548	$ 84.75
Totals	200,000		
Average price			$ 84.75

The following table provides a summary of our natural gas derivatives related to natural gas purchases in our specialty products segment as of June 30, 2012, which we disclose in Note 7 under Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements, none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2012	1,200,000	$ 4.03
Fourth Quarter 2012	600,000	4.08
Totals	1,800,000	
Average price		$ 4.05

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the Exchange Act), as amended, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2012 at the reasonable assurance level.

(b) Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the second fiscal quarter of 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

We completed the Superior Acquisition on September 30, 2011, the Missouri Acquisition on January 3, 2012, the TruSouth Acquisition on January 6, 2012 and the Royal Purple Acquisition on July 3, 2012. These include certain existing information systems and internal controls over financial reporting that previously existed. We are currently in the process of evaluating and integrating Superior, Missouri, TruSouth and Royal Purple historical internal controls over financial reporting with ours. We expect to complete this integration during 2012.

PART II

Item 1. ***Legal Proceedings***

We are not a party to, and our property is not the subject of, any pending legal proceedings other than ordinary routine litigation incidental to our business. Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. The information provided under Note 5 Commitments and Contingencies in Part I Item 1 Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements is incorporated herein by reference.

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Item 1A. ***Risk Factors***

In addition to risks factor set forth below, you should carefully consider the risk factors discussed in Part I Item 1A Risk Factors in our 2011 Annual Report, which could materially affect our business, financial condition or future results. There have been no material changes in the risk factors discussed in Part I Item IA Risk Factors in our 2011 Annual Report other than with respect to the risk factor discussed below.

All or a portion of the assets and operations we are acquiring pursuant to the Royal Purple Acquisition may be subject to federal income tax, which would reduce cash available for distribution from such assets and operations.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a publicly traded partnership such as ours to be treated as a corporation for federal income tax purposes. In order to maintain our status as a partnership for U.S. federal income tax purposes, 90% or more of our gross income in each tax year must be qualifying income under Section 7704 of the Internal Revenue Code.

Our counsel is unable to opine as to the qualifying nature of portions of the income generated by portions of the Royal Purple assets and operations. Consequently, we are in the process of requesting a ruling from the IRS upon which, if granted, we may rely with respect to the qualifying nature of such income. If the IRS is unwilling or unable to provide a favorable ruling in a timely manner with respect to our income from the Royal Purple assets and operations, it may be necessary for us to own some or all of the Royal Purple assets and conduct some or all of the acquired Royal Purple business operations in a taxable corporate subsidiary. In such case, this corporate subsidiary, like our existing corporate subsidiary, would be subject to corporate-level tax on its taxable income at the applicable federal corporate income tax rate of 35% as well as any applicable state income tax rates. Imposition of a corporate level tax would significantly reduce the anticipated cash available for distribution from the Royal Purple assets and operations to us and, in turn, would reduce our cash available for payment on the notes and our other debt obligations. Moreover, if the IRS were to successfully assert that this corporation had more tax liability than we currently anticipate or legislation was enacted that increased the corporate tax rate, our cash available for payments on the notes and our other debt obligations would be further reduced.

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

The following table summarizes the purchases of equity securities by our general partner that were completed during the three months ended June 30, 2012.

	Total Number of Common Units Purchased	Average Price Paid per Common Unit	Total Number of Common Units Purchased as a Part of Publicly Announced Plans	Maximum Number of Common Units that May Yet be Purchased Under Plans
April 1, 2012 April 30, 2012		$		
May 1, 2012 May 31, 2012 (1)	3,109	24.26		
June 1, 2012 June 30, 2012				
Total	3,109	$ 24.26		

(1) A total of 3,109 common units were purchased by our general partner, related to the Calumet GP, LLC Executive Deferred Compensation Plan (the Deferred Compensation Plan). The Long-Term Incentive Plan (LTIP) provides for the delivery of up to 783,960 common units to satisfy awards of phantom units, restricted units or unit options to the employees, consultants or directors of the Company. Such units may be newly issued by the Company or purchased in the open market. None of the common units were purchased pursuant to publicly announced plans or programs. The common units were purchased through a single broker in open market transactions. For more information on the LTIP and Deferred Compensation Plan, refer to Part III Item 11 Executive and Director Compensation Compensation Discussion and Analysis Elements of Executive Compensation Long-Term, Unit-Based Awards in our 2011 Annual Report.

Item 3. ***Defaults Upon Senior Securities***

None.

Item 4. ***Mine Safety Disclosures***

None.

Item 5. ***Other Information***

None.

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Item 6. ***Exhibits***

The following documents are filed as exhibits to this Quarterly Report:

Exhibit Number	Description
1.1	Underwriting Agreement, dated May 8, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet GP, LLC and the Underwriters named therein (incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed with the Commission on May 9, 2012 (File No. 000-51734)).
1.2	Purchase Agreement, dated June 21, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., Calumet GP, LLC, the guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed with the Commission on June 25, 2012 (File No. 000-51734)).
2.1	Unit Purchase Agreement, dated as of June 5, 2012, by and among Calumet Lubricants Co., Limited Partnership, Royal Purple, Inc. and the shareholders of Royal Purple, Inc. named therein (incorporated by reference to Exhibit 2.1 to the Registrant s Current Report on Form 8-K filed with the Commission on June 8, 2012 (File No. 000-51734)).
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant s Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant s Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant s Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
4.1*	Third Supplemental Indenture to the Indenture dated April 21, 2011, dated April 19, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association (as successor by merger to Wilmington Trust FSB), as trustee.
4.2*	Second Supplemental Indenture to the Indenture dated as of September 19, 2011, dated April 19, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee.
4.3	Indenture, dated June 29, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., the guarantors named therein and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed with the Commission on July 5, 2012 (File No. 000-51734)).
4.4	Registration Rights Agreement, dated June 29, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed with the Commission on July 5, 2012 (File No. 000-51734)).
10.1*	Amended and Restated Crude Oil Purchase Agreement, dated April 1, 2012 by and between BP Products North America Inc. and Calumet Superior, LLC. Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

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Exhibit Number	Description
31.1*	Sarbanes-Oxley Section 302 certification of F. William Grube.
31.2*	Sarbanes-Oxley Section 302 certification of R. Patrick Murray, II.
32.1*	Section 1350 certification of F. William Grube and R. Patrick Murray, II.
100.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of the registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

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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.

	CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
	By: Calumet GP, LLC, its general partner
Date: August 9, 2012	By: /s/ R. Patrick Murray, II R. Patrick Murray, II Vice President, Chief Financial Officer and Secretary of Calumet GP, LLC, general partner of Calumet Specialty Products Partners, L.P. (Authorized Person and Principal Accounting Officer)

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Index to Exhibits

Exhibit Number	Description
1.1	Underwriting Agreement, dated May 8, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet GP, LLC and the Underwriters named therein (incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed with the Commission on May 9, 2012 (File No. 000-51734)).
1.2	Purchase Agreement, dated June 21, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., Calumet GP, LLC, the guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed with the Commission on June 25, 2012 (File No. 000-51734)).
2.1	Unit Purchase Agreement, dated as of June 5, 2012, by and among Calumet Lubricants Co., Limited Partnership, Royal Purple, Inc. and the shareholders of Royal Purple, Inc. named therein (incorporated by reference to Exhibit 2.1 to the Registrant s Current Report on Form 8-K filed with the Commission on June 8, 2012 (File No. 000-51734)).
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant s Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
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4.4	Registration Rights Agreement, dated June 29, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., the guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed with the Commission on July 5, 2012 (File No. 000-51734)).
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