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Calumet Specialty Products Partners, L.P.
Form 10-Q
August 09, 2013
Table of Contents

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

Form 10-Q

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

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2013

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: 000-51734

Calumet Specialty Products Partners, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware
(State or Other Jurisdiction of
Incorporation or Organization)

37-1516132
(I.R.S. Employer
Identification Number)

2780 Waterfront Parkway East Drive, Suite 200
Indianapolis, Indiana
(Address of Principal Executive Officers)
(317) 328-5660
(Registrant's Telephone Number, Including Area Code)

46214
(Zip Code)

None
(Former Name, Former Address and Former Fiscal Year, If Changed Since Last Report)

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 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 Registration S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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

Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

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

At August 9, 2013, there were 69,317,278 common units outstanding.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

QUARTERLY REPORT

For the Three and Six Months Ended June 30, 2013

Table of Contents

	Page
<u>Part I</u>	
<u>Item 1. Financial Statements</u>	
<u>Condensed Consolidated Balance Sheets</u>	<u>4</u>
<u>Unaudited Condensed Consolidated Statements of Operations</u>	<u>5</u>
<u>Unaudited Condensed Consolidated Statements of Comprehensive Income</u>	<u>6</u>
<u>Unaudited Condensed Consolidated Statements of Partners' Capital</u>	<u>7</u>
<u>Unaudited Condensed Consolidated Statements of Cash Flows</u>	<u>8</u>
<u>Notes to Unaudited Condensed Consolidated Financial Statements</u>	<u>10</u>
<u>Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>43</u>
<u>Item 3. Quantitative and Qualitative Disclosures About Market Risk</u>	<u>69</u>
<u>Item 4. Controls and Procedures</u>	<u>71</u>
<u>Part II</u>	
<u>Item 1. Legal Proceedings</u>	<u>72</u>
<u>Item 1A. Risk Factors</u>	<u>72</u>
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	<u>72</u>
<u>Item 3. Defaults Upon Senior Securities</u>	<u>72</u>
<u>Item 4. Mine Safety Disclosures</u>	<u>72</u>
<u>Item 5. Other Information</u>	<u>72</u>
<u>Item 6. Exhibits</u>	<u>73</u>

Table of Contents

FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this “Quarterly Report”) includes certain “forward-looking statements.” These statements can be identified by the use of forward-looking terminology including “may,” “intend,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” or other similar words. The statements regarding (i) estimated capital expenditures as a result of required audits or required operational changes or other environmental and regulatory liabilities, (ii) our anticipated levels of, use and effectiveness of derivatives to mitigate our exposure to crude oil price changes, natural gas price changes and fuel products price changes, (iii) estimated costs of complying with the U.S. Environmental Protection Agency’s (“EPA”) Renewable Fuel Standards, including the prices paid for Renewable Identification Numbers (“RINs”) and (iv) our ability to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures, as well as other matters discussed in this Quarterly Report that are not purely historical data, are forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future sales and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in (1) Part I, Item 3 “Quantitative and Qualitative Disclosures About Market Risk” and Part I, Item 1A “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (“2012 Annual Report”), (2) Part II, Item IA “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 (“Q1 Quarterly Report”) and (3) Part II, Item 1A “Risk Factors” in this Quarterly Report. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

References in this Quarterly Report to “Calumet Specialty Products Partners, L.P.,” “the Company,” “we,” “our,” “us” or like terms refer to Calumet Specialty Products Partners, L.P. and its subsidiaries. References in this Quarterly Report to “our general partner” refer to Calumet GP, LLC, the general partner of Calumet Specialty Products Partners, L.P.

Table of Contents

PART I

Item 1. Financial Statements

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2013	December 31, 2012
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 163.2	\$ 32.2
Accounts receivable:		
Trade	298.1	219.3
Other	9.1	7.5
	307.2	226.8
Inventories	589.3	553.6
Derivative assets	14.2	3.1
Prepaid expenses and other current assets	19.8	10.3
Deposits	0.7	7.9
Total current assets	1,094.4	833.9
Property, plant and equipment, net	1,108.3	986.9
Investment in unconsolidated affiliate	16.6	1.9
Goodwill	192.7	187.0
Other intangible assets, net	184.4	197.1
Other noncurrent assets, net	87.8	46.2
Total assets	\$ 2,684.2	\$ 2,253.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	\$ 416.5	\$ 333.4
Accrued interest payable	21.1	23.5
Accrued salaries, wages and benefits	16.2	20.1
Accrued income taxes payable	—	27.6
Other taxes payable	18.1	13.7
Other current liabilities	41.7	8.3
Current portion of long-term debt	0.7	0.8
Derivative liabilities	0.5	48.0
Total current liabilities	514.8	475.4
Pension and postretirement benefit obligations	22.3	24.0
Other long-term liabilities	1.1	1.1
Long-term debt, less current portion	863.4	862.7
Total liabilities	1,401.6	1,363.2
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (69,317,278 and 57,529,778 units issued and outstanding at June 30, 2013 and December 31, 2012, respectively)	1,230.7	884.8
General partner's interest	39.3	30.5
Accumulated other comprehensive income (loss)	12.6	(25.5)

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Total partners' capital	1,282.6	889.8
Total liabilities and partners' capital	\$2,684.2	\$2,253.0
See accompanying notes to unaudited condensed consolidated financial statements.		

Table of ContentsCALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Three Months Ended		For the Six Months Ended	
	June 30,		June 30,	
	2013	2012	2013	2012
	(In millions, except per unit and unit data)			
Sales	\$1,354.2	\$1,087.0	\$2,672.8	\$2,256.6
Cost of sales	1,253.2	958.2	2,437.4	2,043.5
Gross profit	101.0	128.8	235.4	213.1
Operating costs and expenses:				
Selling	16.9	7.2	32.8	11.7
General and administrative	19.0	14.8	44.1	28.5
Transportation	33.8	25.0	69.2	52.5
Taxes other than income taxes	3.0	1.9	6.0	3.6
Other	1.0	1.4	1.6	3.3
Operating income	27.3	78.5	81.7	113.5
Other income (expense):				
Interest expense	(24.7) (18.4) (49.5) (37.0
Realized gain on derivative instruments	9.8	21.2	1.2	30.6
Unrealized gain (loss) on derivative instruments	(4.0) (15.3) 20.5	10.8
Other	(0.4) —	0.3	0.1
Total other income (expense)	(19.3) (12.5) (27.5) 4.5
Net income before income taxes	8.0	66.0	54.2	118.0
Income tax expense	0.2	0.3	0.4	0.4
Net income	\$7.8	\$65.7	\$53.8	\$117.6
Allocation of net income:				
Net income	\$7.8	\$65.7	\$53.8	\$117.6
Less:				
General partner's interest in net income	0.2	1.3	1.1	2.4
General partner's incentive distribution rights	3.8	1.1	7.0	1.6
Non-vested share based payments	—	0.4	0.2	0.7
Net income available to limited partners	\$3.8	\$62.9	\$45.5	\$112.9
Weighted average limited partner units outstanding:				
Basic	69,571,855	55,027,786	66,219,729	53,353,760
Diluted	69,769,536	55,074,265	66,411,968	53,379,593
Limited partners' interest basic net income per unit	\$0.05	\$1.14	\$0.69	\$2.12
Limited partners' interest diluted net income per unit	\$0.05	\$1.14	\$0.68	\$2.12
Cash distributions declared per limited partner unit	\$0.68	\$0.56	\$1.33	\$1.09

See accompanying notes to unaudited condensed consolidated financial statements.

Table of ContentsCALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2013	2012	June 30, 2013	2012
Net income	\$7.8	\$65.7	\$53.8	\$117.6
Other comprehensive income (loss):				
Cash flow hedges:				
Cash flow hedge (gain) loss reclassified to net income	(1.6) 53.2	10.0	96.0
Change in fair value of cash flow hedges	44.5	20.2	27.2	(152.9)
Defined benefit pension and retiree health benefit plans	0.3	0.1	0.9	0.3
Total other comprehensive income (loss)	43.2	73.5	38.1	(56.6)
Comprehensive income attributable to partners' capital	\$51.0	\$139.2	\$91.9	\$61.0

See accompanying notes to unaudited condensed consolidated financial statements.

Table of ContentsCALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Accumulated Other Comprehensive Income (Loss) (In millions)	Partners' Capital General Partner	Limited Partners	Total
Balance at December 31, 2012	\$(25.5)	\$30.5	\$884.8	\$889.8
Other comprehensive income	38.1	—	—	38.1
Net income	—	8.1	45.7	53.8
Units repurchased for phantom unit grants	—	—	(5.0)	(5.0)
Amortization of vested phantom units	—	—	1.6	1.6
Issuances of phantom units, net of repurchases for taxes	—	—	(0.3)	(0.3)
Proceeds from public offerings of common units, net	—	—	392.5	392.5
Contributions from Calumet GP, LLC	—	8.4	—	8.4
Distributions to partners	—	(7.7)	(88.6)	(96.3)
Balance at June 30, 2013	\$12.6	\$39.3	\$1,230.7	\$1,282.6

See accompanying notes to unaudited condensed consolidated financial statements.

Table of ContentsCALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Six Months Ended	
	June 30,	2012
	2013	
	(In millions)	
Operating activities		
Net income	\$53.8	\$117.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	58.8	39.3
Amortization of turnaround costs	6.0	7.2
Non-cash interest expense	3.5	2.8
Provision for doubtful accounts	0.3	0.3
Unrealized gain on derivative instruments	(20.5) (10.8
Non-cash equity based compensation	2.9	1.9
Other non-cash activities	1.7	0.8
Changes in assets and liabilities:		
Accounts receivable	(80.7) (31.8
Inventories	(18.7) (4.8
Prepaid expenses and other current assets	(9.5) (2.9
Derivative activity	(0.9) (0.6
Turnaround costs	(47.0) (14.1
Deposits	7.2	(5.8
Accounts payable	83.7	(57.9
Accrued interest payable	(2.4) (0.2
Accrued salaries, wages and benefits	(3.4) (0.7
Accrued income taxes payable	(27.6) 0.3
Other taxes payable	4.4	1.7
Other liabilities	24.4	2.4
Pension and postretirement benefit obligations	(1.3) (0.1
Net cash provided by operating activities	34.7	44.6
Investing activities		
Additions to property, plant and equipment	(71.6) (22.5
Cash paid for acquisitions, net of cash acquired	(117.8) (46.4
Investment in unconsolidated affiliate	(14.7) —
Change in restricted cash	—	(263.3
Proceeds from sale of property, plant and equipment	—	1.9
Net cash used in investing activities	(204.1) (330.3
Financing activities		
Proceeds from borrowings — revolving credit facility	730.2	1,055.2
Repayments of borrowings — revolving credit facility	(730.2) (1,055.2
Payments on capital lease obligations	(0.5) (0.9
Proceeds from other financing obligations	3.5	—
Proceeds from senior notes offering	—	270.2
Debt issuance costs	—	(7.5
Proceeds from public offerings of common units, net	392.5	146.6
Contributions from Calumet GP, LLC	8.4	3.1

Table of Contents

Units repurchased and taxes paid for phantom unit grants	(7.1) (2.1)
Distributions to partners	(96.4) (58.3)
Net cash provided by financing activities	300.4	351.1	
Net increase in cash and cash equivalents	131.0	65.4	
Cash and cash equivalents at beginning of period	32.2	0.1	
Cash and cash equivalents at end of period	\$163.2	\$65.5	
Supplemental disclosure of noncash financing and investing activities			
Equipment acquired under capital lease	\$—	\$5.8	
See accompanying notes to unaudited condensed consolidated financial statements.			

Table of ContentsCALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2013, the Company had 69,317,278 limited partner common units and 1,414,638 general partner equivalent units outstanding. 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 of the Company’s employees and the Company reimburses the general partner for certain of its expenses. The Company is engaged in the production and marketing of crude oil-based specialty products including lubricating oils, white mineral oils, solvents, petrolatums, waxes, asphalt and fuel and fuel related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company is also engaged in the resale of purchased crude oil to third party customers. The Company owns facilities located in Shreveport, Louisiana (“Shreveport” and “TruSouth”); Superior, Wisconsin (“Superior”); San Antonio, Texas (“San Antonio”); Great Falls, Montana (“Montana”); Princeton, Louisiana (“Princeton”); Cotton Valley, Louisiana (“Cotton Valley”); Karns City, Pennsylvania (“Karns City”); Dickinson, Texas (“Dickinson”); Louisiana, Missouri (“Missouri”) and Porter, 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, 2013 and for the three and six months ended June 30, 2013 and 2012 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, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. These unaudited condensed consolidated financial statements should be read in conjunction with the Company’s 2012 Annual Report.

2. New and Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (“FASB”) issued ASU No. 2011-11, Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (“ASU 2011-11”). ASU 2011-11 requires 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. In January 2013, the FASB issued ASU No. 2013-01, Balance Sheet Topic (210) — Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities (“ASU 2013-01”), which clarifies the scope of the offsetting disclosures and addresses any unintended consequences. Amendments to ASU 2011-11, as superseded by ASU 2013-01, are effective for the first reporting period (including interim periods) beginning on or after January 1, 2013 and should be applied retrospectively for any period presented. The adoption of ASU 2013-01 and ASU 2011-11 concerns presentation and disclosure only.

In October 2012, the FASB issued ASU No. 2012-04, Technical Corrections and Improvements (“ASU 2012-04”). ASU 2012-04 covers a wide range of topics in the Accounting Standards Codification. These amendments include technical corrections and improvements to the Accounting Standards Codification and conforming amendments related to fair value measurements. ASU 2012-04 is effective for fiscal periods beginning after December 15, 2012. The adoption of ASU 2012-04 did not have an impact on the Company’s consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220) — Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (“ASU 2013-02”). ASU 2013-02 requires entities to report either on the statement of operations or disclose in the footnotes to the consolidated financial statements the effects on earnings from items that are reclassified out of comprehensive income. For amounts that are not required to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional details about those amounts. ASU 2013-02 is effective prospectively for the first reporting period after December 15, 2012 with early adoption permitted. The adoption of ASU 2013-02 concerns presentation and disclosure only.

Table of Contents

In February 2013, the FASB issued ASU No. 2013-04, Liabilities (Topic 405) — Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date (“ASU 2013-04”). ASU 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements from which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal periods, (including interim periods), beginning after December 15, 2013 and should be applied retrospectively. The Company is currently evaluating the impacts of the adoption of ASU 2013-04 on its consolidated financial statements.

3. Acquisitions

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., including a manufacturing facility located in Louisiana, Missouri for aggregate consideration of approximately \$19.6 million (“Missouri Acquisition”). The Missouri Acquisition was financed with borrowings under the Company’s revolving credit facility and cash on hand. The Company believes the Missouri Acquisition provides greater diversity to its specialty products segment. The assets acquired and results of operations have been included in the Company’s condensed consolidated balance sheets and the Company’s unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Missouri Acquisition, the Company incurred no acquisition costs during the three months ended June 30, 2012 and \$0.5 million during the six months ended June 30, 2012, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded \$1.5 million of goodwill as a result of the Missouri 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 (in millions):

	Allocation of Purchase Price
Inventories	\$2.7
Property, plant and equipment	10.0
Goodwill	1.5
Other intangible assets	5.4
Total purchase price	\$19.6

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 (in millions):

	Amount	Life (Years)
Customer relationships	\$5.4	20

TruSouth Acquisition

On January 6, 2012, the Company completed the acquisition of all of the outstanding membership interests of TruSouth Oil, LLC (“TruSouth”), a specialty petroleum packaging and distribution company located in Shreveport, Louisiana for aggregate consideration of approximately \$26.9 million, net of cash acquired (“TruSouth Acquisition”). 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 provides greater diversity to its specialty products segment. The assets acquired and liabilities assumed have been included in the Company’s condensed consolidated balance sheets and results of operations have been included in the Company’s unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the TruSouth Acquisition, the Company incurred no acquisition costs during the three months ended June 30, 2012 and approximately \$0.2 million during the six months ended June 30, 2012, which are reflected in general and administrative expenses in the unaudited condensed

consolidated statements of operations.

11

Table of Contents

The Company recorded \$0.4 million of goodwill as a result of the TruSouth 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 (in millions):

	Allocation of Purchase Price
Accounts receivable	\$5.2
Inventories	8.0
Prepaid expenses and other current assets	0.3
Property, plant and equipment	17.7
Goodwill	0.4
Other intangible assets	2.6
Accounts payable	(2.7)
Accrued salaries, wages and benefits	(0.2)
Other current liabilities	(0.9)
Long-term debt	(3.5)
Total purchase price, net of cash acquired	\$26.9

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

	Amount	Life (Years)
Customer relationships	\$1.8	16
Tradenames	0.7	9
Non-competition agreements	0.1	2
Total	\$2.6	
Weighted average amortization period		14

Royal Purple Acquisition

On July 3, 2012, the Company completed the acquisition of Royal Purple, Inc. ("Royal Purple"), a Texas corporation which was converted into a Delaware limited liability company at closing, for aggregate consideration of approximately \$331.2 million, net of cash acquired ("Royal Purple Acquisition"). Royal Purple is a leading independent formulator and marketer of premium industrial and consumer lubricants to a diverse customer base 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 net proceeds of \$262.6 million from the Company's June 2012 private placement of 9 5/8% senior notes due August 1, 2020 and cash on hand. The Company believes the Royal Purple Acquisition increases its position in the specialty lubricants market, expands its geographic reach, increases its asset diversity and enhances its specialty products segment. The assets acquired and liabilities assumed have been included in the Company's condensed consolidated balance sheets and results of operations have been included in the Company's unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Royal Purple Acquisition, the Company incurred approximately \$0.1 million of acquisition costs during the three and six months ended June 30, 2012, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded \$109.2 million of goodwill as a result of the Royal Purple 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 (in millions):

Table of Contents

	Allocation of Purchase Price
Accounts receivable	\$ 15.2
Inventories	19.3
Prepaid expenses and other current assets	0.2
Property, plant and equipment	10.6
Goodwill	109.2
Other intangible assets	183.4
Accounts payable	(3.8)
Accrued salaries, wages and benefits	(1.7)
Taxes payable	(0.2)
Other current liabilities	(1.0)
Total purchase price, net of cash acquired	\$ 331.2

The components of intangible assets listed in the table above as of July 3, 2012, based upon a third party appraisal, were as follows (in millions):

	Amount	Life (Years)
Customer relationships	\$ 118.7	20
Tradenames	14.8	Indefinite
Tradenames	5.7	10
Trade secrets	44.2	12
Total	\$ 183.4	
Weighted average amortization period		18

Montana Acquisition

On October 1, 2012, the Company completed the acquisition from Connacher Oil and Gas Limited (“Connacher”) of all the shares of common stock of Montana Refining Company, Inc. (“Montana”) and an insignificant affiliated company for aggregate consideration of approximately \$191.6 million, net of cash acquired and excluding certain purchase price adjustments (“Montana Acquisition”). Montana produces gasoline, diesel, jet fuel and asphalt, which are marketed primarily into local markets in Washington, Montana, Idaho and Alberta, Canada. The Montana Acquisition was funded primarily with cash on hand with the balance through borrowings under the Company’s revolving credit facility. The Company believes the Montana Acquisition further diversifies its crude oil feedstock slate, operating asset base and geographic presence. The assets acquired and liabilities assumed and results of operations have been included in the Company’s condensed consolidated balance sheets and unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Montana Acquisition, the Company incurred no acquisition costs during the three months ended June 30, 2013 and approximately \$0.1 million during the six months ended June 30, 2013, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

Immediately after closing the Montana Acquisition, the Company converted Montana Refining Company, Inc. into a Delaware limited liability company, Calumet Montana Refining, LLC. This conversion resulted in the recognition of a current income tax liability of approximately \$27.6 million, which was paid during the six months ended June 30, 2013, and was offset by the derecognition of a deferred tax liability for a comparable amount assumed in connection with the acquisition.

The Company recorded \$27.6 million of goodwill as a result of the Montana Acquisition, all of which was recorded within the Company’s fuel products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company’s strategic platform for expansion in its fuel products segment.

The preliminary allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

Table of Contents

	Allocation of Purchase Price
Accounts receivable	\$29.0
Inventories	43.7
Prepaid expenses and other current assets	23.1
Deposits	0.3
Property, plant and equipment	125.9
Goodwill	27.6
Other noncurrent assets, net	0.3
Accounts payable	(8.4)
Accrued salaries, wages and benefits	(1.4)
Deferred income tax liability	(27.6)
Accrued income taxes payable	(15.6)
Other taxes payable	(3.0)
Other current liabilities	(0.1)
Pension and postretirement benefit obligations	(2.2)
Total purchase price, net of cash acquired	\$191.6

San Antonio Acquisition

On January 2, 2013, the Company completed the acquisition of NuStar Energy L.P.'s ("NuStar") San Antonio, Texas refinery, together with related assets and the assumption of certain liabilities and obligations ("San Antonio Acquisition"). Total consideration for the San Antonio Acquisition was approximately \$117.8 million, net of cash acquired and excluding certain purchase price adjustments. The refinery has total crude oil throughput capacity of 14,500 bpd and primarily produces jet fuel, diesel, other fuel products and specialty solvents. The San Antonio Acquisition was funded with borrowings under the Company's revolving credit facility with the balance through cash on hand. The Company believes the San Antonio Acquisition further diversifies the Company's crude oil feedstock slate, operating asset base and geographic presence. The assets acquired and results of operations have been included in the Company's condensed consolidated balance sheets and unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the San Antonio Acquisition, during the three and six months ended June 30, 2013, the Company incurred acquisition costs of approximately \$0.2 million and \$0.5 million, respectively, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded \$5.7 million of goodwill as a result of the San Antonio Acquisition, all of which was recorded within the Company's fuel products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company's strategic platform for expansion in its fuel products segment.

The San Antonio 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. The preliminary allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

	Allocation of Purchase Price
Inventories	\$17.0
Property, plant and equipment, net	98.2
Goodwill	5.7
Other noncurrent assets, net	2.4
Accrued salaries, wages and benefits	(0.1)
Other current liabilities	(5.4)
Total purchase price, net of cash acquired	\$117.8

Table of Contents

Results of Sales and Earnings

The following financial information reflects sales and operating income of the Royal Purple, Montana and San Antonio Acquisitions that are included in the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2013 (in millions):

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Sales	\$279.0	\$533.9
Operating income	\$16.5	\$25.6

Pro Forma Financial Information (Unaudited)

The following unaudited pro forma financial information reflects the unaudited condensed consolidated results of operations of the Company as if the Royal Purple, Montana and San Antonio Acquisitions had taken place on January 1, 2012 (in millions, except for per unit data):

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Sales	\$1,373.8	\$2,786.0
Net income	\$78.2	\$121.9
Limited partners' interest net income per unit — basic and diluted	\$1.08	\$1.69

The Company's historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Royal Purple, Montana and San Antonio 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.

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 cost of inventory is recorded using the last-in, first-out (LIFO) method. 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. The replacement cost of these inventories, based on current market values, would have been \$57.7 million and \$38.3 million higher as of June 30, 2013 and December 31, 2012, respectively.

Inventories consist of the following (in millions):

	June 30, 2013	December 31, 2012
Raw materials	\$118.8	\$85.4
Work in process	113.9	119.5
Finished goods	356.6	348.7
	\$589.3	\$553.6

Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs.

Table of Contents

5. Joint Venture

On February 7, 2013, the Company entered into a joint venture agreement with MDU Resources Group, Inc. (“MDU”) to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC. The refinery’s total construction cost is estimated at approximately \$300.0 million. The capitalization of the joint venture is expected to be funded through contributions of \$150.0 million from MDU and \$75.0 million from the Company and proceeds of \$75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower. The term loan facility was funded in April 2013. Funding for the project will occur over the course of the construction period, with the majority of the direct funding by the Company expected to occur in 2014. The diesel refinery is expected to be operational in the fourth quarter of 2014. The joint venture will allocate profits on a 50%/50% basis to the Company and MDU. The joint venture will be governed by a board of managers comprised of representatives from both the Company and MDU. MDU will provide a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. The Company will provide refinery operations, crude oil procurement and refined product marketing expertise to the joint venture.

The Company accounts for its ownership in its joint venture under the equity method of accounting. As of June 30, 2013, the Company has contributed \$16.6 million to Dakota Prairie Refining, LLC to fund development of the refinery.

6. 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 EPA, various state environmental regulatory bodies, 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 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 addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require the Company to make additional unforeseen expenditures. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected to increase over time. For example, on September 12, 2012, the EPA published final amendments to the New Source Performance Standards (“NSPS”) for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares. The Company is currently evaluating the effect that the NSPS rule may have on its refinery operations.

Voluntary remediation of subsurface contamination is in process at certain 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.

San Antonio Refinery

In connection with the San Antonio Acquisition, the Company agreed to indemnify NuStar from any environmental liabilities associated with the San Antonio refinery, except for any governmental penalties or fines that may result

from NuStar's actions or inactions during NuStar's 20 month period of ownership of the San Antonio refinery. Anadarko Petroleum Corporation ("Anadarko") and Age Refining, Inc. ("Age Refining"), another third party that has since entered bankruptcy, are subject to a 1995 Agreed Order from the Texas Natural Resource Conservation Commission, now known as the Texas Commission on Environmental Quality ("TCEQ"), pursuant to which Anadarko and Age Refining are obligated to assess and

Table of Contents

remediate contamination at the San Antonio refinery. The Company is not a party to this Agreed Order. The Company is in discussions with both TCEQ and Anadarko over how best to address pre-existing contamination at the San Antonio refinery.

Montana Refinery

In connection with the Montana Acquisition (see Note 3), the Company became a party to an existing 2002 Refinery Initiative consent decree (“Montana Consent Decree”) with the EPA and the Montana Department of Environmental Quality (“MDEQ”). The material obligations imposed by the Montana Consent Decree have been completed. Periodic reporting is the primary current obligation under the Montana Consent Decree. On September 27, 2012, Montana Refining Company, Inc. received a final Corrective Action Order on Consent, replacing the refinery’s previous hazardous waste permit. This Corrective Action Order on Consent governs the investigation and remediation of contamination at the Montana refinery. The Company believes the majority of damages related to such contamination at the Montana refinery are covered by a contractual indemnity provided by Holly Corporation (“Holly”), the owner and operator of the Montana refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Montana refinery. Under this asset purchase agreement, Holly agreed to indemnify Connacher and Montana Refining Company, Inc. for environmental conditions arising under Holly’s ownership and operation of the Montana refinery, and existing as of the date of sale to Connacher. As a result of the Montana Acquisition, the Company’s liability is limited under the asset purchase agreement between Holly and Connacher and the costs to be covered by Calumet are not believed to be material at this time. Some of these costs covered by the Company will be voluntary to prepare the expansion area. Prior to the Montana Acquisition, Holly had reimbursed Connacher in accordance with the contractual indemnity for remedial actions related to such contamination at the Montana refinery.

Superior Refinery

In connection with the Superior Acquisition, the Company became a party to an existing consent decree (“Superior Consent Decree”) with the EPA and the Wisconsin Department of Natural Resources (“WDNR”) that applies, in part, to its Superior refinery. Under the Superior 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 the WDNR. The Company currently estimates costs of approximately \$3.0 million to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform required tasks under the Superior 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 will result in the Company incurring additional costs, which could be substantial. For the three months ended June 30, 2013 and 2012, the Company incurred approximately \$0.1 million and \$0.9 million, respectively, of costs related to installing process equipment pursuant to the EPA fuel content regulations. For the six months ended June 30, 2013 and 2012, the Company incurred approximately \$0.2 million and \$1.4 million, 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 Superior refinery, which included a proposed penalty amount of \$0.1 million. 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 attended an informal conference with the EPA held September 12, 2012. 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.

The Company is contractually indemnified by Murphy Oil Corporation (“Murphy Oil”) under an asset purchase agreement between the Company and Murphy Oil for specified environmental liabilities arising from the operations of the Superior refinery including: (i) certain obligations arising out of the Superior Consent Decree (including payment of a civil penalty required under the Superior 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 believes contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums.

Table of Contents

The Company is also contractually indemnified by Murphy Oil under the asset purchase agreement until October 1, 2013 for liabilities arising from breaches of certain environmental representations and warranties made by Murphy Oil, subject to a maximum liability of \$22.0 million, for which the Company is required to contribute up to the first \$6.6 million. The amount of any damages payable by Murphy Oil pursuant to the contractual indemnities under the asset purchase agreement will be net of any amount recoverable under an environmental insurance policy that the Company has obtained in connection with the Superior Acquisition, which names the Company and Murphy Oil as insureds and covers environmental conditions existing at the Superior refinery prior to the Superior Acquisition. Shreveport, Cotton Valley and Princeton Refineries

On December 23, 2010, the Company entered into a settlement agreement with the Louisiana Department of Environmental Quality (“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. Among other things, the Company 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 months ended June 30, 2013 and 2012, the Company incurred approximately \$2.3 million and \$1.1 million, respectively, of such expenditures. During the six months ended June 30, 2013 and 2012, the Company incurred approximately \$4.5 million and \$2.2 million, respectively, of such expenditures and estimates additional expenditures of approximately \$1.0 million to \$3.0 million of capital expenditures and expenditures related to additional personnel and environmental studies over the next three years as a result of the implementation of these requirements. These capital investment requirements are incorporated into the Company’s annual capital expenditures budgets 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. In August 2011, the EPA conducted an inspection of the Shreveport refinery’s Risk Management Program compliance. An inspection report dated October 20, 2011 was transmitted to the Shreveport refinery. The Company submitted supplemental information to the EPA, which was followed by a site visit from EPA personnel. On February 25, 2013, the EPA issued a draft Consent Agreement and Final Order to the Shreveport refinery, which included a proposed civil penalty of \$0.8 million. The Company met with the EPA on April 3, 2013, to present information refuting some of the EPA’s findings. The Company is in the process of submitting additional information to the EPA.

The Company is contractually indemnified by Shell Oil Company (“Shell”), as successor to Pennzoil-Quaker State Company and Atlas Processing Company under an asset purchase agreement between the Company and Shell, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company’s acquisition of the facility. The contractual indemnity is believed by the Company to be unlimited in amount and duration, but requires the Company to contribute up to \$1.0 million of the first \$5.0 million 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 conducts periodic audits of Process Safety Management (“PSM”) systems at each of its locations subject to the PSM standard 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. Changes in occupational safety and health laws and regulations or a finding of non-compliance with current laws and regulations could result in additional capital expenditures or operating expenses, as well as civil penalties and, in the event of a serious injury or

fatality, criminal charges.

The Company has completed studies to assess the adequacy of its PSM practices at its Shreveport refinery with respect to certain consensus codes and standards. During the three months ended June 30, 2013, the Company incurred approximately \$1.9 million of related capital expenditures. During the three months ended June 30, 2012, the Company incurred no related capital expenditures. During the six months ended June 30, 2013 and 2012, the Company incurred approximately \$2.0 million and \$0.3 million, respectively, of related capital expenditures and expects to incur between \$1.0 million and \$2.0 million of

18

Table of Contents

capital expenditures during the second half of 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 PSM 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 \$0.2 million. The Company has contested the Cotton Valley Citation and associated penalty 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.

Labor Matters

The Company has employees covered by various collective bargaining agreements. The Cotton Valley and Dickinson collective bargaining agreements were ratified on March 21, 2013 and April 1, 2013, respectively, and both will expire on March 31, 2016. The Shreveport collective bargaining agreement was ratified on May 30, 2013 and will expire on April 30, 2016.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued to vendors. As of June 30, 2013 and December 31, 2012, the Company had outstanding standby letters of credit of \$152.3 million and \$222.4 million, respectively, under its senior secured revolving credit facility (the "revolving credit facility"). Refer to Note 7 for additional information regarding the Company's revolving credit facility. The maximum amount of letters of credit the Company could issue at June 30, 2013 and December 31, 2012 under its revolving credit facility is 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 (\$850.0 million at June 30, 2013 and December 31, 2012).

As of June 30, 2013 and December 31, 2012, the Company had availability to issue letters of credit of \$495.8 million and \$355.1 million, respectively, under its revolving credit facility. As of June 30, 2013 and December 31, 2012, the outstanding standby letters of credit issued under the revolving credit facility included a \$25.0 million letter of credit issued to a hedging counterparty to support a portion of its fuel products hedging program.

Table of Contents

7. Long-Term Debt

Long-term debt consisted of the following (in millions):

	June 30, 2013	December 31, 2012
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments monthly, borrowings due June 2016, weighted average rate of 4.5% at June 30, 2013	\$—	\$—
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019, effective interest rate of 9.93% for the six months ended June 30, 2013	600.0	600.0
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 10.02% for the six months ended June 30, 2013	275.0	275.0
Capital lease obligations, at various interest rates, interest and principal payments monthly through January 2027	5.2	5.5
Less unamortized discounts	(16.1) (17.0)
Total long-term debt	864.1	863.5
Less current portion of long-term debt	0.7	0.8
	\$863.4	\$862.7

9 5/8% Senior Notes

On June 29, 2012, in connection with the Royal Purple Acquisition, the Company issued and sold \$275.0 million in aggregate principal amount of 9 5/8% of senior notes due August 1, 2020 (the “2020 Notes”) in a private placement pursuant to Section 4(a)(2) of 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 \$262.6 million, net of discount, underwriters’ fees and expenses, which the Company used to fund a portion of the purchase price of the Royal Purple Acquisition. Refer to Note 3 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 is minor and 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.

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.

On December 4, 2012, the Company filed an exchange offer registration statement for the 2020 Notes with the SEC, which was declared effective on June 27, 2013. The exchange offer was completed on July 26, 2013, thereby fulfilling all of the requirements of the 2020 Notes registration rights agreement.

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.

Table of Contents

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 \$400.0 million 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 Section 4(a)(2) of 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 \$389.0 million 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 \$200.0 million 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 Section 4(a)(2) 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 \$180.3 million 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 is minor and 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.

Upon the occurrence of certain change of control events, each holder of the 2019 Notes will have the right to require that the Company repurchase all or a portion of such holder’s 2019 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 December 16, 2011, the Company filed exchange offer registration statements for the 2019 Notes with the SEC, which were declared effective on January 3, 2012. The exchange offers were completed on February 2, 2012, thereby fulfilling all of the requirements of the 2019 Notes registration rights agreements by the specified dates.

Amended and Restated Senior Secured Revolving Credit Facility

The Company has an \$850.0 million 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, 2013, 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.

Table of Contents

The borrowing capacity at June 30, 2013 under the revolving credit facility was \$648.1 million. As of June 30, 2013, the Company had no outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of \$152.3 million, leaving \$495.8 million 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) \$46.4 million, (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.

Maturities of Long-Term Debt

As of June 30, 2013, maturities of the Company's long-term debt are as follows (in millions):

Year	Maturity
2013	\$0.4
2014	0.4
2015	0.3
2016	0.3
2017	0.4
Thereafter	878.4
Total	\$880.2

8. Derivatives

The Company is exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in the Company's fuel products segment) and natural gas. The Company uses various strategies to reduce its exposure to commodity price risk. The Company does not attempt to eliminate all of the Company's risk as the costs of such actions are believed to be too high in relation to the risk posed to the Company's future cash flows, earnings and liquidity. The strategies to reduce the Company's risk utilize both physical forward contracts and financially settled derivative instruments such as swaps, futures and options to attempt to reduce the Company's exposure with respect to:

• crude oil purchases;

• fuel product sales;

• natural gas purchases; and

• fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as NYMEX WTI, Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS") and Mixed Sweet Blend ("MSW").

The Company does not hold or issue derivative instruments for trading purposes.

The Company recognizes all derivative instruments at their fair values (see Note 9) 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 following tables summarize

Table of Contents

the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets and liabilities on the Company's condensed consolidated balance sheets as of June 30, 2013 and December 31, 2012 (in millions):

	June 30, 2013			December 31, 2012		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Assets Presented in the Condensed Consolidated Balance Sheets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Assets Presented in the Condensed Consolidated Balance Sheets
Derivative instruments designated as hedges:						
Fuel products segment:						
Crude oil swaps	\$ 14.9	\$(27.3)) \$(12.4)) \$24.9	\$(14.4)) \$10.5
Gasoline swaps	0.8	(0.4)) 0.4	5.2	(4.9)) 0.3
Diesel swaps	29.1	(13.2)) 15.9	7.0	(14.9)) (7.9)
Jet fuel swaps	8.9	(0.1)) 8.8	8.0	(7.8)) 0.2
Total derivative instruments designated as hedges	53.7	(41.0)) 12.7	45.1	(42.0)) 3.1
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	0.6	(1.8)) (1.2)) 0.1	(0.1)) —
Crude oil basis swaps	2.9	(2.1)) 0.8	0.1	(0.1)) —
Gasoline swaps	0.2	(0.4)) (0.2)) —	—) —
Diesel swaps	3.0	—) 3.0	5.1	(5.1)) —
Jet fuel swaps	—	(0.1)) (0.1)) —	—) —
Specialty products segment:						
Crude oil swaps	0.1	—) 0.1	1.6	(1.6)) —
Natural gas swaps	—	(0.9)) (0.9)) —	—) —
Total derivative instruments not designated as hedges	6.8	(5.3)) 1.5	6.9	(6.9)) —
Total derivative instruments	\$60.5	\$(46.3)) \$14.2	\$52.0	\$(48.9)) \$3.1

Table of Contents

	June 30, 2013				December 31, 2012			
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Condensed Consolidated Balance Sheets		Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Condensed Consolidated Balance Sheets	
Derivative instruments designated as hedges:								
Fuel products segment:								
Crude oil swaps	\$(31.1) \$27.3	\$(3.8) \$(41.1) \$14.4	\$(26.7)	
Gasoline swaps	—	0.4	0.4	(2.8) 4.9	2.1)	
Diesel swaps	(10.3) 13.2	2.9	(25.2) 14.9	(10.3)	
Jet fuel swaps	(0.1) 0.1	—	(10.1) 7.8	(2.3)	
Total derivative instruments designated as hedges	(41.5) 41.0	(0.5) (79.2) 42.0	(37.2)	
Derivative instruments not designated as hedges:								
Fuel products segment:								
Crude oil swaps	(1.9) 1.8	(0.1) (10.8) 0.1	(10.7)	
Crude oil basis swaps	(0.9) 2.1	1.2	(3.5) 0.1	(3.4)	
Gasoline swaps	(0.4) 0.4	—	(2.2) —	(2.2)	
Diesel swaps	—	—	—	(1.2) 5.1	3.9)	
Jet fuel swaps	(0.1) 0.1	—	—	—	—)	
Specialty products segment:								
Crude oil swaps	—	—	—	—	1.6	1.6)	
Natural gas swaps	(2.0) 0.9	(1.1) —	—	—)	
Total derivative instruments not designated as hedges	(5.3) 5.3	—	(17.7) 6.9	(10.8)	
Total derivative instruments	\$(46.8) \$46.3	\$(0.5) \$(96.9) \$48.9	\$(48.0)	

The Company accounts for certain derivatives hedging purchases of crude oil and sales of gasoline, diesel and jet fuel 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. Periodically, the Company may enter into crude oil and fuel product basis swaps to more effectively hedge its crude oil purchases and fuel products sales. These derivatives can be combined with a swap contract in order to create a more effective hedge. The Company has entered into crude oil basis swaps for 2013 that do not qualify as cash flow hedges for accounting purposes as they were not entered into simultaneously with a corresponding NYMEX WTI derivative contract.

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

Table of Contents

deferred amounts in accumulated other comprehensive income (loss) are immediately recognized in unrealized gain 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. 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 discontinuance of hedge accounting on these derivative instruments has caused the Company to recognize the following gains and losses in realized gain (loss) on derivative instruments and unrealized gain (loss) in the unaudited condensed statements of operations for the three and six months ended June 30, 2013 and 2012 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Realized gain (loss) on derivative instruments	\$2.4	\$27.2	\$(3.0)	\$54.4
Unrealized gain on derivative instruments	\$3.6	\$12.9	\$7.4	\$42.2

The amount reclassified from accumulated other comprehensive income (loss) into earnings, as a result of the discontinuance of hedge accounting for certain jet fuel 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 \$1.1 million and \$0.5 million 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, determined on a derivative by derivative basis or in the aggregate for a specific commodity, and has the potential for the future loss of hedge accounting. 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 comprehensive income and unaudited condensed consolidated statements of partners' capital as of, and for the three months ended June 30, 2013 and 2012 related to its derivative instruments that were designated as cash flow hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion)		Location of Gain (Loss)	Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)		Location of Gain (Loss)	Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion)	
	Three Months Ended			Three Months Ended			Three Months Ended	
	June 30, 2013	2012		June 30, 2013	2012		June 30, 2013	2012

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Fuel products
segment:

Crude oil swaps	\$(40.5)	\$(131.6)	Cost of sales	\$(9.3)	\$13.4	Unrealized/ Realized	\$(3.6)	\$(11.7)
Gasoline swaps	9.3	18.1	Sales	3.7	(22.9)	Unrealized/ Realized	(0.5)	3.4
Diesel swaps	58.7	47.4	Sales	1.4	(16.2)	Unrealized/ Realized	(1.7)	0.8
Jet fuel swaps	17.0	86.3	Sales	5.8	(25.0)	Unrealized/ Realized	6.0	6.2

Specialty
products
segment:

Crude oil swaps	—	—	Cost of sales	—	(2.5)	Unrealized/ Realized	—	—
Total	\$44.5	\$20.2		\$1.6	\$(53.2)		\$0.2	\$(1.3)

25

Table of Contents

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended June 30, 2013 and 2012 related to its derivative instruments not designated as cash flow hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain on Derivative Instruments		Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments	
	Three Months Ended		Three Months Ended	
	June 30, 2013	2012	June 30, 2013	2012
Fuel products segment:				
Crude oil swaps	\$(2.1) \$(7.8) \$0.1	\$(81.9
Crude oil basis swaps	6.1	11.4	(6.3) 39.8
Gasoline swaps	3.3	5.2	1.3	40.9
Diesel swaps	3.2	(1.1) 2.0	(0.5
Jet fuel swaps	—	—	(0.1) —
Specialty products segment:				
Crude oil swaps	—	—	0.1	0.6
Natural gas swaps	—	(2.1) (2.0) 2.6
Interest rate swaps	—	(0.1) —	0.2
Total	\$10.5	\$5.5	\$(4.9) \$1.7

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, 2013 and 2012 related to its derivative instruments that were designated as cash flow hedges (in millions):

Type of Derivative	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 (Effective Portion)	Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion)				
	Six Months Ended			Six Months Ended				
	June 30, 2013	2012		June 30, 2013	2012			
Fuel products segment:								
Crude oil swaps	\$(26.7) \$(98.9) Cost of sales	\$(13.6) \$34.6	Unrealized/ Realized	\$(27.8) \$49.9
Gasoline swaps	(0.4) (40.2) Sales	(0.1) (39.2) Unrealized/ Realized	(0.6) (15.3
Diesel swaps	41.6	(21.4) Sales	1.4	(22.8) Unrealized/ Realized	(3.3) (1.8
Jet fuel swaps	12.7	7.6	Sales	2.0	(68.6) Unrealized/ Realized	6.5	1.9
Specialty products segment:								
	—	—	Cost of sales	0.3	—	Unrealized/ Realized	—	—

Crude oil
swaps

Total	\$ 27.2	\$(152.9)	\$(10.0)	\$(96.0)	\$(25.2)	\$34.7
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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the six months ended June 30, 2013 and 2012 related to its derivative instruments not designated as cash flow hedges (in millions):

26

Table of Contents

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Six Months Ended June 30,		Amount of Gain (Loss) Recognized in Unrealized Gain on Derivative Instruments Six Months Ended June 30,		
	2013	2012	2013	2012	
	Fuel products segment:				
Crude oil swaps	\$ (7.6) \$ (7.3) \$ 39.8	\$ (80.2)
Crude oil basis swaps	6.3	—	5.3	—	
Gasoline swaps	3.6	11.4	—	39.8	
Diesel swaps	4.8	5.2	(3.4) 40.9	
Jet fuel swaps	—	(1.1) (0.1) (0.5)
Specialty products segment:					
Crude oil swaps	1.7	—	(1.5) 0.6	
Natural gas swaps	—	(3.5) (2.0) 1.1	
Interest rate swaps	—	(0.6)	0.9	
Total	\$ 8.8	\$ 4.1	\$ 38.1	\$ 2.6	

The cash flow impact of the Company's derivative activities is classified primarily as a change in derivative activity 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, 2013, the Company had six counterparties, in which derivatives held were net assets, totaling \$14.2 million. As of December 31, 2012, the Company had two counterparties, in which the derivatives held were net assets, totaling \$3.1 million. 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, 2013 or December 31, 2012. 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 is not netted against derivative assets or liabilities. As of June 30, 2013 and December 31, 2012, the Company had provided its counterparties with no collateral except for a \$25.0 million 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 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, 2013 and December 31, 2012, there was a net asset of \$2.8 million and a net

liability \$7.5 million, 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.

The effective portion of the cash flow hedges classified in accumulated other comprehensive income (loss) was \$23.3 million and \$14.0 million, respectively, as of June 30, 2013 and December 31, 2012. Absent a change in the fair market value

Table of Contents

of the underlying transactions, the following other comprehensive income (loss) at June 30, 2013 will be reclassified to earnings by December 31, 2016 with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income (Loss)
2013	\$ 24.4
2014	1.6
2015	(2.7)
2016	—
Total	\$ 23.3

Based on fair values as of June 30, 2013, the Company expects to reclassify \$25.4 million of net gains on derivative instruments from accumulated other comprehensive income 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 — Specialty Products Segment

At June 30, 2013, the Company had purchased a crude oil swap for 150,000 bbls in the second quarter of 2013 related to future crude oil purchases in its specialty products segment, which was not designated as a cash flow hedge. The Company subsequently sold a crude oil derivative swap in the second quarter of 2013, and the net impact of these two derivatives was a net gain of \$0.1 million that has been recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations for the quarter ended June 30, 2013. This gain will be realized in the third quarter of 2013 and will be recorded to realized gain in the unaudited condensed consolidated statement of operations. At December 31, 2012, the Company had purchased a crude oil swap for 200,000 bbls in the second quarter of 2012 related to future crude oil purchases in its specialty products segment, which was not designated as a cash flow hedge. The Company subsequently sold a crude oil derivative swap in the second quarter of 2012, and the net impact of these two derivatives was a net gain of \$1.6 million that was recorded to unrealized loss on derivative instruments in the consolidated statements of operations for the year ended December 31, 2012. This gain was realized in January 2013 upon settlement and was recorded to realized gain on derivative instruments in the unaudited condensed consolidated statements of operations.

Natural Gas Swap Contracts

At June 30, 2013, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as cash flow hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	\$/MMBtu
Fourth Quarter 2013	1,000,000	\$4.11
Calendar Year 2014	2,400,000	4.21
Calendar Year 2015	2,400,000	4.36
Calendar Year 2016	2,000,000	4.48
Totals	7,800,000	
Average price		\$4.31

At December 31, 2012, the Company did not have any natural gas derivatives related to future natural gas purchases in its specialty products segment.

Crude Oil Contracts — Fuel Products Segment**Crude Oil Swap Contracts**

At June 30, 2013, 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:

Table of Contents

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap (\$/Bbl)
Third Quarter 2013	1,518,000	16,500	\$95.52
Fourth Quarter 2013	1,104,000	12,000	93.41
Calendar Year 2014	5,841,500	16,004	89.63
Calendar Year 2015	5,329,000	14,600	89.08
Calendar Year 2016	549,000	1,500	85.75
Totals	14,341,500		
Average price			\$90.19

At June 30, 2013, 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 2013	368,000	4,000	\$96.58
Fourth Quarter 2013	368,000	4,000	96.58
Totals	736,000		
Average price			\$96.58

At June 30, 2013, the Company had the following derivatives to sell crude oil in its fuel products segment, none of which are designated as cash flow hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap (\$/Bbl)
Third Quarter 2013	92,000	1,000	93.50
Totals	92,000		
Average price			\$93.50

At December 31, 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)
First Quarter 2013	1,665,000	18,500	\$101.67
Second Quarter 2013	1,911,000	21,000	100.22
Third Quarter 2013	1,426,000	15,500	95.62
Fourth Quarter 2013	1,104,000	12,000	93.41
Calendar Year 2014	5,110,000	14,000	89.47
Calendar Year 2015	4,781,500	13,100	89.49
Totals	15,997,500		
Average price			\$92.85

At December 31, 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:

Table of Contents

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap (\$/Bbl)
First Quarter 2013	630,000	7,000	\$101.34
Second Quarter 2013	455,000	5,000	98.56
Third Quarter 2013	368,000	4,000	96.58
Fourth Quarter 2013	368,000	4,000	96.58
Totals	1,821,000		

Average price \$98.72

Crude Oil Basis Swap Contracts

During 2012 and 2013, the Company entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between Canadian heavy crude oil and NYMEX WTI crude oil, pricing differentials between LLS and NYMEX WTI and pricing differentials between MSW and NYMEX WTI. At June 30, 2013, 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)
Third Quarter 2013	550,000	5,978	\$(12.67)
Fourth Quarter 2013	552,000	6,000	(12.82)
Totals	1,102,000		

Average price \$(12.74)

At December 31, 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)
First Quarter 2013	180,000	2,000	\$(23.75)
Second Quarter 2013	364,000	4,000	(27.38)
Third Quarter 2013	184,000	2,000	(23.75)
Fourth Quarter 2013	184,000	2,000	(23.75)
Totals	912,000		

Average differential \$(25.20)

Fuel Products Swap Contracts

Diesel Swap Contracts

At June 30, 2013, the Company had the following derivatives related to diesel 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 2013	966,000	10,500	\$121.87
Fourth Quarter 2013	828,000	9,000	120.82
Calendar Year 2014	4,566,500	12,511	116.46
Calendar Year 2015	4,781,500	13,100	115.81
Calendar Year 2016	549,000	1,500	112.37
Totals	11,691,000		

Average price \$116.76

Table of Contents

At June 30, 2013, the Company had the following derivatives related to diesel 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 2013	276,000	3,000	\$124.17
Fourth Quarter 2013	276,000	3,000	124.17
Calendar Year 2014	90,000	247	118.71
Totals	642,000		
Average price			\$123.40

At December 31, 2012, the Company had the following derivatives related to diesel 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)
Second Quarter 2013	546,000	6,000	\$122.74
Third Quarter 2013	874,000	9,500	122.23
Fourth Quarter 2013	828,000	9,000	120.82
Calendar Year 2014	3,835,000	10,507	116.00
Calendar Year 2015	4,781,500	13,100	115.81
Totals	10,864,500		
Average price			\$117.13

At December 31, 2012, the Company had the following derivatives related to diesel 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)
First Quarter 2013	540,000	6,000	\$130.57
Second Quarter 2013	364,000	4,000	126.82
Third Quarter 2013	276,000	3,000	124.17
Fourth Quarter 2013	276,000	3,000	124.17
Totals	1,456,000		
Average price			\$127.20

Jet Fuel Swap Contracts

At June 30, 2013, the Company had the following derivatives related to 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 2013	368,000	4,000	\$125.13
Fourth Quarter 2013	276,000	3,000	122.36
Calendar Year 2014	1,275,000	3,493	116.64
Calendar Year 2015	547,500	1,500	112.51
Totals	2,466,500		
Average price			\$117.63

At June 30, 2013, the Company had the following derivatives to purchase jet fuel in its fuel products segment, none of which are designated as cash flow hedges:

Table of Contents

Jet Fuel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap (\$/Bbl)
Third Quarter 2013	92,000	1,000	\$115.92
Calendar Year 2014	90,000	247	116.71
Totals	182,000		
Average price			\$116.31

At December 31, 2012, the Company had the following derivatives related to 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 2013	1,035,000	11,500	\$127.39
Second Quarter 2013	819,000	9,000	129.20
Third Quarter 2013	368,000	4,000	125.13
Fourth Quarter 2013	276,000	3,000	122.36
Calendar Year 2014	1,275,000	3,493	116.64
Totals	3,773,000		
Average price			\$123.56

Gasoline Swap Contracts

At June 30, 2013, 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)
Third Quarter 2013	184,000	2,000	\$114.73
Totals	184,000		
Average price			\$114.73

At June 30, 2013, 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 2013	92,000	1,000	\$105.50
Fourth Quarter 2013	92,000	1,000	105.50
Totals	184,000		
Average price			\$105.50

At December 31, 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)
First Quarter 2013	630,000	7,000	\$113.59
Second Quarter 2013	546,000	6,000	116.32
Third Quarter 2013	184,000	2,000	114.73
Totals	1,360,000		
Average price			\$114.84

At December 31, 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:

Table of Contents

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap (\$/Bbl)
First Quarter 2013	90,000	1,000	\$ 105.50
Second Quarter 2013	91,000	1,000	105.50
Third Quarter 2013	92,000	1,000	105.50
Fourth Quarter 2013	92,000	1,000	105.50
Totals	365,000		
Average price			\$ 105.50

9. 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, crude oil basis, gasoline, diesel, jet fuel, natural gas and interest rate swaps 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, 2013, the Company's asset was increased by less than \$0.1 million and the liability was reduced by less than \$0.1 million. As a result of applying the CDS at December 31, 2012, the Company's asset was reduced by \$0.1 million and the liability was reduced by approximately \$0.2 million.

Based on the use of various unobservable inputs, principally non-performance risk and unobservable inputs in forward years for crude oil, crude oil basis, gasoline, jet fuel, diesel, natural gas and interest rate swaps, 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 8 for further information on derivative instruments.

Table of Contents

Pension Assets

Pension assets are reported at fair value in the accompanying unaudited condensed consolidated financial statements. At June 30, 2013, the Company's investments associated with its Pension Plan (as such term is hereinafter defined) primarily consist of (i) cash and cash equivalents and (ii) mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and are valued at the net asset value ("NAV") of shares in each fund held by the Pension Plan at quarter end as provided by the third party administrator. See Note 11 for further information on pension assets.

Liability Awards

Unit based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units ("Liability Awards"). The fair value of the Company's Liability Awards are updated each balance sheet date based on the closing unit price on the balance sheet date.

Renewable Identification Numbers Obligation

The Company's RINs obligation ("RINs Obligation") represents a liability for the purchase of RINs to satisfy the EPA requirement to blend biofuels into the fuel products it produces pursuant to the EPA's Renewable Fuel Standard. RINs are assigned to biofuels produced in the U.S. as required by the EPA. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, the Company is required to blend biofuels into the fuel products it produces at a rate that will meet the EPA's annual quota. To the extent the Company is unable to blend biofuels at that rate, it must purchase RINs in the open market to satisfy the annual requirement. The Company's RINs Obligation is based on the amount of RINs it must purchase and the price of those RINs as of the balance sheet date. The RINs Obligation is categorized as Level 2 and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

Hierarchy of Recurring Fair Value Measurements

The Company's recurring assets and liabilities measured at fair value at June 30, 2013 and December 31, 2012 were as follows (in millions):

Table of Contents

	June 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	\$—	\$—	\$(13.5)	\$(13.5)	\$—	\$—	\$10.5	\$10.5
Crude oil basis swaps	—	—	0.8	0.8	—	—	—	—
Gasoline swaps	—	—	0.2	0.2	—	—	0.3	0.3
Diesel swaps	—	—	18.9	18.9	—	—	(7.9)	(7.9)
Jet fuel swaps	—	—	8.7	8.7	—	—	0.2	0.2
Natural gas swaps	—	—	(0.9)	(0.9)	—	—	—	—
Total derivative assets	—	—	14.2	14.2	—	—	3.1	3.1
Pension plan investments	0.2	42.1	—	42.3	38.9	2.7	—	41.6
Total recurring assets at fair value	\$0.2	\$42.1	\$14.2	\$56.5	\$38.9	\$2.7	\$3.1	\$44.7
Liabilities:								
Derivative liabilities:								
Crude oil swaps	\$—	\$—	\$(3.9)	\$(3.9)	\$—	\$—	\$(35.8)	\$(35.8)
Crude oil basis swaps	—	—	1.2	1.2	—	—	(3.4)	(3.4)
Gasoline swaps	—	—	0.4	0.4	—	—	(0.1)	(0.1)
Diesel swaps	—	—	2.9	2.9	—	—	(6.4)	(6.4)
Jet fuel swaps	—	—	—	—	—	—	(2.3)	(2.3)
Natural gas swaps	—	—	(1.1)	(1.1)	—	—	—	—
Total derivative liabilities	—	—	(0.5)	(0.5)	—	—	(48.0)	(48.0)
RINs Obligation	—	(23.2)	—	(23.2)	—	(0.8)	—	(0.8)
Liability Awards	(3.3)	—	—	(3.3)	(2.2)	—	—	(2.2)
Total recurring liabilities at fair value	\$(3.3)	\$(23.2)	\$(0.5)	\$(27.0)	\$(2.2)	\$(0.8)	\$(48.0)	\$(51.0)

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, 2013 and 2012 (in millions):

	Six Months Ended	
	June 30, 2013	2012
Fair value at January 1,	\$(44.9)	\$14.9
Realized gain on derivative instruments	(1.2)	(30.6)
Unrealized gain on derivative instruments	20.5	10.8
Change in fair value of cash flow hedges	27.2	(152.9)
Settlements	12.1	127.2
Transfers in (out) of Level 3	—	—
Fair value at June 30,	\$13.7	\$(30.6)
Total gain included in net income attributable to changes in unrealized gain (loss) relating to financial assets and liabilities held as of June 30,	\$20.5	\$10.8

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 statements of operations in the period that the hedged cash flow occurs. Any "ineffectiveness" associated with these derivative instruments is recorded in earnings in realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of

operations. All settlements from

35

Table of Contents

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 8 for further information on derivative instruments.

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, TruSouth, Royal Purple, Montana and San Antonio 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 value of cash is considered to be representative of its respective fair value.

Debt

The estimated fair value of long-term debt at June 30, 2013 and December 31, 2012 consists primarily of the 2019 Notes and 2020 Notes. The fair values of the Company's 2019 Notes were based upon quoted market prices in an active market and are classified as Level 1. The fair values of the Company's 2020 Notes were based upon directly observable inputs and are classified as Level 2. 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 values as determined by discounted cash flows and are classified as Level 3. See Note 7 for further information on long-term debt.

The Company's carrying and estimated fair value of the Company's financial instruments, carried at adjusted historical cost, at June 30, 2013 and December 31, 2012 were as follows (in millions):

	June 30, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:				
2019 Notes	\$649.1	\$588.3	\$658.8	\$587.6
2020 Notes	\$299.8	\$270.6	\$301.8	\$270.4
Revolving credit facility	\$—	\$—	\$—	\$—
Capital lease and other obligations	\$5.2	\$5.2	\$5.5	\$5.5

10. Partners' Capital

On January 8, 2013, the Company completed a public offering of its common units in which it sold 5,750,000 common units, including the overallotment option of 750,000 common units, to the underwriters of the offering at a price to the public of \$31.81 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 \$175.2 million and were used to repay borrowings under its revolving credit facility and for general partnership purposes. Underwriting discounts totaled \$7.4 million. The Company's general partner contributed \$3.8 million to maintain its 2% general partner interest.

Table of Contents

On April 1, 2013, the Company completed a public offering of its common units in which it sold 5,250,000 common units to the underwriters of the offering at a price to the public of \$37.50 per common unit. On April 4, 2013, the overallotment option of 787,500 common units was exercised by the underwriters in full. 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 \$217.3 million and were used for general partnership purposes. Underwriting discounts totaled \$9.1 million. The Company's general partner contributed \$4.6 million 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, 2013 and 2012, the Company made distributions of \$51.9 million and \$30.1 million, respectively, to its partners. For the six months ended June 30, 2013 and 2012, the Company made distributions of \$96.4 million and \$58.3 million, respectively, to its partners.

For the three months ended June 30, 2013 and 2012, the general partner was allocated \$3.8 million and \$1.1 million, respectively, in incentive distribution rights. For the six months ended June 30, 2013 and 2012, the general partner was allocated \$7.0 million and \$1.6 million, respectively, in incentive distributions rights.

11. Employee Benefit Plans

The components of net periodic pension and other postretirement benefits cost for the three months ended June 30, 2013 and 2012 were as follows (in millions):

	For the Three Months Ended June 30,			
	2013		2012	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	\$0.1	\$—	\$0.3	\$ 0.1
Interest cost	0.6	—	0.6	0.1
Expected return on assets	(0.5) —	(0.6) —
Amortization of net loss	0.2	—	0.1	—
Net periodic benefit cost	\$0.4	\$—	\$0.4	\$ 0.2

The components of net periodic pension and other postretirement benefits cost for the six months ended June 30, 2013 and 2012 were as follows (in millions):

	For the Six Months Ended June 30,			
	2013		2012	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	\$0.2	\$—	\$0.5	\$ 0.2
Interest cost	1.2	—	1.2	0.2
Expected return on assets	(1.0) —	(1.2) —
Amortization of net loss	0.4	—	0.3	—
Net periodic benefit cost	\$0.8	\$—	\$0.8	\$ 0.4

The Company's investments associated with its Pension Plan primarily consist of (i) cash and cash equivalents and (ii) mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and are valued at the NAV of the shares in each fund held by the Pension Plan at quarter end as provided by the third party administrator. The mutual funds provide the Company with the ability to redeem its interests on a daily basis.

See Note 9 for the definition of Levels 1, 2 and 3. The Company's Pension Plan assets measured at fair value at June 30, 2013 and December 31, 2012 were as follows (in millions):

37

Table of Contents

	June 30, 2013		December 31, 2012	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	\$0.2	\$—	\$19.3	\$—
Equity	—	10.5	5.9	—
Foreign equities	—	10.7	2.3	—
Commingled fund	—	—	—	2.7
Balanced fund	—	—	3.0	—
Fixed income	—	20.9	8.4	—
	\$0.2	\$42.1	\$38.9	\$2.7

Investment Fund Strategies

Equity funds include funds that invest in U.S. common and preferred stocks. Foreign equity funds invest in securities issued by companies listed on international stock exchanges. Certain funds have value and growth objectives and managers may attempt to profit from security mispricing in equity markets to meet these objectives. Short term investments (including commercial paper, certificates of deposits and government repurchase agreements) and derivatives may be used for hedging purposes to limit exposure to various risk factors.

Fixed income funds invest in U.S. dollar-denominated, investment grade bonds, including U.S. Treasury and government agency securities, corporate bonds and mortgage and asset-backed securities. These funds may also invest in any combination of non-investment grade bonds, non-U.S. dollar denominated bonds and bonds issued by issuers in emerging capital markets. Short term investments (including commercial paper, certificates of deposits and government repurchase agreements) and derivatives may be used for hedging purposes to limit exposure to various risk factors.

12. Accumulated Other Comprehensive Income (Loss)

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive income (loss) in the Company's unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2013 (in millions):

Components of Accumulated Other Comprehensive Income (Loss)	Amount Reclassified From Accumulated Other Comprehensive Income (Loss)		Location of Gain (Loss)
	For the Three Months Ended	For the Six Months Ended	
	June 30, 2013	June 30, 2013	
Derivative gains (losses) reflected in gross profit	\$10.9 (9.3 \$1.6	\$3.3) (13.3 \$ (10.0	Sales) Cost of sales) Total
Amortization of defined benefit pension and post retirement health benefit plans:			
Amortization of net loss	\$(0.2 \$(0.2) \$(0.4) \$(0.4) (1) Total

(1) This accumulated other comprehensive income (loss) component is included in the computation of net periodic pension cost. See Note 11 for additional details.

13. 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, 2013 and 2012 (in millions, except unit and per unit data):

Table of Contents

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2013	2012	2013	2012
Numerator for basic and diluted earnings per limited partner unit:				
Net income	\$7.8	\$65.7	\$53.8	\$117.6
General partner's interest in net income	0.2	1.3	1.1	2.4
General partner's incentive distribution rights	3.8	1.1	7.0	1.6
Nonvested share based payments	—	0.4	0.2	0.7
Net income available to limited partners	\$3.8	\$62.9	\$45.5	\$112.9
Denominator for basic and diluted earnings per limited partner unit:				
Basic weighted average limited partner units outstanding	69,571,855	55,027,786	66,219,729	53,353,760
Effect of dilutive securities:				
Participating securities — phantom units	197,681	46,479	192,239	25,833
Diluted weighted average limited partner units outstanding	69,769,536	55,074,265	66,411,968	53,379,593
Limited partners' interest basic net income per unit	\$0.05	\$1.14	\$0.69	\$2.12
Limited partners' interest diluted net income per unit	\$0.05	\$1.14	\$0.68	\$2.12

14. 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, synthetic lubricants, 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 specialty products segment also blends and markets through the Company's brand Royal Purple. The fuel products segment produces a variety of fuel and fuel-related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company is also engaged in the resale of purchased crude oil to third party customers. The Company sells the majority of the fuel products it produces to markets located in Arkansas, Canada, Idaho, Iowa, Louisiana, Michigan, Minnesota, Montana, North Dakota, South Dakota, Texas and Wisconsin. The Company also has the ability to ship additional fuel products to the Midwest region and the northern states bordering Canada through the Enterprise and Magellan pipelines should the need arise. The assets and results of the operations from such assets acquired as a result of the Montana Acquisition have been included in both the specialty products and fuel products segment since the date of acquisition, October 1, 2012. The assets and results of the operations from such assets acquired as a result of the San Antonio Acquisition have been included in the fuel products segment since the date of acquisition, January 2, 2013. The assets and results of operations from such assets acquired as a result of the Missouri, TruSouth and Royal Purple Acquisitions have been included in the specialty products segment since their dates of acquisition, January 3, 2012, January 6, 2012 and July 3, 2012, respectively. 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 2012 Annual Report. The Company evaluates segment performance based on operating income. The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. Reportable segment information is as follows (in millions):

Table of Contents

Three Months Ended June 30, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	\$549.2	\$805.0	\$1,354.2	\$—	\$1,354.2
Intersegment sales	—	25.9	25.9	(25.9)) —
Total sales	\$549.2	\$830.9	\$1,380.1	\$(25.9)) \$1,354.2
Depreciation and amortization	\$23.5	\$9.4	\$32.9	\$—	\$32.9
Operating income	\$16.4	\$10.9	\$27.3	\$—	\$27.3
Reconciling items to net income:					
Interest expense					(24.7)
Gain on derivative instruments					5.8
Other					(0.4)
Income tax expense					(0.2)
Net income					\$7.8
Three Months Ended June 30, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	\$572.4	\$514.6	\$1,087.0	\$—	\$1,087.0
Intersegment sales	287.4	13.0	300.4	(300.4)) —
Total sales	\$859.8	\$527.6	\$1,387.4	\$(300.4)) \$1,087.0
Depreciation and amortization	\$18.7	\$4.6	\$23.3	\$—	\$23.3
Operating income	\$50.0	\$28.5	\$78.5	\$—	\$78.5
Reconciling items to net income:					
Interest expense					(18.4)
Gain on derivative instruments					5.9
Other					—
Income tax expense					(0.3)
Net income					\$65.7

Table of Contents

Six Months Ended June 30, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	\$1,084.3	\$1,588.5	\$2,672.8	\$—	\$2,672.8
Intersegment sales	—	48.5	48.5	(48.5)	—
Total sales	\$1,084.3	\$1,637.0	\$2,721.3	\$(48.5)	\$2,672.8
Depreciation and amortization	\$47.4	\$17.4	\$64.8	\$—	\$64.8
Operating income	\$20.8	\$60.9	\$81.7	\$—	\$81.7
Reconciling items to net income:					
Interest expense					(49.5)
Gain on derivative instruments					21.7
Other					0.3
Income tax expense					(0.4)
Net income					\$53.8
Six Months Ended June 30, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	\$1,134.9	\$1,121.7	\$2,256.6	\$—	\$2,256.6
Intersegment sales	597.1	22.2	619.3	(619.3)	—
Total sales	\$1,732.0	\$1,143.9	\$2,875.9	\$(619.3)	\$2,256.6
Depreciation and amortization	\$37.4	\$9.1	\$46.5		\$46.5
Operating income	\$78.7	\$34.8	\$113.5		\$113.5
Reconciling items to net income:					
Interest expense					(37.0)
Gain on derivative instruments					41.4
Other					0.1
Income tax expense					(0.4)
Net income					\$117.6

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and six months ended June 30, 2013 and 2012. All of the Company's long-lived assets are domestically located.

c. Product Information

The Company offers specialty products primarily in six general categories consisting of lubricating oils, solvents, waxes, packaged and synthetic specialty products, fuels and asphalt and other by-products. Fuel products primarily consist of gasoline, diesel, jet fuel and heavy fuel oils. The following table sets forth the major product category sales for the three months ended June 30, 2013 and 2012 (in millions):

Table of Contents

	Three Months Ended June 30,					
	2013		2012			
Specialty products:						
Lubricating oils	\$208.2	15	%	\$269.4	25	%
Solvents	128.0	10	%	122.7	11	%
Waxes	33.4	3	%	34.8	3	%
Packaged and synthetic specialty products	65.6	5	%	31.3	3	%
Fuels	0.3	—	%	0.5	—	%
Asphalt and other by-products	113.7	8	%	113.7	11	%
Total	\$549.2	41	%	\$572.4	53	%
Fuel products:						
Gasoline	343.6	25	%	244.9	23	%
Diesel	303.2	23	%	199.3	18	%
Jet fuel	58.2	4	%	42.3	4	%
Heavy fuel oils and other	100.0	7	%	28.1	2	%
Total	\$805.0	59	%	\$514.6	47	%
Consolidated sales	\$1,354.2	100	%	\$1,087.0	100	%

The following table sets forth the major product category sales for the six months ended June 30, 2013 and 2012 (in millions):

	Six Months Ended June 30,					
	2013		2012			
Specialty products:						
Lubricating oils	\$448.1	17	%	\$558.2	25	%
Solvents	259.7	10	%	257.5	11	%
Waxes	66.2	2	%	71.9	3	%
Packaged and synthetic specialty products	125.1	5	%	57.6	3	%
Fuels	0.9	—	%	1.4	—	%
Asphalt and other by-products	184.3	7	%	188.3	8	%
Total	\$1,084.3	41	%	\$1,134.9	50	%
Fuel products:						
Gasoline	670.9	25	%	538.4	24	%
Diesel	608.5	23	%	440.0	20	%
Jet fuel	108.4	4	%	88.2	4	%
Heavy fuel oils and other	200.7	7	%	55.1	2	%
Total	\$1,588.5	59	%	\$1,121.7	50	%
Consolidated sales	\$2,672.8	100	%	\$2,256.6	100	%

d. Major Customers

During the three and six months ended June 30, 2013 and 2012, the Company had no customer that represented 10% or greater of consolidated sales.

15. Subsequent Events

On July 22, 2013, the Company declared a quarterly cash distribution of \$0.685 per unit on all outstanding common units, or approximately \$52.6 million (including the general partner's incentive distribution rights) in aggregate, for the quarter ended June 30, 2013. The distribution will be paid on August 14, 2013 to unitholders of record as of the close of business on August 2, 2013. This quarterly distribution of \$0.685 per unit equates to \$2.74 per unit per year, or approximately \$210.4 million (including the general partner's incentive distribution rights) in aggregate on an annualized basis.

The fair value of the Company's derivatives increased by approximately \$10.0 million subsequent to June 30, 2013 to a net asset of approximately \$24.0 million. The fair value of the Company's long-term debt, excluding capital leases, has increased by approximately \$12.0 million subsequent to June 30, 2013.

Table of Contents

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

The historical condensed 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," or "us"). The following discussion analyzes the financial condition and results of operations of the Company for the three and six months ended June 30, 2013 and 2012. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Calumet in conjunction with our 2012 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 facilities primarily located in Louisiana, Wisconsin, Montana, Texas 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, waxes and asphalt. 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. We also blend and market specialty products through our Royal Purple brand. 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, as well as reselling purchased crude oil to third party customers. 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 2013 Update

Our specialty products segment generated a gross profit margin of 12.4% during the second quarter 2013, compared to 15.5% in the second quarter 2012. The quarter over quarter decline in gross profit margin was primarily attributable to less favorable pricing on certain specialty products, including lubricating oils and asphalt. We also experienced a decrease in lubricating oils sales volume driven by market conditions, including incremental production by various specialty products refiners in 2013. The decline in gross profit was partially offset by \$17.4 million of gross profit resulting from our Royal Purple and Montana Acquisitions.

Our fuels products segment generated a gross profit margin of 4.1% during the second quarter 2013, compared to 7.8% in the second quarter 2012. The quarter over quarter decline in gross profit margin was primarily attributable to: (1) a planned 45-day turnaround at our Superior refinery during the second quarter 2013; (2) weakening Gulf Coast product crack spreads compared to the prior year period; (3) a narrowing in crude oil differentials between West Texas Intermediate ("WTI") and heavy crude oils compared to the prior year period; and (4) higher than anticipated costs to purchase Renewable Identification Numbers ("RINs") in compliance with the U.S. Renewable Fuels Standard ("RFS"). We completed a planned turnaround at our Superior refinery during May 2013. During the maintenance period, the refinery was not operating, resulting in significantly lower sales volumes at our second largest fuels refinery during the period. We expect our next scheduled turnaround at the Superior refinery to occur in 2018.

For benchmarking purposes, we compare our per barrel refined fuel products margin to the U.S. Gulf Coast 2/1/1 crack spread ("Gulf Coast crack spread"). The Gulf Coast crack spread represents the approximate gross margin per barrel that results from processing two barrels of crude oil into one barrel of gasoline and one barrel of ultra low sulfur diesel fuel. The Gulf Coast crack spread is calculated using the first-month futures price of NYMEX WTI crude oil, the price of U.S. Gulf Coast Pipeline 87 Octane Conventional Gasoline and U.S. Gulf Coast Pipeline Ultra Low Sulfur Diesel. During the second quarter 2013, the Gulf Coast crack spread averaged \$25.82 per barrel, or approximately 10% less than in the second quarter 2012.

During the first half of 2013, a number of market related factors contributed to a sharp narrowing in the price per barrel between WTI and the price per barrel of other crude oils that we process at our refineries, including, Bakken light crude oil, Western Canadian Select ("WCS") and Bow River crude oil. The net impact of this narrowing in crude differentials equated to higher feedstock costs during the second quarter 2013 compared to the second quarter 2012. The narrowing in crude oil differentials is related to a number of potential factors, including, but not limited to, the blended utilization rate of the U.S. refining complex; domestic crude oil production rates; the levels of domestic crude

oil and product inventories; the availability of mechanisms capable of transporting crude oil production, whether by pipeline, barge, truck or rail, from the wellhead to regional refiners on a continuous basis; and commodity arbitrage in the futures markets, such as that engaged in by sophisticated financial entities.

Table of Contents

The following table details average crude oil price differentials of Bakken light crude oil, WCS crude oil and Bow River crude oil to NYMEX WTI crude oil (on a per barrel basis):

Average Per Barrel Crude Oil Pricing Differential to NYMEX WTI	Q2 2013	Q1 2013	Q2 2012
Bakken	\$2.13	\$(1.91)) \$6.55
WCS	\$(16.62)) \$(26.62)) \$(19.96)
Bow River	\$(18.11)) \$(30.97)) \$(21.55)

As part of our overall commodity price risk mitigation strategy, we continue to hedge portions of our anticipated fuels production as a means of curtailing exposure to commodity price fluctuations. At June 30, 2013, we had entered into derivative contracts on approximately 15 million barrels of fuels production at an average crack spread of \$27.48 per barrel through calendar year 2016.

Each year, under the RFS, the EPA will release its requirements for the total volume of renewable transportation fuels, including ethanol and advanced biofuels that are mandated to be blended into the domestic gasoline pool. Under the RFS, domestic producers of gasoline (refiners) are required to establish that they have met their annual Renewable Volume Obligation ("RVO"). RINs are a mechanism by which obligated parties may determine their compliance with the RVO, whereas the obligated party must produce a volume of RINs equal to the number of gallons that it is required to blend under the RVO. During the first half of 2013, the price per RIN increased dramatically, as the demand of RINs by obligated parties far outpaced the available supply. Between December 31, 2012 and June 30, 2013, the price of a D6 ethanol RINs rose from approximately \$0.0025 per RIN to nearly \$1.00 per RINs, representing a significant increase in compliance costs for obligated blenders. During the six months ended June 30, 2013, our total RINs expense was \$25.9 million, compared to \$1.8 million in the same period in 2012, due primarily to a significant escalation in RINs prices. For the remainder of 2013, we anticipate that our purchased RINs expense required to comply with RFS will range from \$20 to \$25 million per quarter, based on market prices as of June 30, 2013. For the full year 2013, we anticipate that our purchased RINs expense required to comply with the RFS will be in the range of \$65 to \$75 million. These estimates are subject to fluctuations in the market price of RINs, in addition to our fuels production volumes during the second half of 2013.

During 2013 and through the fourth quarter 2015, we intend to invest approximately \$420.0 million on multiple organic growth projects that, collectively, have the potential to provide significant Adjusted EBITDA annually upon completion. Under this capital spending plan, the two lead projects that have the potential to provide the vast majority of the Adjusted EBITDA uplift are (1) a crude unit expansion at our Montana refinery; and (2) the construction of a greenfield refinery in North Dakota, in cooperation with our joint venture partner, MDU Resources. The Montana refinery expansion remains on schedule to be completed by the fourth quarter 2015, while the North Dakota refinery remains on schedule to be completed by the fourth quarter of 2014.

On July 22, 2013, we declared a quarterly cash distribution of \$0.685 per unit (\$2.74 on an annualized basis) on all outstanding units, or \$52.6 million, for the second quarter 2013. The distribution will be paid on August 14, 2013 to unitholders of record as of the close of business on August 2, 2013. This quarterly distribution represents an increase of 16.1% over the second quarter 2013.

Table of Contents

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 products 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 derivative instruments 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, 2013, we have hedged refining margins, or crack spreads, on approximately 15.0 million barrels of fuel products through December 2016 at an average refining margin of \$27.48 per barrel with average refining margins ranging from a low of \$26.39 per barrel in 2015 to a high of \$31.39 per barrel in the fourth quarter of 2013. Please refer to Note 8 — “Derivatives” 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—Commodity Price Risk” for detailed information regarding our derivative instruments and our commodity price risk.

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 operating 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, or feedstocks we, or third parties, process, 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, Group 3, PADD 4 Billings, Montana or 3/2/1 and 2/1/1 market crack spreads 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, San Antonio, Texas, Superior, Wisconsin and Great Falls, Montana vicinities as compared to

U.S. Gulf Coast, Group 3 and PADD 4 Billings, Montana postings.

In addition to the foregoing measures, we also monitor our selling and general and administrative expenditures.

45

Table of Contents

Results of Operations for the Three and Six Months Ended June 30, 2013 and 2012

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, biodiesel and the resale of crude oil in our fuel products segment. The table includes the results of operations at our Missouri facility commencing on January 3, 2012, TruSouth facility commencing January 6, 2012, Royal Purple facility commencing July 3, 2012, Montana refinery commencing October 1, 2012 and San Antonio refinery commencing January 2, 2013.

	Three Months Ended June 30,			Six Months Ended June 30,			
	2013 (In bpd)	2012	% Change	2013 (In bpd)	2012	% Change	
Total sales volume (1)	116,352	91,198	27.6	% 114,083	94,357	20.9	%
Total feedstock runs (2)	108,043	90,554	19.3	% 109,684	94,761	15.7	%
Facility production: (3)							
Specialty products:							
Lubricating oils	13,642	15,027	(9.2))% 13,327	14,674	(9.2))%
Solvents	9,465	10,166	(6.9))% 9,015	9,637	(6.5))%
Waxes	1,308	1,234	6.0	% 1,271	1,255	1.3	%
Packaged and synthetic specialty products (4)	2,271	1,299	74.8	% 2,111	1,220	73.0	%
Fuels	1,086	914	18.8	% 925	680	36.0	%
Asphalt and other by-products	13,374	13,696	(2.4))% 15,652	14,196	10.3	%
Total	41,146	42,336	(2.8))% 42,301	41,662	1.5	%
Fuel products:							
Gasoline	26,696	20,582	29.7	% 28,280	22,742	24.4	%
Diesel	24,729	20,176	22.6	% 24,287	21,648	12.2	%
Jet fuel	5,241	3,469	51.1	% 5,019	4,239	18.4	%
Heavy fuel oils and other	7,126	3,491	104.1	% 7,002	3,356	108.6	%
Total	63,792	47,718	33.7	% 64,588	51,985	24.2	%
Total facility production (3)	104,938	90,054	16.5	% 106,889	93,647	14.1	%

Total sales volume includes sales from the production at Calumet's facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks such as ethanol and biodiesel as components of finished fuel products in our fuel products segment sales. The increase in total sales volume for three and six months ended June 30, 2013 compared to the same periods in 2012 is due primarily to incremental sales of fuel products, asphalt and packaged and synthetic specialty products resulting from the Royal Purple, Montana and San Antonio acquisitions partially offset by decreased sales of lubricating oils, asphalt and fuel products at the Shreveport and Superior refineries.

Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at Calumet's facilities and at certain third-party facilities pursuant to supply and/or processing agreements. The increase in total feedstock runs for three months ended June 30, 2013 compared to the same period in 2012 is due primarily to incremental feedstock runs resulting from the Royal Purple, Montana and San Antonio acquisitions, partially offset by reduced run rates at our Superior refinery due to planned turnaround activity during the second quarter of 2013.

The increase in total feedstock runs for six months ended June 30, 2013 compared to the same period in 2012 is due primarily to incremental feedstock runs resulting from the Royal Purple, Montana and San Antonio Acquisitions, partially offset by reduced run rates at our Shreveport refinery during the first quarter of 2013 due to unscheduled downtime associated with various operational reliability issues and planned turnaround activity at the Superior refinery during the second quarter of 2013.

Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at Calumet's facilities and at certain third-party facilities pursuant to

supply and/or processing agreements. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and production of finished products and volume loss. The increase in total facility production for the three and six months ended June 30, 2013 compared to the same periods in 2012 is due

Table of Contents

primarily to incremental production from acquisitions partially offset by lower run rates at the Shreveport and Superior refineries as discussed above in footnote 2 of this table.

(4) Represents production of packaged and synthetic specialty products at our Royal Purple, TruSouth and Missouri facilities.

47

Table of Contents

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 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, please read “—Non-GAAP Financial Measures.”

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Sales	\$1,354.2	\$1,087.0	\$2,672.8	\$2,256.6
Cost of sales	1,253.2	958.2	2,437.4	2,043.5
Gross profit	101.0	128.8	235.4	213.1
Operating costs and expenses:				
Selling	16.9	7.2	32.8	11.7
General and administrative	19.0	14.8	44.1	28.5
Transportation	33.8	25.0	69.2	52.5
Taxes other than income taxes	3.0	1.9	6.0	3.6
Other	1.0	1.4	1.6	3.3
Operating income	27.3	78.5	81.7	113.5
Other income (expense):				
Interest expense	(24.7) (18.4) (49.5) (37.0
Realized gain on derivative instruments	9.8	21.2	1.2	30.6
Unrealized gain (loss) on derivative instruments	(4.0) (15.3) 20.5	10.8
Other	(0.4) —	0.3	0.1
Total other income (expense)	(19.3) (12.5) (27.5) 4.5
Net income before income taxes	8.0	66.0	54.2	118.0
Income tax expense	0.2	0.3	0.4	0.4
Net income	\$7.8	\$65.7	\$53.8	\$117.6
EBITDA	\$62.2	\$104.1	\$162.5	\$194.3
Adjusted EBITDA	\$70.0	\$122.3	\$150.0	\$192.0
Distributable Cash Flow	\$(2.5) \$94.9	\$23.9	\$134.0

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 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.

Table of Contents

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, commercial banks, research analysts and others to meaningfully trend and analyze the performance of our core cash operations.

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.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report 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 commercial banks under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Distributable Cash Flow is used by us, our investors, commercial banks, research analysts and others to analyze our ability to pay distributions. Please refer to “Liquidity and Capital Resources” within this item for additional details regarding the covenants governing our debt instruments.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, 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, our 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 to EBITDA, Adjusted EBITDA and Distributable Cash Flow, and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

Table of Contents

	Three Months Ended June		Six Months Ended June 30,	
	2013	2012	2013	2012
(In millions)				
Reconciliation of Net income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income	\$7.8	\$65.7	\$53.8	\$117.6
Add:				
Interest expense	24.7	18.4	49.5	37.0
Depreciation and amortization	29.5	19.7	58.8	39.3
Income tax expense	0.2	0.3	0.4	0.4
EBITDA	\$62.2	\$104.1	\$162.5	\$194.3
Add:				
Unrealized (gain) loss on derivatives	\$4.0	\$15.3	\$(20.5)	\$(10.8)
Realized gain (loss) on derivatives, not included in net income	0.4	(2.0)	(0.9)	(0.6)
Amortization of turnaround costs	3.4	3.6	6.0	7.2
Non-cash equity based compensation	—	1.3	2.9	1.9
Adjusted EBITDA	\$70.0	\$122.3	\$150.0	\$192.0
Less:				
Replacement capital expenditures (1)	\$16.3	\$3.9	\$32.7	\$9.2
Cash interest expense (2)	22.9	17.0	46.0	34.3
Turnaround costs	33.1	6.2	47.0	14.1
Income tax expense	0.2	0.3	0.4	0.4
Distributable Cash Flow	\$(2.5)	\$94.9	\$23.9	\$134.0

(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.

Table of Contents

	Six Months Ended June 30,	
	2013	2012
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by operating activities:		
Distributable Cash Flow	\$23.9	\$134.0
Add:		
Replacement capital expenditures (1)	32.7	9.2
Cash interest expense (2)	46.0	34.3
Turnaround costs	47.0	14.1
Income tax expense	0.4	0.4
Adjusted EBITDA	\$150.0	\$192.0
Less:		
Unrealized gain on derivative instruments	(20.5) (10.8
Realized loss on derivatives, not included in net income	(0.9) (0.6
Amortization of turnaround costs	6.0	7.2
Non-cash equity based compensation	2.9	1.9
EBITDA	\$162.5	\$194.3
Add:		
Unrealized gain on derivative instruments	(20.5) (10.8
Cash interest expense (2)	(46.0) (34.3
Non-cash equity based compensation	2.9	1.9
Amortization of turnaround costs	6.0	7.2
Income tax expense	(0.4) (0.4
Provision for doubtful accounts	0.3	0.3
Changes in assets and liabilities:		
Accounts receivable	(80.7) (31.8
Inventories	(18.7) (4.8
Other current assets	(2.3) (8.7
Turnaround costs	(47.0) (14.1
Derivative activity	(0.9) (0.6
Accounts payable	83.7	(57.9
Accrued interest payable	(2.4) (0.2
Accrued income taxes payable	(27.6) 0.3
Other current liabilities	25.4	3.5
Other, including changes in noncurrent liabilities	0.4	0.7
Net cash provided by operating activities	\$34.7	\$44.6

(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.

Table of Contents

Changes in Results of Operations for the Three Months Ended June 30, 2013 and 2012

Sales. Sales increased \$267.2 million, or 24.6%, to \$1,354.2 million in the three months ended June 30, 2013 from \$1,087.0 million in the same period in 2012. The results of operations related to the Montana Acquisition have been included in both segments since the date of acquisition, October 1, 2012. The results of operations related to the San Antonio Acquisition have been included in the fuel products segment since the date of acquisition, January 2, 2013. The results of operations related to the Royal Purple Acquisition have been included in the specialty products segment since the date of acquisition, July 3, 2012. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended June 30,			
	2013	2012	% Change	
	(Dollars in millions, except per barrel data)			
Sales by segment:				
Specialty products:				
Lubricating oils	\$208.2	\$269.4	(22.7))%
Solvents	128.0	122.7	4.3	%
Waxes	33.4	34.8	(4.0))%
Packaged and synthetic specialty products (1)	65.6	31.3	109.6	%
Fuels (2)	0.3	0.5	(40.0))%
Asphalt and by-products (3)	113.7	113.7	—	%
Total specialty products	\$549.2	\$572.4	(4.1))%
Total specialty products sales volume (in barrels)	3,687,000	3,490,000	5.6	%
Average specialty products sales price per barrel	\$148.96	\$164.01	(9.2))%
Fuel products:				
Gasoline	\$339.9	\$267.8	26.9	%
Diesel	297.9	233.9	27.4	%
Jet fuel	56.3	48.9	15.1	%
Heavy fuel oils and other (4)	100.0	28.1	255.9	%
Hedging activities gain (loss)	10.9	(64.1)	(117.0))%
Total fuel products	\$805.0	\$514.6	56.4	%
Total fuel products sales volume (in barrels)	6,901,000	4,809,000	43.5	%
Average fuel products sales price per barrel (excluding hedging activities)	\$115.07	\$120.34	(4.4))%
Average fuel products sales price per barrel (including hedging activities)	\$116.65	\$107.00	9.0	%
Total sales	\$1,354.2	\$1,087.0	24.6	%
Total sales volume (in barrels)	10,588,000	8,299,000	27.6	%

(1) Represents production of packaged and synthetic specialty products at the Royal Purple, TruSouth and Missouri facilities.

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

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

(4) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Montana refineries and purchased crude oil sales from the Superior and San Antonio refineries to third parties.

Table of Contents

The components of the \$23.2 million specialty products segment sales decrease for the three months ended June 30, 2013 were as follows:

	Dollar Change (In millions)	
Acquisitions	\$62.7	
Sales price	(48.9)
Volume	(37.0)
Total specialty products segment sales decrease	\$(23.2)

Specialty products segment sales decreased \$23.2 million quarter over quarter, or 4.1%, primarily as a result of a decreased average selling prices per barrel and lower sales volumes, partially offset by incremental sales from acquisitions. Legacy operations' sales decreased \$48.9 million compared to the second quarter of 2012 due to lower average selling prices per barrel of 9.1% driven by lower lubricating oils, solvents and asphalt average selling prices per barrel while the average cost of crude oil per barrel increased 2.3%. The decrease in lubricating oils was driven by market conditions, including incremental production by various specialty products refiners in 2013. Legacy operations' sales volumes decreased 6.5% as compared to the same period in 2012, which resulted in a \$37.0 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils and asphalt, partially offset by increased sales volume of solvents and packaged and synthetic specialty products due to market conditions. The Royal Purple and Montana Acquisitions increased sales by \$62.7 million which were all related to packaged and synthetic specialty products and asphalt.

The components of the \$290.4 million fuel products segment sales increase for the three months ended June 30, 2013 were as follows:

	Dollar Change (In millions)	
Acquisitions	\$216.3	
Sales price	(26.6)
Volume	25.7	
Hedging activities	75.0	
Total fuels products segment sales increase	\$290.4	

Fuel products segment sales increased \$290.4 million quarter over quarter, or 56.4%, due primarily to incremental sales from acquisitions and a \$75.0 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges. Additionally, sales volume from our legacy operations increased slightly despite the turnaround at the Superior refinery in the second quarter of 2013. These increases were partially offset by a decrease in the average selling price per barrel. The Montana and San Antonio Acquisitions increased sales by \$216.3 million. Calumet's legacy operations' sales volumes increased 4.4% as a result of increased sales volume of gasoline and diesel at the Shreveport refinery and increased crude oil sales to third party customers as we continued to grow our crude oil gathering business. The improvements in sales volume at our Shreveport refinery were due primarily to the ExxonMobil pipeline shutdown in April 2012 lowering run rates during the second quarter 2012. Partially offsetting these improvements in sales volume was the turnaround at our Superior refinery that lasted approximately 45 days during the second quarter 2013. Legacy operations' average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased \$5.32, or 4.4%, resulting in a \$26.6 million decrease in sales, compared to a 4.4% increase in the average price of crude oil per barrel.

Table of Contents

Gross Profit. Gross profit decreased \$27.8 million, or 21.6%, to \$101.0 million in the three months ended June 30, 2013 from \$128.8 million in the same period in 2012. Gross profit for our specialty products and fuel products segments were as follows:

	Three Months Ended June 30,		
	2013	2012	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	\$68.2	\$88.6	(23.0)%
Percentage of sales	12.4	% 15.5	%
Specialty products gross profit per barrel	\$18.50	\$25.39	(27.1)%
Fuel products:			
Gross profit excluding hedging activities	\$31.2	\$90.9	(65.7)%
Hedging activities	1.6	(50.7)	(103.2)%
Gross profit	\$32.8	\$40.2	(18.4)%
Percentage of sales	4.1	% 7.8	%
Fuel products gross profit per barrel (excluding hedging activities)	\$4.52	\$18.90	(76.1)%
Fuel products gross profit per barrel (including hedging activities)	\$4.75	\$8.36	(43.2)%
Total gross profit	\$101.0	\$128.8	(21.6)%
Percentage of sales	7.5	% 11.8	%

The components of the \$20.4 million specialty products segment gross profit decrease for the three months ended June 30, 2013 were as follows:

	Dollar Change (In millions)
Quarter ended June 30, 2012 reported gross profit	\$88.6
Acquisitions	17.4
Sales price	(48.9)
Volume	(9.1)
Cost of materials	32.9
Operating costs	(12.7)
Quarter ended June 30, 2013 reported gross profit	\$68.2

The decrease in specialty products segment gross profit of \$20.4 million quarter over quarter was due primarily to decreased average selling prices per barrel and decreased sales volume, partially offset by lower cost of materials and acquisitions. Sales price and cost of materials, net, from our legacy operations decreased gross profit by \$16.0 million, as the decrease in average selling price per barrel of specialty products outpaced the average cost of crude oil by 11.4%. As discussed above, the majority of this variance is due to reduced sales prices per barrel of lubricating oils and asphalt. Other specialty products pricing and demand remained relatively consistent compared to the prior period. Further reducing gross profit were increased operating costs of \$12.7 million primarily as a result of higher natural gas costs. The Royal Purple and Montana Acquisitions contributed \$17.4 million of incremental gross profit to partially offset these decreases.

Table of Contents

The components of the \$7.4 million fuel products segment gross profit decrease for the three months ended June 30, 2013 were as follows:

	Dollar Change (In millions)
Quarter ended June 30, 2012 reported gross profit	\$40.2
Acquisitions	18.5
Sales price	(26.6)
Volume	5.8
Hedging activities	52.3
Cost of materials	(45.6)
Operating costs	(11.8)
Quarter ended June 30, 2013 reported gross profit	\$32.8

The decrease in fuel products segment gross profit of \$7.4 million quarter over quarter was due primarily to decreased gross profit from our legacy operations due to narrowing crack spreads as the average cost of crude oil per barrel increased and the average selling price per barrel decreased. Primarily contributing factors that caused this narrowing of our refining crack spread include: lower heavy crude oil differentials to NYMEX WTI, lower U.S. Gulf Coast crack spreads in the current year and a change in our fuels refining sales mix as a result of our Superior turnaround during the quarter. As a result of the Superior turnaround, our fuel products segment was more heavily weighted to U.S. Gulf Coast refining margins during the current period. Further reducing gross profit in our legacy operations were higher operating costs of \$11.8 million due primarily to \$10.8 million related to rising RINs pricing and rising natural gas prices. These decreases were partially offset by decreased realized losses on derivatives of \$52.3 million and \$18.5 million of incremental gross profit contributed from acquisitions.

Selling. Selling expenses increased \$9.7 million, or 134.7%, to \$16.9 million in the three months ended June 30, 2013 from \$7.2 million in the same period in 2012. This increase was due primarily to increased amortization expense of \$4.9 million primarily related to the recording of intangible assets associated with the Royal Purple Acquisition, additional employee compensation costs from the Royal Purple, Montana and San Antonio Acquisitions with no similar expenses in the same period in 2012 and increased advertising expenses of \$2.0 million.

General and administrative. General and administrative expenses increased \$4.2 million, or 28.4%, to \$19.0 million in the three months ended June 30, 2013 from \$14.8 million in the same period in 2012. The increase was due primarily to increased professional fees of \$5.0 million due primarily to consulting fees related to our enterprise resource planning system implementation and additional employee compensation costs from the Royal Purple, Montana and San Antonio Acquisitions, with no similar expenses in the same period in 2012, partially offset by decreased incentive compensation costs of \$4.2 million due to the lower financial performance in the current year relative to performance targets.

Transportation. Transportation expenses increased \$8.8 million, or 35.2%, to \$33.8 million in the three months ended June 30, 2013 from \$25.0 million in the same period in 2012. This increase is due primarily to incremental transportation expenses related to sales from the Royal Purple, Montana and San Antonio Acquisitions and crude oil sales to third parties.

Interest expense. Interest expense increased \$6.3 million, or 34.2%, to \$24.7 million in the three months ended June 30, 2013 from \$18.4 million in the three months ended June 30, 2012, due primarily to additional outstanding long-term debt in the form of 2020 Notes issued to partially fund the Royal Purple 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, 2013 and 2012.

Table of Contents

	Three Months Ended June 30,	
	2013	2012
	(In millions)	
Derivative gain (loss) reflected in sales	\$10.9	\$(64.1)
Derivative gain (loss) reflected in cost of sales	(9.3)	10.9)
Derivative gains (losses) reflected in gross profit	\$1.6	\$(53.2)
Realized gain on derivative instruments	\$9.8	\$21.2
Unrealized loss on derivative instruments	(4.0)	(15.3)
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	\$7.4	\$(47.3)
Total gain (loss) on derivative settlements	\$11.8	\$(34.0)

Realized gain on derivative instruments. Realized gain on derivative instruments decreased \$11.4 million to \$9.8 million in the three months ended June 30, 2013 from \$21.2 million in the prior period. The change was due primarily to a decreased realized gain of approximately \$24.8 million related to the settlements of derivative instruments used to economically hedge crack spreads at our Superior refinery that are not classified as hedges for accounting purposes and therefore are not reflected in gross profit. Partially offsetting this decreased realized gain were realized gains of approximately \$6.1 million on crude oil basis swaps used to economically hedge crude oil purchases at our Superior refinery and hedging ineffectiveness related to settlements of cash flow hedges.

Unrealized loss on derivative instruments. Unrealized loss on derivative instruments decreased \$11.3 million to \$4.0 million in the three months ended June 30, 2013 from \$15.3 million in the prior period. The change was due primarily to decreased unrealized loss ineffectiveness of approximately \$17.8 million. Partially offsetting this decreased unrealized loss was an increased unrealized loss of \$4.7 million related to derivatives used to economically hedge our natural gas purchases that are not classified as hedges for accounting purposes.

Table of Contents

Changes in Results of Operations for the Six Months Ended June 30, 2013 and 2012

Sales. Sales increased \$416.2 million, or 18.4%, to \$2,672.8 million in the six months ended June 30, 2013 from \$2,256.6 million in the same period in 2012. The results of operations related to the Montana Acquisition have been included in both segments since the date of acquisition, October 1, 2012. The results of operations related to the San Antonio Acquisition have been included in the fuel products segment since the date of acquisition, January 2, 2013. The results of operations related to the Missouri, TruSouth and Royal Purple Acquisitions have been included in the specialty products segment since the dates of acquisition, January 3, 2012, January 6, 2012 and July 3, 2012, respectively. Sales for each of our principal product categories in these periods were as follows:

	Six Months Ended June 30,			
	2013	2012	% Change	
	(Dollars in millions, except per barrel data)			
Sales by segment:				
Specialty products:				
Lubricating oils	\$448.1	\$558.2	(19.7)%
Solvents	259.7	257.5	0.9	%
Waxes	66.2	71.9	(7.9)%
Packaged and synthetic specialty products (1)	125.1	57.6	117.2	%
Fuels (2)	0.9	1.4	(35.7)%
Asphalt and by-products (3)	184.3	188.3	(2.1)%
Total specialty products	\$1,084.3	\$1,134.9	(4.5)%
Total specialty products sales volume (in barrels)	7,106,000	6,917,000	2.7	%
Average specialty products sales price per barrel	\$152.59	\$164.07	(7.0)%
Fuel products:				
Gasoline	\$671.0	\$577.5	16.2	%
Diesel	606.4	513.0	18.2	%
Jet fuel	107.1	106.7	0.4	%
Heavy fuel oils and other (4)	200.7	55.1	264.2	%
Hedging activities gain (loss)	3.3	(130.6)	(102.5) %
Total fuel products	\$1,588.5	\$1,121.7	41.6	%
Total fuel products sales volume (in barrels)	13,543,000	10,256,000	32.0	%
Average fuel products sales price per barrel (excluding hedging activities)	\$117.05	\$122.11	(4.1)%
Average fuel products sales price per barrel (including hedging activities)	\$117.29	\$109.37	7.2	%
Total sales	\$2,672.8	\$2,256.6	18.4	%
Total sales volume (in barrels)	20,649,000	17,173,000	20.2	%

(1) Represents production of packaged and synthetic specialty products at the Royal Purple, TruSouth and Missouri facilities.

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

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

(4) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Montana refineries and purchased crude oil sales from the Superior and San Antonio refineries to third parties.

Table of Contents

The components of the \$50.6 million specialty products segment sales decrease for the six months ended June 30, 2013 were as follows:

	Dollar Change (In millions)	
Acquisitions	\$95.5	
Sales price	(89.4)
Volume	(56.7)
Total specialty products segment sales decrease	\$(50.6)

Specialty products segment sales decreased \$50.6 million for the six months ended June 30, 2013 compared to the same period in 2012, or 4.5%, primarily as a result of a decreased average selling price per barrel and lower sales volumes, partially offset by incremental sales from acquisitions. Legacy operations' sales decreased \$89.4 million due to lower average selling prices per barrel of 8.3% driven by lower average selling prices per barrel of lubricating oils, packaged and synthetic products and asphalt while the average cost of crude oil per barrel decreased 2.5%. Legacy operations' sales volumes decreased 5.0% as compared to the same period in 2012 which resulted in a \$56.7 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils and waxes, partially offset by increased sales volume of packaged and synthetic specialty products due to market conditions and lower run rates at our Shreveport refinery in the first quarter of 2013 due to unscheduled down time caused by various reliability issues. The Royal Purple and Montana Acquisitions increased sales by \$95.5 million which were all related to packaged and synthetic specialty products and asphalt.

The components of the \$466.8 million fuel products segment sales increase for the six months ended June 30, 2013 were as follows:

	Dollar Change (In millions)	
Acquisitions	\$438.4	
Sales price	(41.4)
Volume	(64.1)
Hedging activities	133.9	
Total fuels products segment sales increase	\$466.8	

Fuel products segment sales increased \$466.8 million for the six months ended June 30, 2013 compared to the same period in 2012, or 41.6%, due primarily to incremental sales from acquisitions and a \$133.9 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges, partially offset by decreased sales volume from our legacy operations and a decrease in the average selling price per barrel. The acquisitions of Montana in 2012 and San Antonio in 2013 increased sales by \$438.4 million. Calumet's legacy operations' sales volumes decreased 5.1% as a result of decreased run rates period over period, primarily due to unscheduled down time caused by various reliability issues at the Shreveport refinery and a second quarter 2013 plantwide turnaround at the Superior refinery that lasted approximately 45 days. Legacy operations' average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased \$4.27, or 3.5%, resulting in a \$41.4 million decrease in sales, compared to a 4.9% decrease in the average price of crude oil per barrel with average jet fuel pricing declining the most compared to the prior period.

Table of Contents

Gross Profit. Gross profit increased \$22.3 million, or 10.5%, to \$235.4 million in the six months ended June 30, 2013 from \$213.1 million in the same period in 2012. Gross profit for our specialty products and fuel products segments were as follows:

	Six Months Ended June 30,		
	2013	2012	% Change
(Dollars in millions, except per barrel data)			
Gross profit by segment:			
Specialty products:			
Gross profit	\$131.4	\$155.1	(15.3)%
Percentage of sales	12.1	% 13.7	%
Specialty products gross profit per barrel	\$18.49	\$22.42	(17.5)%
Fuel products:			
Gross profit excluding hedging activities	\$114.3	\$154.0	(25.8)%
Hedging activities	(10.3)) (96.0)) (89.3)%
Gross profit	\$104.0	\$58.0	79.3%
Percentage of sales	6.5	% 5.2	%
Fuel products gross profit per barrel (excluding hedging activities)	\$8.44	\$15.02	(43.8)%
Fuel products gross profit per barrel (including hedging activities)	\$7.68	\$5.65	35.9%
Total gross profit	\$235.4	\$213.1	10.5%
Percentage of sales	8.8	% 9.4	%

The components of the \$23.7 million specialty products segment gross profit decrease for the six months ended June 30, 2013 were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2012 reported gross profit	\$155.1
Acquisitions	27.0
Sales price	(89.4)
Volume	(12.9)
Cost of materials	65.7
Operating costs	(14.1)
Six months ended June 30, 2013 reported gross profit	\$131.4

The decrease in specialty products segment gross profit of \$23.7 million for the six months ended June 30, 2013 compared to the same period in 2012, was due primarily to decreased average selling prices per barrel and decreased sales volume partially offset by lower cost of materials and acquisitions. Sales price and cost of materials, net, from our legacy operations decreased gross profit by \$23.7 million, as the average selling price per barrel of specialty products decreased 8.3% compared to a 2.5% decrease in the average cost of crude oil per barrel. This was primarily due to lower asphalt and lubricating oils pricing as discussed above. Further reducing gross profit were increased operating costs of \$14.1 million primarily as a result of higher natural gas costs. The Royal Purple and Montana Acquisitions contributed \$27.0 million of incremental gross profit to partially offset these decreases.

Table of Contents

The components of the \$46.0 million fuel products segment gross profit increase for the six months ended June 30, 2013 were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2012 reported gross profit	\$58.0
Acquisitions	37.8
Sales price	(41.4)
Volume	(12.1)
Hedging activities	85.7
Cost of materials	(3.1)
Operating costs	(20.9)
Six months ended June 30, 2013 reported gross profit	\$104.0

The increase in fuel products segment gross profit of \$46.0 million for the six months ended June 30, 2013 compared to the same period in 2012, was due primarily to decreased realized losses on derivatives of \$85.7 million and \$37.8 million of gross profit contributed from acquisitions, partially offset by decreased gross profit from our legacy operations due to narrowing crack spreads and increased operating costs. Contributing factors that caused this narrowing of our refining crack spread included lower heavy crude oil differentials to NYMEX WTI, USGC refining crack spreads being lower in the current year and a change in our fuels refining sales mix as a result of the turnaround at the Superior refinery during the quarter. As a result, our fuels segment was more heavily weighted to U.S. Gulf Coast refining margins during the current period. The 5.1% decline in legacy operations' sales volume was primarily due to unscheduled down time caused by various reliability issues at the Shreveport refinery in the first quarter of 2013 and a second quarter 2013 plantwide turnaround at the Superior refinery that lasted 45 days. Operating costs increased \$20.9 million primarily as a result of \$18.3 million of higher RINs costs and natural gas costs in our legacy operations. In total, gross profit decreased by \$25.9 million in the 2013 period due to higher RINs costs which are reflected in the impacts of acquisitions and operating costs above.

Selling. Selling expenses increased \$21.1 million, or 180.3%, to \$32.8 million in the six months ended June 30, 2013 from \$11.7 million in the same period in 2012. This increase was due primarily to increased amortization expense of \$11.2 million primarily related to the recording of intangible assets associated with the Royal Purple Acquisition, additional employee compensation costs from the Royal Purple Acquisition, with no similar expenses in the prior period and increased advertising expenses of \$5.0 million.

General and administrative. General and administrative expenses increased \$15.6 million, or 54.7%, to \$44.1 million in the six months ended June 30, 2013 from \$28.5 million in the same period in 2012. The increase was due primarily to increased professional fees of \$8.6 million due primarily to consulting fees related to our enterprise resource planning system implementation and additional employee compensation costs from the Royal Purple, Montana and San Antonio Acquisitions, with no similar expenses in the prior year.

Transportation. Transportation expenses increased \$16.7 million, or 31.8%, to \$69.2 million in the six months ended June 30, 2013 from \$52.5 million in the same period in 2012. This increase is due primarily to incremental transportation expenses related to sales from the Royal Purple, Montana and San Antonio Acquisitions and crude oil sales to third parties.

Interest expense. Interest expense increased \$12.5 million, or 33.8%, to \$49.5 million in the six months ended June 30, 2013 from \$37.0 million in the in the same period in 2012, due primarily to additional outstanding long-term debt in the form of 2020 Notes issued to partially fund the Royal Purple 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, 2013 and 2012.

Table of Contents

	Six Months Ended June 30,	
	2013	2012
	(In millions)	
Derivative gain (loss) reflected in sales	\$3.3	\$(130.6)
Derivative gain (loss) reflected in cost of sales	(13.3)	34.6
Derivative losses reflected in gross profit	\$(10.0)	\$(96.0)
Realized gain on derivative instruments	\$1.2	\$30.6
Unrealized gain on derivative instruments	20.5	10.8
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	\$11.7	\$(54.6)
Total loss on derivative settlements	\$(9.7)	\$(66.0)

Realized gain on derivative instruments. Realized gain on derivative instruments decreased \$29.4 million to \$1.2 million in the six months ended June 30, 2013 from \$30.6 million in the prior period. The change was due primarily to a decreased realized gain of approximately \$57.4 million related to the settlements of derivative instruments used to economically hedge crack spreads at our Superior refinery that are not classified as hedges for accounting purposes and therefore are not reflected in gross profit. Partially offsetting this decreased realized gain were decreased realized losses of approximately \$3.5 million on natural gas swaps used to economically hedge natural gas purchases and \$14.9 million in decreased hedging ineffectiveness losses related to settlements of cash flow hedges.

Unrealized gain on derivative instruments. Unrealized gain on derivative instruments increased \$9.7 million to \$20.5 million in the six months ended June 30, 2013 from \$10.8 million in the prior period. The change was due primarily to increased unrealized gain ineffectiveness of approximately \$30.9 million. Partially offsetting this increased unrealized gain was decreased unrealized gains of \$20.8 million related to the market value change of derivative instruments used to economically hedge crack spreads at our Superior refinery that are not classified as hedges for accounting purposes and increased unrealized losses on derivatives used to economically hedge our natural gas purchases and specialty products segment crude oil purchases but are not classified as hedges for accounting purposes.

Table of Contents

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 II, Item 7 in our 2012 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 7 — “Long-Term Debt” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” for additional discussion related to our 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 limited partners and general partner and debt service. We expect that our principal uses of cash in the future will be for distributions to our unitholders 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, cash on hand 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, cash on hand 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. In addition, our cash flow from operations may be impacted by the timing of settlements of our derivative instruments. Gains and losses from derivative instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive income (loss), but may impact operating cash flow in the period settled. The following table summarizes our primary sources and uses of cash in each of the periods presented:

	Six Months Ended June 30,	
	2013	2012
	(In millions)	
Net cash provided by operating activities	\$34.7	\$44.6
Net cash used in investing activities	(204.1) (330.3
Net cash provided by financing activities	300.4	351.1
Net increase in cash and cash equivalents	\$131.0	\$65.4

Operating Activities. Operating activities provided cash of \$34.7 million during the six months ended June 30, 2013 compared to \$44.6 million during the same period in 2012. The decrease in cash provided by operating activities is due primarily to decreased net income of \$63.8 million partially offset by a decrease in working capital requirements, primarily decreased accounts receivable, inventories and accounts payable for the six months ended June 30, 2013 compared to the same period in 2012.

Investing Activities. Cash used in investing activities decreased to \$204.1 million during the six months ended June 30, 2013 compared to \$330.3 million during the prior year period. The decrease is due primarily to the net proceeds before expenses of \$263.3 million from the sale of the 2020 Notes in June 2012 that were deposited into an escrow account pending completion of the Royal Purple Acquisition in the 2012 period, partially offset by the higher purchase price of the San Antonio Acquisition of \$117.8 million in 2013 compared to a combined purchase price of \$46.4 million for the Missouri and TruSouth Acquisitions, which closed during 2012, a \$49.1 million increase in capital expenditures and \$14.7 million contributed to the Dakota Prairie Refining, LLC joint venture, with no such

contributions in the prior period.

62

Table of Contents

Financing Activities. Financing activities provided cash of \$300.4 million in the six months ended June 30, 2013 compared to \$351.1 million during the prior year period. This change period over period is due primarily to net proceeds from the private placement of senior notes of \$270.2 million in 2012 with no such proceeds in the 2013 period and increased distributions to our unitholders of \$38.1 million, partially offset by increased net proceeds from public offerings of common units (including our general partner's contributions) of \$251.2 million.

Equity Transactions

On January 8, 2013, we completed a public offering of our common units in which we sold 5,750,000 common units, including the overallotment option of 750,000 common units, to the underwriters of the offering at a price to the public of \$31.81 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 \$175.2 million and were used to repay borrowings under our revolving credit facility and for general partnership purposes. Underwriting discounts totaled \$7.4 million. Our general partner contributed \$3.8 million to maintain its 2% general partner interest.

On April 1, 2013, we completed a public offering of our common units in which we sold 5,250,000 common units to the underwriters of the offering at a price to the public of \$37.50 per common unit. On April 4, 2013, the overallotment option of 787,500 common units was exercised at a price to the public of \$37.50 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 \$217.3 million and were used for general partnership purposes. Underwriting discounts totaled \$9.1 million. Our general partner contributed \$4.6 million to maintain its 2% general partner interest.

On April 22, 2013, we declared a quarterly cash distribution of \$0.68 per unit on all outstanding common units, or approximately \$51.9 million (including our general partner's incentive distribution rights) in aggregate, for the quarter ended March 31, 2013. The distribution will be paid on May 15, 2013 to unitholders of record as of the close of business on May 3, 2013. This quarterly distribution of \$0.68 per unit equates to \$2.72 per unit per year, or approximately \$207.6 million (including our general partner's incentive distribution rights) in aggregate on an annualized basis.

On July 22, 2013, we declared a quarterly cash distribution of \$0.685 per unit on all outstanding common units, or approximately \$52.6 million (including our general partner's incentive distribution rights) in aggregate, for the quarter ended June 30, 2013. The distribution will be paid on August 14, 2013 to unitholders of record as of the close of business on August 2, 2013. This quarterly distribution of \$0.685 per unit equates to \$2.74 per unit per year, or approximately \$210.4 million (including our general partner's incentive distribution rights) in aggregate on an annualized basis.

Acquisitions

On January 2, 2013, we completed the acquisition of our San Antonio, Texas refinery, together with the associated crude oil pipeline, crude oil terminal, other operating and logistics assets and inventories of NuStar Refining, LLC and NuStar Logistics, L.P., both wholly owned subsidiaries of NuStar Energy L.P., for aggregate consideration of approximately \$117.8 million, subject to certain post-closing adjustments. The San Antonio refinery produces jet fuel, diesel, other fuel products and specialty solvents. The San Antonio Acquisition was funded primarily with borrowings under our revolving credit facility with the balance through cash on hand. We believe the San Antonio Acquisition further diversifies our crude oil feedstock slate, operating asset base and geographic presence.

Joint Venture

On February 7, 2013, we entered into a joint venture agreement with MDU Resources Group, Inc. ("MDU") to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC. The refinery is expected to process 20,000 bpd of Bakken crude oil primarily to serve diesel demand in the region. Construction of the refinery began during the first quarter of 2013 with startup of the refinery expected late in the fourth quarter of 2014. The refinery's total construction cost is estimated at approximately \$300.0 million. The capitalization of the joint venture is expected to be funded through contributions of \$150.0 million from MDU and \$75.0 million from us and proceeds of \$75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower. The term loan facility was funded in April 2013. Funding for the project will occur over the course of the construction period, with the majority of the direct funding by us and MDU expected to occur in 2014.

As of June 30, 2013, we have contributed \$16.6 million to the Dakota Prairie Refining, LLC joint venture. The joint venture will allocate profits on a 50%/50% basis to us and MDU. We will cover the debt service cost of the lower interest rate term loan facility pursuant to the joint venture agreement. The joint venture will be governed by a board of managers comprised of representatives from both us and MDU. MDU will provide a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. We will provide refinery operations, crude oil procurement and refined product marketing expertise to the joint venture.

Table of Contents

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,	
	2013	2012
	(In millions)	
Capital improvement expenditures	\$38.9	\$13.3
Replacement capital expenditures	18.7	2.9
Environmental capital expenditures	14.0	6.3
Total	\$71.6	\$22.5

We anticipate that future capital expenditure requirements will be provided primarily through cash from operations and available borrowings under our revolving credit facility. Our environmental capital expenditures have increased during the six months ended June 30, 2013 as compared to the same period in 2012 due primarily to expenditures related to the Global Settlement with the LDEQ and OSHA compliance matters. Please read Note 6 of Part I, Item 1 “Financial Statements—Commitments and Contingencies—Environmental — Occupational Health and Safety” for additional information on the Global Settlement and OSHA compliance issues.

We estimate our replacement and environmental capital expenditures will be approximately \$22.0 million for the remainder of 2013. These estimated amounts for 2013 include a portion of the \$1.0 million to \$3.0 million in environmental projects to be spent over the next three years as required by our settlement with the LDEQ under the “Small Refinery and Single Site Refining Initiative.” Please read Note 6 of Part I, Item 1 “Financial Statements—Commitments and Contingencies—Environmental — Occupational Health and Safety” for additional information.

During the six months ended June 30, 2013, we spent approximately \$47.0 million primarily related to scheduled turnarounds at our Shreveport refinery in the first quarter of 2013 and Superior refinery in the second quarter of 2013. Additionally, we anticipate turnaround spending requirements will be approximately \$22.0 million for the remainder of 2013 related to scheduled turnarounds at our Montana and San Antonio refineries. We expect these expenditures will be funded primarily through cash flow from operations.

We have several capital improvement projects under consideration including capacity expansions at certain of our facilities, as well as planned investments such as the joint venture located in North Dakota with MDU. We currently estimate that these organic growth opportunities could lead to capital improvement expenditures over the next two years of approximately \$420.0 million. Decisions to proceed on such projects are based on several factors, including, but not limited to, feasibility studies, cost estimates, availability of funding sources and, in certain cases, required approval of the board of directors of our general partner. Due to these factors, the estimated amount to be spent in 2013 on capital improvement projects is approximately \$100.0 million to \$200.0 million.

Debt and Credit Facilities

As of June 30, 2013, our primary debt and credit instruments consisted 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, 2013, we believe we were in compliance with all covenants under the debt instruments in place at June 30, 2013 and have adequate liquidity to conduct our business.

Table of Contents

Short Term Liquidity

As of and for the three and six months ended June 30, 2013, our principal sources of short-term liquidity were (i) \$495.8 million of availability under our revolving credit facility and (ii) \$163.2 million of cash. Borrowings under our revolving credit facility can be used for, among other things, working capital, capital expenditures, and other lawful partnership purposes including 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, 2013, we had availability on our revolving credit facility of \$495.8 million, based on a \$648.1 million borrowing base, \$152.3 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 under our revolving credit facility 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 mainly 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, 2013 were \$99.6 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, 2013, availability for additional borrowings under our revolving credit facility was approximately \$359.0 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, 2013, 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 either 0.375% or 0.50% per annum depending on the average daily available unused borrowing capacity for the preceding month. 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 cash and availability under the revolving credit facility totaling at least the greater of (i) 15% 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 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 credit agreement)) and (b) the credit agreement commitments then in effect and (ii) \$46.4 million, 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.

Table of Contents

For additional information regarding our revolving credit facility, see Note 7 of Part I, Item 1 “Financial Statements—Long-Term Debt” and Note 6 “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data” in our 2012 Annual Report.

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 the issuance of 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 to the extent they are unsecured. As of June 30, 2013 and December 31, 2012, we had \$600.0 million in 2019 Notes and \$275.0 million in 2020 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 our 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.

Upon the occurrence of certain change of control events, each holder of the 2019 and 2020 Notes will have the right to require that we repurchase all or a portion of such holder’s 2019 and 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.

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 2019 and 2020 Notes, see Note 7 — “Long-Term Debt” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” and Note 6 — “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data” of our 2012 Annual Report.

Master Derivative Contracts and Collateral Trust Agreement

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 our 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 with this counterparty. We had no additional letters of credit or cash margin posted with any hedging counterparty as of June 30, 2013. 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 increased by approximately \$10.0 million subsequent to June 30, 2013 to a net asset of approximately \$24.0 million. All credit support thresholds with our hedging counterparties are at levels such that it would take

Table of Contents

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 trust 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 from time to time.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of June 30, 2013 at current maturities and reflects only those line items that have materially changed since December 31, 2012 is as follows:

	Total	Payments Due by Period			
		Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(In millions)				
Operating activities:					
Interest on long-term debt at contractual rates (1)	\$534.6	\$90.6	\$174.6	\$166.1	\$103.3
Operating lease obligations (2)	114.8	26.5	37.1	24.6	26.6
Letters of credit (3)	152.3	152.3	—	—	—
Purchase commitments (4)	1,828.1	1,764.7	62.8	0.6	—
Financing activities:					
Capital lease obligations	5.2	0.7	0.6	0.7	3.2
Long-term debt obligations, excluding capital lease obligations	875.0	—	—	—	875.0
Total obligations	\$3,510.0	\$2,034.8	\$275.1	\$192.0	\$1,008.1

(1) Interest on long-term debt at contractual rates and maturities relates primarily to our 2019 and 2020 Notes, revolving credit facility and capital lease obligations.

(2) We have various operating leases primarily for railcars, the use of land, storage tanks, compressor stations, 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 Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the “LVT Feedstock Agreement”). Pursuant to the LVT Feedstock Agreement, Phillips 66 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 \$68.4 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of June 30, 2013. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2013 and 2014, for which we have not contractually committed, refer to “Capital Expenditures” above.

Off-Balance Sheet Arrangements

We did not enter into any material off-balance sheet debt or operating lease transactions during the three and six months ended June 30, 2013.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Part II, Item 7 of our 2012 Annual Report.

Table of Contents

Recent Accounting Pronouncements

For additional discussion regarding recent accounting pronouncements, see Note 2 — “New and Recently Adopted Accounting Pronouncements” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

68

Table of Contents

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 II, Item 7A in our 2012 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 8 — “Derivatives” 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.

Commodity Price Risk

Derivative Instruments

We are exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in our fuel products segment) and natural gas. We use various strategies to reduce our exposure to commodity price risk. We do not attempt to eliminate all of our risk as the costs of such actions are believed to be too high in relation to the risk posed to our future cash flows, earnings and liquidity. The strategies to reduce our risk utilize both physical forward contracts and financially settled derivative instruments such as swaps, futures and options to attempt to reduce our exposure with respect to:

- crude oil purchases;
- refined product sales;
- natural gas purchases; and
- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as NYMEX WTI, LLS, WCS and Mixed Sweet Blend (“MSW”).

As of June 30, 2013, we have entered into swap contracts on forecasted purchases from 2013 through 2016 for 15.1 million barrels of NYMEX WTI crude oil and forecasted sales of 0.4 million barrels of U.S. Gulf Coast conventional gasoline, 12.3 million barrels of U.S. Gulf Coast ultra-low sulfur diesel and 2.5 million barrels of U.S. Gulf Coast jet fuel. These derivative instruments, on a combined basis, were entered into to hedge a portion of our margin in our fuels products segment. Please read Note 8 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” for a discussion of the accounting treatment for the various types of derivative instruments, and a further discussion of our hedging policies.

We also enter into basis swap contracts that improve the effectiveness of our crude oil swap contracts by locking in the spread between NYMEX WTI and the crude oil that we are actually purchasing for use by our refineries. As of June 30, 2013, we had 1.1 million barrels of crude oil basis swap contracts locking in the differential between NYMEX WTI and WCS crude oil, LLS crude oil or MSW crude oil. Please read Note 8 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” for additional information.

The following table provides a summary of the implied crack spreads for the crude oil, diesel, jet fuel and gasoline swaps, as well as our WCS, LLS and MSW crude oil compared to NYMEX WTI crude oil basis swaps as of June 30, 2013 in our fuels products segment which we disclose in Note 8 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

	Barrels	BPD	Implied Crack Spread (\$/Bbl)
Third Quarter 2013	1,794,000	19,500	\$29.67
Fourth Quarter 2013	1,472,000	16,000	31.39
Calendar Year 2014	5,841,500	16,004	26.90
Calendar Year 2015	5,329,000	14,600	26.39
Calendar Year 2016	549,000	1,500	26.62
Totals	14,985,500		
Average price			\$27.48

The following table provides a summary of natural gas swaps as of June 30, 2013 in our specialty products segment which we disclose in Note 8 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Table of Contents

	MMBtu	\$/MMBtu
Fourth Quarter 2013	1,000,000	\$4.11
Calendar Year 2014	2,400,000	4.21
Calendar Year 2015	2,400,000	4.36
Calendar Year 2016	2,000,000	4.48
Totals	7,800,000	
Average price		\$4.31

Our derivative instruments and overall specialty products and fuel products hedging positions are monitored regularly by our risk management committee, which includes our executive officers. The risk management committee reviews market information and our hedging positions regularly to determine if additional derivative activity is required. A summary of derivative positions and a summary of hedging strategy are presented to our general partner's board of directors quarterly.

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, 2013:

	In millions	
Crude oil swaps	\$15.0	
Crude oil basis swaps	\$1.1	
Diesel swaps	\$(12.3))
Jet fuel swaps	\$(2.3))
Gasoline swaps	\$(0.4))
Natural gas swaps	\$7.8	

Interest Rate Risk

We have an \$850.0 million revolving credit facility as of June 30, 2013 and December 31, 2012, with borrowings bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. We have no variable rate debt and no interest rate swaps outstanding as of June 30, 2013. Borrowings under this facility are variable and at the time of borrowing we assess whether or not to enter into an interest rate swap to fix the rate.

For our fixed rate 2019 and 2020 Notes, changes in interest rates will generally affect the fair value, but not our interest expense or cash flows. The following table provides information about the fair value of our debt instruments.

	June 30, 2013		December 31, 2012	
	Fair Value (In millions)	Carrying Value	Fair Value	Carrying Value
Financial Instrument:				
2019 Notes	\$649.1	\$588.3	\$658.8	\$587.6
2020 Notes	\$299.8	\$270.6	\$301.8	\$270.4

Foreign Currency Risk

We have minimal exposure to foreign currency risk and as such the cost of hedging this risk is viewed to be in excess of the benefit of further reductions in our exposure to foreign currency exchange rate fluctuations.

Table of Contents

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, 2013 at the reasonable assurance level.

(b) Changes in Internal Control over Financial Reporting

On January 1, 2013, we implemented an enterprise resource planning (“ERP”) system on a company-wide basis, which is expected to improve the efficiency of certain financial and related transaction processes. The implementation resulted in business and operational interruptions, which required changes to our internal controls over financial reporting. We believe we have designed adequate controls into and around the new ERP system, which includes performing significant procedures, both within the ERP and outside the ERP, to monitor, review and reconcile financial activity for the three and six months ended June 30, 2013 to ensure ongoing reliability of our financial reporting.

On January 3, 2012, January 6, 2012, July 3, 2012, October 1, 2012 and January 2, 2013, we completed the Missouri, TruSouth, Royal Purple, Montana and San Antonio Acquisitions, respectively, which include certain existing information systems and internal controls over financial reporting that previously existed. We are currently in the process of evaluating and integrating the Missouri, TruSouth, Royal Purple, Montana and San Antonio Acquisitions’ historical internal controls over financial reporting with ours. We expect to complete the integration of Missouri, TruSouth, Royal Purple and Montana in fiscal year 2013 and the integration of San Antonio in fiscal year 2014.

Table of Contents

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 incidental 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 6 — “Commitments and Contingencies” in Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes in the risk factors previously disclosed in our 2012 Annual Report and our Q1 Quarterly Report under Item 1A, “Risk Factors.” In addition to the other information set forth in this Quarterly Report you should carefully consider the risk factors discussed in Part I, Item 1A “Risk Factors” in our 2012 Annual Report and our Q1 Quarterly Report, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

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

Exhibit Number	Description
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)).
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.

73

Table of Contents

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, 2013

By: /s/ R. Patrick Murray, II
R. Patrick Murray, II
Senior Vice President, Chief Financial Officer and
Secretary of Calumet GP, LLC (Principal Accounting and
Financial Officer)
(Authorized Person and Principal Accounting Officer)

Table of Contents

Index to Exhibits

Exhibit Number	Description
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)).
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.

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75