Calumet Specialty Products Partners, L.P.
Form 10-K
March 03, 2014
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2013

OR

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

Commission file number 000-51734

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

Delaware	37-1516132
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

2780 Waterfront Parkway East Drive
Suite 200
Indianapolis, Indiana 46214
(317) 328-5660
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant's Principal Executive Offices)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Common units representing limited partner interests	The NASDAQ Stock Market LLC

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
NONE.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ

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 þ No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

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

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $1,862.2 million on June 28, 2013, based on $36.38 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

On March 3, 2014, there were 69,317,278 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE.

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Annual 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 Annual 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 Part I, Item 1A "Risk Factors" of this Annual 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 Annual Report to "Calumet Specialty Products Partners, L.P.," "Calumet," "the Company," "we," "our," "us like terms refer to Calumet Specialty Products Partners, L.P. and its subsidiaries. References to "Predecessor" in this Annual Report refer to Calumet Lubricants Co., Limited Partnership and its subsidiaries, the assets and liabilities of which were contributed to Calumet Specialty Products Partners, L.P. and its subsidiaries upon the completion of our initial public offering in 2006. References in this Annual Report to "our general partner" refer to Calumet GP, LLC, the general partner of Calumet Specialty Products Partners, L.P.

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PART I

Items 1 and 2. Business and Properties

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, Pennsylvania and New Jersey. We own and lease additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("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 and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple and Bel-Ray brands. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, as well as reselling purchased crude oil to third party customers. For the year ended December 31, 2013, approximately 32.7% of our sales and 78.6% of our gross profit were generated from our specialty products segment and approximately 67.3% of our sales and 21.4% of our gross profit were generated from our fuel products segment.

Our Primary Operating Assets

Our primary operating assets consist of:

Refinery/Facility	Location	Year Acquired	Feedstock Throughput Capacity in barrels per day ("bpd")	Products
Shreveport	Louisiana	2001	60,000	Specialty lubricating oils and waxes, gasoline, diesel, jet fuel and asphalt
Superior	Wisconsin	2011	45,000	Gasoline, diesel, asphalt and heavy fuel oils
San Antonio	Texas	2013	17,500	Diesel, jet fuel, gasoline, other fuel products and specialty solvents
Cotton Valley	Louisiana	1995	13,500	Specialty solvents used principally in the manufacture of paints, cleaners, automotive products and drilling fluids
Montana	Montana	2012	10,000	Gasoline, diesel, jet fuel and asphalt
Princeton	Louisiana	1990	10,000	Specialty lubricating oils, including process oils, base oils, transformer oils, refrigeration oils and asphalt
Karns City	Pennsylvania	2008	5,500	White mineral oils, solvents, petrolatums, gelled hydrocarbons, cable fillers and natural petroleum sulfonates

Dickinson	Texas	2008	1,300	White mineral oils, compressor lubricants, natural petroleum sulfonates and biodiesel
Royal Purple	Texas	2012	N/A	Specialty products including premium industrial and consumer synthetic lubricants
Bel-Ray	New Jersey	2013	N/A	Specialty products including premium industrial and consumer synthetic lubricants and greases

Crude Oil Logistics Assets. We own and operate seven crude oil loading facilities and related assets in North Dakota and Montana, which provide us the ability to transport crude oil directly from the point of lease, into our crude oil

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loading facilities and then onto the Enbridge Pipeline System ("Enbridge Pipeline") where it can be routed to our refineries and/or third party customers.

Storage, Distribution and Logistics Assets. We own and operate product terminals in Burnham, Illinois ("Burnham"), Rhinelander, Wisconsin ("Rhinelander"), Crookston, Minnesota ("Crookston") and Proctor, Minnesota ("Duluth") with aggregate storage capacities of approximately 150,000, 166,000, 156,000, and 200,000 barrels, respectively. These terminals, as well as additional owned and leased facilities throughout the U.S., facilitate the distribution of products in the Upper Midwest, East Coast and Mid-Continent regions of the U.S. and Canada.

We also use approximately 2,700 leased railcars to receive crude oil or distribute our products throughout the U.S. and Canada. In total, we have approximately 12.5 million barrels of aggregate storage capacity at our facilities and leased storage locations.

Business Strategies

Our management team is dedicated to improving our operations by executing the following strategies:

- Concentrate on Stable Cash Flows. We intend to continue to focus on operating assets and businesses that generate stable cash flows. Approximately 32.7% of our sales and 78.6% of our gross profit in 2013 were generated by the sale of specialty products, a segment of our business which is characterized by stable customer relationships due to our customers' requirements for the highly specialized products that we provide. In addition, we manage our exposure to crude oil price fluctuations in this segment by passing on incremental feedstock costs to our specialty products customers. In our fuel products segment, which accounted for 67.3% of our sales and 21.4% of our gross profit in 2013, we seek to mitigate our exposure to fuel products margin volatility by maintaining a longer-term fuel products hedging program. In addition, our recent acquisitions of various refineries located in different geographical locations provides for diversity of cash flows based on the refining margin environment in each such region. We believe the diversity of our operating assets, products, our broad customer base and our hedging activities help contribute to the stability of our cash flows.
- Develop and Expand Our Customer Relationships. Due to the specialized nature of, and the long lead-time associated with, the development and production of many of our specialty products, our customers are incentivized to continue their relationships with us. We believe that our larger competitors do not work with customers as we do from product design to delivery for smaller volume specialty products like ours. We intend to continue to assist our existing customers in their efforts to expand their product offerings, as well as marketing specialty product formulations to new customers. By striving to maintain our long-term relationships with our broad base of existing customers and by adding new customers, we seek to limit our dependence on any one portion of our customer base.
- Enhance Profitability of Our Existing Assets. We continue to evaluate opportunities to improve our existing asset base, to increase our throughput, profitability and cash flows. Following each of our asset acquisitions, we have undertaken projects designed to maximize the profitability of our acquired assets, such as: (1) the enhancement at our Superior refinery completed in November 2012, which enables the refinery to ship crude oil by railcar to our other facilities as well as third party customers, (2) the enhancements at our San Antonio refinery completed in December 2013 allowing us to blend finished gasoline and increasing its production capacity from 14,500 bpd to 17,500 bpd and (3) the increase of production capacity at our Montana refinery from 10,000 bpd to 20,000 bpd, expected to be completed in the first quarter of 2016. We intend to further increase the profitability of our existing asset base through various measures which may include changing the product mix of our processing units, debottlenecking and expanding units as necessary to increase throughput, restarting idle assets and reducing costs by improving operations. We also continue to focus on optimizing current operations through energy savings initiatives, improving reliability, product quality enhancements and product yield improvements.
- Pursue Strategic and Complementary Acquisitions. Since 1990, our management team has demonstrated the ability to identify opportunities to acquire assets and product lines where we can enhance operations and improve profitability. In the future, we intend to continue to consider strategic acquisitions of assets or agreements with third parties that offer the opportunity for operational efficiencies, the potential for increased utilization and expansion of facilities, or the expansion of product offerings in each of our specialty products and fuel products segments. In addition, we may pursue selected acquisitions in new geographic or product areas to the extent we perceive similar

opportunities. For example, since 2011 we have completed the following acquisitions that we believe significantly enhance and diversify our existing specialty products and fuel products segments:

Superior, Wisconsin refinery ("Superior") - a refinery that produces and sells gasoline, diesel, asphalt and heavy fuel oils acquired in September 2011 ("Superior Acquisition").

Calumet Packaging, LLC ("Calumet Packaging") - a specialty petroleum packaging and distribution company acquired in January 2012. This company was formerly known as TruSouth Oil, LLC.

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Louisiana, Missouri facility - an aviation and refrigerant synthetic lubricants business acquired in January 2012.
Royal Purple, Inc. ("Royal Purple") - a leading independent formulator and marketer of specialty synthetic lubricants acquired in July 2012.
Great Falls, Montana refinery ("Montana Refining") - a refinery that produces and sells gasoline, diesel, jet fuel and asphalt products acquired in October 2012.
San Antonio, Texas refinery - a refinery that produces and sells diesel, gasoline, jet fuel, other fuel products and specialty solvents acquired in January 2013.
Crude oil logistics assets - seven crude oil loading facilities and related assets in North Dakota and Montana acquired in August 2013.
Bel-Ray Company, LLC- ("Bel-Ray") - a manufacturer and global distributor of high-performance synthetic lubricants acquired in December 2013.

See "—Recent Acquisitions" below for additional information regarding our recent acquisitions.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully based on the following competitive strengths:

- We Offer Our Customers a Diverse Range of Specialty Products. We offer a wide range of over 5,000 specialty products. We believe that our ability to provide our customers with a more diverse selection of products than most of our competitors gives us an advantage in competing for new business. We believe that we are the only specialty products manufacturer that produces all four of naphthenic lubricating oils, paraffinic lubricating oils, waxes and solvents. A contributing factor in our ability to produce numerous specialty products is our ability to ship products between our facilities for product upgrading in order to meet customer specifications.
- We Have Strong Relationships with a Broad Customer Base. We have long-term relationships with many of our customers and we believe that we will continue to benefit from these relationships. Our customer base includes more than 4,500 active accounts and we are continually seeking new customers. No single customer accounted for more than 10% of our consolidated sales in each of the three years ended December 31, 2013, 2012 and 2011.
- Our Facilities Have Advanced Technology. Our facilities are equipped with advanced, flexible technology that allows us to produce high-grade specialty products and to produce fuel products that comply with low sulfur fuel regulations. For example, our fuel products refineries have the capability to make ultra-low sulfur diesel and gasoline that meet federally mandated low sulfur standards and the Mobile Source Air Toxic Rule II standards ("MSAT II Standards") set by the EPA requiring the reduction of benzene levels in gasoline. Also, unlike larger refineries, which lack some of the equipment necessary to achieve the narrow distillation ranges associated with the production of specialty products, our operations are capable of producing a wide range of products tailored to our customers' needs.
- We Have an Experienced Management Team. Our management has a proven track record of enhancing value through the acquisition, exploitation and integration of refining assets and the development and marketing of specialty products. Our senior management team has an average of over 25 years of industry experience. Our team's extensive experience and contacts within the refining industry provide a strong foundation and focus for managing and enhancing our operations, accessing strategic acquisition opportunities and constructing and enhancing the profitability of new assets.

Recent Acquisitions

Bel-Ray

On December 10, 2013, we completed the acquisition of Bel-Ray Company, LLC, a manufacturer and global distributor of high-performance lubricants and greases, for aggregate consideration of approximately $53.6 million, net of cash acquired and excluding debt assumed and certain purchase price adjustments ("Bel-Ray Acquisition"). Bel-Ray manufactures and distributes, both domestically and internationally, a wide array of high-end specialty synthetic lubricants and greases which are used in the aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles industries. The Bel-Ray Acquisition was financed by using a portion of the net proceeds of $337.4 million from our November 2013 private placement of 7 5/8% senior notes due January 15, 2022. We believe the Bel-Ray Acquisition increases our sales in the specialty lubricants market, expands our geographic reach and increases our asset diversity.

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Crude Oil Logistics Assets

On August 9, 2013, we completed the acquisition of seven crude oil loading facilities and related assets in North Dakota and Montana from Murphy Oil USA, Inc. (“Murphy”) for aggregate consideration of approximately $6.2 million (“Crude Oil Logistics Acquisition”). The Crude Oil Logistics Acquisition was funded with cash on hand. As part of this acquisition, we assumed pipeline space on the Enbridge Pipeline previously held by Murphy. We now have the ability to transport crude oil directly from the point of lease, into our newly acquired crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to our refineries and/or third party customers. As part of this transaction, we jointly consented with Murphy to terminate an existing crude oil purchase agreement wherein Murphy supplied our Superior refinery with up to 10,000 bpd of crude oil. We believe this acquisition expands our growing portfolio of crude oil logistics assets, while positioning us to purchase increased volumes of price-advantaged feedstocks directly from the producers that operate in some of the major shale oil plays encompassing our refineries.

San Antonio Refinery

On January 2, 2013, we 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. Total consideration for the San Antonio Acquisition was approximately $117.9 million, net of cash acquired (“San Antonio Acquisition”). The refinery has total crude oil throughput capacity of 17,500 bpd and primarily produces diesel, jet fuel, gasoline, other fuel products and specialty solvents. The San Antonio Acquisition was funded 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.

Please see Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Cash Flows from Operating, Investing and Financing Activities” for additional information regarding the repayments of these revolving credit facility borrowings.

Ongoing Acquisition Activities

Consistent with our business growth strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. These acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as “auction” processes, as well as situations in which we believe we are the only potential buyer or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets and operations which, if acquired, could have a material effect on our financial condition and results of operations and require special financing.

We typically do not announce a transaction until we have executed a definitive acquisition agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of an acquisition until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive acquisition agreement will be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition efforts will be successful. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized.

Partnership Structure and Management

Calumet Specialty Products Partners, L.P. is a Delaware limited partnership formed on September 27, 2005. Our general partner is Calumet GP, LLC, a Delaware limited liability company. As of March 3, 2014, we had 69,317,278 common units and 1,414,638 general partner units outstanding. Our general partner owns 2% of the Company and all incentive distribution rights and has sole responsibility for conducting our business and managing our operations. For more information about our general partner’s board of directors and executive officers, please read Part III, Item 10 “Directors, Executive Officers of Our General Partner and Corporate Governance.”

Our Operating Assets and Contractual Arrangements

General

The following tables set forth information about our combined operations and sales of our principal products by segment. Facility production volume differs from sales volume due to changes in inventory and the sale of purchased fuel product blendstocks such as ethanol and biodiesel in our fuel products segment sales. The tables include the results of operations at our Superior refinery commencing October 1, 2011, Missouri facility commencing January 3, 2012, Calumet Packaging facility commencing January 6, 2012, Royal Purple facility commencing July 3, 2012, Montana refinery commencing October 1, 2012, San Antonio refinery commencing January 2, 2013 and Bel-Ray facility commencing December 10, 2013.

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	Year Ended December 31,			Year Ended December 31,		
	2013	2012	% Change	2012	2011	% Change
	(In bpd)			(In bpd)		
Total sales volume (1)	116,477	97,789	19.1 %	97,789	66,134	47.9 %
Total feedstock runs (2)	110,237	97,600	12.9 %	97,600	69,295	40.8 %
Facility production: (3)						
Specialty products:						
Lubricating oils	13,247	14,524	(8.8)%	14,524	14,427	0.7 %
Solvents	8,759	9,332	(6.1)%	9,332	10,508	(11.2)%
Waxes	1,443	1,280	12.7 %	1,280	1,269	0.9 %
Packaged and synthetic specialty products (4)	1,934	1,351	43.2 %	1,351	—	—
Other	2,192	3,084	(28.9)%	3,084	4,424	(30.3)%
Total specialty products	27,575	29,571	(6.7)%	29,571	30,628	(3.5)%
Fuel products:						
Gasoline	29,374	24,394	20.4 %	24,394	13,409	81.9 %
Diesel	26,015	22,438	15.9 %	22,438	14,721	52.4 %
Jet fuel	4,105	4,325	(5.1)%	4,325	4,520	(4.3)%
Asphalt, heavy fuel oils and other	19,976	15,444	29.3 %	15,444	7,631	102.4 %
Total fuel products	79,470	66,601	19.3 %	66,601	40,281	65.3 %
Total facility production (3)	107,045	96,172	11.3 %	96,172	70,909	35.6 %

(1) Total sales volume includes sales from the production at our 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.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements.

(3) Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. 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.

(4) Represents production of packaged and synthetic specialty products at our Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

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	Year Ended December 31,								
	2013			2012			2011		
	(In millions)	% of Sales		(In millions)	% of Sales		(In millions)	% of Sales	
Sales of specialty products:									
Lubricating oils	$848.8	15.7	%	$1,007.9	21.6	%	$947.8	30.2	%
Solvents	511.7	9.4	%	491.1	10.5	%	495.9	15.8	%
Waxes	141.0	2.6	%	142.8	3.1	%	143.1	4.6	%
Packaged and synthetic specialty products (1)	233.6	4.3	%	161.7	3.5	%	—	—	%
Other (2)	39.8	0.7	%	46.4	1.0	%	43.7	1.4	%
Total	1,774.9	32.7	%	1,849.9	39.7	%	1,630.5	52.0	%
Sales of fuel products:									
Gasoline	1,409.4	26.0	%	1,174.9	25.2	%	619.6	19.8	%
Diesel	1,259.2	23.3	%	941.0	20.2	%	513.3	16.4	%
Jet fuel	191.4	3.5	%	184.0	4.0	%	148.0	4.7	%
Asphalt, heavy fuel oils and other (3)	786.5	14.5	%	507.5	10.9	%	223.5	7.1	%
Total	3,646.5	67.3	%	2,807.4	60.3	%	1,504.4	48.0	%
Consolidated sales	$5,421.4	100.0	%	$4,657.3	100.0	%	$3,134.9	100.0	%

(1) Represents production of packaged and synthetic specialty products at the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, 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, Shreveport and San Antonio refineries to third party customers.

Please read Note 16 “Segments and Related Information” in Part II, Item 8 “Financial Statements and Supplementary Data” of this Annual Report for additional financial information about each of our segments and the geographical areas in which we conduct business.

Shreveport Refinery

The Shreveport refinery, located on a 240-acre site in Shreveport, Louisiana (“Shreveport”), currently has aggregate crude oil throughput capacity of 60,000 bpd and processes paraffinic crude oil and associated feedstocks into fuel products, paraffinic lubricating oils, waxes, asphalt and by-products.

The Shreveport refinery consists of 17 major processing units including hydrotreating, catalytic reforming and dewaxing units with approximately 3.3 million barrels of storage capacity in 130 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Shreveport refinery in 2001, we have expanded the refinery’s capabilities by adding additional processing and blending facilities, adding a second reactor to the high pressure hydrotreater, resuming production of gasoline, diesel and other fuel products and adding both 18,000 bpd of crude oil throughput capacity and the capability to run up to 25,000 bpd of sour crude oil with an expansion project completed in May 2008. The following table sets forth historical information about production at our Shreveport refinery.

	Shreveport Refinery		
	Year Ended December 31,		
	2013	2012	2011
	(In bpd)		
Crude oil throughput capacity	60,000	60,000	60,000
Total feedstock runs (1) (2)	36,178	39,831	39,910
Total refinery production (2) (3)	34,832	38,849	39,888

(1) Total feedstock runs represents the barrels per day of crude oil and other feedstocks processed at our Shreveport refinery. Total feedstock runs does not include certain interplant feedstocks supplied by our Cotton Valley and Princeton refineries.

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(2) Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks. The difference between total refinery 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.

(3) Total refinery production includes certain interplant feedstock supplied to our Cotton Valley and Princeton refineries and Karns City facility.

The Shreveport refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities. The refinery has an idle residual fluid catalytic cracking unit, alkylation unit, vacuum tower and a number of idle towers that can be utilized for future project needs. Certain idle towers were utilized as a part of the Shreveport refinery expansion project completed in 2008.

The Shreveport refinery receives crude oil via tank truck, railcar and a common carrier pipeline system that is operated by a subsidiary of Plains All American Pipeline, L.P. (“Plains”) and is connected to the Shreveport refinery’s facilities. The Plains pipeline system delivers local supplies of crude oil and condensates from north Louisiana and east Texas. In November 2012 we completed an expansion project at our Superior refinery, which enables the refinery to ship crude oil by railcar to our Shreveport refinery, as well as third party customers. Crude oil is also purchased from various suppliers, including local producers, who deliver crude oil to the Shreveport refinery via tank truck.

The Shreveport refinery also has direct pipeline access to the Enterprise Products Partners L.P. pipeline (“TEPPCO pipeline”), on which it can ship certain grades of gasoline, diesel and jet fuel. Further, the refinery has direct access to the Red River Terminal facility, which provides the refinery with barge access, via the Red River, to major feedstock and petroleum products logistics networks on the Mississippi River and Gulf Coast inland waterway system. The Shreveport refinery also ships its finished products throughout the U.S. through both truck and railcar service.

Superior Refinery

The Superior refinery is located on a 245-acre site, with an additional 430 acres owned around the existing refinery, in Superior, Wisconsin. The Superior refinery currently has aggregate crude oil throughput capacity of 45,000 bpd and processes light and heavy crude oil from the Bakken Shale formation in North Dakota and western Canada into fuel products and asphalt.

The Superior refinery consists of 14 major processing units including hydrotreating, catalytic reforming, fluid catalytic cracking and alkylation units with approximately 3.2 million barrels of storage capacity in 76 tanks and related loading and unloading facilities and utilities. The following table sets forth historical information about production at our Superior refinery since its acquisition on September 30, 2011.

	Superior Refinery		
	Year Ended December 31,		Three Months Ended December 31,
	2013	2012	2011
	(In bpd)		
Crude oil throughput capacity	45,000	45,000	45,000
Total feedstock runs (1) (2)	32,821	34,609	35,335
Total refinery production (2)	31,757	33,438	33,746

(1) Total feedstock runs represents the barrels per day of crude oil and other feedstocks processed at our Superior refinery.

(2) Total refinery production represents the barrels per day of fuel products and specialty products yielded from processing crude oil and other feedstocks. The difference between total refinery 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 Superior refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities. Currently the Superior refinery produces gasoline, diesel, asphalt and heavy fuel oils.

Finished fuel products produced at the Superior refinery are sold through the Superior refinery truck rack, several Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota and South Dakota and through our Duluth terminal. The Superior wholesale fuel business also sells gasoline wholesale to SPUR branded gas stations located throughout the Upper Midwest (including Minnesota, Wisconsin and Michigan), which are owned and operated by independent franchisees. The Superior refinery ships finished fuel products by railcar, truck service and pipeline. Asphalt products produced at the Superior refinery are shipped by railcar and truck service and are sold through our terminals in Rhinelander and Crookston and through other leased terminals in the U.S.

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Finished fuel products sales are primarily made through spot agreements and short-term contracts. Asphalt is primarily sold through spot agreements and short-term contracts with customers primarily located in and around the Upper Midwest, North Dakota, South Dakota, Utah and New York.

The Superior refinery receives crude oil via pipeline. The Enbridge Pipeline delivers crude oil to the Superior refinery and is adjacent to one of the Enbridge Pipeline's first crude oil holding facilities after crossing the Canadian border into the U.S., providing reliable access to high quality crude oil from the Bakken Shale oil formation in North Dakota and from western Canada. The refinery receives approximately 62% of its daily crude oil requirements under a crude oil purchase agreement (the "BP Purchase Agreement") with BP Products North America Inc. ("BP"). For more information about the BP Purchase Agreement, please read the information provided under Note 6 "Commitments and Contingencies" in Part II, Item 8 "Financial Statements and Supplementary Data" of this Annual Report. In November 2012 the Superior refinery completed an expansion project, which enables the refinery to ship crude oil by railcar to our Shreveport refinery, as well as third party customers.

San Antonio Refinery

The San Antonio refinery, located on a 32-acre site in San Antonio, Texas, has aggregate crude oil throughput capacity of 17,500 bpd and processes light crude oil from south Texas, including the Eagle Ford Shale formation, into a variety of transportation fuels, feedstocks and specialty products. The San Antonio refinery consists of five major processing units including hydrotreating, catalytic reforming and solvents distillation with approximately 162,000 barrels of storage capacity in 57 tanks and related loading and unloading facilities and utilities.

Currently, the San Antonio refinery produces diesel, jet fuel, gasoline, other fuel products and specialty solvents. The San Antonio refinery is compliant with federal regulations for ultra-low sulfur diesel. The San Antonio refinery ships products by railcar and truck. Product sales are primarily made through spot agreements and short-term contracts. The San Antonio refinery purchases crude oil and intermediate products from various suppliers and receives crude oil by pipeline originating from its crude oil terminal in Elmendorf, Texas ("Elmendorf"), providing reliable access to high quality crude oil from Texas, primarily the Eagle Ford Shale formation. The Elmendorf terminal has aggregate storage capacity of approximately 188,000 barrels.

Since acquiring the San Antonio refinery, we expanded the refinery's capabilities by adding additional processing and blending facilities which allow the San Antonio refinery to blend up to 5,000 bpd of finished gasoline. In addition, in December 2013 we completed an expansion project adding 3,000 bpd of crude oil throughput capacity.

In 2013, the San Antonio refinery entered into an agreement with TexStar Midstream Logistics, L.P. ("TexStar") under which TexStar will construct, own and operate a 30,000 bpd crude oil pipeline system that will supply significant volumes of Eagle Ford crude oil to the refinery. Under the terms of the 15-year agreement, TexStar has committed to install and operate the Karnes North Pipeline System ("KNPS"), an 8-inch, 50-mile pipeline that will transport crude oil from Karnes City, Texas to the refinery's Elmendorf terminal. We expect to receive deliveries of at least 10,000 bpd of crude oil at the refinery through the KNPS-Elmendorf terminal supply route once the pipeline comes into service, expected during the second quarter 2014.

The following table sets forth historical information at our San Antonio refinery since our acquisition of the refinery on January 2, 2013.

	San Antonio Refinery Year Ended December 31, 2013 (In bpd)
Crude oil throughput capacity	17,500
Total feedstock runs (1) (2)	10,908
Total refinery production (2)	10,381

(1) Total feedstock runs represents the barrels per day of crude oil and other feedstocks processed at our San Antonio refinery from January 2, 2013 through December 31, 2013.

(2)

Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks from January 2, 2013 through December 31, 2013. The difference between total refinery 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.

Cotton Valley Refinery

The Cotton Valley refinery, located on a 77-acre site in Cotton Valley, Louisiana ("Cotton Valley"), currently has aggregate crude oil throughput capacity of 13,500 bpd, hydrotreating capacity of 6,200 bpd and processes crude oil into specialty solvents and residual fuel oil. The residual fuel oil is an important feedstock for the production of specialty products

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at our Shreveport refinery. We believe the Cotton Valley refinery produces the most complete, single-facility line of paraffinic solvents in the U.S.

The Cotton Valley refinery consists of three major processing units that include a crude unit, a hydrotreater and a fractionation train, approximately 625,000 barrels of storage capacity in 74 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Cotton Valley refinery in 1995, we have expanded the refinery's capabilities by installing a hydrotreater that removes aromatics, increased the crude unit processing capability to 13,500 bpd and reconfigured the refinery's fractionation train to improve product quality, enhance flexibility and lower utility costs. The following table sets forth historical information about production at our Cotton Valley refinery.

	Cotton Valley Refinery		
	Year Ended December 31,		
	2013	2012	2011
	(In bpd)		
Crude oil throughput capacity	13,500	13,500	13,500
Total feedstock runs (1) (2)	5,667	5,487	5,806
Total refinery production (2) (3)	6,678	6,043	7,951

(1) Total feedstock runs do not include certain interplant solvent feedstocks supplied by our Shreveport refinery.

(2) Total refinery production represents the barrels per day of specialty products yielded from processing crude oil and other feedstocks. The difference between total refinery 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.

(3) Total refinery production includes certain interplant feedstocks supplied to our Shreveport refinery.

The Cotton Valley refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities, which allows us to respond to market changes and customer demands by modifying the refinery's product mix. The reconfigured fractionation train also allows the refinery to satisfy demand fluctuations efficiently without large finished product inventory requirements.

The Cotton Valley refinery receives crude oil via truck and through a pipeline system operated by a subsidiary of Plains. The Cotton Valley refinery's feedstock is primarily low sulfur, paraffinic crude oil originating from north Louisiana and is purchased from various marketers and gatherers. In addition, the Cotton Valley refinery receives interplant feedstocks for solvent production from the Shreveport refinery. The Cotton Valley refinery ships finished products by both truck and railcar service.

Montana Refinery

The Montana refinery, located on an 86-acre site in Great Falls, Montana, currently has aggregate crude oil throughput capacity of 10,000 bpd and processes light and heavy crude oil from Canada into fuel and asphalt products. During 2013, we commenced an expansion project which will add 10,000 bpd of crude oil throughput capacity at completion, which is expected during the first quarter of 2016.

The Montana refinery consists of 13 major processing units including hydrotreating, catalytic reforming, fluid catalytic cracking and alkylation units with approximately 939,000 barrels of storage capacity in 71 tanks and related loading and unloading facilities and utilities. The following table sets forth historical information about production at the Montana refinery since our acquisition of the refinery on October 1, 2012.

	Montana Refinery	
	Year Ended December 31,	Three Months Ended December 31,
	2013	2012
	(In bpd)	
Crude oil throughput capacity	10,000	10,000
Total feedstock runs (1) (2)	9,290	10,169

Total refinery production (2)	9,015	9,992

(1) Total feedstock runs represents the barrels per day of crude oil and other feedstocks processed at our Montana refinery from October 1, 2012 through December 31, 2013.

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(2) Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks from October 1, 2012 through December 31, 2013. The difference between total refinery 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.

Currently, the Montana refinery produces gasoline, diesel, jet fuel and asphalt products. The Montana refinery ships finished fuel and asphalt products by railcar and truck service. Finished fuel and asphalt products sales are primarily made through spot agreements and short-term contracts.

The Montana refinery purchases crude oil from various suppliers and receives crude oil by pipeline through the Front Range Pipeline via the Bow River Pipeline in Canada, providing reliable access to high quality crude oil from western Canada.

Princeton Refinery

The Princeton refinery, located on a 208-acre site in Princeton, Louisiana (“Princeton”), currently has aggregate crude oil throughput capacity of 10,000 bpd and processes naphthenic crude oil into lubricating oils, asphalt and feedstock for the Shreveport refinery for further processing into ultra-low sulfur diesel. The asphalt produced may be further processed or blended for coating and roofing product applications at the Princeton refinery or transported to the Shreveport refinery for further processing into bright stock.

The Princeton refinery consists of seven major processing units, approximately 650,000 barrels of storage capacity in 200 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Princeton refinery in 1990, we have debottlenecked the crude unit to increase production capacity to 10,000 bpd, increased the hydrotreater’s capacity to 7,000 bpd and upgraded the refinery’s fractionation unit, which has enabled us to produce higher value specialty products. The following table sets forth historical information about production at our Princeton refinery.

	Princeton Refinery		
	Year Ended December 31,		
	2013	2012	2011
	(In bpd)		
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs (1)	6,464	6,914	6,844
Total refinery production (1) (2)	5,313	7,044	6,761

(1) Total refinery production represents the barrels per day of specialty products yielded from processing crude oil and other feedstocks. The difference between total refinery 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.

(2) Total refinery production includes certain interplant feedstocks supplied to our Shreveport refinery.

The Princeton refinery has a hydrotreater and significant fractionation capability enabling the refining of high quality naphthenic lubricating oils at numerous distillation ranges. The Princeton refinery’s processing capabilities consist of atmospheric and vacuum distillation, hydrotreating, asphalt oxidation processing and clay/acid treating. In addition, we have the necessary tankage and technology to process our asphalt into higher value product applications such as coatings, road paving and emulsions for road paving and specialty applications.

The Princeton refinery receives crude oil via tank truck, railcar and the Plains pipeline system. Its crude oil supply primarily originates from east Texas and north Louisiana, which is purchased directly from third-party suppliers under month-to-month evergreen supply contracts and on the spot market. The Princeton refinery ships its finished products throughout the U.S. via both truck and railcar service.

Royal Purple

The Royal Purple facility, located on a 28-acre site in Porter, Texas, develops, blends and packages high performance synthetic lubricants and fluid additive technology for use in industrial, commercial and automotive applications. The Royal Purple facility’s processing capability includes 10 in-house packaging and production lines. Outsourced packaging services for specific products are also used. The facility has approximately 30,500 barrels of storage capacity in 91 tanks and related loading and unloading facilities and utilities. The facility receives its base oil

feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.
The Royal Purple facility utilizes the latest automated batch processing technology designed to ensure blending accuracy while maintaining production flexibility to meet customer needs.

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Bel-Ray

The Bel-Ray facility, located on a 32-acre site in Wall Township, New Jersey, blends and packages high performance synthetic lubricants and greases for use primarily in aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles applications. The Bel-Ray facility's processing capability includes 27 blending tanks and packaging production lines. In addition, the Bel-Ray facility has approximately 13,000 barrels of storage capacity in 67 tanks and related loading and unloading facilities and utilities. The Bel-Ray facility receives its base oil feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.

The Bel-Ray facility is designed with batch processing technology and is also designed to maximize blending flexibility to meet customer needs. The packaging operations utilize both in-house packaging equipment and outsourced packaging services for specific products.

Karns City and Dickinson Facilities and Other Processing Agreements

The Karns City facility, located on a 225-acre site in Karns City, Pennsylvania ("Karns City"), has aggregate base oil throughput capacity of 5,500 bpd and processes white mineral oils, solvents, petrolatums, gelled hydrocarbons, cable fillers and natural petroleum sulfonates. The Karns City facility's processing capability includes hydrotreating, fractionation, acid treating, filtering, blending and packaging. In addition, the facility has approximately 817,000 barrels of storage capacity in 250 tanks and related loading and unloading facilities and utilities.

The Dickinson facility, located on a 28-acre site in Dickinson, Texas ("Dickinson"), has aggregate base oil throughput capacity of 1,300 bpd and processes white mineral oils, compressor lubricants, natural petroleum sulfonates and biodiesel. The Dickinson facility's processing capability includes acid treating, filtering and blending, approximately 183,000 barrels of storage capacity in 186 tanks and related loading and unloading facilities and utilities.

The facilities each receive their base oil feedstocks by railcar and truck under supply agreements or spot purchases with various suppliers, the most significant of which is a long-term supply agreement with Phillips 66. Please read "— Crude Oil and Feedstock Supply" below for further discussion of the long-term supply agreement with Phillips 66.

The following table sets forth the combined historical information about production at our Karns City, Dickinson and other facilities.

	Combined Karns City, Dickinson and Other Facilities		
	Year Ended December 31,		
	2013	2012	2011
	(in bpd)		
Feedstock throughput capacity (1)	11,300	11,300	11,300
Total feedstock runs (2) (3)	7,250	7,030	7,829
Total production (3)	7,137	7,012	7,803

(1) Includes Karns City, Dickinson and other facilities.

(2) Includes feedstock runs at our Karns City and Dickinson facilities as well as throughput at certain third-party facilities pursuant to supply and/or processing agreements and includes certain interplant feedstocks supplied from our Shreveport refinery. For more information regarding our purchase commitments related to these supply and/or processing agreements, please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Commitments" for additional information.

(3) Total production represents the barrels per day of specialty products yielded from processing feedstocks at our Karns City and Dickinson facilities and certain third-party facilities pursuant to supply and/or processing agreements. The difference between total production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products.

Terminals

Our terminals are complementary to our refineries and play a key role in moving our products to end-user markets by providing services including distribution and blending to achieve specified products and storage and inventory management. We operate the following terminals:

Burnham Terminal: We own and operate a terminal located on an 11-acre site, in Burnham, Illinois. The Burnham terminal receives specialty products from certain of our refineries primarily by railcar and distributes them by truck and railcar to our customers in the Upper Midwest and East Coast regions of the U.S. and in Canada. The terminal includes a tank farm

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with 90 tanks having aggregate storage capacity of approximately 150,000 barrels, as well as blending equipment for producing engine oil additives and tackifiers.

Rhinelander Terminal: We own and operate a terminal located on an 18-acre site, in Rhinelander, Wisconsin. The Rhinelander terminal receives asphalt by truck from the Superior refinery and distributes product by truck. Asphalt from this terminal is sold to customers in the Upper Midwest region of the U.S. The terminal includes a tank farm with four tanks with aggregate storage capacity of approximately 166,000 barrels.

Crookston Terminal: We own and operate a terminal located on a 19-acre site in Crookston, Minnesota. The Crookston terminal receives asphalt by truck from the Superior refinery and distributes product by truck. Asphalt from this terminal is sold to customers in the Upper Midwest region of the U.S. The terminal includes a tank farm with three tanks with aggregate storage capacity of approximately 156,000 barrels.

Duluth Terminal: We own and operate a terminal located on a 49-acre site in Proctor, Minnesota. The Duluth terminal is supplied refined fuel products from the Superior refinery by the Magellan pipeline and receives ethanol and biodiesel products by truck. Fuel products from this terminal are distributed by truck to customers in Minnesota and northern Wisconsin. The terminal includes seven tanks with aggregate storage capacity of approximately 200,000 barrels.

In addition to the above terminals, we own and lease additional facilities, primarily related to distribution of finished products, throughout the U.S.

Crude Oil Logistics Assets

We own and operate seven crude oil loading facilities and related assets in North Dakota and Montana, which provides us with the ability to transport crude oil directly from the point of lease, into our crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to our refineries and/or third party customers.

Other Logistics Assets

We use approximately 2,700 railcars leased from various lessors. This fleet of railcars enables us to receive and ship crude oil and distribute various specialty products and fuel products throughout the U.S. and Canada to and from each of our facilities.

Our Crude Oil and Feedstock Supply

We purchase crude oil and other feedstocks from major oil companies, as well as from various crude oil gatherers and marketers in Texas, north Louisiana, North Dakota and Canada. Crude oil supplies at our refineries are as follows:

Refinery	Crude Oil Slate	Mode of Transportation
Shreveport	West Texas Intermediate ("WTI"), local crude oils from East Texas, North Louisiana, Arkansas and Light Louisiana Sweet ("LLS")	Tank truck, railcar and Plains Pipeline
Superior	Canadian Heavy, Canadian Synthetic, North Dakota Sweet (e.g. Bakken) and Mixed Sweet Blend ("MSW")	Enbridge Pipeline
San Antonio	Local Texas sweet crude oil (e.g. Eagle Ford)	Truck, pipeline connected to its Elmendorf crude oil terminal
Cotton Valley	Local paraffinic crude oil	Plains Pipeline and tank truck
Montana	Canadian Heavy and Canadian Sour (e.g. Bow River)	Front Range Pipeline
Princeton	Local napthentic crude oil	Tank truck, railcar and Plains Pipeline

In 2013, subsidiaries of Plains supplied us with approximately 31.4% of our total crude oil supply under term contracts and month-to-month evergreen crude oil supply contracts. In 2013, BP supplied us with approximately 22.7% of our total crude oil supply under the BP Purchase Agreement. Each of our refineries is dependent on one or more key suppliers and the loss of any of these suppliers would adversely affect our financial results to the extent we were unable to find another supplier of this substantial amount of crude oil. For more information about the BP Purchase Agreement, please read the information provided under Note 6 "Commitments and Contingencies" in Part II, Item 8 “Financial Statements and Supplementary Data” of this Annual Report.

We do not maintain long-term contracts with most of our crude oil suppliers. For example, our contracts with Plains are currently month-to-month, terminable upon 90 days’ notice. In April 2012, we amended and restated the BP Purchase Agreement, which had an initial term of one year ending April 1, 2013, and automatically renews for successive one-year terms unless terminated by either party upon 90 days’ notice prior to the end of any renewal term. We also purchase foreign crude oil

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when its spot market price is attractive relative to the price of crude oil from domestic sources. We believe that adequate supplies of crude oil will continue to be available to us.

We have various long-term feedstock supply agreements with Phillips 66, with remaining terms ranging from one to four years, with some agreements operating under the option to continue on a month-to-month basis thereafter, for feedstocks that are key to the operations of our Karns City and Dickinson facilities. In addition, certain products of our refineries can be used as feedstocks by these facilities. We believe that adequate supplies of feedstocks are available for these facilities.

Our cost to acquire crude oil and feedstocks and the prices for which we ultimately can sell refined products depend on a number of factors beyond our control, including regional and global supply of and demand for crude oil and other feedstocks and specialty and fuel products. These, in turn, are dependent upon, among other things, the availability of imports, overall economic conditions, production levels of domestic and foreign suppliers, U.S. relationships with foreign governments, political affairs and the extent of governmental regulation. We have historically been able to pass on the costs associated with increased crude oil and feedstock prices to our specialty products customers, although the increase in selling prices for specialty products typically lags a rising cost of crude oil. From time to time, we use a hedging program to manage a portion of our commodity price risk. Please read Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk —Derivative Instruments" for a discussion of our hedging program.

Our Products, Markets and Customers

Products

We produce a full line of specialty products, including lubricating oils, solvents, waxes, packaged and synthetic specialty products, other by-products, as well as a variety of fuel and fuel related products, asphalt and heavy fuel oils. Our customers purchase these products primarily as raw material components for basic industrial, consumer and automotive goods. The following table depicts a representative sample of the diversity of end-use applications for the products we produce:

Representative Sample of End Use Applications by Product

Lubricating Oils	Solvents	Waxes	Packaged and Synthetic Specialty Products	Other	Fuels & Fuel Related
12% (1)	8% (1)	1% (1)	2% (1)	3% (1)	74% (1)
• Hydraulic oils • Passenger car motor oils • Railroad engine oils • Cutting oils • Compressor oils • Metalworking fluids • Transformer oils • Rubber process oils • Industrial lubricants • Gear oils • Grease • Automatic transmission fluid • Animal feed dedusting • Baby oils	• Waterless hand cleaners • Alkyd resin diluents • Automotive products • Calibration fluids • Camping fuel • Charcoal lighter fluids • Chemical processing • Drilling fluids • Printing inks • Water treatment • Paint and coatings	• Paraffin waxes • FDA compliant products • Candles • Adhesives • Crayons • Floor care • PVC • Paint strippers • Skin & hair care • Timber treatment • Waterproofing • Pharmaceuticals • Cosmetics	• Refrigeration compressor oils • Positive displacement and roto-dynamic compressor oils • Commercial and military jet engine oil • Lubricating greases • Gear oils • Aviation hydraulic oils • High performance small engine fuels • Two cycle and four stroke engine oils • High performance automotive engine oils	• Roofing • Paving	• Gasoline • Diesel • Jet fuel • Marine diesel fuel • Biodiesel • Ethanol • Ethanol free fuels • Fluid catalytic cracking feedstock • Asphalt vacuum residuals • Mixed butanes • Roofing • Paving • Heavy fuel oils

• Bakery pan oils	• Stains	• High performance industrial lubricants
• Catalyst carriers		• High temperature chain lubricants
• Gelatin capsule lubricants		• Food contact grade lubricants
• Sunscreen		• Charcoal lighter fluids and other solvents
		• Engine treatment additives

(1) Based on the percentage of actual total production for the year ended December 31, 2013 and includes the results of operations at our San Antonio and Bel-Ray operations commencing January 2, 2013 and December 10, 2013, respectively. Except for the listed fuel products and certain products sold by our Royal Purple, Bel-Ray and Calumet Packaging facilities, we do not produce any of these end-use products.

We have an experienced marketing department with average industry tenure of approximately 20 years. Our salespeople regularly visit customers and our marketing department works closely with both the laboratories at our refineries and our technical services department to help create specialized blends that will work optimally for our customers.

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Markets

Specialty Products. The specialty products market represents a small portion of the overall petroleum refining industry in the U.S. Of the nearly 150 refineries currently in operation in the U.S., only a small number of the refineries are considered specialty products producers and only a few compete with us in terms of the number of products produced.

Our specialty products are utilized in applications across a broad range of industries, including in:

- industrial goods such as metalworking fluids, belts, hoses, sealing systems, batteries, hot melt adhesives, pressure sensitive tapes, electrical transformers, refrigeration compressors and drilling fluids;
- consumer goods such as candles, petroleum jelly, creams, tonics, lotions, coating on paper cups, chewing gum base, automotive aftermarket car-care products (fuel injection cleaners, tire shines and polishes), lamp oils, charcoal lighter fluids, camping fuel and various aerosol products; and
- automotive goods such as motor oils, greases, transmission fluid and tires.

We have the capability to ship our specialty products worldwide. In the U.S. and Canada, we ship our specialty products via railcars, trucks and barges. We use our fleet of approximately 2,700 leased railcars to ship our specialty products and a majority of our specialty products sales were shipped in trucks owned and operated by several different third-party carriers. For shipments outside of North America, which accounted for less than 10% of our consolidated sales in 2013, we ship via railcars and trucks to several ports where the product is loaded onto vessels for shipment to customers abroad.

Fuel Products. The fuel products market represents a large portion of the overall petroleum refining industry in the U.S. Of the nearly 150 refineries currently in operation in the U.S., a large number of the refineries are fuel products producers; however, only a few compete with us in our local markets.

Gulf Coast Market (PADD 3)

Fuel products produced at our Shreveport refinery can be sold locally or to the Midwest region of the U.S. through the TEPPCO pipeline. Local sales are made from the TEPPCO terminal in Bossier City, Louisiana, located approximately 15 miles from the Shreveport refinery, as well as from our own Shreveport refinery terminal.

Gasoline, diesel and jet fuel from the Shreveport refinery is sold primarily into the Louisiana, Texas and Arkansas markets, and any excess volumes are sold to marketers further up the TEPPCO pipeline. Should the appropriate market conditions arise, we have the capability to redirect and sell additional volumes into the Louisiana, Texas and Arkansas markets rather than transport them to the Midwest region via the TEPPCO pipeline.

The Shreveport refinery has the capacity to produce about 9,000 bpd of commercial jet fuel that can be marketed to the U.S. Department of Defense, sold as Jet-A locally or sold via the TEPPCO pipeline, or occasionally transferred to the Cotton Valley refinery to be processed further as a feedstock to produce solvents. We have a sales contract with the U.S. Department of Defense for approximately 3,000 bpd of jet fuel. This contract is effective until March 31, 2015 and is bid annually.

Fuel products produced at our San Antonio refinery are sold locally in Texas. Additionally, the San Antonio refinery produces commercial and specialty jet fuel that can be marketed to the U.S. Department of Defense or sold locally as Jet-A fuel. We have a sales contract with the U.S. Department of Defense for approximately 550 bpd of jet fuel. This contract is effective until March 2014 with one year renewal increments through March 2017 at the option of the U.S. Department of Defense.

Additionally, we produce a number of fuel-related products including fluid catalytic cracking ("FCC") feedstock, vacuum residuals and mixed butanes. FCC feedstock is sold to other refiners as a feedstock for their FCC units to make fuel products. Vacuum residuals are blended or processed further to make asphalt products. Volumes of vacuum residuals which we cannot process are sold locally into the fuel oil market or sold via railcar to other refiners. Mixed butanes are primarily available in the summer months and are primarily sold to local marketers. If the mixed butanes are not sold, they are blended into our gasoline production.

Upper Midwest Market (PADD 2)

Fuel products produced at our Superior refinery can be sold locally and in the Upper Midwest region of the U.S. and in Canada. The Superior wholesale business sells fuel products produced at the Superior refinery through several

Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota and South Dakota and through its own leased or owned product terminals located in Superior, Wisconsin and Duluth, Minnesota. The Superior wholesale business also sells gasoline wholesale to SPUR branded gas stations throughout the Upper Midwest, which are owned and operated by independent franchisees.

Northwest Market (PADD 4)

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Fuel products produced at our Montana refinery can be sold locally and in Idaho and Canada via tank and railcar. Seasonally, the Montana refinery transports fuel products to terminals in Washington.

We have a sales contract with the U.S. Department of Defense for approximately 210 bpd of jet fuel. This contract is effective until May 2014.

Customers

Specialty Products. We have a diverse customer base for our specialty products, with approximately 3,900 active accounts. Many of our customers are long-term customers who use our products in specialty applications, after an approval process ranging from six months to two years. No single customer of our specialty products segment accounted for more than 10% of our consolidated sales in each of the three years ended December 31, 2013, 2012 and 2011.

Fuel Products. We have a diverse customer base for our fuel products, with approximately 600 active accounts. Our diverse customer base includes wholesale distributors and retail chains. We are able to sell the majority of the fuel products we produce at the Shreveport refinery to the local markets of Louisiana, Texas and Arkansas. We also have the ability to ship additional fuel products from the Shreveport refinery to the Midwest region through the TEPPCO pipeline should the need arise. Additionally, we are able to sell the majority of the fuel products we produce at the Superior refinery to local markets in Minnesota and Wisconsin. We also have the ability to ship additional fuel products from the Superior refinery to the Upper Midwest region through the Magellan pipeline. The majority of our fuel products produced at our Montana refinery are sold to local markets in Montana and Idaho as well as in Canada. Fuel products produced at our San Antonio refinery are sold to local markets in Texas. No single customer of our fuel products segment represented 10% or greater of consolidated sales in each of the three years ended December 31, 2013, 2012 and 2011.

Competition

Competition in our markets is from a combination of large, integrated petroleum companies, independent refiners and wax production companies. Many of our competitors are substantially larger than us and are engaged on a national or international basis in many segments of the petroleum products business, including exploration and production, refining, transportation and marketing. These competitors may have greater flexibility in responding to or absorbing market changes occurring in one or more of these business segments. We distinguish our competitors according to the products that they produce. Set forth below is a description of our significant competitors according to product category.

Naphthenic Lubricating Oils. Our primary competitor in producing naphthenic lubricating oils is Ergon Refining, Inc. We also compete with Cross Oil Refining and Marketing, Inc. and San Joaquin Refining Co., Inc.

Paraffinic Lubricating Oils. Our primary competitors in producing paraffinic lubricating oils include ExxonMobil, Motiva Enterprises, LLC, Phillips 66, Petro-Canada, HollyFrontier Corporation, Chevron Corporation and Sonneborn Refined Products.

Paraffin Waxes. Our primary competitors in producing paraffin waxes include ExxonMobil and The International Group Inc.

Solvents. Our primary competitors in producing solvents include CITGO Petroleum Corporation, ExxonMobil Chemical and Phillips 66.

Packaged and Synthetic Specialty Products. Our primary competitors in retail and commercial packaged and synthetic specialty products include ExxonMobil (Mobil 1), Ashland, Inc. (Valvoline) and BP Lubricants, USA (Castrol). Our primary competitors in industrial packaged and synthetic specialty products include ExxonMobil, Shell and Chevron.

Fuel Products and By-Products. Our primary competitors in producing fuel products in the local markets in which we operate include Delek Refining, Ltd., Lion Oil Company, Flint Hills Resources, Northern Tier Energy, Inc., ExxonMobil, Valero Energy Corporation, Phillips 66 and Cenex.

Our ability to compete effectively depends on our responsiveness to customer needs and our ability to maintain competitive prices and product offerings. We believe that our flexibility and customer responsiveness differentiate us from many of our larger competitors. However, it is possible that new or existing competitors could enter the markets in which we operate, which could negatively affect our financial performance.

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Environmental and Occupational Health and Safety Matters

From time to time, we are a party to certain claims and litigation incidental to our 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 a result of audits or reviews of our business. We do have property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to us.

Environmental

We operate crude oil and specialty hydrocarbon refining and terminal operations, which are subject to stringent 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 our operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which we 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 on us for pollution resulting from our 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.

Failure to comply with environmental laws and regulations may result in the triggering of administrative, civil and criminal measures, including the assessment of monetary penalties, the imposition of remedial obligations and the issuance of injunctions limiting or prohibiting some or all of our operations. On occasion, we receive notices of violation or enforcement and other complaints from regulatory agencies alleging non-compliance with applicable environmental laws and regulations.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly pollution controls or remediation requirements could have a material adverse effect on our operations and financial position. Moreover, in connection with accidental spills or releases associated with our results of operations, we cannot assure our unitholders that we will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. In the event of future increases in costs, we may be unable to pass on those increases to our customers. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with these requirements will not have a material adverse effect on us, there can be no assurance that our environmental compliance expenditures will not become material in the future.

San Antonio Refinery

In connection with the San Antonio Acquisition, we agreed to indemnify NuStar for an unlimited term and without consideration of a monetary cap 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. The indemnification is unlimited in duration and not subject to any monetary deductibles or maximums. Anadarko Petroleum Corporation ("Anadarko") and Age Refining, Inc. ("Age Refining"), a 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 remediate certain contamination at our San Antonio refinery that pre-dates our acquiring the facility. We are not a party to this Agreed Order. We are in discussions with both TCEQ and Anadarko over how best to address this pre-existing contamination at the San Antonio refinery.

Montana Refinery

In connection with the Montana Acquisition from Connacher Oil and Gas Limited ("Connacher"), we 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 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. We believe the majority of damages related to such contamination at our Montana refinery are covered by a contractual indemnity provided by HollyFrontier 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, subject to a 5-year time limit following closing and certain monetary baskets and cap, 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, our liability is limited under the asset purchase agreement between Holly and Connacher and the costs to

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be covered by us are not believed to be material at this time. Some of these costs covered by us will be voluntary to prepare the expansion area in conjunction with our planned capacity expansion at the Montana refinery. 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. To date, Holly has reimbursed us for eligible remediation costs.

Superior Refinery

In connection with the Superior Acquisition, we became a party to an existing Refinery Initiative consent decree ("Superior Consent Decree") with the EPA and the Wisconsin Department of Natural Resources ("WDNR") that applies, in part, to our Superior refinery. Under the Superior Consent Decree, we will have to complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the refinery to the EPA and the WDNR, and we currently estimate costs of approximately $1.0 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 material. In addition, we may have to pursue certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in us incurring additional costs, which could be substantial. During 2013 and 2012, we incurred approximately $1.9 million and $2.4 million, respectively, in 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 our Superior refinery, which included a proposed penalty amount of $0.1 million. This finding is in response to information provided to the EPA by us in response to an information request. The EPA alleges that the efficiency of the flares at our Superior refinery is lower than regulatory requirements. We are contesting the allegations and attended an informal conference with the EPA held September 12, 2012. We do not believe that the resolution of these allegations will have a material adverse effect on our financial results or operations.

We are contractually indemnified by Murphy Oil Corporation ("Murphy Oil") under an asset purchase agreement between us and Murphy Oil for specified environmental liabilities arising from the operation 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 otherwise discharged by Murphy Oil. We believe our contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums. We were 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 we are 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 are net of any amount recoverable under an environmental insurance policy that we obtained in connection with the Superior Acquisition, which named us 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, we entered into a settlement agreement with the Louisiana Department of Environmental Quality ("LDEQ") under LDEQ's "Small Refinery and Single Site Refinery Initiative," covering our 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 that arose prior to December 31, 2010. Among other things, we agreed to complete beneficial environmental programs and implement emissions reduction projects at our Shreveport, Cotton Valley and Princeton refineries, on an agreed-upon schedule. During 2013 and 2012, we incurred approximately $4.9 million and $4.2 million, respectively, of such expenditures and estimate additional expenditures of approximately $6.0 million to $8.0

million of capital expenditures and expenditures related to additional personnel and environmental studies over the next two years as a result of the implementation of these requirements. These capital investment requirements will be incorporated into our annual capital expenditures budget, and we do 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 our financial results or operations. For additional information regarding the impact on our capital expenditures, please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Expenditures."

In August 2011, the EPA conducted an inspection of our Shreveport refinery's Risk Management Program compliance. An inspection report dated October 20, 2011 was transmitted to our Shreveport refinery. We submitted supplemental information to the EPA, which was followed by a site visit from EPA personnel. On November 7, 2013, the EPA issued a Consent Agreement and Final Order to our Shreveport refinery, which included a civil penalty of $0.3 million.

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Current and former owners of a property in Bossier Parish, Louisiana, filed a lawsuit in March 2006 against us and other defendants, including Chevron USA, Inc. ("Chevron"), Legacy Resources Co., L.P. ("Legacy") and Exxon Mobil Corporation ("Exxon Mobil"), alleging damage from salt water and other environmental contamination on the property arising from historical oil field production on the property. Oil field exploration and production on the property began in the 1920's by predecessors of Exxon Mobil. We received an assignment of certain mineral leases for portions of the property in 1993 from an affiliate of Texaco, prior to Texaco's merger with Chevron. We then assigned those mineral leases to Legacy. The mineral lease assignments include indemnity provisions obligating the assignees to provide certain indemnities for an unlimited term and without consideration of a monetary cap for the benefit of the assignors. We, Chevron, Legacy and the plaintiffs are participating in mediation in an attempt to settle the litigation. We believe any obligations will be covered under the indemnification.

We are indemnified by Shell Oil Company ("Shell"), as successor to Pennzoil-Quaker State Company and Atlas Processing Company under an asset purchase agreement between us and Shell, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to our acquisition of the facility. The contractual indemnity is believed by us to be unlimited in amount and duration, but requires us to contribute up to $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities.

Bel-Ray Facility

Bel-Ray executed an Administrative Consent Order ("ACO") with the New Jersey Department of Environmental Protection, effective January 4, 1994, which required investigation and remediation of contamination at or emanating from the Bel-Ray facility. In 2000, Bel-Ray entered into a fixed price remediation contract with Weston Solutions ("Weston") (a large remediation contractor) whereby Weston agreed to be fully liable for the remediation of the soil and groundwater issues at the facility, including an offsite groundwater plume pursuant to the ACO ("Weston Agreement"). The Weston Agreement set up a trust fund to reimburse Weston, administered by Bel-Ray's environmental counsel. As of December 31, 2013, the trust fund contained approximately $0.7 million. In addition, we have remediation cost containment insurance should Weston be unable to complete the work required under the Weston Agreement. In connection with the Bel-Ray Acquisition, we became a party to the Weston Agreement. Weston has been addressing the environmental issues at the Bel-Ray facility over time, and the next phase will address the groundwater issues, which extend offsite.

Air Emissions

Our operations are subject to the federal Clean Air Act, as amended, and comparable state and local laws. The federal Clean Air Act Amendments of 1990 require most industrial operations in the U.S. to incur capital expenditures to meet the air emission control standards that are developed and implemented by the EPA and state environmental agencies. Under the federal Clean Air Act, facilities that emit certain air pollutants face increasingly stringent regulations, including requirements to install various levels of control technology on sources of pollutants. In addition, the petroleum refining sector has come under stringent new EPA regulations, imposing maximum achievable control technology ("MACT") on refinery equipment emitting certain listed hazardous air pollutants. Some of our facilities have been included within the categories of sources regulated by MACT rules. In addition, air permits are required for our refining and terminal operations that result in the emission of regulated air contaminants. These permits incorporate stringent control technology requirements and are subject to extensive review and periodic renewal. We believe that we are in substantial compliance with the federal Clean Air Act and similar state and local laws.

The federal Clean Air Act authorizes the EPA to require modifications in the formulation of the refined transportation fuel products we manufacture in order to limit the emissions associated with the fuel product's final use. For example, in December 1999, the EPA promulgated regulations limiting the sulfur content allowed in gasoline. These regulations required the phase-in of gasoline sulfur standards beginning in 2004, with special provisions for small refiners and for refiners serving those western U.S. states exhibiting lesser air quality problems. Similarly, the EPA promulgated regulations that limit the sulfur content of highway diesel beginning in 2006 from its former level of 500 parts per million ("ppm") to 15 ppm (the "ultra-low sulfur standard"). Our Shreveport, Superior, Montana and San Antonio refineries have implemented the sulfur standard with respect to produced gasoline and produced diesel meeting the ultra-low sulfur standard. In addition, we are required to meet the Mobil Source Air Toxics II ("MSAT II") standards adopted by the EPA to reduce the benzene content of motor gasoline produced at our facilities. We have completed capital projects at our Shreveport and Superior refineries to comply with these fuel quality requirements.

Pursuant to the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, the EPA issued respective initial and expanded Renewable Fuels Standards (collectively, the "RFSII") implementing mandates to blend renewable fuels into the petroleum fuels produced and sold in the U.S. Under RFSII, the EPA annually establishes a volume of renewable fuels that obligated refineries such as our Shreveport, Superior, Montana and San Antonio refineries must blend into their finished petroleum fuels. We may meet these RFSII requirements by blending the necessary volumes of renewable transportation fuels obtained from third parties, from purchases of RINs in the open market that are generated by third parties, or through a combination of blending of renewable transportation fuels and purchase of RINs. To the extent that we exceed the minimum volumetric requirements for blending of renewable transportation fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFSII compliance or selling those RINs on the open market.

We currently purchase RINs for some fuel categories on the open market to comply with the RFSII and, in the future, we may be required to purchase additional RINs beyond the amount we currently purchase on the open market in order to maintain compliance with the RFSII. Our gross 2013 annual RINs obligation, which includes RINs that were required to be secured through either blending or through the purchase of RINs in the open market, were 81 million RINs for the full year 2013. There is no assurance that we will not need to obtain more RINs in 2014 or future years in comparison to 2013 to comply with the RFSII mandate. Moreover, while the minimum number of renewable fuels that must be blended with refined petroleum fuels is currently set, existing laws and regulations could change and require increases in such volume. There was volatility in the purchase price for RINs during 2013, with prices increasing significantly in the first seven months of 2013 as compared to past years but declining at a more moderate rate since that time, and we cannot currently predict the future prices or availability of RINs or the total extent of our ability to mitigate our future RFSII compliance expenses such as, by example, increasing the blending of transportation fuels that qualify for RINs in our refining system or passing on some of the increased costs associated with RFSII compliance to our customers. The costs to obtain the necessary number of RINs in 2014 and beyond could be material and have a material adverse effect on our results of operations and financial condition as well as on the refining industry in general. Finally, while there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties, we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFSII requirements.

On October 13, 2010, the EPA raised the maximum amount of ethanol allowed under federal law from 10% to 15% for cars and light trucks manufactured since 2007, and on January 21, 2011, EPA extended the maximum allowable ethanol content of 15% to apply to cars and light trucks manufactured since 2001. The maximum amount allowed under federal law currently remains at 10% ethanol for all other vehicles. EPA required that fuel and fuel additive manufacturers take certain steps before introducing gasoline containing 15% ethanol (“E15”) into the market, including developing and obtaining EPA approval of a plan to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver. EPA has taken several recent actions to authorize the introduction of E15 into the market, including approving, on June 15, 2012, the first plans to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver, followed by approving, on February 7, 2013, a new blender pump configuration for general use by retail stations that wish to dispense E15 and gasoline containing 10% ethanol (“E10”) from a common hose and nozzle. Existing laws and regulations could change, and the minimum volumes of renewable fuels that must be blended with refined petroleum fuels may increase. Because we do not produce renewable transportation fuels at all of our refineries, increasing the volume of renewable fuels that must be blended into our products displaces an increasing volume of our Shreveport, Superior, Montana and San Antonio refineries’ fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make payments on our debt obligations.

Climate Change

In response to findings by the EPA in December 2009 that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHG”) present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth’s atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act, establishing Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit program requiring reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet “best available control technology” standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. Moreover, on December 23, 2010, the EPA entered a settlement agreement with environmental groups requiring the agency to propose by December 10, 2011 GHG New Source Performance

Standards (“NPNS”) for refineries and to finalize these rules by November 15, 2012. To date, the EPA has not completed those rulemakings, and we do not know when they will be completed. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified large GHG emission sources in the U.S., including petroleum refineries, on an annual basis. We monitor for GHG emissions at our facilities, where required, and believe we are in substantial compliance with the applicable GHG reporting requirements. These EPA policies and rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In addition, from time to time Congress has considered legislation to reduce emissions of GHG, and almost one-half of the states have already taken legal measures to reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the refined petroleum products

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that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. Such classes of persons include the current and past owners and operators of sites where a hazardous substance was released and companies that disposed or arranged for disposal of hazardous substances at offsite locations, such as landfills. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. In the course of our operations, we generate wastes or handle substances that may be regulated as hazardous substances, and we could become subject to liability under CERCLA and comparable state laws.

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state laws, which impose requirements related to the handling, storage, treatment and disposal of hazardous and non-hazardous wastes. In the course of our operations, we generate petroleum product wastes and ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. In addition, our operations also generate non-hazardous solid wastes, which are regulated under RCRA and state laws. We believe that we are in substantial compliance with the existing requirements of RCRA and similar state and local laws, and the cost involved in complying with these requirements is not material.

We currently own or operate, and have in the past owned or operated, properties that for many years have been used for refining and terminal activities. These properties have in the past been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes were not under our control. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes have been released on or under the properties owned or operated by us. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial activities to prevent future contamination.

In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require us 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 NSPS for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares. We are currently evaluating the effect that the NSPS rule may have on our operations.

Voluntary remediation of subsurface contamination is in process at certain of our refinery sites. The remedial projects are being overseen by the applicable state agencies. Based on current investigative and remedial activities, we believe that the groundwater contamination at these refineries can be controlled or remedied without having a material adverse effect on our financial condition. However, such costs are often unpredictable and, therefore, there can be no assurance that the future costs will not become material.

Water Discharges

The Federal Water Pollution Control Act of 1972, as amended, also known as the federal Clean Water Act, and analogous state laws impose restrictions and stringent controls on the discharge of pollutants, including oil, into federal and state waters. Such discharges are prohibited, except in accordance with the terms of a permit issued by the

EPA or the appropriate state agencies. Any unpermitted release of pollutants, including crude oil or hydrocarbon specialty oils as well as refined products, could result in penalties, as well as significant remedial obligations. Spill prevention, control, and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. We believe that we are in substantial compliance with the requirements of the federal Clean Water Act and similar state laws.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990, as amended (“OPA”), which addresses three principal areas of oil pollution — prevention, containment and cleanup. OPA applies to vessels, offshore facilities and onshore facilities, including refineries, terminals and associated facilities that may affect waters of the U.S. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages

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as well as a variety of public and private damages from oil spills. We believe that we are in substantial compliance with OPA and similar state laws.

Occupational Health and Safety

We are 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 our operations and that this information be provided to employees, contractors, state and local government authorities and customers. We maintain safety and training programs as part of our ongoing efforts to ensure compliance with applicable laws and regulations. We conduct periodic audits of Process Safety Management (“PSM”) systems at each of our locations subject to the PSM standard and have implemented a quality system that meets the requirements of the ISO-9001-2008 Standard. The integrity of our ISO-9001-2008 Standard certification is maintained through surveillance audits by our registrar at regular intervals designed to ensure adherence to the standards. Our 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.

We have completed studies to assess the adequacy of our PSM practices at our Shreveport refinery with respect to certain consensus codes and standards. As of December 31, 2013, we have incurred approximately $3.2 million of capital expenditures and expect to incur up to $1.0 million of capital expenditures during 2014 to address OSHA compliance issues identified in these studies. We expect these capital expenditures will enhance our 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 us as a result of our Cotton Valley inspection, which included a proposed penalty amount of $0.2 million. We have contested the Cotton Valley Citation and have reached a tentative settlement with OSHA on the matter, which we do not believe will have a material adverse effect on our results of operations or financial condition. Notwithstanding the Cotton Valley Citation, we believe our total operations are in substantial compliance with OSHA and similar state laws.

Other Environmental and Maintenance Items

We perform preventive and normal maintenance on all of our refining and terminal assets and make repairs and replacements when necessary or appropriate. We also conduct inspections of these assets as required by law or regulation.

Insurance

Our operations are subject to certain hazards of operations, including fire, explosion and weather-related perils. We maintain insurance policies, including business interruption insurance for each of our facilities, with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, ensure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

Seasonality

The operating results for the fuel products segment, including the selling prices of asphalt products we produce, can be seasonal. Asphalt demand is generally lower in the first and fourth quarters of the year as compared to the second and third quarters due to the seasonality of annual road construction. Demand for gasoline is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months. As a result, our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year due to this seasonality.

Properties

We own and lease the properties listed below. The properties we own are pledged as collateral under our Collateral Trust Agreement as discussed in Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities.” We believe that all properties are suitable for their intended purpose, are being efficiently utilized and provide adequate capacity to meet demand for the next several years.

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Property	Business Segment(s)	Acres	Owned / Leased	Location
Shreveport refinery	Fuels and Specialty	240	Owned	Shreveport, Louisiana
Superior refinery	Fuels	675	Owned	Superior, Wisconsin
Montana refinery	Fuels	86	Owned	Great Falls, Montana
San Antonio refinery	Fuels	32	Owned	San Antonio, Texas
Princeton refinery	Specialty	208	Owned	Princeton, Louisiana
Cotton Valley refinery	Specialty	77	Owned	Cotton Valley, Louisiana
Burnham terminal	Specialty	11	Owned	Burnham, Illinois
Karns City facility	Specialty	225	Owned	Karns City, Pennsylvania
Dickinson facility	Specialty	28	Owned	Dickinson, Texas
Rhinelander terminal	Fuels	18	Owned	Rhinelander, Wisconsin
Crookston terminal	Fuels	19	Owned	Crookston, Minnesota
Missouri facility	Specialty	22	Owned	Louisiana, Missouri
Calumet Packaging facility	Specialty	10	Leased	Shreveport, Louisiana
Royal Purple facility	Specialty	28	Owned	Porter, Texas
Bel-Ray facility	Specialty	32	Owned	Wall Township, New Jersey
Elmendorf terminal	Fuels	8	Owned	Elmendorf, Texas
Duluth terminal	Fuels	49	Owned	Proctor, Minnesota
Duluth marine terminal	Fuels	3	Leased	Duluth, Minnesota

In addition to the items listed above, we lease or own a number of storage tanks, railcars, equipment, land, crude oil loading facilities and precious metals.

Office Facilities

In addition to our refineries and terminals discussed above, we occupy the following square feet of office space, all of which are under leases:

Location	Square Feet
Indianapolis, Indiana	41,216
El Dorado, Arkansas	1,050
Louisiana, Missouri	4,600
San Antonio, Texas	41,000

While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed.

Employees

As of March 3, 2014, our general partner employs approximately 1,420 people who provide direct support to our operations. Of these employees, approximately 570 are covered by collective bargaining agreements. Employees at the following locations are covered by the following separate collective bargaining agreements:

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Facility/ Refinery	Union	Expiration Date
Superior	International Union of Operating Engineers	June 30, 2017
Cotton Valley	International Union of Operating Engineers	March 31, 2016
Princeton	International Union of Operating Engineers	October 31, 2014
Dickinson	International Union of Operating Engineers	March 31, 2016
Shreveport	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2016
Missouri	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2014
Karns City	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2015
Montana	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2015

None of the employees at the San Antonio refinery, Calumet Packaging facility, Royal Purple facility, Bel-Ray facility or at the Burnham, Rhinelander, Crookston, Duluth or Elmendorf terminals are covered by collective bargaining agreements. Our general partner considers its employee relations to be good, with no history of work stoppages.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana 46214 and our telephone number is (317) 328-5660. Our website is located at http://www.calumetspecialty.com.

Our Securities and Exchange Commission ("SEC") filings are available on our website as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC. We make available, free of charge on our website, our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These documents are located on our website at http://www.calumetspecialty.com — by selecting the "Investor Relations" link and then selecting the "SEC Filings" link. We also make available, free of charge on our website, our Charters for the Audit, Compensation and Conflicts Committees, Related Party Transactions Policy and Code of Business Conduct and Ethics. These documents are located on our website at http://www.calumetspecialty.com — by selecting the "Investor Relations" link and then selecting the "Corporate Governance" link.

The above information is available to anyone who requests it and is free of charge either in print from our website or upon request by contacting Investor Relations using the contact information listed above. Information on our website is not incorporated into this Annual Report or our other securities filings and is not a part of them.

All reports and documents filed with the SEC are also available via the SEC website, http://www.sec.gov, or may be read and copied at the SEC Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information on the operation of the SEC Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330.

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Item 1A. Risk Factors

Risks Relating to our Business

We may not have sufficient cash from operations to enable us to pay the minimum quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash from operations each quarter to enable us to pay the minimum quarterly distribution. Under the terms of our partnership agreement, we must pay expenses, including payments to our general partner, and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which is primarily dependent upon our producing and selling quantities of fuel and specialty products, or refined products, at margins that are high enough to cover our fixed and variable expenses. Crude oil costs, fuel and specialty products prices and, accordingly, the cash we generate from operations, will fluctuate from quarter to quarter based on, among other things:

- overall demand for specialty hydrocarbon products, fuel and other refined products;
- the level of foreign and domestic production of crude oil and refined products;
- our ability to produce fuel and specialty products that meet our customers' unique and precise specifications;
- the marketing of alternative and competing products;
- the extent of government regulation;
- results of our hedging activities; and
- overall economic and local market conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make, including those for acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions on distributions and on our ability to make working capital borrowings for distributions contained in our debt instruments; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Refining margins are volatile, and a reduction in our refining margins will adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations.

Our financial results are primarily affected by the relationship, or margin, between our specialty products prices and fuel products prices and the prices for crude oil and other feedstocks. The cost to acquire our feedstocks and the price at which we can ultimately sell our refined products depend upon numerous factors beyond our control. Historically, refining margins have been volatile, and they are likely to continue to be volatile in the future.

A widely used benchmark in the fuel products industry to measure market values and margins is the "Gulf Coast 2/1/1 crack spread," which represents the approximate gross margin resulting from refining crude oil, assuming that two barrels of a benchmark crude oil are converted, or cracked, into one barrel of gasoline and one barrel of heating oil. The Gulf Coast 2/1/1 crack spread ranged from a high of $38.89 per barrel to a low of $9.29 per barrel during 2013 and averaged $21.57 per barrel during 2013 compared to an average of $30.07 in 2012 and $25.65 in 2011.

Our actual refining margins vary from the Gulf Coast 2/1/1 crack spread due to the actual crude oil used and products produced, transportation costs, regional differences, and the timing of the purchase of the feedstock and sale of the refined products, but we use the Gulf Coast 2/1/1 crack spread as an indicator of the volatility and general levels of refining margins.

The prices at which we sell specialty products are strongly influenced by the commodity price of crude oil. If crude oil prices increase, our specialty products segment margins will fall unless we are able to pass through these price increases to our customers. Increases in selling prices for specialty products typically lag behind the rising cost of crude oil and may be difficult to implement quickly enough when crude oil costs increase dramatically over a short period of time. For example, in the first six months of 2008, excluding the effects of hedges, we experienced a 31.3%

increase in the cost of crude oil per barrel as compared to an 18.3% increase in the average sales price per barrel of our specialty products. It is possible we may not be able

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to pass through all or any portion of increased crude oil costs to our customers. In addition, we are not able to completely eliminate our commodity risk through our hedging activities.

Because refining margins are volatile, unitholders should not assume that our current margins will be sustained. If our refining margins fall, it will adversely affect the amount of cash we will have available for distribution to our unitholders.

Our hedging activities may not be effective in reducing the volatility of our cash flows and may reduce our earnings, profitability and cash flows.

We are exposed to fluctuations in the price of crude oil, fuel products, natural gas and interest rates. From time to time, we utilize derivative financial instruments related to the future price of crude oil, natural gas and fuel products with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices. Historically, we have utilized derivative instruments related to interest rates for future periods with the intent of reducing volatility in our cash flows due to fluctuations in interest rates. We are not able to enter into derivative financial instruments to reduce the volatility of the prices of the specialty products we sell as there is no established derivative market for such products.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. The derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual crude oil prices, natural gas prices or fuel products prices that we incur or realize in our operations. For example, excluding our crude oil basis swaps, all of the crude oil derivatives in our hedge portfolio are based on the market price of NYMEX WTI and the fuel products derivatives are all based on U.S. Gulf Coast market prices. In recent periods, the spread between NYMEX WTI and other crude oil indices (specifically Light Louisiana Sweet, Western Canadian Select and Brent, on which a portion of our crude oil purchases are priced) has widened, which has reduced the effectiveness of certain crude oil hedges. Accordingly, our commodity price risk management policy may not protect us from significant and sustained increases in crude oil or natural gas prices or decreases in fuel products prices. Conversely, our policy may limit our ability to realize cash flows from crude oil and natural gas price decreases.

We have a policy to enter into derivative transactions related to only a portion of the volume of our expected purchase and sales requirements and, as a result, we will continue to have direct commodity price exposure to the unhedged portion of our expected purchase and sales requirements. Thus, we could be exposed to significant crude oil cost increases on a portion of our purchases. Please read Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk."

Our actual future purchase and sales requirements may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which may result in a substantial diminution of our liquidity. As a result, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. In addition, our hedging activities are subject to the risks that a counterparty may not perform its obligations under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our hedging policies and procedures are not properly followed. It is possible that the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Our financing arrangements contain operating and financial provisions that restrict our business and financing activities.

The operating and financial restrictions and covenants in our financing arrangements, including our revolving credit facility, indentures governing each series of our outstanding senior notes and master derivative contracts, do currently restrict, and any future financing agreements could restrict, our ability to finance future operations or capital needs or to engage, expand or pursue our business activities, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;

- pay distributions or redeem or repurchase our units or repurchase our subordinated debt;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or repay other debt or make other restricted payments;
- enter into transactions with affiliates;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;

- create unrestricted subsidiaries;
- enter into sale and leaseback transactions;
- enter into a merger, consolidation or transfer or sale of assets, including equity interests in our subsidiaries; and
- engage in certain business activities.

Our revolving credit facility also contains a springing financial covenant which provides that, if 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 revolving credit agreement commitments then in effect and (ii) $46.4 million, then we 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.

Our existing indebtedness imposes, and any future indebtedness may impose, a number of covenants on us regarding collateral maintenance and insurance maintenance. As a result of these covenants and restrictions, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with the covenants and restrictions contained in our financing arrangements may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants and restrictions may be impaired. A failure to comply with the covenants, ratios or tests in our financing arrangements or any future indebtedness could result in an event of default under these financing arrangements, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. Among other things, in the event of any default on our indebtedness, our debt holders and lenders:

- will not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- could elect to require that all obligations accrue interest at the default rate, if such rate has not already been imposed;
- may have the ability to require us to apply all of our available cash to repay these borrowings;
- may prevent us from making debt service payments under our other agreements, any of which could result in an event of default under our other financing arrangements; or
- in the case of our revolving credit facility, foreclose on the collateral pledged pursuant to the terms of the revolving credit facility.

If our existing indebtedness were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. Even if new financing were available, it may be on terms that are less attractive to us than our then existing indebtedness or it may not be on terms that are acceptable to us. In addition, our obligations under our revolving credit facility are secured by a first priority lien on our cash, accounts receivable, inventory and certain other personal property and our obligations under our master derivative contracts are secured by a first priority lien on our 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 forgoing (including proceeds of hedge agreements), and if we are unable to repay our indebtedness under the revolving credit facility or master derivative contracts, the lenders under our revolving credit facility and the counterparties to our master derivative contracts could seek to foreclose on these assets. Please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities," "—Short Term Liquidity," "—Long-Term Financing," and "—Master Derivative Co for additional information regarding our long-term debt.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities. We had approximately $1,129.8 million of outstanding indebtedness as of December 31, 2013 and availability for borrowings of $472.4 million under our senior secured revolving credit facility. We continue to have the ability to incur additional debt, including the ability to borrow up to an aggregate principal amount of $850.0 million at any time outstanding, subject to borrowing base limitations, under our revolving credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and payments of our debt obligations; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions to our unitholders, reducing or delaying our business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms, or at all. Please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for additional information regarding our indebtedness.

Decreases in the price of crude oil may lead to a reduction in the borrowing base under our revolving credit facility and our ability to issue letters of credit or the requirement that we post substantial amounts of cash collateral for derivative instruments, which could adversely affect our liquidity, financial condition and our ability to distribute cash to our unitholders.

We rely on borrowings and letters of credit under our revolving credit agreement to purchase crude oil or other feedstocks for our facilities, lease certain precious metals for use in our refinery operations and enter into derivative instruments of crude oil and natural gas purchases and fuel products sales. We also rely on our ability to issue letters of credit to enter into certain hedging arrangements in an effort to reduce our exposure to adverse fluctuations in the prices of crude oil, natural gas and crack spreads. The borrowing base under our revolving credit facility is determined weekly or monthly depending upon availability levels or the existence of a default or event of default. Reductions in the value of our inventories as a result of lower crude oil prices could result in a reduction in our borrowing base, which would reduce the amount of financial resources available to meet our capital requirements. If, under certain circumstances, our available capacity under our revolving credit facility falls below certain threshold amounts, or a default or event of default exists, then our cash balances in a dominion account established with the administrative agent will be applied on a daily basis to our outstanding obligations under our revolving credit facility. In addition, decreases in the price of crude oil may require us to post substantial amounts of cash collateral to our hedging counterparties in order to maintain our derivative instruments. If, due to our financial condition or other reasons, the borrowing base under our revolving credit facility decreases, we are limited in our ability to issue letters of credit or we are required to post substantial amounts of cash collateral to our hedging counterparties, our liquidity, financial condition and our ability to distribute cash to our unitholders could be materially and adversely affected. Please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for additional information.

A failure in our information technology infrastructure or applications could negatively affect our business.

We have implemented a new enterprise resource planning ("ERP") system to further enhance operating efficiencies and provide more effective management of our business operations. The new ERP system was deployed for use throughout our company in a number of "go live" phases, the first of which occurred in the first quarter of 2013. Implementing a new ERP system is costly and involves risks inherent in the conversion to a new computer system, including loss of information, disruption to our normal operations, changes in accounting procedures and internal control over financial reporting, as well as problems achieving accuracy in the conversion of electronic data. Failure to properly or adequately address these issues could result in increased costs, the diversion of management's and employees' attention and resources and could materially adversely affect our operating results, internal controls over financial reporting and ability to manage our business effectively. While the ERP system is intended to further improve and enhance our information systems, large scale implementation of a new information system exposes us to the risks of starting up the new system and integrating that system with our existing systems and processes, including possible disruption of our financial reporting, which could lead to a failure to make required filings under the federal securities laws on a timely basis.

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We depend on certain key crude oil and other feedstock suppliers for a significant portion of our supply of crude oil and other feedstocks, and the loss of any of these key suppliers or a material decrease in the supply of crude oil and other feedstocks generally available to our facilities could materially reduce our ability to make distributions to unitholders.

We purchase crude oil and other feedstocks from major oil companies as well as from various crude oil gatherers and marketers primarily in Texas, north Louisiana, North Dakota and Canada. In 2013, subsidiaries of Plains supplied us with approximately 31.4% of our total crude oil supplies under term contracts and month-to-month evergreen crude oil supply contracts. In 2013, BP supplied us with approximately 22.7% of our total crude oil supplies under the BP Purchase Agreement. Each of our facilities is dependent on one or more of these suppliers and the loss of any of these suppliers would adversely affect our financial results to the extent we were unable to find another supplier of this substantial amount of crude oil. We do not maintain long-term contracts with most of our suppliers. For example, our contracts with Plains are currently month-to-month and terminable upon 90 days' notice and our contract with BP automatically renewed in April 2013 for a one year term and will continue to automatically renew for successive one-year terms unless terminated by either party upon 90 days' notice.

We purchase all of the crude oil supply directly from third-party suppliers, generally under month-to-month evergreen supply contracts and on the spot market. These evergreen contracts are generally terminable upon 30 days' notice and purchases on the spot market may expose us to changes in commodity prices. For additional discussion regarding our crude oil and feedstock supply, please read Items 1 and 2 "Business and Properties — Our Crude Oil and Feedstock Supply."

To the extent that our suppliers reduce the volumes of crude oil and other feedstocks that they supply us as a result of declining production or competition or otherwise, our sales, net income and cash available for distribution to unitholders and payments of our debt obligations would decline unless we were able to acquire comparable supplies of crude oil and other feedstocks on comparable terms from other suppliers, which may not be possible in areas where the supplier that reduces its volumes is the primary supplier in the area. Fluctuations in crude oil prices can greatly affect production rates and investments by third parties in the development of new oil reserves. Drilling activity generally decreases as crude oil prices decrease. We have no control over the level of drilling activity in the fields that supply our refineries, the amount of reserves underlying the wells in these fields, the rate at which production from a well will decline or the production decisions of producers. A material decrease in either the crude oil production from or the drilling activity in the fields that supply our refineries, as a result of depressed commodity prices, natural production declines, governmental moratoriums on drilling or production activities, the availability and the cost of capital or otherwise, could result in a decline in the volume of crude oil we refine.

We depend on certain third-party pipelines for transportation of crude oil and refined fuel products, and if these pipelines become unavailable to us, our revenues and cash available for distributions to our unitholders and payment of our debt obligations could decline.

Our Shreveport refinery is interconnected to a pipeline that supplies a portion of its crude oil and a pipeline that ships a portion of its refined fuel products to customers, such as pipelines operated by subsidiaries of Enterprise Products Partners L.P. and Plains All American Pipeline, L.P. Our Superior refinery receives crude oil through the Enbridge Pipeline and the Superior wholesale business transports products produced at the Superior refinery through several Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota and South Dakota. Our Montana refinery receives crude oil through the Front Range pipeline system via the Bow River Pipeline in Canada. Since we do not own or operate any of these pipelines, their continuing operation is not within our control. In addition, any of these third-party pipelines could become unavailable to transport crude oil or our refined fuel products because of acts of God, accidents, earthquakes or hurricanes, government regulation, terrorism or other third-party events. For example, our refinery run rates were affected by an approximately three-week shutdown during May and June 2011 of the ExxonMobil crude oil pipeline serving our Shreveport refinery resulting from the Mississippi River flooding occurring during this period. In addition, ExxonMobil shut down this pipeline on April 28, 2012 after a leak was discovered. Also, on June 20, 2012, excessive flooding caused our Superior refinery to reduce its run rate to approximately half its usual throughput for one day and shut down the portion of the Magellan pipeline that connects our Superior refinery to our Duluth terminal for one day. The unavailability of any of these third-party pipelines for the transportation of crude oil or our refined fuel products, because of acts of God, accidents, earthquakes or hurricanes, government regulation, terrorism or other third-party events, could lead to disputes or litigation with certain of our suppliers or a decline in our sales, net income and cash available for distributions to our unitholders and payments of our debt obligations.

The price volatility of fuel and utility services may result in decreases in our earnings, profitability and cash flows.

The volatility in costs of fuel, principally natural gas, and other utility services, principally electricity, used by our refinery and other operations affect our net income and cash flows. Fuel and utility prices are affected by factors outside of our control, such as supply and demand for fuel and utility services in both local and regional markets. Natural gas prices have historically been volatile.

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For example, daily prices for natural gas as reported on the New York Mercantile Exchange (“NYMEX”) ranged between $4.46 and $3.11 per million British thermal unit, or MMBtu, in 2013 and between $1.91 and $3.90 per MMBtu in 2012. Typically, electricity prices fluctuate with natural gas prices. Future increases in fuel and utility prices may have a material adverse effect on our results of operations. Fuel and utility costs constituted approximately 15.6% and 16.2% of our total operating expenses included in cost of sales for the years ended December 31, 2013 and 2012, respectively. If our natural gas costs rise, it will adversely affect the amount of cash available for distribution to our unitholders.

Our refineries, blending and packaging sites, terminals and related facility operations face operating hazards, and the potential limits on insurance coverage could expose us to potentially significant liability costs.

Our refineries, blending and packaging sites, terminals and related facility operations are subject to certain operating hazards, and our cash flow from those operations could decline if any of our facilities experiences a major accident, pipeline rupture or spill, explosion or fire, is damaged by severe weather or other natural disaster, or otherwise is forced to curtail its operations or shut down. For example, in 2010, our Shreveport refinery experienced an explosion that caused us to shut down one of this refinery’s environmental operating units between February and August 2010 when it was replaced with a newly constructed unit, resulting in modified operations during the interim period, including lower throughput rates at certain times during this period. These operating hazards could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in significant curtailment or suspension of our related operations.

Although we maintain insurance policies, including personal and property damage and business interruption insurance for each of our facilities with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent, we cannot ensure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or significant interruption of operations. Our business interruption insurance will not apply unless a business interruption exceeds 60 days. Furthermore, we may be unable to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. In addition, we are not fully insured against all risks incident to our business because certain risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures. For example, we are not insured for all environmental liabilities, including, for example, product spills and other releases at all of our facilities. If we were to incur a significant liability for which we were not fully insured, it could diminish our ability to make distributions to our unitholders.

Our business subjects us to the inherent risk of incurring significant environmental costs and liabilities in the operation of our refineries, terminals and related facilities.

There is inherent risk of incurring significant environmental costs and liabilities in the operation of refineries, blending sites, terminals, and related facilities due to our handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to our operations, and as a result of historical operations and waste disposal practices at our facilities, some of which may have been conducted by prior owners or operators. We currently own or operate properties that for many years have been used for industrial activities, including refining and blending operations or terminal storage operations, sometimes by third parties over whom we had no control with respect to their operations or waste disposal activities. Petroleum hydrocarbons or wastes have been released on, under or from the properties owned or operated by us. For example, we are investigating and remediating, in some cases pursuant to government order, soil and groundwater contamination at our Montana refinery arising from a predecessor operators’ handling of petroleum hydrocarbons and wastes. Our costs in pursuing these investigatory and remedial activities are subject to reimbursement under a contractual indemnification we received from our predecessor operator in the share purchase agreement transferring ownership of this refinery. We expect that our costs in completing these investigatory and remedial activities at our Montana refinery will be reimbursed under the contractual indemnification. Joint and several, strict liability may be incurred in connection with releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities. Neither the owners of our general partner nor their affiliates have indemnified us for any environmental liabilities, including those arising from non-compliance or pollution, that may be discovered at, or arise from operations on, the assets they contributed to us in connection with the closing of our initial public offering. Private parties, including the owners of properties adjacent to our operations and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance or other sources of indemnity. To the extent that the costs associated with meeting any or all of these requirements are substantial and not adequately provided for, there could be a material adverse effect on our business, financial condition, and results of operations.

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We are subject to compliance with stringent environmental and occupational health and safety laws and regulations that may expose us to substantial costs and liabilities.

Our refining, blending, terminal and related facility operations are subject to stringent federal, regional, state 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 numerous obligations that are applicable to our operations, including the obligation to obtain permits to conduct regulated activities, the incurrence of significant capital expenditures for air pollution control equipment to otherwise limit or prevent releases of pollutants from our refineries, blending sites, terminals, and related facilities, the expenditure of significant monies in the application of specific health and safety criteria addressing worker protection, the requirement to maintain information about hazardous materials used or produced in our operations and to provide this information to employees, state and local government authorities, and local residents and the incurrence of substantial costs and liabilities for pollution resulting from our operations or from those of prior owners or operators of our facilities. Numerous federal governmental authorities, such as the EPA and OSHA as well as state agencies, such as the LDEQ, TCEQ, MDEQ and the WDNR have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations as well as any issued permits and orders may result in the assessment of administrative, civil, and criminal sanctions, including monetary penalties, the imposition of remedial obligations or corrective actions, and the issuance of injunctions limiting or preventing some or all of our operations.

On occasion, we receive notices of violation, enforcement proceedings and regulatory inquiries from governmental agencies alleging non-compliance with applicable environmental and occupational health and safety laws and regulations. For example, we entered into a Consent Agreement and Final Order with the EPA on November 7, 2013 in which we agreed to pay a $0.3 million civil penalty and take various corrective actions in association with the EPA's previous inspection of the Shreveport refinery's risk management program compliance and also have pending proceedings with the LDEQ involving a series of alleged unauthorized emissions of pollutants from equipment at the Shreveport refinery, as described in a draft "Consolidated Compliance Order and Notice of Potential Penalty" issued on or around April 13, 2013, and with the EPA involving alleged unauthorized emissions of pollutants from flares at the Superior Refinery, as described in a "Notice of Violation" issued by the EPA on or around June 29, 2012. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require us 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. For example, on September 12, 2012, the EPA issued final amendments to the NSPS for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares, the impact of which standards we have evaluated and do not expect will have a material adverse effect on our refinery operations. In another example, on March 29, 2013, the EPA announced its proposed Tier 3 fuel standards that require, among other things, a lower allowable sulfur level in gasoline to no more than 10 parts per million by January 1, 2017. The EPA is assessing public comments on the standards received during the rulemaking's public comment period and the agency is expected to finalize the Tier 3 fuel standards in 2014. While the proposed updated Tier 3 standards are not expected to have a material financial impact on us, we are not able to predict the impact of any new or changed laws or regulations or changes in the ways that such laws or regulations are administered, interpreted, or enforced but we may incur increased operating costs and capital expenditures to comply with such finalized requirements, which could be material. To the extent that the costs associated with meeting any of these requirements are substantial and not adequately provided for, our results of operations and cash flows could suffer. Please read Items 1 and 2 "Business and Properties — Environmental and Occupational Health and Safety Matters" for additional information regarding our communications with the LDEQ and EPA.

Renewable transportation fuels mandates may reduce demand for the petroleum fuels we produce, which could have a material adverse effect on our results of operations and financial condition, and our ability to make distributions to our unitholders.

Pursuant to the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, the EPA has issued RFSII requirements implementing mandates to blend renewable fuels into the petroleum fuels produced and sold in the U.S. Under RFSII, the volume of renewable fuels that obligate refineries like our Shreveport, Superior, Montana and San Antonio refineries to blend into their finished petroleum fuels increases annually over time until 2022. We may meet these RFSII requirements by blending the necessary volumes of renewable transportation fuels obtained from third parties or produced by us, from purchases of RINs in the open market that are generated by third parties, or through a combination of blending of renewable transportation fuels and purchase of RINs. To the extent that we exceed the minimum volumetric requirements for blending of renewable transportation fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFSII compliance or selling those RINs on the open market.

We currently purchase RINs for some fuel categories on the open market to comply with the RFSII and, in the future, we may be required to purchase additional RINs beyond the amount we currently purchase on the open market in order to maintain compliance with the RFSII. Our gross 2013 annual RINs obligation, which includes RINs that were required to be secured through either blending or through the purchase of RINs in the open market, were 81 million RINs for the full year 2013. Notwithstanding the EPA's proposed rule published on November 29, 2013 to lower the RFSII mandate for 2014 in comparison to 2013, our acquisition of the Montana and San Antonio refineries in October 2012 and January 2013, respectively, together with other changes in our overall refining system, may increase the total amount of RINs that we may need to obtain in 2014 or future years in comparison to 2013 to comply with the RFSII mandate. Moreover, there has been volatility in the purchase price for RINs during 2013, with prices increasing significantly in the first seven months of 2013 as compared to past years but declining at a more moderate rate since that time, and we cannot currently predict the future prices or availability of RINs or the total extent of our ability to mitigate our future RFSII compliance expenses such as, for example, increasing the blending of transportation fuels that qualify for RINs in our refining system or passing on some of the increased costs associated with RFSII compliance to our customers. The costs to obtain the necessary number of RINs in 2014 and beyond could be material and have a material adverse effect on our results of operations and financial condition as well as on the refining industry in general. Finally, while there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties, we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFSII requirements.

On October 13, 2010, the EPA raised the maximum amount of ethanol allowed under federal law from 10% to 15% for cars and light trucks manufactured since 2007, and on January 21, 2011, the EPA extended the maximum allowable ethanol content of 15% to apply to cars and light trucks manufactured since 2001. The maximum amount allowed under federal law currently remains at 10% ethanol for all other vehicles. EPA required that fuel and fuel additive manufacturers take certain steps before introducing gasoline containing 15% ethanol ("E15") into the market, including developing and obtaining EPA approval of a plan to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver. EPA has taken several recent actions to authorize the introduction of E15 into the market, including approving, on June 15, 2012, the first plans to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver, followed by approving, on February 7, 2013, a new blender pump configuration for general use by retail stations that wish to dispense E15 and E10 from a common hose and nozzle. Existing laws and regulations could change, and the minimum volumes of renewable fuels that must be blended with refined petroleum fuels may increase. Because we do not produce renewable transportation fuels at all of our refineries, increasing the volume of renewable fuels that must be blended into our products displaces an increasing volume of our Shreveport, Superior, Montana and San Antonio refineries' fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make distributions to our unitholders.

Downtime for maintenance at our refineries and facilities will reduce our revenues and cash available for distributions to our unitholders and payments of our debt obligations.

Our refineries and facilities consist of many processing units, a number of which have been in operation for a long time. One or more of the units may require additional unscheduled downtime for unanticipated maintenance or repairs that are more frequent than our scheduled turnaround for each unit every one to five years. Scheduled and unscheduled maintenance reduce our revenues and increase our operating expenses during the period of time that our processing units are not operating and could reduce our ability to make distributions to our unitholders.

If we do not successfully execute growth through acquisitions, our future growth and ability to increase distributions to our unitholders may be limited.

Our ability to grow depends in substantial part on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to consummate acquisitions on favorable terms, (3) unable to obtain financing for these acquisitions on economically acceptable terms, or (4) outbid by competitors, then our future growth and ability to increase distributions to our unitholders may be limited. Furthermore, any acquisition, involves potential risks, including, among other things:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- an inability to timely and effectively integrate the operations of recently acquired businesses or assets, particularly those in new geographic areas or in new lines of business;
- the incurrence of substantial seen or unforeseen environmental and other liabilities arising out of the acquired businesses or assets;
- the diversion of management's attention from other business concerns;

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- customer or key employee losses at the acquired businesses; and
- significant changes in our capitalization and results of operations.

Our asset reconfiguration and enhancement initiatives may not result in revenue or cash flow increases, may be subject to significant cost overruns and are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our business, operating results, cash flows and financial condition.

Historically we have grown our business in part through the reconfiguration and enhancement of our existing refinery assets. For example, we completed an expansion project at our Shreveport refinery to increase throughput capacity and crude oil processing flexibility in May 2008. In addition, during 2013 we commenced an expansion project at our Montana refinery to increase crude oil throughput capacity from 10,000 bpd to 20,000 bpd. These expansion projects and the construction of other additions or modifications to our existing refineries have and will continue to involve numerous regulatory, environmental, political, legal, labor and economic uncertainties beyond our control, which could cause delays in construction or require the expenditure of significant amounts of capital, which we may finance with additional indebtedness or by issuing additional equity securities. Our forecasted internal rates of return on such projects are also based on our projections of future market fundamentals, which are not within our control, including changes in general economic conditions, available alternative supply and customer demand. For example, the total cost of the Shreveport refinery expansion project completed in 2008 was approximately $375.0 million and was significantly over budget due primarily to increased construction labor costs. Future reconfiguration and enhancement projects may not be completed at the budgeted cost, on schedule, or at all due to the risks described above which could significantly affect our cash flows and financial condition.

We face substantial competition from other refining companies.

The refining industry is highly competitive. Our competitors include large, integrated, major or independent oil companies that, because of their more diverse operations, larger refineries or stronger capitalization, may be better positioned than we are to withstand volatile industry conditions, including shortages or excesses of crude oil or refined products or intense price competition at the wholesale level. If we are unable to compete effectively, we may lose existing customers or fail to acquire new customers. For example, if a competitor attempts to increase market share by reducing prices, our operating results and cash available for distribution to our unitholders and payments of our debt obligations could be reduced.

The amount of cash we have available for distribution to unitholders depends primarily on our cash flow and not solely on profitability.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may not make cash distributions during periods when we record net income.

Distributions to unitholders and payments of our debt obligations could be adversely affected by a decrease in the demand for our specialty products.

Changes in our customers’ products or processes may enable our customers to reduce consumption of the specialty products that we produce or make our specialty products unnecessary. Should a customer decide to use a different product due to price, performance or other considerations, we may not be able to supply a product that meets the customer’s new requirements. In addition, the demand for our customers’ end products could decrease, which could reduce their demand for our specialty products. Our specialty products customers are primarily in the industrial goods, consumer goods and automotive goods industries and we are therefore susceptible to overall economic conditions, which may change demand patterns and products in those industries. Consequently, it is important that we develop and manufacture new products to replace the sales of products that mature and decline in use. If we are unable to manage successfully the maturation of our existing specialty products and the introduction of new specialty products our revenues, net income and cash available for distribution to our unitholders and payments of our debt obligations could be reduced.

Distributions to unitholders and payments of our debt obligations could be adversely affected by a decrease in demand for fuel products in the markets we serve.

Any sustained decrease in demand for fuel products in the markets we serve could result in a significant reduction in our cash flows, reducing our ability to make distributions to unitholders and payments of our debt obligations. Factors that could lead to a decrease in market demand include:

- a recession or other adverse economic condition that results in lower spending by consumers on gasoline, diesel and travel;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of fuel products;

- an increase in fuel economy or the increased use of alternative fuel sources;
- an increase in the market price of crude oil that lead to higher refined product prices, which may reduce demand for fuel products;
- competitor actions; and
- availability of raw materials.

We depend on unionized labor for the operation of our facilities. Any work stoppages or labor disturbances at these facilities could disrupt our business.

Substantially all of our operating personnel at our Shreveport, Superior, Montana, Princeton, Cotton Valley, Karns City, Dickinson and Missouri facilities are employed under collective bargaining agreements, two of which expire in April and October 2014 and two of which expire in January 2015. If we are unable to renegotiate these agreements as they expire, any work stoppages or other labor disturbances at these facilities could have an adverse effect on our business and reduce our ability to make distributions to our unitholders. In addition, employees who are not currently represented by labor unions may seek union representation in the future, and any renegotiation of current collective bargaining agreements may result in terms that are less favorable to us.

Because of the volatility of crude oil and refined products prices, our method of valuing our inventory may result in decreases in net income.

The nature of our business requires us to maintain substantial quantities of crude oil and refined product inventories. Because crude oil and refined products are essentially commodities, we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market value, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a non-cash charge to cost of sales. In a period of decreasing crude oil or refined product prices, our inventory valuation methodology may result in decreases in net income.

The operating results for our fuel products segment, including the asphalt we produce and sell, are seasonal and generally lower in the first and fourth quarters of the year.

The operating results for the fuel products segment, including the selling prices of asphalt products we produce, can be seasonal. Asphalt demand is generally lower in the first and fourth quarters of the year as compared to the second and third quarters due to the seasonality of road construction. Demand for gasoline is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months. Our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year as a result of this seasonality.

Due to our lack of asset and geographic diversification, adverse developments in our operating areas would reduce our ability to make distributions to our unitholders.

We rely primarily on sales generated from products processed at the facilities we own. Furthermore, the majority of our assets and operations are located in Louisiana, Wisconsin, Montana and Texas. Due to our lack of diversification in asset type and location, an adverse development in these businesses or areas, including adverse developments due to catastrophic events or weather, decreased supply of crude oil and feedstocks and/or decreased demand for refined petroleum products, would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets in more diverse locations.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and a decreased demand for our refined products.

In 2009, the EPA adopted rules for establishing a reporting program for emissions of carbon dioxide, methane and other GHGs from specified large GHG emissions sources in the U.S., including refineries, and subsequently expanded the scope of this rule to include the reporting of GHG emissions from onshore oil and natural gas processing, transmission, storage and distribution facilities. Operators of covered sources in the U.S. must annually monitor and report these GHG emissions to EPA and certain state agencies. Our refineries and certain of our other facilities are subject to the federal GHG reporting requirements because of combustion GHG emissions and potential fugitive emissions that exceed reporting thresholds. While our compliance with this reporting program has increased our operating costs, we presently do not believe that these increased costs have a material adverse effect on our results of

operations.
Following its determination in December 2009 that emissions of GHG present a danger to public health and the environment, the EPA promulgated regulations in 2010 establishing Title V and PSD permitting requirements for large sources of GHG that apply to certain of our facilities, including our refineries, which are potential major sources of GHG emissions. In the absence of any control requirements for GHG for our facilities that would need to be incorporated into existing Title V

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permits, we believe the impact of these permitting requirements on our facilities will not be material. However, we may be required to install "best available control technology" to limit emissions of GHG from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHG. Best available control technology is determined on a case-by-case basis by the relevant permitting agency to date, whether EPA or state. PSD permits with GHG emissions limitations have generally required efficient combustion requirements on sources that burn large volumes of fossil fuels rather than post-combustion GHG capture requirements. If the EPA imposes efficient combustion requirements, we do not anticipate that they will have a material adverse effect on the cost of our operations. In October 2013, the U.S. Supreme Court agreed to hear a lawsuit challenging whether the EPA permissibly determined that its regulation of GHG emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit GHGs, with a decision expected in 2014. Moreover, as part of a settlement in December 2010 with certain environmental groups derived out of legal challenges seeking judicial review of an EPA final rule on standards of performance for petroleum refineries, the EPA agreed to propose new source performance standards for GHG emissions from petroleum refineries by December 10, 2011 and to finalize these rules by November 15, 2012. While no such standards have been proposed by the EPA to date, we expect the agency to continue to pursue this rulemaking. Depending on the nature of the requirements imposed by the EPA as part of this rulemaking, we could encounter increased operating costs and capital expenditures that could be significant.

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHG, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions. Two of the more significant non-federal GHG programs are the Regional Greenhouse Gas Initiative ("RGGI") and California's cap-and-trade program. RGGI, which includes a number of states in the northeastern U.S., implemented a cap-and-trade program applicable to utility power plants in 2009. None of our facilities are affected by RGGI. Enforceable compliance obligations under California's cap-and-trade program became effective with respect to certain industrial GHG emitters in the state on January 1, 2013, but we do not operate in California and thus our operations are not impacted by the implementation of this cap-and-trade program.

If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax. A carbon tax could impose additional direct costs on our operations and reduce demand for refined products. The ultimate impact of any carbon tax on our operations would further depend upon whether a carbon tax supplanted the other federal GHG regulations to which we are currently subject or is administered as an additional program.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our products, results of operations and cash flows. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets and operations.

We could be subject to damages based on claims brought against us by our customers or lose customers as a result of the failure of our products to meet certain quality specifications.

Our specialty products provide precise performance attributes for our customers' products. If a product fails to perform in a manner consistent with the detailed quality specifications required by the customer, the customer could seek replacement of the product or damages for costs incurred as a result of the product failing to perform as guaranteed. A successful claim or series of claims against us could result in a loss of one or more customers and reduce our ability to make distributions to unitholders and payments of our debt obligations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the Commodity Futures Trading Commission (“CFTC”) and the SEC to promulgate rules and regulations implementing the Act. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or derivative instruments would be exempt from these position limits. The position limits rule was vacated by the U.S. District Court for the District of Colombia in September 2012. The CFTC recently proposed two sets of rules relating to position limits that would replace the vacated rule. The CFTC also has finalized other regulations, including critical rulemakings on the definition of “swap,” “security-based swap,” “swap dealer” and “major swap participant.” Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished and

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when the compliance date for those regulations will commence. The Act also may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us and the schedule for effectiveness of those regulations is uncertain at this time. The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Act and any new regulations could significantly increase the cost of derivative instruments (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative instruments, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. An increase in the cost of derivatives contracts would affect our results of operations and cash available for distribution to our unitholders and payments of our debt obligations. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make distributions to our unitholders and payments of our debt obligations. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

We depend on key personnel for the success of our business and the loss of those persons could adversely affect our business and our ability to make distributions to our unitholders.

The loss of the services of any member of senior management or key employee could have an adverse effect on our business and reduce our ability to make distributions to our unitholders. We may not be able to locate or employ on acceptable terms qualified replacements for senior management or other key employees if their services were no longer available. Except with respect to Mr. Grube, neither we, our general partner nor any affiliate thereof has entered into an employment agreement with any member of our senior management team or other key personnel. Furthermore, we do not maintain any key-man life insurance.

An increase in interest rates will cause our debt service obligations to increase.

Borrowings under our revolving credit facility bear interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option. As of December 31, 2013, there were no borrowings outstanding under our revolving credit facility and $95.2 million in standby letters of credit were issued under our revolving credit facility. The interest rate is subject to adjustment based on fluctuations in the London Interbank Offered Rate (“LIBOR”) or prime rate, as applicable. An increase in the interest rates associated with our floating-rate debt would increase our debt service costs and affect our results of operations and cash flow available for distribution to our unitholders. In addition, an increase in interest rates could adversely affect our future ability to obtain financing or materially increase the cost of any additional financing.

A change of control could result in us facing substantial repayment obligations under our revolving credit agreement, our senior notes and our Collateral Trust Agreement.

Certain events relating to a change of control of our general partner, our partnership and our operating subsidiaries would constitute an event of default under our revolving credit agreement, the indentures governing our senior notes and our Collateral Trust Agreement. In addition, an event of default under our revolving credit agreement would likely constitute an event of default under our master derivatives contracts and a crude oil purchase agreement with BP (the “BP Purchase Agreement”). As a result, upon a change of control event, we may be required immediately to repay the outstanding principal, any accrued interest on and any other amounts owed by us under our revolving credit facility and the senior notes and the outstanding payment obligations under our master derivatives contracts and the BP Purchase Agreement. The source of funds for these repayments would be our available cash or cash generated from other sources and there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness and other payment obligations in full. In addition, our obligations under our revolving credit facility are secured by a first priority lien on our cash, accounts receivable, inventory and certain related assets and our obligations under our master derivatives contracts and the BP Purchase Agreement are secured by a first priority lien on our 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 forgoing (including proceeds of hedge agreements). If we are unable to repay our indebtedness under the revolving credit facility, the payment obligations under our master derivative contracts or the payment obligations under the BP Purchase Agreement or obtain waivers of such defaults, then the lenders under our revolving credit facility, the derivative counterparties under our master derivative contracts and BP would have the right to foreclose on those assets, which would have a material adverse effect on us. There is no restriction in our partnership agreement on the ability of our general partner to enter into a transaction which would trigger the change of control provisions of our revolving credit facility agreement, the indentures governing our senior notes or our Collateral Trust Agreement.

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We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers and by counterparties of our derivative instruments. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties could reduce our ability to make distributions to our unitholders and payments of our debt obligations.

Risks Inherent in an Investment in Us

At March 3, 2014, the families of our chairman, chief executive officer and vice chairman, The Heritage Group and certain of their affiliates own an approximate 26.2% limited partner interest in us and own and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to other unitholders' detriment.

At March 3, 2014, the families of our chairman, chief executive officer and vice chairman, the Heritage Group, and certain of their affiliates own an approximate 26.2% limited partner interest in us. In addition, The Heritage Group and the families of our chairman and chief executive officer and vice chairman own our general partner. Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, the general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- our general partner is allowed to take into account the interests of parties other than us, such as its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing common units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under Delaware law;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a capital expenditure for acquisitions or capital improvements, which does not. This determination can affect the amount of cash that is available for distribution to our unitholders and payments of our debt obligations;
- our general partner has the flexibility to cause us to enter into a broad variety of derivative transactions covering different time periods, the net cash receipts from which will increase operating surplus and adjusted operating surplus, with the result that our general partner may be able to shift the recognition of operating surplus and adjusted operating surplus between periods to increase the distributions it and its affiliates receive on their incentive distribution rights; and
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

The Heritage Group and certain of its affiliates may engage in limited competition with us.

Pursuant to the omnibus agreement we entered into in connection with our initial public offering, The Heritage Group and its controlled affiliates have agreed not to engage in, whether by acquisition or otherwise, the business of refining or marketing specialty lubricating oils, solvents and wax products as well as gasoline, diesel and jet fuel products in the continental U.S. for so long as it controls us. This restriction does not apply to certain assets and businesses which are more fully described under Part III, Item 13 "Certain Relationships and Related Transactions and Director Independence — Omnibus Agreement."

Although Mr. Grube is prohibited from competing with us pursuant to the terms of his employment agreement, the owners of our general partner, other than The Heritage Group, are not prohibited from competing with us, except to the extent described above.

Our partnership agreement limits our general partner’s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- Permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of our partnership or amendment of our partnership agreement;
- Provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- Generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us. In determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- Provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person’s conduct was criminal.

By purchasing a common unit, a unitholder agrees to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders do not elect our general partner or its board of directors, and have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by the members of our general partner. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, the vote of the holders of at least 66 $^{2}/3$% of all outstanding units voting together as a single class is required to remove the general partner. At March 3, 2014, the owners of our general partner and certain of their affiliates own approximately 26.2% of our common units. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our common units.

Unitholders’ voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders’ ability to influence the manner or direction of management.

Our general partner interest or control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their respective membership interests in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and thereby control the decisions taken by the board of directors.

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We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs.

We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs. We can provide no assurance that our general partner will continue to provide us the officers and employees that are necessary for the conduct of our business nor that such provision will be on terms that are acceptable to us. If our general partner fails to provide us with adequate personnel, our operations could be adversely impacted and our cash available for distribution to unitholders and payments of our debt obligations could be reduced.

We may issue additional common units without unitholder approval, which would dilute our current unitholders' existing ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units. The issuance of additional common units or other equity securities of equal or senior rank to the common units will have the following effects:

- our unitholders' proportionate ownership interest in us may decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

Our general partner's determination of the level of cash reserves may reduce the amount of available cash for distribution to unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that it establishes are necessary to fund our future operating expenditures. In addition, our partnership agreement also permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These reserves will affect the amount of cash available for distribution to unitholders.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets and our ability to distribute cash to our unitholders and make payments of our debt obligations depends on the performance of our subsidiaries and their ability to distribute funds to us.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the equity interests in our subsidiaries. As a result, our ability to distribute cash to our unitholders and make payments of debt obligations depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us is restricted by our revolving credit facility and the indentures governing our senior notes and may be restricted by, among other things, applicable state laws and other laws and regulations. If we are unable to obtain the funds necessary to distribute cash to our unitholders or make payments of debt obligations, we may be required to adopt one or more alternatives, such as a refinancing of our indebtedness or incurring borrowings under our revolving credit facility. We cannot assure unitholders that we would be able to refinance our indebtedness or that the terms on which we could refinance our indebtedness would be favorable.

Cost reimbursements due to our general partner and its affiliates will reduce cash available for distribution to unitholders and payments of our debt obligations.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner and will reduce the cash available for distribution to unitholders and payments of our debt obligations. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. Please read Part III, Item 13 "Certain Relationships and Related Transactions and Director Independence."

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the issued and outstanding common units, our general partner will have the right, but not the obligation, which right it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units to our general partner, its affiliates or us at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their common units. At March 3, 2014, our general partner and its affiliates own approximately 26.2% of the common units.

Unitholder liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, which we call the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Purchasers of units who become limited partners are liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of the units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our common units have a low trading volume compared to other units representing limited partner interests.

Our common units are traded publicly on the NASDAQ Global Select Market under the symbol "CLMT." However, our common units have a low average daily trading volume compared to many other units representing limited partner interests quoted on the NASDAQ Global Select Market.

The market price of our common units may continue to be volatile and may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- changes in commodity prices or refining margins;
- loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- the other factors described in Item 1A "Risk Factors" of this Annual Report.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes, or if we become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the anticipated quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

Unitholders will be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from that income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination.

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Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for federal income tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS recently announced a relief procedure whereby if a publicly-traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease in such unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to our unitholders if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation and deductions and certain other items. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as "IRAs"), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to non-U.S persons, and each non-U.S. person will be required to file U.S. federal tax returns and pay tax on their shares of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS may materially and adversely impact the market for our common units and the price at which they trade. Our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to their tax returns.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly-traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

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We have adopted certain valuation methodologies for U.S. federal income tax purposes that may result in a shift of income, gain, loss, and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss, and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss, and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. We own assets and conduct business in 45 states. Our unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in any state in which we now or may conduct business in the future. Further, they may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is the responsibility of our unitholders to file all U.S. federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are not a party to, and our property is not the subject of, any pending legal proceedings other than ordinary routine litigation incidental to our business. Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. Please see Items 1 and 2 "Business and Properties — Environmental and Occupational Health and Safety Matters" for a description of our current regulatory matters related to the environment, health and safety. Additionally, the information provided under Note 6 “Commitments and Contingencies” in Part II, Item 8 “Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements” is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities
Market Information
Our common units are quoted and traded on the NASDAQ Global Select Market ("NASDAQ") under the symbol "CLMT." The following table shows the low and high sales prices per common unit, as reported by NASDAQ, for the periods indicated. Cash distributions presented below represent amounts declared subsequent to each respective quarter end based on the results of that quarter.

	Low	High	Cash Distribution per Unit (1)
2012:			
First quarter	$20.00	$27.50	$0.56
Second quarter	$20.76	$27.74	$0.59
Third quarter	$24.01	$32.02	$0.62
Fourth quarter	$27.53	$33.96	$0.65
2013:			
First quarter	$31.05	$40.25	$0.68
Second quarter	$31.60	$38.10	$0.685
Third quarter	$26.67	$36.91	$0.685
Fourth quarter	$24.84	$31.83	$0.685

(1) We also paid cash distributions to our general partner with respect to its 2% general partner interest and, to the extent distributions exceeded $0.495 per unit, its incentive distribution rights, as described below in "Cash Distribution Policy — General Partner Interest and Incentive Distribution Rights."

As of March 3, 2014, there were approximately 43 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. As of March 3, 2014, there were 69,317,278 common units outstanding. The last reported sale price of our common units by NASDAQ on February 28, 2014 was $25.47.
Cash Distribution Policy
General. Within 45 days after the end of each quarter, we distribute our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date.
Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves established by our general partner to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; and
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made. Working capital borrowings are generally borrowings that will be made under our revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Intent to Distribute the Minimum Quarterly Distribution. We distribute to the holders of common units on a quarterly basis at least the minimum quarterly distribution of $0.45 per unit, or $1.80 in aggregate per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our

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partnership agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under our debt instruments, including our revolving credit agreement and the indentures governing our 2019 Notes, 2020 Notes and 2022 Notes. Please read Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for a discussion of the restrictions in our debt instruments that restrict our ability to make distributions. On February 14, 2014, we paid a quarterly cash distribution of $0.685 per unit on all outstanding units totaling approximately $52.6 million for the quarter ended December 31, 2013 to all unitholders of record as of the close of business on February 4, 2014.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2% of all quarterly distributions since inception that we make prior to our liquidation. This general partner interest is represented by 1,414,638 general partner units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.495 per unit. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest, and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on units that it owns. Our general partner earned incentive distribution rights of approximately $14.7 million and $5.5 million during the years ended December 31, 2013 and December 31, 2012, respectively.

Conversion of Subordinated Units. In February 2011, we satisfied the last of the earnings and distribution tests contained in our partnership agreement for the automatic conversion of all 13,066,000 outstanding subordinated units into common units on a one-for-one basis. The last of these requirements was met upon payment of the quarterly distribution paid on February 14, 2011. Two days following this quarterly distribution to unitholders, or February 16, 2011, all of the outstanding subordinated units automatically converted to common units.

Our general partner is entitled to incentive distributions if the amount we distribute to unitholders with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount Per Common Unit	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98 %	2 %
First Target Distribution	up to $0.495	98 %	2 %
Second Target Distribution	above $0.495 up to $0.563	85 %	15 %
Third Target Distribution	above $0.563 up to $0.675	75 %	25 %
Thereafter	above $0.675	50 %	50 %

Equity Compensation Plans

The equity compensation plan information required by Item 201(d) of Regulation S-K in response to this Item 5 is incorporated by reference into Part III, Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" of this Annual Report.

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following table shows selected historical consolidated financial and operating data of the Company. The selected historical consolidated financial data as of and after December 31, 2013, 2012 and 2011 includes the operations acquired as part of the acquisitions of Superior, Missouri, Calumet Packaging, Royal Purple, Montana, San Antonio and Bel-Ray from their respective dates of acquisition, September 30, 2011, January 3, 2012, January 6, 2012, July 3, 2012, October 1, 2012, January 2, 2013 and December 10, 2013.

The following table 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

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operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with U.S. generally accepted accounting principles (“GAAP”), please read “—Non-GAAP Financial Measures.” We derived the information in the following table from, and the information should be read together with, and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included in Item 8 “Financial Statements and Supplementary Data” except for operating data, such as sales volume, feedstock runs and facility production. The following table also should be read together with Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except unit, per unit and operating data)				
Summary of Operations Data:					
Sales	$5,421.4	$4,657.3	$3,134.9	$2,190.8	$1,846.6
Cost of sales	5,011.4	4,144.1	2,860.8	1,992.1	1,673.5
Gross profit	410.0	513.2	274.1	198.7	173.1
Operating costs and expenses:					
Selling	62.6	41.6	12.2	8.4	9.4
General and administrative	82.1	60.9	38.6	26.8	23.2
Transportation	142.7	107.9	94.2	85.5	68.0
Taxes other than income taxes	14.2	9.1	5.7	4.6	3.8
Insurance recoveries	—	—	(8.7)	—	—
Other	16.8	7.8	6.8	1.9	1.3
Operating income	91.6	285.9	125.3	71.5	67.4
Other income (expense):					
Interest expense	(96.8)	(85.6)	(48.7)	(30.5)	(33.6)
Debt extinguishment costs	(14.6)	—	(15.1)	—	—
Realized gain (loss) on derivative instruments	(4.7)	9.5	(7.9)	(7.7)	8.3
Unrealized gain (loss) on derivative instruments	25.7	(3.8)	(10.4)	(15.8)	23.7
Other	2.7	0.5	0.8	(0.2)	(3.8)
Total other expense	(87.7)	(79.4)	(81.3)	(54.2)	(5.4)
Income before income taxes	3.9	206.5	44.0	17.3	62.0
Income tax expense	0.4	0.8	1.0	0.6	0.2
Net income	$3.5	$205.7	$43.0	$16.7	$61.8

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	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except unit, per unit and operating data)				
Weighted average limited partner units outstanding:					
Basic	67,938,784	55,559,183	42,598,876	35,334,720	32,371,726
Diluted	67,938,784	55,676,741	42,644,086	35,351,020	32,371,726
Limited partners' interest basic net income (loss) per unit	$(0.17)	$3.51	$0.98	$0.46	$1.87
Limited partners' interest diluted net income (loss) per unit	$(0.17)	$3.50	$0.98	$0.46	$1.87
Cash distributions declared per limited partner unit	$2.70	$2.30	$1.94	$1.83	$1.80
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$1,160.4	$986.9	$842.1	$612.4	$629.3
Total assets	2,688.1	2,253.0	1,732.1	1,016.7	1,031.9
Accounts payable	355.8	332.6	302.8	171.6	106.9
Long-term debt	1,110.8	863.5	587.1	369.3	401.1
Total partners' capital	1,062.8	889.8	728.9	398.3	485.3
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$39.1	$380.1	$63.8	$134.1	$101.0
Investing activities	(370.3)	(624.2)	(460.4)	(34.7)	(22.7)
Financing activities	420.1	276.2	396.7	(99.4)	(78.1)
Other Financial Data:					
EBITDA	$233.1	$383.7	$170.9	$108.1	$157.3
Adjusted EBITDA	241.5	404.6	211.0	138.5	151.2
Distributable Cash Flow	18.5	281.1	127.2	76.2	98.7
Operating Data (bpd):					
Total sales volume (1)	116,477	97,789	66,134	55,668	57,086
Total feedstock runs (2)	110,237	97,600	69,295	55,957	60,081
Total facility production (3)	107,045	96,172	70,909	57,314	58,792

(1) Total sales volume includes sales from the production at our 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.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements.

(3) Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. 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.

Non-GAAP Financial Measures

We include in this Annual 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 operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP.

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

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

We believe that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions. We believe that excluding these transactions allows investors to meaningfully analyze trends and 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 and environmental capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense) and income tax expense. Distributable Cash Flow is used by us and our investors and analysts to analyze our ability to pay distributions.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Annual Report have been updated to reflect the calculation of "Consolidated Cash Flow" contained in the indentures governing our 2019 Notes, 2020 Notes and 2022 Notes (as defined in this Annual Report). We are required to report Consolidated Cash Flow to the holders of our 2019 Notes, 2020 Notes and 2022 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Adjusted EBITDA and Distributable Cash Flow that are presented in this Annual Report for prior periods have been updated to reflect the use of the new calculations. Please read Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" 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 (loss), operating income (loss), net cash provided by (used in) operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA, Adjusted EBITDA and Distributable Cash Flow do not reflect our obligations for the payment of income taxes, interest expense or other obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of the measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner. The following tables present a reconciliation of both net income 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.

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	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions)				
Reconciliation of Net income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:					
Net income	$3.5	$205.7	$43.0	$16.7	$61.8
Add:					
Interest expense	96.8	85.6	48.7	30.5	33.6
Debt extinguishment costs	14.6	—	15.1	—	—
Depreciation and amortization	117.8	91.6	63.1	60.3	61.7
Income tax expense	0.4	0.8	1.0	0.6	0.2
EBITDA	$233.1	$383.7	$170.9	$108.1	$157.3
Add:					
Unrealized (gain) loss on derivatives	$(25.7)	$3.8	$10.4	$15.8	$(23.7)
Realized gain (loss) on derivatives, not included in net income	(1.8)	(5.0)	10.9	3.1	9.2
Amortization of turnaround costs	15.9	13.4	11.4	10.0	7.3
Non-cash equity based compensation and other non-cash items	20.0	8.7	7.4	1.5	1.1
Adjusted EBITDA	$241.5	$404.6	$211.0	$138.5	$151.2
Less:					
Replacement and environmental capital expenditures (1)	64.2	28.3	23.7	24.4	15.5
Cash interest expense (2)	89.8	79.5	45.0	26.6	29.9
Turnaround costs	68.6	14.9	14.1	10.7	6.9
Income tax expense	0.4	0.8	1.0	0.6	0.2
Distributable Cash Flow	$18.5	$281.1	$127.2	$76.2	$98.7

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations.

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

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	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions)				
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by operating activities:					
Distributable Cash Flow	$18.5	$281.1	$127.2	$76.2	$98.7
Add:					
Replacement and environmental capital expenditures (1)	64.2	28.3	23.7	24.4	15.5
Cash interest expense (2)	89.8	79.5	45.0	26.6	29.9
Turnaround costs	68.6	14.9	14.1	10.7	6.9
Income tax expense	0.4	0.8	1.0	0.6	0.2
Adjusted EBITDA	$241.5	$404.6	$211.0	$138.5	$151.2
Less:					
Unrealized (gain) loss on derivatives	$(25.7)	$3.8	$10.4	$15.8	$(23.7)
Realized gain (loss) on derivatives, not included in net income	(1.8)	(5.0)	10.9	3.1	9.2
Amortization of turnaround costs	15.9	13.4	11.4	10.0	7.3
Non-cash equity based compensation and other non-cash items	20.0	8.7	7.4	1.5	1.1
EBITDA	$233.1	$383.7	$170.9	$108.1	$157.3
Add:					
Unrealized (gain) loss on derivatives	(25.7)	3.8	10.4	15.8	(23.7)
Cash interest expense (2)	(89.8)	(79.5)	(45.0)	(26.6)	(29.9)
Non-cash equity based compensation	4.8	6.5	4.9	1.5	1.1
Amortization of turnaround costs	15.9	13.4	11.4	10.0	7.3
Income tax expense	(0.4)	(0.8)	(1.0)	(0.6)	(0.2)
Provision for doubtful accounts	0.1	—	0.4	0.1	(0.9)
Debt extinguishment costs	(11.2)	—	(0.7)	—	—
Changes in assets and liabilities:					
Accounts receivable	(32.3)	34.6	(54.5)	(35.3)	(12.3)
Inventories	14.3	17.9	(167.0)	(9.9)	(18.7)
Other current assets	6.8	15.8	(0.4)	4.7	(2.9)
Turnaround costs	(68.6)	(14.9)	(14.1)	(10.7)	(6.9)
Derivative activity	(1.8)	(5.0)	11.7	3.0	8.5
Other noncurrent assets	(0.1)	(4.0)	(0.4)	(2.0)	—
Accounts payable	6.8	11.1	131.3	64.6	16.6
Accrued interest payable	(1.0)	13.0	7.4	0.1	(0.6)
Accrued income taxes payable	(27.6)	(16.1)	0.4	—	(0.2)
Other current liabilities	2.7	4.6	(2.5)	11.4	0.6
Other, including changes in non-current liabilities	13.1	(4.0)	0.6	(0.1)	5.9
Net cash provided by operating activities	$39.1	$380.1	$63.8	$134.1	$101.0

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations.

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

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The historical consolidated financial statements included in this Annual Report reflect all of the assets, liabilities and results of operations of the Company. The following discussion analyzes the financial condition and results of operations of the Company for the years ended December 31, 2013, 2012 and 2011. For the year ended December 31, 2013, the Company realigned its reportable segments for financial reporting purposes as a result of the significant growth in the Company. The change primarily represents reporting asphalt produced at the Shreveport, Superior and Montana refineries in the fuel products segment. Prior to this change, asphalt was reported as part of the specialty products segment. While this reporting change did not impact the Company's consolidated results, segment data for previous years has been restated and is consistent with the current year presentation throughout the financial statements and the accompanying notes. Unitholders should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with the historical consolidated financial statements and notes of the Company included elsewhere in this Annual 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, Pennsylvania and New Jersey. We own and lease additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("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 and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple and Bel-Ray brands. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, as well as reselling purchased crude oil to third party customers.

2013 Update

Financial Results

Our specialty products segment generated a gross profit margin of 18.2% during 2013 compared to 21.6% in 2012. The year over year decline was primarily attributable to a return to more normalized gross profit margins compared the prior year and higher operating costs, partially offset by acquisitions. Our fuel products segment generated a gross profit margin of 2.4% during 2013, compared to 4.0% in 2012. The year over year decline in gross profit margin was primarily attributable to a decline in refined product margins, as reflected by a 28% year over year decline in the 2/1/1 U.S. Gulf Coast crack spread and increased operating costs, primarily higher compliance costs associated with the Renewable Fuel Standard ("RFSII"), partially offset by lower realized losses on derivatives and gross profit contributed from the Montana and San Antonio Acquisitions.

During 2013, the Gulf Coast 2/1/1 crack spread averaged $21.57 per barrel, or approximately 28% less than in 2012. The U.S. Gulf Coast gasoline crack spread averaged $16.59 per barrel in 2013 compared to $26.07 in 2012. The benchmark gasoline and diesel margins both declined on a year over year basis, although the diesel crack remained elevated as compared to historical levels. The Gulf Coast diesel crack spread averaged $26.55 per barrel during 2013, compared to $34.08 per barrel in 2012.

Liquidity

On December 31, 2013, we had availability under our revolving credit facility of $472.4 million, based on a $567.6 million borrowing base, $95.2 million in outstanding standby letters of credit and no outstanding borrowings. In addition, we had $121.1 million of cash on hand as of December 31, 2013. We believe we will continue to have sufficient cash flow from operations and borrowing capacity to meet our financial commitments, minimum quarterly distributions to unitholders, debt service obligations, contingencies and anticipated capital expenditures.

Recent Debt Offering

In November 2013, we issued $350.0 million in 7 5/8% of senior notes due 2022, generating net proceeds of $337.4 million. From the net proceeds, we repurchased approximately $100.0 million of outstanding 9 3/8% senior notes due

2019. We also used a portion of the net proceeds from the offering to fund the Bel-Ray Acquisition and intend to continue to use the remaining net proceeds for general partnership purposes, including funding previously announced organic growth projects.

Recent Equity Offerings

During 2013, we completed two public offerings of our common units. In January 2013, we completed an equity offering of approximately 5.8 million units, including the overallotment option, at $31.81 per unit, generating net proceeds of $175.2 million. Net proceeds were used to repay borrowings under our revolving credit facility and for general partnership purposes.

In April 2013, we completed an equity offering of approximately 6.0 million units, including the overallotment option, at $37.50 per unit, generating net proceeds of $217.3 million. Net proceeds were used for general partnership purposes.

Cash Distribution

For 2013, we paid $201.6 million in cash distributions to our unitholders, an increase of 52% from the $132.4 million paid in 2012. On January 24, 2014, 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 (including the general partner's incentive distribution rights), for the fourth quarter 2013. The distribution was paid on February 14, 2014 to unitholders of record as of the close of business on February 4, 2014.

Renewable Fuels Standard

As set forth under RFSII, the EPA provides annual 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 RFSII, 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. In conjunction with our ongoing compliance with the RFSII, we will regularly purchase RINs in the open market to cover our anticipated blending obligation. We recognize our outstanding RINs obligation as a balance sheet liability. This liability is marked-to-market on a quarterly basis to reflect the market price of RINs on the last day of each quarter.

For the year ended December 31, 2013, our total cost to purchase RINs was $29.6 million, versus $3.8 million in 2012. RINs prices were highly volatile during 2013, resulting in significant quarterly variances in RFSII compliance costs. We expect our gross estimated RINs obligation, which includes RINs that are required to be secured through either blending or through the purchase of RINs in the open market, to be in the range of 90 to 95 million RINs for 2014. Despite the recent decline in RINs prices from record levels during mid-2013, we continue to anticipate that expenses related to RFSII compliance have the potential to remain a significant expense, assuming current market prices for RINs. Our estimated RINs obligation is subject to fluctuations in fuels production volumes during 2014.

Organic Growth Projects

During 2013, we introduced a series of high-return organic growth projects requiring a total capital investment estimated at $500 million to $550 million between 2013 and the first quarter of 2016. During 2013, we invested more than $100 million on these projects. During 2014, we estimate that our total capital investment on growth projects will be between approximately $270 million to $300 million. Upon completion, we estimate the incremental Adjusted EBITDA generated from these projects should result in highly attractive rates of return for the Partnership.

During 2013, we completed two projects at our San Antonio refinery that represent the first two projects completed under the multi-year organic growth campaign. These projects included the completion of a 3,000 bpd crude unit expansion, in addition to a fuels blending project designed to allow the refinery to blend and sell 5,000 bpd of finished gasoline. Between 2014 and the first quarter of 2016, we intend to complete three additional organic growth projects, including the following:

Dakota Prairie Refinery Project

We, together with our 50/50 joint venture partner, MDU Resources Group, Inc. ("MDU"), are in the process of constructing a 20,000 bpd diesel refinery located in Dickinson, North Dakota to meet growing local demand for finished diesel. The refinery, which is expected to be completely supplied with cost-advantaged local Bakken crude oil, is expected to commence operations during the fourth quarter 2014. The estimated total cost of the expansion project to the joint venture is approximately $300 million, subject to periodic reviews of project costs.

Missouri Esters Plant Expansion Project

We have initiated a project designed to double the esters production capacity at our Missouri esters plant from 35 to 75 million pounds per year. We anticipate this project should reach completion during the second quarter 2015. Esters are a key base stock used in the aviation, refrigerant and automotive lubricants markets. The estimated total cost of the expansion project is approximately $40 million.

Montana Refinery Expansion Project

We have initiated a project designed to double production capacity at our Great Falls, Montana refinery from 10,000 bpd to 20,000 bpd. The expansion will allow us to capitalize on local access to cost-advantaged Bow River Canadian crude oil, while producing additional fuels and refined products for delivery into regional markets. The scope of this project includes the installation of a new 20,000 bpd crude oil unit and a new 25,000 bpd hydrocracker. We estimate that this project will be completed during the first quarter of 2016. The estimated total cost of the expansion is approximately $400 million.

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Acquisitions

San Antonio Refinery

On January 2, 2013, we 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. Total consideration for the San Antonio Acquisition was approximately $117.9 million, net of cash acquired ("San Antonio Acquisition"). The refinery has total crude oil throughput capacity of 17,500 bpd and primarily produces jet fuel, diesel, gasoline, other fuel products and specialty solvents. The San Antonio Acquisition was funded 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.

Crude Oil Logistics Assets

On August 9, 2013, we completed the acquisition of seven crude oil loading facilities and related assets in North Dakota and Montana from Murphy Oil USA, Inc. ("Murphy") for aggregate consideration of approximately $6.2 million ("Crude Oil Logistics Acquisition"). The Crude Oil Logistics Acquisition was funded with cash on hand. As part of this acquisition, we assumed pipeline space on the Enbridge Pipeline System ("Enbridge Pipeline") previously held by Murphy. We will have the ability to transport crude oil directly from the point of lease, into our newly acquired crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to the our refineries and/or third party customers. As part of this transaction, we jointly consented with Murphy to terminate an existing crude oil purchase agreement wherein Murphy supplied the our Superior refinery with up to 10,000 bpd of crude oil. We believe this acquisition expands our growing portfolio of crude oil logistics assets, while positioning us to purchase increased volumes of price-advantaged feedstocks directly from the producers that operate in some of the major shale oil plays encompassing our refineries.

Bel-Ray

On December 10, 2013, we completed the acquisition of Bel-Ray Company, LLC ("Bel-Ray"), a manufacturer and global distributor of high-performance lubricants and greases, for aggregate consideration of approximately $53.6 million, net of cash acquired and excluding debt assumed and certain purchase price adjustments ("Bel-Ray Acquisition"). Bel-Ray manufactures and distributes both domestically and internationally a wide array of high-end specialty synthetic lubricants and greases which are used in the aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles industries. The Bel-Ray Acquisition was financed by using a portion of the $337.4 million net proceeds from our November 2013 private placement of 7 5/8% senior notes due January 15, 2022. We believe the Bel-Ray Acquisition increases our sales in the specialty lubricants market, expands our geographic reach, increases our asset diversity and enhances our specialty products segment.

Montana Refinery

On October 1, 2012, we completed the acquisition from Connacher of all the shares of common stock of Montana Refining Company, Inc., which was converted into a Delaware limited liability company, Calumet Montana Refining, LLC, at closing, and an insignificant affiliated company for aggregate consideration of approximately $191.6 million, net of cash acquired, including an estimated $27.6 million of income taxes due to the conversion to a Delaware limited liability company ("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 our revolving credit facility. We believe the Montana Acquisition further diversifies our crude oil feedstock slate, operating asset base and geographic presence.

Royal Purple

On July 3, 2012, we completed the acquisition of Royal Purple, Inc., 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 $262.5 million from our

June 2012 private placement of 9 5/8% senior notes due August 1, 2020 and cash on hand. We believe the Royal Purple Acquisition increases our position in the specialty lubricants market, expands our geographic reach, increases our asset diversity and enhances our specialty products segment.

TruSouth Oil

On January 6, 2012, we completed the acquisition of all of the outstanding membership interests. TruSouth Oil, LLC, renamed Calumet Packaging, LLC in 2013, a specialty petroleum packaging and distribution company located in Shreveport, Louisiana for aggregate consideration of approximately $26.9 million, net of cash acquired (“Calumet Packaging Acquisition”). The Calumet Packaging Acquisition was financed with borrowings under our revolving credit facility (“Calumet Packaging

Acquisition"). We believe the TruSouth Acquisition provides greater diversity to our specialty products segment. Please read Part III, Item 13 "Certain Relationships and Related Transactions and Director Independence — TruSouth Acquisition" for further discussion of our acquisition of TruSouth.

Hercules Synthetic Lubricants Business

On January 3, 2012, we completed the acquisition of the aviation and refrigerant lubricants business (a polyolester based synthetic lubricants business) and a manufacturing facility located in Louisiana, Missouri from Hercules Incorporated, a subsidiary of Ashland, Inc., for aggregate consideration of approximately $19.6 million ("Missouri Acquisition"). We believe the Missouri Acquisition provides greater diversity to our specialty products segment. The Missouri Acquisition was financed with borrowings under our revolving credit facility and cash on hand.

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. As of December 31, 2013, we have hedged refining margins, or crack spreads, on approximately 20.2 million barrels of fuel products through December 2016 at an average refining margin of $23.49 per barrel with average refining margins ranging from a low of $19.17 per barrel in the first quarter of 2014 to a high of $27.27 per barrel in 2016. Please refer to Note 8 under Item 8 "Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements" and Item 7A "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;
- specialty products and fuel products segment gross profit; and
- specialty products and fuel products segment Adjusted EBITDA.

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 segment 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.

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Our fuel products segment gross profit may differ from 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, 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.

Specialty products and fuel products segment Adjusted EBITDA. We believe that specialty products and fuel products segment Adjusted EBITDA measures are useful as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions to our unitholders as Adjusted EBITDA is a component in the calculation of distributable cash flow and allows us to meaningfully analyze the trends and performance of our core cash operations as well as make decisions regarding the allocation of resources to segments.

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

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Results of Operations

The following table sets forth information about our combined operations. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks such as ethanol and biodiesel in our fuel products segment. The tables include the results of operations at our Superior refinery commencing October 1, 2011, Missouri facility commencing January 3, 2012, Calumet Packaging facility commencing January 6, 2012, Royal Purple facility commencing July 3, 2012, Montana refinery commencing October 1, 2012, San Antonio refinery commencing January 2, 2013 and Bel-Ray facility commencing December 10, 2013.

	Year Ended December 31,		
	2013	2012	2011
	(In bpd)		
Total sales volume (1)	116,477	97,789	66,134
Total feedstock runs (2)	110,237	97,600	69,295
Facility production: (3)			
Specialty products:			
Lubricating oils	13,247	14,524	14,427
Solvents	8,759	9,332	10,508
Waxes	1,443	1,280	1,269
Packaged and synthetic specialty products (4)	1,934	1,351	—
Other	2,192	3,084	4,424
Total specialty products	27,575	29,571	30,628
Fuel products:			
Gasoline	29,374	24,394	13,409
Diesel	26,015	22,438	14,721
Jet fuel	4,105	4,325	4,520
Asphalt, heavy fuel oils and other	19,976	15,444	7,631
Total fuel products	79,470	66,601	40,281
Total facility production (3)	107,045	96,172	70,909

(1) Total sales volume includes sales from the production at our 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 in 2013 compared to 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 from the Shreveport and Superior refineries. The increase in total sales volume in 2012 compared to 2011 is due primarily to incremental sales of fuel products, asphalt and packaged and synthetic specialty products subsequent to the Superior, Missouri, Calumet Packaging, Royal Purple and Montana Acquisitions.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements.

The increase in total feedstock runs in 2013 compared to 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 due to unscheduled downtime associated with various operational reliability issues and planned turnaround activity at the Shreveport and Superior refineries during 2013. The increase in total feedstock runs in 2012 compared to 2011 is due primarily to incremental feedstock runs from the Superior, Missouri, Calumet Packaging, Royal Purple and Montana Acquisitions.

(3)

Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. 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.

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The increases in total facility production in 2013 over 2012 and 2012 over 2011 are due primarily to the operational items discussed above in footnote 2 of this table.

(4) Represents production of packaged and synthetic specialty products at our Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

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 operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with GAAP, please read "— Non-GAAP Financial Measures."

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Sales	$5,421.4	$4,657.3	$3,134.9
Cost of sales	5,011.4	4,144.1	2,860.8
Gross profit	410.0	513.2	274.1
Operating costs and expenses:			
Selling	62.6	41.6	12.2
General and administrative	82.1	60.9	38.6
Transportation	142.7	107.9	94.2
Taxes other than income taxes	14.2	9.1	5.7
Insurance recoveries	—	—	(8.7)
Other	16.8	7.8	6.8
Operating income	91.6	285.9	125.3
Other income (expense):			
Interest expense	(96.8)	(85.6)	(48.7)
Debt extinguishment costs	(14.6)	—	(15.1)
Realized gain (loss) on derivative instruments	(4.7)	9.5	(7.9)
Unrealized gain (loss) on derivative instruments	25.7	(3.8)	(10.4)
Other	2.7	0.5	0.8
Total other expense	(87.7)	(79.4)	(81.3)
Income before income taxes	3.9	206.5	44.0
Income tax expense	0.4	0.8	1.0
Net income	$3.5	$205.7	$43.0
EBITDA	$233.1	$383.7	$170.9
Adjusted EBITDA	$241.5	$404.6	$211.0
Distributable Cash Flow	$18.5	$281.1	$127.2

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Sales. Sales increased $764.1 million, or 16.4%, to $5,421.4 million in 2013 from $4,657.3 million in 2012. The results of operations related to the Montana, San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segment since their dates of acquisition, October 1, 2012, January 2, 2013 and August 9, 2013, respectively. The results of operations related to the Missouri, Calumet Packaging, Royal Purple and Bel-Ray Acquisitions have been included in the specialty products segment since their dates of acquisition, January 3, 2012, January 6, 2012, July 3, 2012 and December 10, 2013, respectively. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2013	2012	% Change
	(In millions, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$848.8	$1,007.9	(15.8)%
Solvents	511.7	491.1	4.2%
Waxes	141.0	142.8	(1.3)%
Packaged and synthetic specialty products (1)	233.6	161.7	44.5%
Other (2)	39.8	46.4	(14.2)%
Total specialty products	$1,774.9	$1,849.9	(4.1)%
Total specialty products sales volume (in barrels)	9,630,000	9,769,000	(1.4)%
Average specialty products sales price per barrel	$184.31	$189.36	(2.7)%
Fuel products:			
Gasoline	$1,409.8	$1,213.3	16.2%
Diesel	1,263.2	1,081.1	16.8%
Jet fuel	190.1	211.3	(10.0)%
Asphalt, heavy fuel oils and other (3)	786.5	507.5	55.0%
Hedging activities loss	(3.1)	(205.8)	(98.5)%
Total fuel products	$3,646.5	$2,807.4	29.9%
Total fuel products sales volume (in barrels)	32,884,000	25,924,000	26.8%
Average fuel products sales price per barrel (excluding hedging activities)	$110.98	$116.23	(4.5)%
Average fuel products sales price per barrel (including hedging activities loss)	$110.89	$108.29	2.4%
Total sales	$5,421.4	$4,657.3	16.4%
Total sales volume (in barrels)	42,514,000	35,693,000	19.1%

(1) Represents production of packaged and synthetic specialty products at the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, 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, Shreveport and San Antonio refineries to third party customers.

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The components of the $75.0 million specialty products segment sales decrease in 2013 were as follows:

	Dollar Change (In millions)
Sales price	$(94.6)
Volume	(38.1)
Acquisitions	57.7
Total specialty products segment sales decrease	$(75.0)

Specialty products segment sales for 2013 decreased $75.0 million, or 4.1%, primarily as a result of decreased average selling prices per barrel and lower sales volumes, partially offset by incremental sales from acquisitions. Legacy operations' sales decreased $94.6 million, or 5.2%, compared to 2012 primarily due to lower average selling prices per barrel of lubricating oils, while the average cost of crude oil per barrel increased 1.5%. Legacy operations' sales volumes decreased 2.1% as compared to 2012 which resulted in a $38.1 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils as a result of market conditions and lower run rates at our Shreveport refinery, partially offset by increased sales volume of solvents and packaged and synthetic specialty products. The Shreveport refinery had lower run rates in 2013 due to unscheduled down time caused by various reliability issues and a planned turnaround as well as a change in the crude oil mix which reduced specialty products production yields. The Royal Purple and Bel-Ray Acquisitions increased sales by $57.7 million which were all related to packaged and synthetic specialty products.

The components of the $839.1 million fuel products segment sales increase in 2013 were as follows:

	Dollar Change (In millions)
Acquisitions	$799.4
Hedging activities	202.7
Sales price	(142.7)
Volume	(20.3)
Total fuel products segment sales increase	$839.1

Fuel products segment sales for 2013 increased $839.1 million, or 29.9%, due primarily to incremental sales from acquisitions and a $202.7 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges, partially offset by a decrease in the average selling price per barrel and lower sales volumes in our legacy operations. The acquisitions of Montana in 2012 and San Antonio in 2013 increased sales by $799.4 million. Legacy operations' average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $5.55, or 4.8%, resulting in a $142.7 million decrease in sales, compared to a 1.5% increase in the average price of crude oil per barrel with the average gasoline, asphalt and diesel selling prices per barrel declining the most compared to the prior year. Calumet's legacy operations' sales volumes remained relatively consistent as a result of increased crude oil sales to third party customers as we continued to grow our crude oil gathering business, partially offset by decreased run rates year over year. The decreased run rates were primarily due to unscheduled down time caused by various reliability issues at the Shreveport refinery and a plantwide turnaround at the Superior refinery that lasted approximately 45 days.

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Gross Profit. Gross profit decreased $103.2 million, or 20.1%, to $410.0 million in 2013 from $513.2 million in 2012. Gross profit for our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2013	2012	% Change
	(Dollars in millions except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$322.3	$400.1	(19.4)%
Percentage of sales	18.2%	21.6%	
Specialty products gross profit per barrel	$33.47	$40.96	(18.3)%
Fuel products:			
Gross profit excluding hedging activities	$87.7	$269.1	(67.4)%
Hedging activities	—	(156.0)	(100.0)%
Gross profit	$87.7	$113.1	(22.5)%
Percentage of sales	2.4%	4.0%	
Fuel products gross profit per barrel (excluding hedging activities)	$2.67	$10.38	(74.3)%
Fuel products gross profit per barrel (including hedging activities)	$2.67	$4.36	(38.8)%
Total gross profit	$410.0	$513.2	(20.1)%
Percentage of sales	7.6%	11.0%	

The components of the $77.8 million specialty products segment gross profit decrease in 2013 were as follows:

	Dollar Change
	(In millions)
2012 reported gross profit	$400.1
Sales price	(94.6)
Operating costs	(14.4)
Volume	(11.5)
Cost of materials	12.9
Acquisitions	29.8
2013 reported gross profit	$322.3

The decrease in specialty products segment gross profit of $77.8 million year over year was due primarily to decreased average selling prices per barrel and increased operating costs of $14.4 million primarily as a result of higher repairs and maintenance and natural gas costs partially offset by acquisitions. Sales price and cost of materials, net, from our legacy operations decreased gross profit by $81.7 million, as the average selling price per barrel of specialty products decreased 5.2% compared to a 1.5% increase in the average cost of crude oil per barrel. This pricing decrease was primarily due to decreased average selling prices per barrel of lubricating oils. The Royal Purple and Bel-Ray Acquisitions contributed $29.8 million of incremental gross profit to partially offset these decreases.

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The components of the $25.4 million fuel products segment gross profit decrease in 2013 were as follows:

	Dollar Change (In millions)
2012 reported gross profit	$113.1
Sales price	(142.7)
Operating costs	(38.7)
Cost of materials	(34.0)
Volume	(3.3)
Hedging activities	156.0
Acquisitions	37.3
2013 reported gross profit	$87.7

The decrease in fuel products segment gross profit of $25.4 million year over year was due primarily to decreased gross profit from our legacy operations due to narrowing crack spreads, lower asphalt average selling prices per barrel and increased operating costs, partially offset by decreased realized losses on derivatives of $156.0 million and $37.3 million of gross profit contributed from the Montana and San Antonio Acquisitions. Contributing factors to this narrowing of our fuel products crack spreads included lower crude oil differentials to NYMEX WTI and lower market Gulf Coast crack spreads in the current year due to market conditions. Operating costs increased $38.7 million primarily as a result of $22.1 million of higher RINs costs in our legacy operations and higher repairs and maintenance and natural gas costs.

Selling. Selling expenses increased $21.0 million, or 50.5%, to $62.6 million in 2013 from $41.6 million in 2012. This increase was due primarily to the Royal Purple Acquisition which includes increased amortization expense of $11.6 million primarily related to the recording of intangible assets, additional employee compensation costs and increased advertising expenses of $6.4 million.

General and administrative. General and administrative expenses increased $21.2 million, or 34.8%, to $82.1 million in 2013 from $60.9 million in 2012. The increase was due primarily to a $7.2 million gain related to the curtailment of certain benefits in benefit plans covering employees at the Superior refinery in the 2012 period with no similar gains in the same period in 2013, increased professional fees of $11.9 million due primarily to consulting fees related to our enterprise resource planning system implementation and additional employee compensation costs from the Royal Purple, Montana, San Antonio and Bel-Ray Acquisitions, with no similar expenses in the prior year. These increases were partially offset by decreased incentive compensation costs of $10.0 million due to the lower financial performance in the current year relative to performance targets.

Transportation. Transportation expenses increased $34.8 million, or 32.3%, to $142.7 million in 2013 from $107.9 million 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 party customers.

Other operating costs and expenses. Other operating costs and expenses increased $9.0 million, or 115.4%, to $16.8 million in 2013 from $7.8 million in 2012. The increase was due primarily to a non-cash charge of $10.5 million related to a write-down of idle fixed assets, compared to a $1.6 million write-down of idle fixed assets in the prior year.

Interest expense. Interest expense increased $11.2 million, or 13.1%, to $96.8 million in 2013 from $85.6 million in 2012. The increase is due primarily to additional outstanding long-term debt in the form of 2020 Notes issued to partially fund the Royal Purple Acquisition and 2022 Notes issued to fund general partnership purposes, the Bel-Ray Acquisition and the redemption of $100.0 million in aggregate principal amount outstanding of 2019 Notes.

Debt extinguishment costs. Debt extinguishment costs were $14.6 million in 2013. Debt extinguishment costs were primarily due to the partial redemption of 2019 Notes with a portion of the proceeds from the issuance of 2022 Notes. Please read Note 7 to our consolidated financial statements in Part II, Item 8 “Financial Statements and Supplementary Data” for additional information.

Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2013 and 2012.

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	Year Ended December 31,	
	2013	2012
	(In millions)	
Derivative loss reflected in sales	$(3.1)	$(205.8)
Derivative gain reflected in cost of sales	3.6	51.7
Derivative gain (loss) reflected in gross profit	$0.5	$(154.1)
Realized gain (loss) on derivative instruments	$(4.7)	$9.5
Unrealized gain (loss) on derivative instruments	25.7	(3.8)
Total derivative gain (loss) reflected in the consolidated statements of operations	$21.5	$(148.4)
Total loss on derivative settlements	$(6.0)	$(149.7)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments decreased $14.2 million to a loss of $4.7 million in 2013 from a gain of $9.5 million in 2012. The change was due primarily to increased realized losses of approximately $39.9 million related to 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 and increased realized losses of approximately $9.8 million on crude oil basis swaps used to economically hedge crude oil purchases at our Shreveport and Superior refineries. Partially offsetting these increased realized losses were increased realized gains of $26.5 million from decreased hedging ineffectiveness related to settlements of cash flow hedges as well as increased realized gains of approximately $4.8 million on natural gas swaps used to economically hedge natural gas purchases.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments increased $29.5 million to a gain of $25.7 million in 2013 from a loss of $3.8 million in 2012. This change was due primarily to increased unrealized gain ineffectiveness of approximately $31.2 million and increased unrealized gains of approximately $7.2 million on crude oil basis swaps used to economically hedge crude oil purchases at our Shreveport and Superior refineries. Partially offsetting these increased unrealized gains were increased unrealized losses of approximately $7.6 million on derivatives used to economically hedge our specialty products segment natural gas purchases and specialty products segment crude oil purchases but are not classified as hedges for accounting purposes.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Sales. Sales increased $1,522.4 million, or 48.6%, to $4,657.3 million in 2012 from $3,134.9 million in 2011. The results of operations related to the Superior and Montana Acquisitions have been included in the fuel products segment since the dates of acquisition, September 30, 2011 and October 1, 2012, respectively. The results of operations related to the Missouri, Calumet Packaging 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:

	Year Ended December 31,		
	2012	2011	% Change
	(Dollars in millions, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$1,007.9	$947.8	6.3%
Solvents	491.1	495.9	(1.0)%
Waxes	142.8	143.1	(0.2)%
Packaged and synthetic specialty products (1)	161.7	—	—
Other (2)	46.4	43.7	6.2%
Total specialty products	$1,849.9	$1,630.5	13.5%
Total specialty products sales volume (in barrels)	9,769,000	9,099,000	7.4%
Average specialty products sales price per barrel	$189.36	$179.20	5.7%
Fuel products:			
Gasoline	$1,213.3	$649.1	86.9%
Diesel	1,081.1	671.1	61.1%
Jet fuel	211.3	172.5	22.5%
Asphalt, heavy fuel oils and other (3)	507.5	223.5	127.1%
Hedging activities loss	(205.8)	(211.8)	(2.8)%
Total fuel products	$2,807.4	$1,504.4	86.6%
Total fuel products sales volume (in barrels)	25,924,000	15,040,000	72.4%
Average fuel products sales price per barrel (excluding hedging activities)	$116.23	$114.11	1.9%
Average fuel products sales price per barrel (including hedging activities)	$108.29	$100.03	8.3%
Total sales	$4,657.3	$3,134.9	48.6%
Total sales volume (in barrels)	35,693,000	24,139,000	47.9%

(1) Represents packaged and synthetic specialty products at the Royal Purple, Calumet Packaging and Missouri facilities.

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

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

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The components of the $219.4 million specialty products segment sales increase in 2012 were as follows:

	Dollar Change (In millions)
Acquisitions	$161.7
Sales price	1.9
Volume	55.8
Total specialty products segment sales increase	$219.4

Specialty products segment sales for 2012 increased $219.4 million, or 13.5%, as a result of acquisitions and increased volumes from our legacy operations. The acquisitions of Calumet Packaging, Missouri and Royal Purple in 2012 increased sales by $161.7 million, which were all related to packaged and synthetic specialty products. Calumet’s legacy operations’ sales volumes increased 3.4% as compared to the same period in 2011, which resulted in a $55.8 million increase in sales. The increase in sales volume is due primarily to increased lubricating oils sales volumes due to market conditions. Calumet’s legacy operations’ average selling prices remained relatively consistent year over year.

The components of the $1,303.0 million fuel products segment sales increase in 2012 were as follows:

	Dollar Change (In millions)
Acquisitions	$1,192.7
Sales price	39.2
Volume	65.1
Hedging activities	6.0
Total fuel products segment sales increase	$1,303.0

Fuel products segment sales for 2012 increased $1,303.0 million, or 86.6%, due primarily to acquisitions, increased volumes from our legacy operations and higher average selling prices per barrel. The acquisitions of Superior in 2011 and Montana in 2012 increased sales by $1,192.7 million. Calumet’s legacy operations’ sales volumes increased 3.8% due to higher run rates of fuel products which were impacted by a turnaround at the Shreveport refinery in 2011. Calumet’s legacy operations’ average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) increased $2.51, or 2.2%, resulting in a $39.2 million increase in sales, compared to a 0.6% decrease in the average crude oil price per barrel.

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Gross Profit. Gross profit increased $239.1 million, or 87.2%, to $513.2 million in 2012 from $274.1 million in 2011. Gross profit for our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2012	2011	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$400.1	$356.3	12.3 %
Percentage of sales	21.6 %	21.9 %	
Specialty products gross profit per barrel	$40.96	$39.16	4.6 %
Fuel products:			
Gross profit excluding hedging activities	$269.1	$18.6	1,346.8 %
Hedging activities	$(156.0)	$(100.8)	(54.8)%
Gross profit (loss)	$113.1	$(82.2)	237.6 %
Percentage of sales	4.0 %	(5.5)%	
Fuel products gross profit (loss) per barrel (excluding hedging activities)	$10.38	$1.24	737.1 %
Fuel products gross profit (loss) per barrel (including hedging activities)	$4.36	$(5.47)	179.7 %
Total gross profit	$513.2	$274.1	87.2 %
Percentage of sales	11.0 %	8.7 %	

The components of the $43.8 million specialty products segment gross profit increase in 2012 were as follows:

	Dollar Change
	(In millions)
2011 reported gross profit	$356.3
Acquisitions	28.9
Sales price	1.9
Volume	17.9
Cost of materials	(20.4)
Operating costs	15.5
2012 reported gross profit	$400.1

The increase in specialty products segment gross profit of $43.8 million year over year was due primarily to the acquisitions of Missouri, Calumet Packaging and Royal Purple, which contributed $28.9 million of gross profit, increased sales volume and decreased operating costs, partially offset by an increase in the average cost of crude oil per barrel. Sales price and cost of materials changes, net, decreased gross profit by $18.5 million, as the average cost of crude oil per barrel outpaced the average selling price per barrel by 3.4%. Partially offsetting this decrease is an increase in legacy operations sales volume due primarily to increased lubricating oils sales volume due to market conditions. Operating costs in our legacy operations decreased $15.5 million primarily due to lower natural gas prices and repair and maintenance costs.

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The components of the $195.3 million fuel products segment gross profit increase in 2012 were as follows:

	Dollar Change (In millions)
2011 reported gross loss	$(82.2)
Acquisitions	200.8
Sales price	39.2
Volume	6.4
Hedging activities	(55.2)
Cost of materials	(4.8)
Operating costs	8.9
2012 reported gross profit	$113.1

The increase in fuel products segment gross profit of $195.3 million year over year was due primarily to the Superior and Montana Acquisitions, which contributed $200.8 million (excluding hedging activities) and increased gross profit from our legacy operations driven by sales price and volume, partially offset by increased realized losses on derivatives of $55.2 million. Sales price and cost of material changes, net, increased gross profit by $34.4 million, as the average selling price per barrel for fuel products outpaced the average cost of crude oil per barrel by 2.8% due to widening crack spreads experienced in our markets, partially offset by the unfavorable impact of the liquidation of higher cost LIFO inventory layers of $7.6 million. Operating costs in our legacy operations decreased $8.9 million year over year, primarily due to lower repairs and maintenance. Calumet's legacy operations experienced increased sales volume of 3.8%, leading to a $6.4 million increase in gross profit primarily due to higher run rates of fuel products which were impacted by a turnaround at the Shreveport refinery in 2011.

Selling. Selling expenses increased $29.4 million, or 241.0%, to $41.6 million in 2012 from $12.2 million in 2011. This increase was due primarily to increased amortization expense of $13.8 million primarily related to the recording of intangible assets associated with the Missouri, Calumet Packaging and Royal Purple Acquisitions and additional employee compensation costs from the Calumet Packaging and Royal Purple Acquisitions, with no similar expenses in the prior year, and increased advertising expenses of $6.5 million.

General and administrative. General and administrative expenses increased $22.3 million, or 57.8%, to $60.9 million in 2012 from $38.6 million in 2011. The increase was due primarily to additional employee compensation costs from the Superior, Missouri, Calumet Packaging, Royal Purple and Montana Acquisitions (with no similar expenses in the prior year), increased professional fees of $11.3 million as a result of acquisition activities and increased incentive compensation costs of $5.1 million, partially offset by a $7.2 million gain related to the curtailment of certain benefits in benefit plans covering employees at the Superior refinery.

Transportation. Transportation expenses increased $13.7 million, or 14.5%, to $107.9 million in 2012 from $94.2 million in 2011. This increase is due primarily to incremental transportation expenses related to sales from the Superior, Royal Purple and Montana Acquisitions and higher freight rates.

Insurance recoveries. Insurance recoveries were $8.7 million for the year ended December 31, 2011. This gain was related to a claim settled in the second quarter of 2011 with insurers related to the failure of an environmental operating unit at the Shreveport refinery in 2010. Insurance recoveries were used to repair the failed unit and for working capital needs. This claim related to both property damage and business interruption. Recoveries of $1.9 million related to property damage have been reflected within investing activities (with the remainder in operating activities) in the consolidated statements of cash flows.

Interest expense. Interest expense increased $36.9 million, or 75.8%, to $85.6 million in 2012 from $48.7 million in 2011. The increase is due primarily to additional outstanding long-term debt, namely the 2019 Notes issued to partially fund the Superior Acquisition and the 2020 Notes issued to partially fund the Royal Purple Acquisition.

Debt extinguishment costs. Debt extinguishment costs were $15.1 million for the year ended December 31, 2011. The debt extinguishment costs were related to the extinguishment of the prior term loan in April 2011 using proceeds from the issuance of the 2019 Notes.

Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2012 and 2011.

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	Year Ended December 31,	
	2012	2011
	(In millions)	
Derivative loss reflected in sales	$(205.8)	$(211.8)
Derivative gain reflected in cost of sales	51.7	108.5
Derivative loss reflected in gross profit	$(154.1)	$(103.3)
Realized gain (loss) on derivative instruments	$9.5	$(7.9)
Unrealized loss on derivative instruments	(3.8)	(10.4)
Derivative loss reflected in interest expense	—	(0.7)
Total derivative loss reflected in the consolidated statements of operations	$(148.4)	$(122.3)
Total loss on derivative settlements	$(149.7)	$(100.9)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments increased $17.4 million to a gain of $9.5 million in 2012 from a loss of $7.9 million in 2011. The change was due primarily to an increased realized gain of approximately $40.1 million related to settlements of derivative instruments used to economically hedge crack spreads at our Superior refinery that are not accounted for as hedges for accounting purposes and therefore are not reflected in gross profit. Partially offsetting this increased realized gain was an increased realized loss due to hedging ineffectiveness of approximately $19.0 million related to settlements of cash flow hedges and increased realized loss of $6.2 million related to natural gas and crude oil derivative settlements included in our specialty products segment but not designated as cash flow hedges.

Unrealized loss on derivative instruments. Unrealized loss on derivative instruments decreased $6.6 million to $3.8 million in 2012 from $10.4 million in 2011. This change was due primarily to a decreased unrealized loss of $6.4 million on natural gas derivative instruments included in our specialty products segment but not designated as cash flow hedges and decreased unrealized loss ineffectiveness of approximately $4.4 million. Partially offsetting this decreased unrealized loss was an unrealized loss of approximately $3.4 million in 2012 related to crude oil basis swaps included in our fuel products segment which were not designated as cash flow hedges and an unrealized loss of approximately $2.9 million in 2012 related to derivative instruments used to economically hedge crack spreads at our Superior refinery that are not accounted for as hedges for accounting purposes.

Liquidity and Capital Resources

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 and borrowings under our revolving credit facility. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Cash Flows from Operating, Investing and Financing Activities

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

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The following table summarizes our primary sources and uses of cash in each of the most recent three years:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Net cash provided by operating activities	$39.1	$380.1	$63.8
Net cash used in investing activities	$(370.3)	$(624.2)	$(460.4)
Net cash provided by financing activities	$420.1	$276.2	$396.7
Net increase in cash and cash equivalents	$88.9	$32.1	$0.1

Operating Activities. Operating activities provided cash of $39.1 million during 2013 compared to $380.1 million during 2012. The decrease in cash provided by operating activities is due primarily to decreased net income of $202.2 million and an increase in turnaround costs of $53.7 million in 2013 compared to 2012.

Operating activities provided $380.1 million in cash during 2012 compared to $63.8 million during 2011. The increase in cash provided by operating activities is due primarily to increased net income of $162.7 million and reduced working capital requirements in 2012 providing $49.4 million of cash, including a reduction in working capital requirements for the Montana Acquisition since the date of closing on October 1, 2012, compared to 2011 working capital requirements using $89.0 million.

Investing Activities. Cash used in investing activities decreased to $370.3 million in 2013 compared to $624.2 million in 2012. The decrease is due primarily to the higher combined purchase price of $569.2 million for the Missouri, Calumet Packaging, Royal Purple and Montana Acquisitions, which closed during 2012, compared to a combined purchase price of $177.7 million for the San Antonio, Crude Oil Logistics and Bel-Ray Acquisitions in 2013, partially offset by an increase in capital expenditures of $103.8 million due primarily to the capital improvement projects discussed below and $31.8 million contributed to the Dakota Prairie Refining, LLC joint venture.

Cash used in investing activities increased to $624.2 million in 2012 compared to $460.4 million in 2011. The increase is due primarily to the aggregate purchase prices of the Missouri, Calumet Packaging, Royal Purple and Montana acquisitions, which closed in 2012, of $569.2 million compared to the purchase price of $413.2 million for the Superior Acquisition in 2011.

Financing Activities. Financing activities provided cash of $420.1 million during 2013 compared to $276.2 million during 2012. The change is due primarily to increased net proceeds from public offerings of common units (including our general partner’s contributions) of $251.2 million and increased net proceeds from the private placement of senior notes of $74.5 million, partially offset by the partial redemption of senior notes of $100.0 million, repayment of $11.9 million of debt assumed in the Bel-Ray Acquisition and increased distributions to our unitholders of $69.2 million.

Financing activities provided cash of $276.2 million during 2012 compared to $396.7 million during 2011. This change is due primarily to decreased net proceeds from the public offering of common units (including the general partner’s contribution) of $151.3 million, decreased net proceeds from the private placement of senior notes of $315.8 million and increased distributions to our unitholders of $49.7 million, partially offset by the repayment of the senior secured first lien term loan facility in April 2011 of $367.4 million, with no such similar activity in 2012.

Acquisitions

Acquisitions impact our results of operations commencing on the closing date of each acquisition. Our acquisitions are discussed further in Note 3 “Acquisitions” in the notes to our consolidated financial statements under Item 8 “Financial Statements and Supplementary Data.” Information regarding acquisitions completed in 2013, 2012 and 2011 is set forth in the table below (in millions):

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Acquisition	Closing Date	Purchase Price	Funding Method	Segment
San Antonio	January 2, 2013	$117.9	Borrowings under our revolving credit facility	Fuel Products
Crude Oil Logistics Assets	August 9, 2013	6.2	Cash on hand	Fuel Products
Bel-Ray	December 10, 2013	53.6	Net proceeds from our November 2013 private placement of 2022 Notes	Specialty Products
2013 Total		$177.7		
Missouri	January 3, 2012	$19.6	Borrowings under our revolving credit facility and cash on hand	Specialty Products
Calumet Packaging	January 6, 2012	26.9	Borrowings under our revolving credit facility	Specialty Products
Royal Purple	July 3, 2012	331.2	Net proceeds from our June 2012 private placement of 2020 Notes	Specialty Products
Montana	October 1, 2012	191.6	Cash on hand and borrowings under our revolving credit facility	Fuel Products
2012 Total		$569.3		
Superior	September 30, 2011	413.2	Net proceeds from our September 2011 common unit offering and net proceeds from our September 2011 private placement of 2019 Notes	Fuel Products
2011 Total		$413.2		

Joint Venture

On February 7, 2013, we entered into a joint venture agreement with 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 to primarily 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 a total of $150.0 million from us comprised of $75.0 million through contributions and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower which is expected be repaid by us through our allocation of profits from the joint venture.. 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 December 31, 2013, we have contributed $31.8 million to the Dakota Prairie Refining, LLC joint venture, funded primarily through cash flow from operations. The joint venture will allocate profits on a 50%/50% basis to us and MDU. We are covering the debt service cost of the lower interest rate term loan facility pursuant to the joint venture agreement. The joint venture is governed by a board of managers comprised of representatives from both us and MDU. MDU is to provide a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. We are providing refinery operations, crude oil procurement and refined product marketing expertise to the joint venture.

Capital Expenditures

Our property plant and equipment 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.

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Capital improvement expenditures	$109.7	$28.7	$25.8
Replacement capital expenditures	33.8	12.9	13.3
Environmental capital expenditures	30.4	15.4	10.4
Total	$173.9	$57.0	$49.5

We anticipate that future capital expenditure requirements will be provided primarily through cash flow from operations, cash on hand and available borrowings under our revolving credit facility. Our environmental capital improvement expenditures have increased in 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 II Item 8 "Financial Statements and Supplementary Data — 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 $50.0 million to $60.0 million in 2014. These estimated amounts for 2014 include a portion of the $6.0 million to $8.0 million in environmental projects to be spent over the next year as required by our settlement with the LDEQ under the "Small Refinery and Single Site Refining Initiative." Please read Part I, Items 1 and 2 "Business and Properties — Environmental and Occupational Health and Safety Matters — Air Emissions" for additional information.

We have several capital improvement projects underway including capacity expansions at certain of our facilities, as well as active investments, such as the joint venture with MDU. We currently estimate that these organic growth opportunities could lead to capital improvement expenditures between 2013 and the first quarter of 2016 of approximately $500.0 million to $550.0 million. During 2014, we estimate that our total capital investment on growth projects will be between approximately $270 million to $300 million. Our primary capital improvements projects include the following:

- Montana Refinery Expansion - We plan to increase our Montana refinery's crude oil throughput capacity from 10,000 bpd to 20,000 bpd, including a new 20,000 bpd crude oil unit ("Montana Refinery Expansion"). The incremental production slate will consist primarily of gasoline, diesel, jet fuel and diluent, all of which will be sold into regional markets. We anticipate the total cost of the Montana Refinery Expansion to be approximately $400.0 million which and expected to be completed by the first quarter of 2016.
- Dakota Prairie Refining, LLC - We entered into a joint venture agreement with MDU to develop, build and operate a 20,000 bpd diesel refinery in southwestern North Dakota. Please read "— Joint Venture" above for additional information.

Turnaround costs represent capitalized costs associated with our periodic major maintenance and repairs. During the year ended December 31, 2013, we spent approximately $68.6 million primarily related to scheduled turnarounds at our Superior, Montana, Shreveport and San Antonio refineries funded through cash flow from operations. Additionally, we estimate turnaround spending requirements will be $20.0 million to $25.0 million in 2014 primarily related to scheduled turnaround activity at our Shreveport refinery. We expect these expenditures will be funded primarily through cash flow from operations.

Debt and Credit Facilities

As of December 31, 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;
- $500.0 million of 9 3/8% senior notes due 2019 ("2019 Notes");
- $275.0 million of 9 5/8% senior notes due 2020 ("2020 Notes"); and
- $350.0 million of 7 5/8% senior notes due 2022 ("2022 Notes").

On November 26, 2013, we redeemed approximately $74.0 million and $26.0 million in aggregate principal amount outstanding of our 2019 issued in April 2011 and 2019 Notes issued in September 2011, respectively, with a portion of the net proceeds from the issuance of our 2022 Notes at a redemption price of $111.2 million.

As of December 31, 2013, we believe we were in compliance with all covenants under our debt instruments in place at December 31, 2013 and have adequate liquidity to conduct our business.

Short Term Liquidity

As of December 31, 2013, our principal sources of short-term liquidity were (i) $472.4 million of availability under our revolving credit facility and (ii) $121.1 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 December 31, 2013, we had availability on our revolving credit facility of $472.4 million, based on a $567.6 million borrowing base, $95.2 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 fourth quarter of 2013 were $111.0 million. Nonetheless, our availability on our revolving credit facility during the peak borrowing days of the quarter has been ample to support our operations and service upcoming requirements. During the quarter ended December 31, 2013, availability for additional borrowings under our revolving credit facility was approximately $395.6 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 December 31, 2013, this margin was 100 basis points for prime and 225 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. As of December 31, 2013, our Fixed Charge Coverage Ratio was 2.39 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.

For additional information regarding our revolving credit facility, see Note 7 “Long-Term Debt” in Item 8 “Financial Statements and Supplementary Data.”

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 December 31, 2013, we had $500.0 million in 2019 Notes, $275.0 million in 2020 Notes and $350.0 million in 2022 Notes outstanding. As of December 31, 2012, we had $600.0 million in 2019 Notes and $275.0 million in 2020 Notes outstanding.

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The indentures governing our senior 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 senior 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 senior 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 senior notes will have the right to require that we repurchase all or a portion of such holder’s senior 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 senior notes, see Note 7 “Long-Term Debt”, Item 8 “Financial Statements and Supplementary Data.”

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 had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 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 $56.0 million subsequent to December 31, 2013 to a net asset of approximately $1.0 million. All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads to significantly impact our liquidity.

Additionally, we have a collateral 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 are 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.

Equity Transactions

During 2013, we completed the following public offerings of our common units (in millions except unit and per unit data):

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Closing Date	Number of Common Units Offered		Price per Unit	Net Proceeds (1)	General Partner Contribution (2)	Underwriting Discount	Use of Proceeds
January 8, 2013	5,750,000	(3)	$31.81	$175.2	$3.8	$ 7.4	Net proceeds were used to repay borrowings under our revolving credit facility and for general partnership purposes
April 1, 2013	6,037,500	(4)	37.50	217.3	4.6	9.1	Net proceeds were used for general partnership purposes
Total				$392.5	$8.4	$ 16.5	

(1) Proceeds are net of underwriting discounts, commissions and expenses but before our general partner’s capital contribution.
(2) Our general partner contributions were made to retain its 2% general partner interest.
(3) Includes the full exercise of the overallotment option of 750,000 common units, which closed concurrently with the 5,000,000 firm units on January 8, 2013.
(4) Includes the full exercise of the overallotment option of 787,500 common units, which closed on April 4, 2013.

During 2013 and through February 2014, we made the following cash distributions on all outstanding common units (including our general partner’s incentive distribution rights) (in millions except per unit data):

Quarter Ended	Declaration Date	Record Date	Distribution Date	Quarterly Distribution per Unit	Aggregate Quarterly Distribution	Annualized Distribution per Unit	Aggregate Annualized Distribution
December 31, 2012	January 14, 2013	February 4, 2013	February 14, 2013	$ 0.65	$ 44.5	$ 2.60	$ 178.2
March 31, 2013	April 22, 2013	May 3, 2013	May 15, 2013	0.68	51.9	2.72	207.6
June 30, 2013	July 22, 2013	August 2, 2013	August 14, 2013	0.685	52.6	2.74	210.4
September 30, 2013	October 22, 2013	November 4, 2013	November 14, 2013	0.685	52.6	2.74	210.4
December 31, 2013	January 24, 2014	February 4, 2014	February 14, 2014	0.685	52.6	2.74	210.4

Seasonality Impacts on Liquidity

Asphalt demand is typically lower in the first and fourth quarters of the year as compared to the second and third quarters due to the seasonality of annual road construction. Demand for gasoline is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months. This seasonality causes significant changes to our profitability and working capital requirements, which cause significant changes in borrowings under our revolving credit facility and our liquidity during such periods.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of December 31, 2013 at current maturities 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)	$675.5	$96.8	$207.1	$200.6	$171.0
Operating lease obligations (2)	146.1	30.0	49.2	36.3	30.6
Letters of credit (3)	95.2	95.2	—	—	—
Purchase commitments (4)	871.2	867.0	3.9	0.3	—
Pension obligations	10.9	1.6	4.0	2.3	3.0
Employment agreements (5)	0.9	0.4	0.5	—	—
Financing Activities:					
Capital lease obligations	4.8	0.4	0.7	0.8	2.9
Long-term debt obligations, excluding capital lease obligations	1,125.0	—	—	—	1,125.0
Total obligations	$2,929.6	$1,091.4	$265.4	$240.3	$1,332.5

(1) Interest on long-term debt at contractual rates and maturities relates primarily to our senior notes, revolving credit facility fees 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 April 2027.

(3) Letters of credit primarily supporting crude oil purchases and precious metals leasing.

(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil, other feedstocks, finished products for resale and renewable fuels from various suppliers based on current market prices at the time of delivery.

(5) Annual compensation under the employment agreement of F. William Grube, chief executive officer and vice chairman of the board of our general partner.

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 $77.0 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of December 31, 2013. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures, 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 fiscal year.

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements for the years ended December 31, 2013, 2012 and 2011. These consolidated financial statements have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in those financial statements. On an ongoing basis, we evaluate estimates and base our estimates on historical experience and assumptions believed to be reasonable under the circumstances. Those estimates form the basis for our judgments that affect the amounts reported in the financial statements. Actual results could differ from our estimates under different assumptions or conditions. Our significant accounting policies, which may be affected by our estimates and assumptions, are more fully described in Note 2 to our consolidated financial statements in Item 8 "Financial Statements and Supplementary Data." We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Revenue Recognition We recognize revenue on orders received from our customers when there is persuasive evidence of an arrangement with the customer that is supportive of revenue recognition, the customer has made a fixed commitment to purchase the product for a fixed or determinable sales price, collection is reasonably assured under our normal billing and credit terms, all of our obligations related to the product have been fulfilled and ownership and all risks of loss have been transferred to the buyer, which is primarily upon shipment to the customer or, in certain cases, upon receipt by the customer in accordance with contractual terms. We maintain an allowance for doubtful accounts for estimated losses in the collection of accounts receivable.	Our revenue recognition accounting methodology contains uncertainties because it requires management to make assumptions and to apply judgment to estimate the amount and timing of uncollectible accounts. We make estimates regarding the future ability of our customers to make required payments based on historical credit experience, the age of the accounts receivable balance, credit quality of our customers, current economic conditions and expected future trends that affect our customers' ability to pay. Individual accounts are written off against the allowance for doubtful accounts after all reasonable collection efforts have been exhausted.	We have not made any material changes in the accounting methodology we use to measure doubtful accounts during the past three fiscal years. We do not believe there is a reasonable likelihood that there will be a material change in the future estimates or assumptions we use to measure doubtful accounts. However, if actual results are not consistent with our estimates or assumptions, we may be exposed to losses or gains that could be material. A 10% change in our allowance for doubtful accounts at December 31, 2013 would have affected net income by approximately $0.1 million for the year ended December 31, 2013.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Inventories The cost of inventory is recorded using the last-in, first-out (LIFO) method. Costs include crude oil and other feedstocks, labor, processing costs and refining	Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our	We have not made any material changes in the accounting methodology we use to establish our markdown or inventory loss adjustments during the past three

overhead costs. Inventories are valued at the lower of cost or market. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Accordingly, interim LIFO calculations are based on management's estimates of expected year-end inventory levels and are subject to the final year-end LIFO inventory valuation.

inventory.

Because crude oil and refined products are essentially commodities, we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market value, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a non-cash charge to cost of sales. In a period of decreasing crude oil or refined product prices, our inventory valuation methodology may result in decreases in net income.

We review our inventory balances quarterly for excess inventory levels or obsolete inventory and write down, if necessary, the inventory to net realizable value.

fiscal years.

The replacement cost of our inventory, based on current market values, would have been $32.2 million and $38.3 million higher at December 31, 2013 and 2012, respectively. During the years ended December 31, 2013 and 2012, we recorded $6.0 million and $8.1 million of losses, respectively, in cost of sales in the consolidated statements of operations due to lower of cost or market valuation. During the year ended December 31, 2013, we recorded $4.2 million of gains in cost of sales in the consolidated statements of operations due to the liquidation of lower cost inventory layers. During the year ended December 31, 2012, we recorded $4.2 million of losses in cost of sales in the consolidated statements of operations due to the liquidation of higher cost inventory layers.

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We do not believe there is a reasonable likelihood that there will be a material change in the future estimates or assumptions we use to calculate our inventory. If commodity prices were to decrease by 10% below our December 31, 2013 inventory values, our net income would have been negatively impacted by approximately $60.0 million.

Fair Value of Financial Instruments

In accordance with ASC 815-10, Derivatives and Hedging, we recognize all derivative instruments as either assets or liabilities at fair value on the consolidated balance sheets. Our derivative instruments are valued at Level 3 fair value measurement under ASC 820-10, Fair Value Measurements and Disclosures, depending upon the degree by which inputs are observable.

Our derivative instruments consist of over-the-counter ("OTC") contracts, which are not traded on a public exchange. Substantially all of our derivative instruments are with counterparties that have long-term credit ratings of at least Baa2 and A- by Moody's and S&P, respectively.

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To estimate the fair values of our derivative instruments, we use the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract

We have not made any material changes in the accounting methodology we use to establish our derivative estimates or pension asset valuations during the past three fiscal years. We have consistently applied these valuation techniques in all periods presented and believe we obtained the most accurate information available for the types of derivative instruments and pension assets we hold.

The decrease in the fair market value of our outstanding derivative instruments from a net liability of $44.9 million as of December 31, 2012 to $54.8 million as of December 31, 2013 was due primarily to increases in the forward market values of fuel products margins, or crack spreads, relative to our hedged products margins and settlements of derivatives in 2013 that resulted in realized losses. We recorded realized losses of $4.7 million and unrealized gains of $25.7 million on derivative instruments for the year ended December 31, 2013.

The decrease in the fair market value of our outstanding derivative instruments from a net asset of $14.9 million as of December 31, 2011 to a net liability of $44.9 million as of December 31, 2012 was due primarily to increases in the forward market values of fuel products margins, or crack spreads, relative to our hedged products margins and settlements of derivatives in 2012 that resulted in realized losses.

We measure our investments associated with our non-contributory defined benefit plans ("Pension Plan") on a recurring basis. As of December 31, 2013, our 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 net asset value ("NAV") of shares in each fund held by the Pension maturity. Various analytical tests are performed to validate the counterparty data. The fair values of our derivative instruments are adjusted for nonperformance risk and credit worthiness of the hedging entities through our credit valuation adjustment ("CVA"). The CVA is calculated at the counterparty level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. We use the counterparty's marginal default rate and our survival rate when we are in a net asset position at the payment date and use our marginal default rate and the counterparty's survival rate when we are in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2013, our net liability was reduced by approximately $1.9 million. As a result of applying the CVA at December 31, 2012, our net asset was reduced by approximately $0.1 million and our net liability was reduced by approximately $0.2 million.

Observable inputs utilized to estimate the fair values of our derivative instruments were primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, we have 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. We believe we have obtained the most accurate information available for the types of derivative instruments it holds. See Note 8 for further information on derivative instruments.

Our weighted-average expected rate of return on pension assets was 6.75% at the end of 2013. The weighted-average

We believe that the fair values of our derivative instruments may diverge materially from the amounts currently recorded at fair value at settlement due to the volatility of commodity prices. 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 December 31, 2013:

	In millions	
Crude oil swaps	$20.2	
Crude oil basis swaps	$0.7	
Diesel swaps	$(13.2	)
Jet fuel swaps	$(2.0	)
Gasoline swaps	$(5.0	)
Natural gas swaps	$10.3	
	$11.0	

A 100 basis point increase or decrease in the expected rate of return on pension assets would decrease or increase the annual net periodic benefit cost by approximately $0.4 million.

A 100 basis point increase or decrease in the discount rate decreases or increases the annual net periodic benefit cost by approximately $0.4 million.

Impacts due to assumption changes on the pension plan and post retirement benefit plan could be positive or negative depending on the direction of the change in rates. See Note 12 to our consolidated financial statements included in Item 8 "Financial Statements and Supplementary Data" for key assumptions and other information regarding our pension and post retirement benefit plans.

Plan at quarter end as provided by the third party administrator.

As of December 31, 2013 none of our assets and approximately 86% of our liabilities were measured at fair value and classified as Level 3 in the fair value hierarchy.

discount rate was 4.74% for the pension benefit obligations and 4.29% for the other post retirement benefit obligations as of December 31, 2013. Changes in pension and other post retirement benefit expense and the recognized obligations may occur in the future as a result of a number of factors, including changes to any of these assumptions.

Recent Accounting Pronouncements

For a summary of recently issued and adopted accounting standards applicable to us, see Note 2 to our consolidated financial statements included in Item 8 “Financial Statements and Supplementary Data.”

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk
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. Our primary strategies to reduce our risk utilize both physical forward contracts and financially settled derivative instruments such as swaps, collars and options to attempt to reduce our exposure with respect to:

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

As of December 31, 2013, we primarily had entered into swap contracts on forecasted purchases from 2014 through 2017 of NYMEX WTI crude oil and natural gas and forecasted sales of U.S. Gulf Coast ultra-low sulfur diesel, jet fuel and gasoline. These derivative instruments, on a combined basis, were entered into to hedge a portion of our margin in our fuel products segment. We have entered 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 facilities.
The following table provides a summary of the implied crack spreads for our crude oil and diesel fuel swaps on a combined basis as of December 31, 2013 in our fuel products segment:

Crude Oil and Diesel Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
First Quarter 2014	1,350,000	15,000	$27.15
Second Quarter 2014	1,319,500	14,500	27.63
Third Quarter 2014	1,472,000	16,000	27.63
Fourth Quarter 2014	1,426,000	15,500	27.59
Calendar Year 2015	5,785,500	15,851	26.59
Calendar Year 2016	1,830,000	5,000	27.27
Total	13,183,000		
Average price			$27.07

The following table provides a summary of the implied crack spreads for our crude oil and jet fuel swaps on a combined basis as of December 31, 2013 in our fuel products segment:

Crude Oil and Jet Fuel Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
First Quarter 2014	360,000	4,000	$27.86
Second Quarter 2014	273,000	3,000	25.33
Third Quarter 2014	276,000	3,000	24.83
Fourth Quarter 2014	276,000	3,000	24.30
Calendar Year 2015	775,000	2,123	27.54
Total	1,960,000		
Average price			$26.45

The following table provides a summary of the implied crack spreads for our crude oil and gasoline fuel swaps on a combined basis as of December 31, 2013 in our fuel products segment:

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Crude Oil and Gasoline Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
First Quarter 2014	1,575,000	17,500	$10.35
Second Quarter 2014	1,365,000	15,000	14.91
Third Quarter 2014	1,610,000	17,500	13.99
Fourth Quarter 2014	460,000	5,000	11.82
Total	5,010,000		
Average price			$12.90

The following table provides a summary of natural gas swaps as of December 31, 2013 in our specialty products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2014	750,000	$4.14
Second Quarter 2014	750,000	4.14
Third Quarter 2014	750,000	4.14
Fourth Quarter 2014	850,000	4.21
Calendar Year 2015	3,500,000	4.27
Calendar Year 2016	2,700,000	4.42
Calendar Year 2017	1,000,000	4.29
Total	10,300,000	
Average price		$4.28

Please read Note 8 "Derivatives" in the notes to our consolidated financial statements under Item 8 "Financial Statements and Supplementary Data" for a discussion of the accounting treatment for the various types of derivative instruments, and a further discussion of our hedging policies and more information relating to our implied crack spreads of crude oil, diesel, gasoline and jet fuel derivative instruments.

Our derivative instruments and overall specialty products segment and fuel products segment 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 derivatives 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.

The following table illustrates how a change in market price (holding all other variables constant and excluding the impact of our current hedges) would affect our sales and cost of sales in the consolidated statements of operations:

	Sales		Cost of Sales	
	Year Ended December 31,		Year Ended December 31,	
	2013	2012	2013	2012
	(In millions)			
Fuel Products:				
$1.00 change in per barrel price of crude oil (1)			$23.9	$20.2
$1.00 change in per barrel selling price of gasoline, diesel and jet fuel (1)	$23.9	$20.2		
Specialty Products:				
$1.00 change in per barrel price of crude oil (1)			$9.6	$9.8
$0.50 change in MMBtu (one million British Thermal Units) of natural gas (2)			$5.6	$5.2

(1) Based on our 2013 and 2012 sales volumes.

(2) Based on our results for the years ended December 31, 2013 and 2012.

Pension Assets Volatility and Investment Policy

Our Pension Plan assets are also subject to volatility that can be caused by fluctuation in general economic conditions. Plan assets are invested by the Plan's fiduciaries, which direct investments according to specific policies. Our consolidated

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statement of operations is currently shielded from volatility in plan assets due to the way accounting standards are applied for pension plans, although favorable or unfavorable investment performance over the long term will impact our pension expense if it deviates from our assumption related to the future rate of return. Please read Note 12 “Employee Benefit Plans” in the notes to our consolidated financial statements under Item 8 “Financial Statements and Supplementary Data” for a further discussion of our investment policies.

Compliance Price Risk

Renewable Identification Numbers

We are exposed to market risks related to the volatility in the price of credits needed to comply with governmental programs. 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, we are required to blend biofuels into the fuel products we produce at a rate that will meet the EPA’s annual quota. To the extent we are unable to blend biofuels at that rate, we must purchase RINs in the open market to satisfy the annual requirement. We have not entered into any derivative instruments to manage this risk, but we have purchased RINs when the price of these instruments is deemed favorable.

Interest Rate Risk

We have an $850.0 million revolving credit facility as of December 31, 2013 and 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 December 31, 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 Notes, 2020 Notes and 2022 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:

	December 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2019 Notes	$554.2	$490.5	$658.8	$587.6
2020 Notes	$309.4	$270.7	$301.8	$270.4
2022 Notes	$353.9	$344.8	$—	$—

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.

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Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of Calumet Specialty Products Partners, L.P. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Bel-Ray Company, LLC, which are included in the Company's 2013 consolidated financial statements and constituted $73,372,000 and $67,757,000 of the Company's total and net assets, respectively, as of December 31, 2013 and $1,845,000 and $353,000 of the Company's sales and net loss, respectively, for the year then ended. Management also did not perform an evaluation of the internal control over financial reporting of Bel-Ray Company, LLC.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, based on criteria for effective internal control over financial reporting described in "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) ("COSO"). Based on this assessment, we have concluded that internal control over financial reporting was effective as of December 31, 2013.

Ernst & Young LLP, an independent registered public accounting firm, has audited the Company's consolidated financial statements and has issued an attestation report on the effectiveness of internal control over financial reporting which appears on the following page.

/s/ F. William Grube
F. William Grube
Chief Executive Officer, Director and
Vice Chairman of the Board of Calumet GP, LLC

March 3, 2014

/s/ R. Patrick Murray, II
R. Patrick Murray, II
Senior Vice President, Chief Financial Officer and
Secretary of Calumet GP, LLC

March 3, 2014

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Report of Independent Registered Public Accounting Firm
The Board of Directors of Calumet GP, LLC
General Partner of Calumet Specialty Products Partners, L.P.

We have audited Calumet Specialty Products Partners, L.P.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Calumet Specialty Products Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Bel-Ray Company, LLC, which is included in the 2013 consolidated financial statements of Calumet Specialty Products Partners, L.P. and constituted $73,372,000 and $67,757,000 of total and net assets, respectively, as of December 31, 2013 and $1,845,000 and $353,000 of sales and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of Calumet Specialty Products Partners, L.P. also did not include an evaluation of the internal control over financial reporting of Bel-Ray Company, LLC.

In our opinion Calumet Specialty Products Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Calumet Specialty Products Partners, L.P. as of December 31, 2013 and 2012, and the related consolidated statements of operations and comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2013 of Calumet Specialty Products Partners, L.P. and our report dated March 3, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Indianapolis, Indiana
March 3, 2014

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Calumet GP, LLC
General Partner of Calumet Specialty Products Partners, L.P.

We have audited the accompanying consolidated balance sheets of Calumet Specialty Products Partners, L.P. as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Calumet Specialty Products Partners, L.P. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Calumet Specialty Products Partners, L.P.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated March 3, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Indianapolis, Indiana
March 3, 2014

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

	Year Ended December 31,	
	2013	2012
	(In millions, except unit and per unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$121.1	$32.2
Accounts receivable:		
Trade, less allowance for doubtful accounts of $1.2 million and $1.2 million, respectively	250.3	219.3
Other	13.0	7.5
	263.3	226.8
Inventories	567.4	553.6
Derivative assets	—	3.1
Prepaid expenses and other current assets	18.9	10.3
Deposits	3.7	7.9
Total current assets	974.4	833.9
Property, plant and equipment, net	1,160.4	986.9
Investment in unconsolidated affiliate	33.4	1.9
Goodwill	207.0	187.0
Other intangible assets, net	212.9	197.1
Other noncurrent assets, net	100.0	46.2
Total assets	$2,688.1	$2,253.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$355.8	$332.6
Accrued interest payable	22.5	23.5
Accrued salaries, wages and benefits	14.0	20.1
Accrued income taxes payable	—	27.6
Other taxes payable	18.4	13.7
Other current liabilities	36.2	9.1
Current portion of long-term debt	0.4	0.8
Derivative liabilities	54.8	48.0
Total current liabilities	502.1	475.4
Pension and postretirement benefit obligations	11.7	24.0
Other long-term liabilities	1.1	1.1
Long-term debt, less current portion	1,110.4	862.7
Total liabilities	1,625.3	1,363.2
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (69,317,278 units and 57,529,778 units, issued and outstanding at December 31, 2013 and 2012, respectively)	1,079.6	884.8
General partner's interest	36.6	30.5
Accumulated other comprehensive loss	(53.4)	(25.5)
Total partners' capital	1,062.8	889.8
Total liabilities and partners' capital	$2,688.1	$2,253.0

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except unit and per unit data)		
Sales	$5,421.4	$4,657.3	$3,134.9
Cost of sales	5,011.4	4,144.1	2,860.8
Gross profit	410.0	513.2	274.1
Operating costs and expenses:			
Selling	62.6	41.6	12.2
General and administrative	82.1	60.9	38.6
Transportation	142.7	107.9	94.2
Taxes other than income taxes	14.2	9.1	5.7
Insurance recoveries	—	—	(8.7)
Other	16.8	7.8	6.8
Operating income	91.6	285.9	125.3
Other income (expense):			
Interest expense	(96.8)	(85.6)	(48.7)
Debt extinguishment costs	(14.6)	—	(15.1)
Realized gain (loss) on derivative instruments	(4.7)	9.5	(7.9)
Unrealized gain (loss) on derivative instruments	25.7	(3.8)	(10.4)
Other	2.7	0.5	0.8
Total other expense	(87.7)	(79.4)	(81.3)
Income before income taxes	3.9	206.5	44.0
Income tax expense	0.4	0.8	1.0
Net income	$3.5	$205.7	$43.0
Allocation of net income:			
Net income	$3.5	$205.7	$43.0
Less:			
General partner’s interest in net income	0.1	4.1	0.9
General partner’s incentive distribution rights	14.7	5.5	0.2
Non-vested share based payments	0.2	1.1	—
Net income (loss) available to limited partners	(11.5)	195.0	41.9
Weighted average limited partner units outstanding:			
Basic	67,938,784	55,559,183	42,598,876
Diluted	67,938,784	55,676,741	42,644,086
Limited partners’ interest basic net income (loss) per unit	$(0.17)	$3.51	$0.98
Limited partners’ interest diluted net income (loss) per unit	$(0.17)	$3.50	$0.98
Cash distributions declared per limited partner unit	$2.70	$2.30	$1.94

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Net income	$3.5	$205.7	$43.0
Other comprehensive income (loss):			
Cash flow hedges:			
Cash flow hedge (income) loss reclassified to net income	(0.5)	154.1	104.0
Change in fair value of cash flow hedges	(36.9)	(215.1)	(34.2)
Defined benefit pension and retiree health benefit plans	9.6	(3.0)	(3.7)
Foreign currency translation adjustment	(0.1)	—	—
Total other comprehensive income (loss)	(27.9)	(64.0)	66.1
Comprehensive income (loss) attributable to partners’ capital	$(24.4)	$141.7	$109.1

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Accumulated Other Comprehensive Income (Loss)	Partners' Capital			
			Limited Partners		
		General Partner	Common	Subordinated	Total
	(In millions)				
Balance at December 31, 2010	$(27.6)	$18.2	$390.8	$16.9	$398.3
Other comprehensive income	66.1	—	—	—	66.1
Net income	—	1.1	41.9	—	43.0
Common units repurchased for phantom unit grants	—	—	(0.6)	—	(0.6)
Issuance of phantom units, net of taxes withheld	—	—	0.8	—	0.8
Amortization of vested phantom units	—	—	3.0	—	3.0
Proceeds from public offerings of common units, net	—	—	294.7	—	294.7
Contribution from Calumet GP, LLC	—	6.3	—	—	6.3
Subordinated unit conversion	—	—	10.8	(10.8)	—
Distributions to partners	—	(1.7)	(74.9)	(6.1)	(82.7)
Balance at December 31, 2011	$38.5	$23.9	$666.5	$—	$728.9
Other comprehensive loss	(64.0)	—	—	—	(64.0)
Net income	—	9.6	196.1	—	205.7
Common units repurchased for phantom unit grants	—	—	(2.1)	—	(2.1)
Issuance of phantom units, net of taxes withheld	—	—	1.7	—	1.7
Amortization of vested phantom units	—	—	2.3	—	2.3
Proceeds from public offerings of common units, net	—	—	146.6	—	146.6
Contributions from Calumet GP, LLC	—	3.1	—	—	3.1
Distributions to partners	—	(6.1)	(126.3)	—	(132.4)
Balance at December 31, 2012	$(25.5)	$30.5	$884.8	$—	$889.8
Other comprehensive loss	(27.9)	—	—	—	(27.9)
Net income (loss)	—	14.8	(11.3)	—	3.5
Common units repurchased for phantom unit grants	—	—	(5.0)	—	(5.0)
Issuance of phantom units, net of taxes withheld	—	—	(0.3)	—	(0.3)
Amortization of vested phantom units	—	—	3.2	—	3.2
Proceeds from public offerings of common units, net	—	—	392.5	—	392.5
Contributions from Calumet GP, LLC	—	8.4	—	—	8.4
Distributions to partners	—	(17.1)	(184.3)	—	(201.4)
Balance at December 31, 2013	$(53.4)	$36.6	$1,079.6	$—	$1,062.8

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Operating activities			
Net income	$3.5	$205.7	$43.0
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	117.8	91.6	63.1
Amortization of turnaround costs	15.9	13.4	11.4
Non-cash interest expense	7.0	6.1	3.7
Non-cash debt extinguishment costs	3.4	—	14.4
Provision for doubtful accounts	0.1	—	0.4
Unrealized (gain) loss on derivative instruments	(25.7)	3.8	10.4
Loss on disposal of fixed assets	15.2	2.5	1.5
Non-cash equity based compensation	4.8	6.5	4.9
Other non-cash activities	0.6	1.1	—
Changes in assets and liabilities:			
Accounts receivable	(32.3)	34.6	(54.5)
Inventories	14.3	17.9	(167.0)
Prepaid expenses and other current assets	2.6	21.7	(0.4)
Derivative activity	(1.8)	(5.0)	11.7
Turnaround costs	(68.6)	(14.9)	(14.1)
Deposits	4.2	(5.9)	—
Other assets	(0.1)	(4.0)	(0.4)
Accounts payable	6.8	11.1	131.3
Accrued interest payable	(1.0)	13.0	7.4
Accrued salaries, wages and benefits	(7.1)	1.0	4.1
Accrued income taxes payable	(27.6)	(16.1)	0.4
Other taxes payable	3.0	0.9	5.5
Other liabilities	6.8	2.7	(12.1)
Pension and postretirement benefit obligations	(2.7)	(7.6)	(0.9)
Net cash provided by operating activities	39.1	380.1	63.8
Investing activities			
Additions to property, plant and equipment	(160.8)	(57.0)	(49.5)
Investment in unconsolidated affiliate	(31.8)	—	—
Proceeds from insurance recoveries — equipment	—	—	1.9
Cash paid for acquisitions, net of cash acquired	(177.7)	(569.2)	(413.2)
Proceeds from sale of property, plant and equipment	—	2.0	0.4
Net cash used in investing activities	(370.3)	(624.2)	(460.4)
Financing activities			
Proceeds from borrowings — revolving credit facility	865.6	1,558.3	1,598.7
Repayments of borrowings — revolving credit facility	(865.6)	(1,558.3)	(1,609.5)
Repayments of borrowings — term loan credit facility	—	—	(367.4)
Repayments of borrowings — senior notes	(100.0)	—	—
Repayments of borrowings — acquisition debt assumed	(11.9)	—	—
Payments on capital lease obligations	(1.1)	(1.5)	(1.1)

Proceeds from other financing obligations	3.5	—	—
Proceeds from public offerings of common units, net	392.5	146.6	294.7
Proceeds from senior notes offerings	344.7	270.2	586.0
Debt issuance costs	(7.3)	(7.7)	(27.7)
Contributions from Calumet GP, LLC	8.4	3.1	6.3
Common units repurchased and taxes paid for phantom unit grants	(7.1)	(2.1)	(0.6)
Distributions to partners	(201.6)	(132.4)	(82.7)
Net cash provided by financing activities	420.1	276.2	396.7
Net increase in cash and cash equivalents	88.9	32.1	0.1
Cash and cash equivalents at beginning of year	32.2	0.1	—
Cash and cash equivalents at end of year	$121.1	$32.2	$0.1
Supplemental disclosure of cash flow information			
Interest paid, net of capitalized interest	$91.4	$66.2	$37.9
Income taxes paid	$29.8	$0.7	$0.6
Supplemental disclosure of non-cash investing activities			
Non-cash property, plant and equipment additions	$13.1	$5.8	$—

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO 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 December 31, 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 and fuel and fuel-related products including gasoline, diesel, jet fuel, asphalt 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 "Calumet Packaging" (formerly "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"); Porter, Texas ("Royal Purple") and Wall Township, New Jersey ("Bel-Ray") and terminals located in Burnham, Illinois ("Burnham"); Rhinelander, Wisconsin ("Rhinelander"); Crookston, Minnesota ("Crookston") and Proctor, Minnesota ("Duluth").

2. Summary of Significant Accounting Policies

Consolidation

The consolidated financial statements reflect the accounts of the Company and its wholly-owned and majority-owned subsidiaries. All intercompany profits, transactions and balances have been eliminated.

Reclassifications

Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the current year presentation.

Use of Estimates

The Company's consolidated financial statements are prepared in conformity with U.S. generally accepted accounting ("U.S. GAAP") principles which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents includes all highly liquid investments with a maturity of three months or less at the time of purchase.

Accounts Receivable

The Company performs periodic credit evaluations of customers' financial condition and generally does not require collateral. Accounts receivable are carried at their face amounts and are generally due within 30 days to 45 days from date of invoice for the specialty products segment and 10 days from date of invoice for the fuel products segment. The Company maintains an allowance for doubtful accounts for estimated losses in the collection of accounts receivable. The Company makes estimates regarding the future ability of its customers to make required payments based on historical experience, the age of the accounts receivable balances, credit quality of the Company's customers, current economic conditions, expected future trends and other factors that may affect customers' ability to pay. Individual accounts are written off against the allowance for doubtful accounts after all reasonable collection efforts have been exhausted. The activity in the allowance for doubtful accounts was as follows (in millions):

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	December 31,		
	2013	2012	2011
Beginning balance	$1.2	$0.9	$0.6
Provision	0.1	—	0.4
Recoveries	—	0.4	—
Write-offs, net	(0.1)	(0.1)	(0.1)
Ending balance	$1.2	$1.2	$0.9

Inventories

The cost of inventory is recorded using the last-in, first-out (LIFO) method. 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 $32.2 million and $38.3 million higher as of December 31, 2013 and 2012, respectively. At December 31, 2013 and 2012, the Company had $2.6 million and $2.3 million, respectively, of consigned inventory.

Inventories consist of the following (in millions):

	December 31,	
	2013	2012
Raw materials	$122.7	$85.4
Work in process	102.6	119.5
Finished goods	342.1	348.7
	$567.4	$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. For each of the years ended December 31, 2013, 2012 and 2011, the Company recorded gains and (losses) of $4.2 million, $(4.2) million and $5.2 million, respectively, in cost of sales in the consolidated statements of operations due to the liquidation of inventory layers.

In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. During the years ended December 31, 2013, 2012 and 2011 the Company recorded $6.0 million, $8.1 million and $2.0 million, respectively, of losses in cost of sales in the consolidated statements of operations due to the lower of cost or market valuation.

Derivatives

The Company is exposed to fluctuations in the price of numerous commodities, such as crude oil (its principal raw material) and natural gas, as well as the sales prices of gasoline, diesel and jet fuel. Given the historical volatility of commodity prices, these fluctuations can significantly impact sales, gross profit and net income. Therefore, the Company utilizes derivative instruments primarily to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas and the sale of fuel products. The Company employs various hedging strategies and does not hold or issue derivative instruments for trading purposes. For further information, please refer to Note 8.

Property, Plant and Equipment

Property, plant and equipment are stated on the basis of cost. Depreciation is calculated generally on composite groups, using the straight-line method over the estimated useful lives of the respective groups. Assets under capital leases are amortized over the lesser of the useful life of the asset or the term of the lease.

Property, plant and equipment, including depreciable lives, consisted of the following (in millions):

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	December 31,	
	2013	2012
Land	$17.6	$11.2
Buildings and improvements (10 to 40 years)	39.1	28.1
Machinery and equipment (10 to 20 years)	1,327.4	1,173.0
Furniture and fixtures (5 to 10 years)	21.7	7.6
Assets under capital leases (10 to 28 years)	11.1	11.1
Construction-in-progress	121.5	53.8
	1,538.4	1,284.8
Less accumulated depreciation	(378.0)	(297.9)
	$1,160.4	$986.9

Under the composite depreciation method, the cost of partial retirements of a group is charged to accumulated depreciation. However, when there are dispositions of complete groups or significant portions of groups, the cost and related accumulated depreciation are retired, and any gain or loss is reflected in earnings.

During 2013, 2012 and 2011, the Company incurred $101.2 million, $86.3 million and $49.3 million, respectively, of interest expense of which $4.4 million, $0.7 million and $0.6 million, respectively, was capitalized as a component of property, plant and equipment.

The Company has not recorded an asset retirement obligation as of December 31, 2013 or 2012 because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

During the years ended December 31, 2013, 2012 and 2011, the Company recorded $92.0 million, $74.3 million and $55.5 million, respectively, of depreciation expense on its property, plant and equipment. Depreciation expense included $0.7 million, $1.0 million and $1.1 million for the years ended 2013, 2012 and 2011, respectively, related to the Company’s capital lease assets.

The Company capitalizes the cost of computer software developed or obtained for internal use. Capitalized software is amortized using the straight-line method over five years. As of December 31, 2013 and 2012, the Company has $17.3 million and $15.0 million, respectively, of unamortized capitalized software costs. During the years ended December 31, 2013, 2012 and 2011, the Company recorded $3.3 million, $1.0 million, and $0.4 million, respectively, of amortization expense on capitalized computer software.

Investment in Unconsolidated Affiliate

The Company accounts for its ownership in its Dakota Prairie Refining, LLC joint venture in accordance with ASC 323, Investments — Equity Method and Joint Ventures. The joint venture’s refinery was not operational in 2013. The equity method of accounting is applied when the investor has an ownership interest of less than 50% and/or has significant influence over the operating or financial decisions of the investee. Under the equity method, the Company’s proportionate share of net income (loss) is reflected as a single-line item in the consolidated statements of operations and increases or decreases, as applicable, in the carrying value of the Company’s investment in the consolidated balance sheets. In addition, the proportionate share of net income (loss) is reflected as a non-cash activity in operating activities in the consolidated statements of cash flows. Contributions increase the carrying value of the investment and are reflected as an investing activity in the consolidated statements of cash flows.

Equity method investments are assessed for other-than-temporary impairment when the investment generates net losses. No impairment was recognized in 2013 or 2012. For further information on investment in unconsolidated affiliate, refer to Note 4.

Goodwill and Indefinite Lived Intangible Assets

Goodwill represents the excess of purchase price over fair value of the net assets acquired in various acquisitions. See Note 3 for more information. The Company reviews goodwill for impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable in accordance with ASC 350, Intangibles — Goodwill and Other (Topic 350): Testing Goodwill for Impairment (“ASU 2011-08”). In September 2011, the FASB amended ASU 2011-08 which amended the rules for testing for impairment. Under ASU 2011-08, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. The Company early adopted ASU 2011-08 for the October 1, 2011 annual goodwill impairment test.

In assessing the qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company assesses relevant events and circumstances that may impact the fair value and the carrying amount of the reporting unit. The identification of relevant events and circumstances and how these may impact a reporting unit's fair value or carrying amount involve significant judgment and assumptions. The judgment and assumptions include the identification of macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and Company specific events and making the assessment on whether each relevant factor will impact the impairment test positively or negatively and the magnitude of any such impact.

If the Company's qualitative assessment concludes that it is probable that an impairment exists or the Company skips the qualitative assessment then the Company needs to perform a quantitative assessment. In the first step of the quantitative assessment, the Company's assets and liabilities, including existing goodwill and other intangible assets, are assigned to the identified reporting units to determine the carrying value of the reporting units. If the carrying value of a reporting unit is in excess of its fair value, an impairment may exist, and the Company must perform an impairment analysis, in which the implied fair value of the goodwill is compared to its carrying value to determine the impairment charge, if any.

When performing the quantitative assessment, 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.

Intangible assets with an indefinite life are not amortized but are subject to review each reporting period to determine whether events and circumstances continue to support an indefinite useful life as well as an annual impairment test.

Based on the results of the quantitative assessment in 2013 and qualitative assessments in 2012 and 2011 of the reporting units, the Company believes it is more likely than not that the fair value of its reporting units are greater than their carrying amounts. No impairment was recognized for goodwill and indefinite lived intangible assets in 2013, 2012 or 2011.

Other Intangible Assets

Other intangible assets consist of intangible assets associated with customer relationships, supplier agreements, tradenames, trade secrets, patents, non-competition agreements, distributor agreements and royalty agreements that were acquired in various acquisitions. The majority of these assets are being amortized using discounted estimated future cash flows over the term of the related agreements. Intangible assets associated with customer relationships are being amortized using the discounted estimated future cash flows method based upon assumed rates of annual customer attrition. For more information, refer to Note 5.

Other Noncurrent Assets

Other noncurrent assets include deferred debt issuance costs and turnaround costs. Deferred debt issuance costs were \$29.7 million and \$29.4 million as of December 31, 2013 and 2012, respectively, and are being amortized by the effective interest rate method over the lives of the related debt instruments. These amounts are net of accumulated amortization of \$13.6 million and \$6.6 million at December 31, 2013 and 2012, respectively.

Turnaround costs represent capitalized costs associated with the Company's periodic major maintenance and repairs and were \$67.0 million and \$14.3 million as of December 31, 2013 and 2012, respectively. The Company capitalizes these costs and amortizes the costs on a straight-line basis over the lives of the turnaround assets. These amounts are net of accumulated amortization of $25.7 million and $17.8 million at December 31, 2013 and 2012, respectively.

Impairment of Long-Lived Assets

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including definite-lived intangible assets, when events or circumstances warrant such a review. The carrying value of a long-lived asset to be held and used is considered impaired when the anticipated separately identifiable undiscounted cash flows from such an asset are less than the carrying value of the asset. In such an event, a write-down of the asset would be recorded through a charge to operations, based on the amount by which the carrying value exceeds the fair value of the long-lived asset. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved. Long-lived assets to be disposed of other than by sale are considered held and used until disposal.

During 2013 and 2012, the Company recorded write-downs related to idle fixed assets within its specialty products segment. The non-cash charges of $10.5 million and $1.6 million, were recorded in other operating costs and expenses on the consolidated statements of operations and loss on disposal of fixed assets in the consolidated statements of cash flows for the years ended December 31, 2013 and 2012, respectively.

Business Combinations and Related Business Acquisition Costs

Assets and liabilities associated with business acquisitions are recorded at fair value, using the acquisition method of accounting. The Company allocates the purchase price of acquisitions based upon the fair value of each component, which may be derived from various observable or unobservable inputs and assumptions. The Company may utilize third-party valuation specialists to assist the Company in this allocation. Initial purchase price allocations are preliminary and subject to revision within the measurement period, not to exceed one year from the date of acquisition. 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 identifiable assets acquired and liabilities assumed.

Business acquisition costs are expensed as incurred, and are reported as general and administrative expenses in the consolidated statements of operations. The Company defines these costs to include finder’s fees, advisory, legal, accounting, valuation, and other professional or consulting fees, as well as travel associated with the evaluation and effort to acquire specific businesses. For further information, refer to Note 3.

Revenue Recognition

The Company recognizes revenue on orders received from its customers when there is persuasive evidence of an arrangement with the customer that is supportive of revenue recognition, the customer has made a fixed commitment to purchase the product for a fixed or determinable sales price, collection is reasonably assured under the Company’s normal billing and credit terms, all of the Company’s obligations related to product have been fulfilled and ownership and all risks of loss have been transferred to the buyer, which is primarily upon shipment to the customer or, in certain cases, upon receipt by the customer in accordance with contractual terms.

Concentrations of Credit Risk

The Company performs periodic credit evaluations of its customers’ financial condition and in some instances requires cash in advance or letters of credit prior to shipment for domestic orders. For international orders, letters of credit are generally required and the Company maintains insurance policies which cover certain export orders. The Company maintains an allowance for doubtful customer accounts for estimated losses resulting from the inability of its customers to make required payments. The allowance for doubtful accounts is developed based on several factors including historical experience, the age of the accounts receivable balances, credit quality of the Company’s customers, current economic conditions, expected future trends and other factors that may affect customers’ ability to pay, which exist as of the balance sheet dates. If the financial condition of the Company’s customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. In addition, from time to time the Company has significant derivative assets with a limited number of counterparties. The evaluation of these counterparties is performed quarterly in connection with the Company’s ASC 820-10, Fair Value Measurements and Disclosures, valuations to determine the impact of the counterparty credit risk on the valuation of its derivative instruments.

Income Taxes

The Company, as a partnership, is generally not liable for federal income taxes on the earnings of Calumet Specialty Products Partners, L.P. and its wholly-owned subsidiaries. However, certain wholly-owned subsidiaries of the

Company, are corporations and, as a result, are liable for income taxes on their earnings. Income taxes related to these subsidiaries were not significant in 2013, 2012 and 2011. Additionally, the Company is subject to franchise taxes which were not material for 2013, 2012 and 2011. Income taxes on the earnings of the Company, with the exception of the above mentioned items, are the responsibility of its partners, with earnings of the Company included in partners' earnings.

In the event that the Company's taxable income did not meet certain qualification requirements, the Company would be taxed as a corporation. Interest and penalties related to income taxes, if any, would be recorded in income tax expense. Generally, tax returns remain subject to examination by taxing authorities for three years. The Company had no unrecognized tax benefits as of December 31, 2013 and 2012.

Excise and Sales Taxes

The Company assesses, collects and remits excise taxes associated with the sale of certain of its fuel products. Furthermore, the Company collects and remits sales taxes associated with certain sales of its products to non-exempt customers. Excise taxes and sales taxes assessed and collected from customers are recorded on a net basis within sales in the Company’s consolidated statements of operations.

Earnings per Unit

The Company calculates earnings per unit under ASC 260-10, Earnings per Share. The Company treats incentive distribution rights (“IDRs”) as participating securities for the purposes of computing earnings per unit in the period that the general partner becomes contractually obligated to receive IDRs. Also, the undistributed earnings are allocated to the partnership interests based on the allocation of earnings to the Company’s partners’ capital accounts as specified in the Company’s partnership agreement. When distributions exceed earnings, net income is reduced by the actual distributions with the resulting net loss being allocated to capital accounts as specified in the Company’s partnership agreement.

Unit Based Compensation

For unit based compensation awards granted, compensation expense is recognized in the Company’s consolidated financial statements on a straight line basis over the awards’ vesting periods based on their fair values on the dates of grant. The unit based compensation awards vest over a period not exceeding four years. The amount of compensation expense recognized at any date is at least equal to the portion of the grant date value of the award that is vested at that date.

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”). Liability Awards are recorded in accrued salaries, wages and benefits based on the vested portion of the fair value of the awards on the balance sheet date. The fair values of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to compensation expense. See Note 11 for more information on Liability Awards.

Shipping and Handling Costs

The Company complies with ASC 605-45, Revenue Recognition — Principal Agent Considerations. ASC 605-45 requires the classification of shipping and handling costs billed to customers in sales and the classification of shipping and handling costs incurred in cost of sales, or to be disclosed if classified elsewhere. The Company has reflected $142.7 million, $107.9 million and $94.2 million, respectively, for the years ended December 31, 2013, 2012, and 2011, in transportation expense in the consolidated statements of operations, the majority of which is billed to customers.

Advertising Expenses

The Company expenses advertising costs as incurred which totaled $14.6 million, $8.2 million and $1.7 million in 2013, 2012 and 2011, respectively. Advertising expenses are reported as selling expenses in the consolidated statements of operations.

Renewable Identification Numbers Obligation

The Company’s Renewable Identification Numbers obligation (“RINs Obligation”) represents a liability for the purchase of RINs to satisfy the U.S. Environmental Protection Agency (“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 Company uses the inventory model to account for RINs, measuring acquired

RINs at weighted-average cost. The cost of RINs used each period is charged to cost of sales with cash inflows and outflows recorded in the operating cash flow section of the consolidated statements of cash flows. Excess RINs are classified as inventory in the consolidated balance sheets. The Company recognizes a liability at the end of each reporting period in which the Company does not have sufficient RINs to cover the RINs Obligation. The liability is calculated by multiplying the RINs shortage (based on actual results) by the period end RIN spot price.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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 in the consolidated statements 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.

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

On December 10, 2013, the Company completed the acquisition of Bel-Ray Company, LLC, a manufacturer and global distributor of high-performance lubricants and greases, for aggregate consideration of approximately $53.6

million, net of cash acquired and excluding debt assumed and certain purchase price adjustments ("Bel-Ray Acquisition"). Bel-Ray manufactures and distributes both domestically and internationally, a wide array of high-end specialty synthetic lubricants and greases which are used in the aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles industries. The Bel-Ray Acquisition was financed by using a portion of the net proceeds of $337.4 million from the Company's November 2013 private placement of 7 5/8% senior notes due January 15, 2022. The Company believes the Bel-Ray Acquisition increases its sales in the specialty lubricants market, expands its geographic reach and increases its asset diversity. At closing, the Company repaid the $11.9 million of debt assumed in connection with the Bel-Ray Acquisition.

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On August 9, 2013, the Company completed the acquisition of seven crude oil loading facilities and related assets in North Dakota and Montana from Murphy Oil USA, Inc. (“Murphy”) for aggregate consideration of approximately $6.2 million (“Crude Oil Logistics Acquisition”). The Crude Oil Logistics Acquisition was funded with cash on hand. As part of this acquisition, the Company assumed pipeline space on the Enbridge Pipeline System (“Enbridge Pipeline”) previously held by Murphy. The Company will have the ability to transport crude oil directly from the point of lease, into the Company’s newly acquired crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to the Company’s refineries and/or third party customers. As part of this transaction, the Company and Murphy jointly consented to terminate an existing crude oil purchase agreement (“Murphy Crude Oil Supply Agreement”) wherein Murphy supplied the Company’s Superior refinery with up to 10,000 barrels per day of crude oil. The Company believes this acquisition expands its growing portfolio of crude oil logistics assets, while positioning the Company to purchase increased volumes of price-advantaged feedstock directly from the producers that operate in some of the major shale oil plays encompassing the Company’s refineries.

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 $117.9 million, net of cash acquired. The refinery has total crude oil throughput capacity of 17,500 bpd and primarily produces diesel, jet fuel, gasoline, 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.

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 Refining”) and an insignificant affiliated company for aggregate consideration of approximately $191.6 million, net of cash acquired (“Montana Acquisition”). Montana Refining 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. Immediately after closing the Montana Acquisition, the Company converted Montana Refining 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 year ended December 31, 2013 and was offset by the derecognition of a deferred tax liability for a comparable amount assumed in connection with the 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 $262.5 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.

On January 6, 2012, the Company completed the acquisition of all of the outstanding membership interests of TruSouth Oil, LLC, renamed Calumet Packaging, LLC in 2013 (“Calumet Packaging”), a specialty petroleum packaging and distribution company located in Shreveport, Louisiana for aggregate consideration of approximately $26.9 million, net of cash acquired (“Calumet Packaging Acquisition”). The Calumet Packaging Acquisition was financed with borrowings under the Company’s revolving credit facility. Immediately prior to its acquisition by the Company, Calumet Packaging was owned in part by affiliates of the Company’s general partner. The Company believes the Calumet Packaging Acquisition provides greater diversity to its specialty products segment.

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.

Purchase Price Allocation

The Bel-Ray 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 assets and liabilities will be completed as soon as the information

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necessary to complete the analysis is obtained. The assets and results of the operations from such assets acquired as a result of the Superior, Montana, San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segments since the date of acquisition, September 30, 2011, October 1, 2012, January 2, 2013 and August 9, 2013, respectively. The assets and results of operations from such assets acquired as a result of the Missouri, Calumet Packaging, Royal Purple and Bel-Ray Acquisitions have been included in the specialty products segment since the date of acquisition, January 3, 2012, January 6, 2012, July 3, 2012 and December 10, 2013, respectively.
The allocations of the aggregate purchase prices to assets acquired and liabilities assumed for acquisitions are as follows (in millions):

	2013 Acquisitions			2012 Acquisitions			
	Bel-Ray	Crude Oil Logistics	San Antonio	Montana	Royal Purple	Calumet Packaging	Missouri
Accounts receivable	$4.3	$—	$—	$29.0	$15.2	$ 5.2	$—
Inventories	11.1	—	17.0	43.7	19.3	8.0	2.7
Prepaid expenses and other current assets	0.6	0.1	—	23.1	0.2	0.3	—
Deposits	—	—	—	0.3	—	—	—
Property, plant and equipment	6.5	0.9	100.7	125.4	10.6	17.7	10.0
Goodwill	9.1	5.2	5.7	27.6	109.2	0.4	1.5
Other intangible assets	41.4	—	—	—	183.4	2.6	5.4
Other noncurrent assets, net	0.3	—	—	0.3	—	—	—
Accounts payable	(3.9)	—	—	(8.4)	(3.8)	(2.7)	—
Accrued salaries, wages and benefits	(1.3)	—	(0.1)	(1.4)	(1.7)	(0.2)	—
Deferred income tax liability	—	—	—	(27.6)	—	—	—
Accrued income taxes payable	—	—	—	(15.6)	—	—	—
Other taxes payable	(1.7)	—	—	(3.0)	(0.2)	—	—
Other current liabilities	(0.8)	—	(5.4)	(0.1)	(1.0)	(0.9)	—
Current portion of long-term debt	(11.9)	—	—	—	—	—	—
Long-term debt	—	—	—	—	—	(3.5)	—
Pension and postretirement benefit obligations	—	—	—	(1.7)	—	—	—
Other long-term liabilities	(0.1)	—	—	—	—	—	—
Total purchase price, net of cash acquired	$53.6	$6.2	$117.9	$191.6	$331.2	$ 26.9	$19.6

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

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	Bel-Ray December 10, 2013		Royal Purple July 3, 2012		Calumet Packaging January 6, 2012		Missouri January 3, 2012	
	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)
Customer relationships	$28.6	30	$118.7	20	$1.8	16	$5.4	20
Trade names	—	Indefinite	14.8	Indefinite	—	Indefinite	—	Indefinite
Trade names	4.2	18	5.7	10	0.7	9	—	—
Trade secrets	8.5	18	44.2	12	—	—	—	—
Non-competition agreements	0.1	3	—	—	0.1	2	—	—
Totals	$41.4		$183.4		$2.6		$5.4	
Weighted average amortization period		26		18		14		20

Goodwill

The Company recorded the following goodwill (in millions):

	Amount	Business Segment
Bel-Ray Acquisition (1)	$9.1	Specialty Products
Crude Oil Logistics Acquisition (2)	$5.2	Fuel Products
San Antonio Acquisition (1)	$5.7	Fuel Products
Montana Acquisition (1)	$27.6	Fuel Products
Royal Purple Acquisition (1)	$109.2	Specialty Products
Calumet Packaging Acquisition (1)	$0.4	Specialty Products
Missouri Acquisition (1)	$1.5	Specialty Products

(1) Goodwill recognized relates primarily to enhancing the Company’s strategic platform for expansion in the respective business segment noted above.

(2) Goodwill recognized relates primarily to enhancing the Company’s crude oil gathering operations to support the Superior refinery.

Acquisition Expenses

In connection with the respective acquisition, the Company incurred the following expenses, which are reflected in general and administrative expenses in the consolidated statements of operations for the years ended December 31, 2013 and 2012 (in millions):

	Year Ended December 31,	
	2013	2012
Bel-Ray Acquisition	$0.4	$—
Crude Oil Logistics Acquisition	$0.2	$—
San Antonio Acquisition	$0.5	$—
Montana Acquisition	$0.1	$3.3
Royal Purple Acquisition	$—	$0.4
Calumet Packaging Acquisition	$—	$0.2
Missouri Acquisition	$—	$0.5

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Acquisition Sales and Operating Income

The following financial information reflects sales and operating income of the acquisitions of San Antonio and Bel-Ray in 2013, the acquisitions of Missouri, Calumet Packaging, Royal Purple and Montana in 2012 and the acquisition of Superior in 2011 that are included in the consolidated statements of operations (in millions):

	Year Ended December 31,		
	2013	2012	2011
Sales	$480.1	$266.1	$341.2
Operating income (loss)	$(22.5)	$18.6	$18.0

Unaudited Pro Forma Financial Information

The following unaudited pro forma financial information reflects the 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 per unit data):

	Year Ended December 31, 2012
Sales	$5,626.1
Net income	$189.2
Limited partners' interest net income per unit — basic	$2.61
Limited partners' interest net income per unit — diluted	$2.60

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.

4. Investment in Unconsolidated Affiliate

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 a total of $150.0 million from the Company comprised of $75.0 million through contributions and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower which is expected be repaid by the Company through its allocation of profits from the joint venture. 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 joint venture will allocate profits on a 50%/50% basis to the Company and MDU. The joint venture is 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 is providing 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 December 31, 2013 and 2012, the Company has an investment of $33.4 million and $1.9 million, respectively, in Dakota Prairie Refining, LLC primarily related to the development of the refinery.

5. Goodwill and Other Intangible Assets

Changes in goodwill balances are as follows (in millions):

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	Year Ended December 31,					
	2013			2012		
	Specialty Products	Fuel Products	Total	Specialty Products	Fuel Products	Total
Beginning balance:	$159.4	$27.6	$187.0	$48.3	$—	$48.3
Acquisitions	9.1	10.9	20.0	111.1	27.6	138.7
Accumulated impairment losses	—	—	—	—	—	—
Ending balance:	$168.5	$38.5	$207.0	$159.4	$27.6	$187.0

Other intangible assets consist of the following (in millions):

	Weighted Average Life (Years)	December 31, 2013 Gross Amount	December 31, 2013 Accumulated Amortization	December 31, 2012 Gross Amount	December 31, 2012 Accumulated Amortization
Customer relationships	22	$182.9	$(40.3)	$154.3	$(22.6)
Supplier agreements	4	21.5	(21.5)	21.5	(21.5)
Tradenames	Indefinite	14.8	—	14.8	—
Tradenames	13	10.6	(1.6)	6.4	(0.6)
Trade secrets	13	52.7	(9.6)	44.2	(3.1)
Patents	12	1.6	(1.2)	1.6	(1.1)
Non-competition agreements	5	5.9	(5.8)	5.8	(5.8)
Distributor agreements	3	2.0	(2.0)	2.0	(2.0)
Royalty agreements	19	4.5	(1.6)	4.5	(1.3)
	18	$296.5	$(83.6)	$255.1	$(58.0)

Supplier agreements, tradenames (other than indefinite lived), trade secrets, patents, non-competition agreements, distributor agreements and royalty agreements are being amortized to properly match expense with the discounted estimated future cash flows over the terms of the related agreements. Agreements with terms allowing for the potential extension of such agreements are being amortized based on the initial term only. Customer relationships are being amortized using discounted estimated future cash flows based upon assumed rates of annual customer attrition. For the years ended December 31, 2013, 2012 and 2011, the Company recorded amortization expense of intangible assets of $25.6 million, $16.9 million and $7.0 million, respectively.

The Company estimates that amortization of intangible assets for the next five years will be as follows (in millions):

Year	Amortization Amount
2014	$29.4
2015	$26.8
2016	$24.4
2017	$21.4
2018	$18.2

6. Commitments and Contingencies

Operating Leases

The Company has various operating leases primarily for the use of land, storage tanks, railcars, equipment, precious metals and office facilities that extend through April 2027. Renewal options are available on certain of these leases in which the Company is the lessee. Rent expense for the years ended December 31, 2013, 2012, and 2011 was $35.3 million, $26.9 million and $20.5 million, respectively.

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As of December 31, 2013, the Company had estimated minimum commitments for the payment of rentals under leases which, at inception, had a noncancelable term of more than one year, as follows (in millions):

Year	Operating Leases
2014	$30.0
2015	26.8
2016	22.4
2017	19.6
2018	16.7
Thereafter	30.6
Total	$146.1

Crude Oil Supply, Other Feedstocks and Finished Products

The Company is currently purchasing a majority of its crude oil under month-to-month evergreen contracts or on a spot basis.

On October 5, 2011, the Company entered into a Crude Oil Purchase Agreement (the “BP Purchase Agreement”) with BP Products North America Inc. (“BP”), pursuant to which BP supplies the Superior refinery with a portion of its daily crude oil requirements, utilizing a market-based pricing mechanism, plus transportation and handling costs. Total crude oil requirements for the Superior refinery are estimated to be between 35,000 and 45,000 bpd. In April 2012, the Company amended and restated the BP Purchase Agreement, which had an initial term of one year ending April 1, 2013, and automatically renews for successive one-year terms unless terminated by either party upon 90 days’ notice prior to the end of any renewal term. To secure a portion of the Company’s payment obligations under the BP Purchase Agreement, the Company and its affiliates have granted a limited interest capped at $100.0 million for physical forwards in the collateral pledged as security under the Collateral Trust Agreement to BP as a “Forward Purchase Secured Hedge Counterparty” under its Collateral Trust Agreement, as such term is defined therein.

On October 16, 2013, the Company entered into a definitive agreement with TexStar Midstream Logistics, L.P. (“TexStar”) under which TexStar will construct, own and operate a 30,000 bpd crude oil pipeline system that will supply crude oil to the Company’s San Antonio refinery. Under the terms of the 15 year agreement, TexStar has committed to install and operate the Karnes North Pipeline System (“KNPS”), a pipeline that will transport crude oil from Karnes City, Texas to the San Antonio refinery’s Elmendorf, Texas terminal, a key supply hub for the San Antonio refinery. The Company expects to receive deliveries of at least 10,000 bpd of crude oil through the KNPS-Elmendorf terminal supply route once the pipeline comes into service during the fourth quarter of 2014.

Certain other feedstocks are purchased under long-term supply contracts. The Company also purchases finished products from Houston Refining. The Company is required to purchase at least a minimum volume of 3,100 bpd of naphthenic lubricating oils produced at Houston Refining’s refinery in Houston, Texas, and has a right of first refusal to purchase any additional naphthenic lubricating oils produced at the refinery. In addition, Houston Refining is required to process a minimum of approximately 800 bpd of white mineral oil for the Company at Houston Refining’s Houston, Texas refinery. The annual purchase commitment under these agreements is approximately $140.7 million.

As of December 31, 2013, the estimated minimum purchase commitments under the Company’s crude oil, other feedstock supply and finished product agreements were as follows (in millions):

Year	Commitment
2014	$867.0
2015	3.1
2016	0.8
2017	0.3
2018	—

Thereafter	—
Total	$871.2

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In connection with the Company’s acquisition of Penreco on January 3, 2008, the Company 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, the Company is obligated to purchase approximately $77.0 million of feedstock for the LVT unit in each fiscal year of the term of the contract, expiring January 1, 2018, based on pricing estimates as of December 31, 2013. This amount is not included in the table above.

Labor Matters

The Company has approximately 570 employees covered by various collective bargaining agreements, or approximately 40.7% of its total workforce of approximately 1,400 employees. These agreements have expiration dates of April 30, 2014, October 31, 2014, January 31, 2015, March 31, 2016, April 30, 2016 and June 30, 2017. The Company has approximately 80 employees, or approximately 5.7% of its total workforce, covered by collective bargaining agreements that expire in less than one year and does not expect any work stoppages.

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.

Insurance Recoveries

During the second quarter of 2011, the Company reached a final settlement of its insurance claim related to the failure of an environmental operating unit at its Shreveport refinery in 2010, resulting in a gain (insurance recoveries) of $8.7 million recorded for the year ended December 31, 2011 in the consolidated statements of operations and used the proceeds to repair the failed unit and for working capital needs. This claim related to both property damage and business interruption. Recoveries of $1.9 million related to property damage have been reflected within investing activities (with the remainder in operating activities) in the consolidated statements of cash flows.

Environmental

The Company operates crude oil and specialty hydrocarbon refining and terminal operations, which are subject to stringent 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.

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San Antonio Refinery

In connection with the San Antonio Acquisition (see Note 3), the Company agreed to indemnify NuStar for an unlimited term and without consideration of a monetary cap 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. The indemnification is unlimited in duration and not subject to any monetary deductibles or maximums. Anadarko Petroleum Corporation ("Anadarko") and Age Refining, Inc. ("Age Refining"), a 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 remediate certain contamination at the San Antonio refinery that pre-dates the Company's acquiring of the facility. 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 this pre-existing contamination at the San Antonio refinery.

Montana Refinery

In connection with the Montana Acquisition from Connacher (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 HollyFrontier 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., subject to a 5-year time limit following closing and certain monetary baskets and cap, 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 the Company 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 in conjunction with the Company's planned capacity expansion at the Montana refinery. 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. To date, Holly has reimbursed the Company for eligible remediation costs.

Superior Refinery

In connection with the Superior acquisition, the Company became a party to an existing Refinery Initiative 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 refinery to the EPA and the WDNR. The Company currently estimates costs of approximately $1.0 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 material. In addition, the Company may have to pursue certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in the Company incurring additional costs, which could be substantial. During 2013 and 2012, the Company incurred approximately $1.9 million and $2.4 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 operation 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 otherwise 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. The Company was 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 was 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 are net of any amount recoverable under an environmental insurance policy that the Company obtained in connection with the Superior Acquisition, which named 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 that arose 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 2013 and 2012, the Company incurred approximately $4.9 million and $4.2 million, respectively, of such expenditures and estimates additional expenditures of approximately $6.0 million to $8.0 million of capital expenditures and expenditures related to additional personnel and environmental studies over the next two years as a result of the implementation of these requirements. These capital investment requirements will be incorporated into the Company's annual capital expenditures budget and the Company does not expect any additional capital expenditures as a result of the required audits or required operational changes included in the Global Settlement to have a material adverse effect on the Company's financial results or operations.

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 November 7, 2013, the EPA issued a Consent Agreement and Final Order to the Shreveport refinery, which included a civil penalty of $0.3 million.

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.

Current and former owners of a property in Bossier Parish, Louisiana, filed a lawsuit in March 2006 against the Company and other defendants, including Chevron USA, Inc. ("Chevron"), Legacy Resources Co., L.P. ("Legacy") and Exxon Mobil Corporation ("Exxon Mobil"), alleging damage from salt water and other environmental contamination on the property arising from historical oil field production on the property. Oil field exploration and production on the property began in the 1920's by predecessors of Exxon Mobil. The Company received an assignment of certain mineral leases for portions of the property in 1993 from an affiliate of Texaco, prior to Texaco's merger with Chevron. The Company then assigned those mineral leases to Legacy. The mineral lease assignments include indemnity provisions obligating the assignees to provide certain indemnities for an unlimited term and without consideration of a monetary cap for the benefit of the assignors. The Company, Chevron, Legacy and the plaintiffs are participating in mediation in an attempt to settle the litigation. The Company believes any obligation will be covered under the indemnification.

Bel-Ray Facility

Bel-Ray executed an Administrative Consent Order ("ACO") with the New Jersey Department of Environmental Protection, effective January 4, 1994, which required investigation and remediation of contamination at or emanating from the Bel-Ray facility. In 2000, Bel-Ray entered into a fixed price remediation contract with Weston Solutions ("Weston") (a large remediation contractor) whereby Weston agreed to be fully liable for the remediation of the soil and groundwater issues at the facility, including an offsite groundwater plume pursuant to the ACO ("Weston Agreement"). The Weston Agreement set up a trust fund to reimburse Weston, administered by Bel-Ray's environmental counsel. As of December 31, 2013, the trust fund contained approximately $0.7 million. In addition, there is remediation cost containment insurance, should Weston be unable to complete the work required under the Weston Agreement. In connection with the Bel-Ray Acquisition, the Company became a party to the Weston Agreement.

Weston has been addressing the environmental issues at the Bel-Ray facility over time, and the next phase will address the groundwater issues, which extend offsite.

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 and has implemented 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 years ended December 31, 2013 and 2012, the Company incurred approximately $3.2 million and $0.7 million, respectively, of related capital expenditures and expects to incur up to $1.0 million of capital expenditures during 2014 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.

Beginning in February 2010, OSHA conducted an inspection of the Shreveport refinery's process safety management program under OSHA's National Emphasis Program. On August 19, 2010, OSHA issued a Citation and Notification of Penalty to the Company as a result of the Shreveport inspection, which included a civil penalty amount of $0.1 million that was paid in January 2011. In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery's PSM program under this OSHA initiative. 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 have reached a tentative settlement with OSHA on the matter, which the Company does not believe will have a material adverse effect on its results of operations or financial condition.

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 December 31, 2013 and December 31, 2012, the Company had outstanding standby letters of credit of $95.2 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 December 31, 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 December 31, 2013 and December 31, 2012).

As of December 31, 2013 and December 31, 2012, the Company had availability to issue letters of credit of $472.4 million and $355.1 million, respectively, under its revolving credit facility. As of 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.

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7. Long-Term Debt

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

	December 31, 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	$—	$—
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019, effective interest rate of 9.9% for the years ended December 31, 2013 and 2012	500.0	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 10.0% for the years ended December 31, 2013 and 2012	275.0	275.0
Borrowings under 2022 Notes, interest at a fixed rate of 7.625%, interest payments semiannually, borrowings due January 2022, effective interest rate of 7.9% for the year ended December 31, 2013	350.0	—
Capital lease obligations, at various interest rates, interest and principal payments monthly through January 2027	4.8	5.5
Less unamortized discounts	(19.0)	(17.0)
Total long-term debt	1,110.8	863.5
Less current portion of long-term debt	0.4	0.8
	$1,110.4	$862.7

7 5/8% Senior Notes

On November 26, 2013, the Company issued and sold $350.0 million in aggregate principal amount of 7 5/8% of senior notes due January 15, 2022 (the “2022 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 98.494 percent of par. The 2022 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. The Company received net proceeds of $337.4 million, net of discount, underwriters’ fees and expenses, which the Company used for general partnership purposes, to fund previously announced organic growth projects, to fund the purchase price of the Bel-Ray Acquisition and the redemption of $100.0 million in aggregate principal amount outstanding of 2019 Notes (defined below). Refer to Note 3 for additional information regarding the Bel-Ray Acquisition.

Interest on the 2022 Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2014. The 2022 Notes will mature on January 15, 2022, unless redeemed prior to maturity. The 2022 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. (“Calumet Finance”) (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company’s indebtedness, including the 2022 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 2022 Notes. Since all Company’s operating subsidiaries, with the exception of Calumet Finance and three immaterial subsidiaries, guarantee the 2022 Notes, condensed consolidating financial statements of non-guarantors are not required in accordance with Rule 3-10 of Regulation S-X.

At any time prior to January 15, 2017, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.625% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2022 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

On and after January 15, 2018, the Company may on any one or more occasions redeem all or a part of the 2022 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2022 Notes, if redeemed during the twelve-month period beginning on January 15 of the years indicated below:

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Year	Percentage	
2018	103.813	%
2019	101.906	%
2020 and thereafter	100.000	%

Prior to January 15, 2018, the Company may on any one or more occasions redeem all or part of the 2022 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indenture governing the 2022 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

The indenture governing the 2022 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 2022 Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no Default or Event of Default, each as defined in the indenture governing the 2022 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 2022 Notes will have the right to require that the Company repurchase all or a portion of such holder's 2022 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 November 26, 2013, in connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2022 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2022 Notes can offer to exchange the 2022 Notes for registered notes having substantially the same terms as the 2022 Notes and evidencing the same indebtedness as the 2022 Notes. On November 27, 2013, the Company filed an exchange offer registration statement for the 2022 Notes with the SEC, which was declared effective on December 10, 2013. The exchange offer was completed on January 13, 2014, thereby fulfilling all of the requirements of the 2022 Notes registration rights agreement.

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, 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 U.S. pursuant to Regulation S under the Securities Act. The Company received net proceeds of $262.5 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 (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2020 Notes). The operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indenture governing the 2020 Notes. Since all Company's operating subsidiaries, with the exception of Calumet Finance and three immaterial subsidiaries, guarantee the 2020 Notes, condensed consolidating financial statements of non-guarantors are not required in accordance with Rule 3-10 of Regulation S-X. At any time prior to August 1, 2015, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.625% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2020 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 120 days of the date of the closing of such public or private equity offering.

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

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

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

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

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

In connection with the issuance and sale of the 2020 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2020 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC so that holders of the 2020 Notes could offer to exchange the 2020 Notes for registered notes having substantially the same terms as the 2020 Notes and evidencing the same indebtedness as the 2020 Notes. On December 4, 2012, the Company filed initially 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.

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 of the Securities Act and to persons outside the U.S. 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) of 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 of the Securities Act and to persons outside the U.S. 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 Annual 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."

On November 26, 2013, the Company redeemed approximately $74.0 million and $26.0 million in aggregate principal amount outstanding of the 2019 issued in April 2011 and 2019 Notes issued in September 2011, respectively, with the net proceeds from the issuance of the 2022 Notes at a redemption price of $111.2 million. In conjunction with the early redemption, the Company recognized a loss of $14.6 million recorded in debt extinguishment costs on the consolidated statements of operations for the year ended December 31, 2013.

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. (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2019 Notes). The operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indentures governing the 2019 Notes. Since all Company's operating subsidiaries, with the exception of Calumet Finance and three immaterial subsidiaries, guarantee the 2019 Notes, condensed consolidating financial statements of non-guarantors are not required in accordance with Rule 3-10 of Regulation S-X.

At any time prior to May 1, 2014, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2019 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.375% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2019 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 120 days of the date of the closing of such public or private equity offering.

On and after May 1, 2015, the Company may on any one or more occasions redeem all or a part of the 2019 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2019 Notes, if redeemed during the twelve-month period beginning on May 1 of the years indicated below:

Year	Percentage	
2015	104.688	%
2016	102.344	%
2017 and at any time thereafter	100.000	%

Prior to May 1, 2015, the Company may on any one or more occasions redeem all or part of the 2019 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indentures governing the 2019 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

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.
In connection with the issuances and sales of the 2019 Notes, the Company entered into registration rights agreements with the initial purchasers of the 2019 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC so that holders of the 2019 Notes could offer to exchange the 2019 Notes for registered notes having substantially the same terms as the 2019 Notes and evidencing the same indebtedness as the 2019 Notes. 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 December 31, 2013, the margin was 100 basis points for prime and 225 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 as follows:

Quarterly Average Availability Percentage	Margin on Base Rate Revolving Loans	Margin on LIBOR Revolving Loans
≥ 66%	1.00%	2.25%
≥ 33% and < 66%	1.25%	2.50%
< 33%	1.50%	2.75%

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% or 0.50% per annum depending on the average daily available unused borrowing capacity for the preceding month. The Company also pays a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

The borrowing capacity at December 31, 2013 under the revolving credit facility was $567.6 million. As of December 31, 2013, the Company had no outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $95.2 million, leaving $472.4 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. As of December 31, 2013, the Company's Fixed Charge Coverage Ratio was 2.39 to 1.0.

As of December 31, 2013, the Company was in compliance with all covenants under the revolving credit facility.

Amendments to Master Derivative Contracts

The Company's payment obligations under all of the Company's master derivatives contracts for commodity hedging generally are secured by a first priority lien on the Company's 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). The Company had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 2013. The Company issued to one counterparty a $25.0 million standby letter of credit under the revolving credit facility as of

December 31, 2012. The Company’s master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on the Company’s operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements.

Collateral Trust Agreement

The Company has a collateral sharing agreement (the “Collateral Trust Agreement”) with each of its secured hedging counterparties and an administrative agent for the benefit of the secured hedging counterparties, which governs how the secured hedging counterparties will share collateral pledged as security for the payment obligations owed by the Company to the 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, the Company has the ability to add secured hedging counterparties from time to time.

Maturities of Long-Term Debt

As of December 31, 2013, maturities of the Company's long-term debt are as follows (in millions):

Year	Maturity
2014	$0.4
2015	0.4
2016	0.3
2017	0.4
2018	0.4
Thereafter	1,127.9
Total	$1,129.8

Capital Lease Obligations

The Company had a capital lease obligation for catalysts used in refining processes which expired in 2013. In connection with the Calumet Packaging Acquisition, the Company recorded $5.8 million of capital leases for a building and equipment that will expire in 2027 and 2018, respectively. Assets recorded under these capital lease obligations are included in property, plant and equipment and total $11.1 million as of December 31, 2013 and 2012. As of December 31, 2013 and 2012, the Company had recorded $5.0 million and $4.3 million, respectively, in accumulated depreciation for these capital lease assets.

As of December 31, 2013, the Company had estimated minimum commitments for the payment of total rentals under capital leases as follows (in millions):

Year	Capital Leases
2014	$0.8
2015	0.7
2016	0.7
2017	0.7
2018	0.7
Thereafter	4.1
Total minimum lease payments	7.7
Less amount representing interest	2.9
Capital lease obligations	4.8
Less obligations due within one year	0.4
Long-term capital lease obligations	$4.4

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, collars and options to attempt to reduce the Company's exposure with respect to:

- crude oil purchases and sales;

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- fuel product sales and purchases;
- natural gas purchases; and
- fluctuations in the value of crude oil between geographic regions and in between the different types of crude oil such as NYMEX WTI, Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent ("Brent").

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

	December 31, 2013			December 31, 2012		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Derivative instruments designated as hedges:						
Fuel products segment:						
Crude oil swaps	$45.4	$(45.4)	$—	$24.9	$(14.4)	$10.5
Gasoline swaps	1.0	(1.0)	—	5.2	(4.9)	0.3
Diesel swaps	3.5	(3.5)	—	7.0	(14.9)	(7.9)
Jet fuel swaps	0.1	(0.1)	—	8.0	(7.8)	0.2
Total derivative instruments designated as hedges	50.0	(50.0)	—	45.1	(42.0)	3.1
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	6.3	(6.3)	—	0.1	(0.1)	—
Crude oil basis swaps	1.0	(1.0)	—	0.1	(0.1)	—
Gasoline swaps	—	—	—	—	—	—
Diesel swaps	0.7	(0.7)	—	5.1	(5.1)	—
Jet fuel swaps	0.9	(0.9)	—	—	—	—
Diesel crack spread collars	0.3	(0.3)	—	—	—	—
Specialty products segment:						

Crude oil swaps	—	—	—	1.6	(1.6)	—
Natural gas swaps	0.4	(0.4)	—	—	—	—
Total derivative instruments not designated as hedges	9.6	(9.6)	—	6.9	(6.9)	—
Total derivative instruments	$59.6	$(59.6)	$—	$52.0	$(48.9)	$3.1

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	December 31, 2013			December 31, 2012		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Derivative instruments designated as hedges:						
Fuel products segment:						
Crude oil swaps	$(13.0)	$45.4	$32.4	$(41.1)	$14.4	$(26.7)
Gasoline swaps	(19.7)	1.0	(18.7)	(2.8)	4.9	2.1
Diesel swaps	(51.3)	3.5	(47.8)	(25.2)	14.9	(10.3)
Jet fuel swaps	(13.4)	0.1	(13.3)	(10.1)	7.8	(2.3)
Total derivative instruments designated as hedges	(97.4)	50.0	(47.4)	(79.2)	42.0	(37.2)
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	(1.7)	6.3	4.6	(10.8)	0.1	(10.7)
Crude oil basis swaps	(0.6)	1.0	0.4	(3.5)	0.1	(3.4)
Gasoline swaps	(9.4)	—	(9.4)	(2.2)	—	(2.2)
Diesel swaps	(3.5)	0.7	(2.8)	(1.2)	5.1	3.9
Jet fuel swaps	—	0.9	0.9	—	—	—
Diesel crack spread collars	(0.2)	0.3	0.1	—	—	—
Specialty products segment:						
Crude oil swaps	—	—	—	—	1.6	1.6
Natural gas swaps	(1.6)	0.4	(1.2)	—	—	—
Total derivative instruments not designated as hedges	(17.0)	9.6	(7.4)	(17.7)	6.9	(10.8)
Total derivative instruments	$(114.4)	$59.6	$(54.8)	$(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 consolidated statements of operations upon recording the related hedged transaction in sales or cost of sales. 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, crude oil sales 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 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 consolidated balance sheets, until the underlying transaction hedged is recognized in the 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 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

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forecasted transaction will not occur, at which time, associated deferred amounts in accumulated other comprehensive income (loss) are immediately recognized in unrealized gain (loss) on derivative instruments.

Effective January 1, 2012, hedge accounting was discontinued prospectively for certain crude oil derivative instruments when it was determined that they were no longer highly effective in offsetting changes in the cash flows associated with crude oil purchases at the Company's Superior refinery due to the volatility in crude oil pricing differentials between heavy crude oil and NYMEX WTI. 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 consolidated statements of operations for the years ended December 31, 2013 and December 31, 2012 (in millions):

	Year Ended December 31,	
	2013	2012
Realized gain on derivative instruments	$0.2	$40.1
Unrealized loss on derivative instruments	$(3.9)	$(2.9)

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, caused the Company to recognize derivative losses of $1.7 million in realized gain (loss) on derivative instruments in the consolidated statements of operations for the year ended December 31, 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 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 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 consolidated balance sheets, consolidated statements of operations, consolidated statements of other comprehensive income (loss) and its consolidated statements of partners' capital as of, and for the years ended December 31, 2013 and 2012 related to its derivative instruments that were designated as cash flow hedges (in millions):

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Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Loss on Derivatives (Effective Portion) Year Ended December 31, 2013	2012	Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Effective Portion) Location of (Gain) Loss	Year Ended December 31, 2013	2012	Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion) Location of Gain (Loss)	Year Ended December 31, 2013	2012
Fuel products segment:								
Crude oil swaps	$18.7	$(100.0)	Cost of sales	$3.1	$49.8	Unrealized/Realized	$(3.0)	$99.7
Gasoline swaps	(19.5)	(16.0)	Sales	(0.4)	(38.4)	Unrealized/Realized	(1.7)	(52.0)
Diesel swaps	(28.8)	(59.3)	Sales	(4.4)	(63.0)	Unrealized/Realized	(5.3)	(10.5)
Jet fuel swaps	(7.3)	(39.8)	Sales	1.7	(104.4)	Unrealized/Realized	5.1	(0.1)
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	0.5	1.9	Unrealized/Realized	—	—
Total	$(36.9)	$(215.1)		$0.5	$(154.1)		$(4.9)	$37.1

The Company recorded the following gains (losses) in its consolidated statements of operations for the years ended December 31, 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 (Loss) on Derivatives Year Ended December 31, 2013	2012	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivatives Year Ended December 31, 2013	2012
Fuel products segment:				
Crude oil swaps	$(6.3)	$(30.5)	$46.3	$(40.0)
Crude oil basis swaps	(7.7)	2.1	3.8	(3.4)
Gasoline swaps	3.2	22.1	(9.9)	0.5
Diesel swaps	8.1	10.9	(11.7)	8.9
Jet fuel swaps	0.7	(1.7)	0.9	—
Diesel crack spread collars	—	—	0.1	—
Specialty products segment:				
Crude oil swaps	1.8	—	(1.6)	1.6
Natural gas swaps	(0.6)	(5.4)	(1.2)	3.2
Interest rate swaps:	—	(0.7)	—	1.0
Total	$(0.8)	$(3.2)	$26.7	$(28.2)

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 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 December 31, 2013, the Company had no counterparties in which derivatives held were net assets. 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 A- 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 December 31, 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 consolidated balance sheets and not netted against derivative assets or liabilities. As of December 31, 2013, the Company had provided its counterparties with no collateral. As of 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 is lowered below specified levels by Moody's and 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 December 31, 2013 there were no net positions associated with the Company's outstanding derivative instruments subject to such requirements. As of December 31, 2012, there was a net liability of $7.5 million, 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 loss was $51.4 million and $14.0 million as of December 31, 2013 and 2012, respectively. Absent a change in the fair market value of the underlying transactions, the following other comprehensive loss at December 31, 2013 will be reclassified to earnings by December 31, 2016 with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Loss
2014	$ (26.8)
2015	(22.3)
2016	(2.3)
Total	$ (51.4)

Based on fair values as of December 31, 2013, the Company expects to reclassify $26.8 million of net losses on derivative instruments from accumulated other comprehensive loss to earnings during the next 12 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 settlements.

Crude Oil Swap Contracts — Specialty Products Segment

As of December 31, 2013, the Company did not have any crude oil derivatives related to future crude oil purchases in its specialty products segment.

As of December 31, 2012, the Company had purchased a crude oil swap for 200,000 barrels in the second quarter of 2012 related to future crude oil purchases in its specialty products segment, which is not designated as a cash flow hedge. The Company subsequently sold a crude oil derivative swap in the third quarter of 2012, and the net impact of these two derivatives is a net gain of $1.6 million that has been recorded to unrealized loss 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 (loss) on derivative instruments in the consolidated statements of operations.

Natural Gas Swap Contracts

At December 31, 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:

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Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2014	750,000	$4.14
Second Quarter 2014	750,000	4.14
Third Quarter 2014	750,000	4.14
Fourth Quarter 2014	850,000	4.21
Calendar Year 2015	3,500,000	4.27
Calendar Year 2016	2,700,000	4.42
Calendar Year 2017	1,000,000	4.29
Total	10,300,000	
Average price		$4.28

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 December 31, 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.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2014	2,520,000	28,000	$92.06
Second Quarter 2014	2,411,500	26,500	91.97
Third Quarter 2014	2,530,000	27,500	91.23
Fourth Quarter 2014	2,024,000	22,000	90.61
Calendar Year 2015	5,556,500	15,223	89.08
Calendar Year 2016	1,830,000	5,000	84.73
Total	16,872,000		
Average price			$89.97

At December 31, 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)
First Quarter 2014	810,000	9,000	$94.56
Second Quarter 2014	591,500	6,500	94.37
Third Quarter 2014	874,000	9,500	92.92
Fourth Quarter 2014	184,000	2,000	94.62
Calendar Year 2015	1,004,000	2,751	89.28
Total	3,463,500		
Average price			$92.59

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2013, the Company had the following derivatives related to crude oil sales 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)
First Quarter 2014	45,000	500	$96.90
Second Quarter 2014	45,500	500	96.90
Third Quarter 2014	46,000	500	96.90
Fourth Quarter 2014	46,000	500	96.90
Total	182,500		
Average price			$96.90

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
Total	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.

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
Total	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 December 31, 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)
First Quarter 2014	118,000	1,311	$(28.50)
Third Quarter 2014	184,000	2,000	(21.75)
Fourth Quarter 2014	184,000	2,000	(21.50)

Total	486,000	
Average differential		$(23.29)

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As of December 31, 2013, the Company had approximately 248,000 barrels of crude oil basis swaps related to future crude oil purchases and sales to mitigate the risk of future changes in pricing differentials between Brent and NYMEX WTI on the Company's reselling of crude oil. The net impact of these derivative instruments, none of which are designated as cash flow hedges, was a net loss of $0.6 million that has been recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations for the year ended December 31, 2013. The net impact of these derivative instruments will be realized upon settlement in the first quarter of 2014 and will be recorded to realized gain (loss) on derivative instruments in the consolidated statements of operations.

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)
Total	912,000		
Average differential			$(25.20)

At December 31, 2012, the Company did not have any crude oil basis swaps related to future crude oil purchases and sales to mitigate the risk of future changes in pricing differentials between Brent and NYMEX WTI.

Fuel Products Swap Contracts

Diesel Swap Contracts

At December 31, 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)
First Quarter 2014	1,125,000	12,500	$117.54
Second Quarter 2014	1,183,000	13,000	116.78
Third Quarter 2014	1,288,000	14,000	116.82
Fourth Quarter 2014	1,288,000	14,000	116.96
Calendar Year 2015	4,781,500	13,100	115.81
Calendar Year 2016	1,830,000	5,000	112.00
Total	11,495,500		
Average price			$115.72

At December 31, 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.

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Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2014	270,000	3,000	$ 121.72
Second Quarter 2014	182,000	2,000	123.22
Third Quarter 2014	230,000	2,500	121.74
Fourth Quarter 2014	184,000	2,000	123.02
Calendar Year 2015	1,004,000	2,751	117.15
Total	1,870,000		
Average price			$ 119.54

At December 31, 2013, the Company had the following derivatives related to diesel purchases in its fuel products segment, none of which are designated as cash flow hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2014	45,000	500	$ 121.80
Second Quarter 2014	45,500	500	121.80
Third Quarter 2014	46,000	500	121.80
Fourth Quarter 2014	46,000	500	121.80
Total	182,500		
Average price			$ 121.80

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
Total	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
Total	1,456,000		
Average price			$ 127.20

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
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Jet Fuel Swap Contracts
At December 31, 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)
First Quarter 2014	450,000	5,000	$117.50
Second Quarter 2014	273,000	3,000	116.68
Third Quarter 2014	276,000	3,000	116.18
Fourth Quarter 2014	276,000	3,000	115.65
Calendar Year 2015	775,000	2,123	114.05
Total	2,050,000		
Average price			$115.66

At December 31, 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:

Jet Fuel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2014	90,000	1,000	$116.71
Total	90,000		
Average price			$116.71

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
Total	3,773,000		
Average price			$123.56

Gasoline Swap Contracts
At December 31, 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)
First Quarter 2014	945,000	10,500	$104.39
Second Quarter 2014	955,500	10,500	109.68
Third Quarter 2014	966,000	10,500	106.60
Fourth Quarter 2014	460,000	5,000	104.85
Total	3,326,500		
Average price			$106.61

At December 31, 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.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2014	630,000	7,000	$105.67
Second Quarter 2014	409,500	4,500	110.48
Third Quarter 2014	644,000	7,000	108.24
Total	1,683,500		
Average price			$107.82

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
Total	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.

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
Total	365,000		
Average price			$105.50

Diesel Crack Spread Collars

At December 31, 2013, the Company had the following diesel crack spread collars related to diesel sales and crude oil purchases in its fuel products segment, none of which are designated as hedges.

Diesel Crack Spread Collars by Expiration Dates	Barrels Purchased and Sold	BPD	Average Bought Put ($/Bbl)	Average Sold Call ($/Bbl)
First Quarter 2014	90,000	1,000	$26.00	$35.00
Second Quarter 2014	91,000	1,000	26.00	35.00
Third Quarter 2014	92,000	1,000	26.00	35.00
Fourth Quarter 2014	92,000	1,000	26.00	35.00
Total	365,000			
Average price			$26.00	$35.00

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

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- 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 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 A- by Moody’s and S&P, respectively.

To estimate the fair values of the Company’s derivative instruments, the Company uses the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. Various analytical tests are performed to validate the counterparty data. The fair values of the Company’s derivative instruments are adjusted for nonperformance risk and credit worthiness of the hedging entities through the Company’s credit valuation adjustment (“CVA”). The CVA is calculated at the counterparty level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. The Company uses the counterparty’s marginal default rate and the Company’s survival rate when the Company is in a net asset position at the payment date and uses the Company’s marginal default rate and the counterparty’s survival rate when the Company is in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2013, the net liability of the Company was reduced by approximately $1.9 million. As a result of applying the CVA at December 31, 2012, the Company’s net asset was reduced by approximately $0.1 million and the net liability was reduced by approximately $0.2 million.

Observable inputs utilized to estimate the fair values of the Company’s derivative instruments were primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, 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 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.

Pension Assets

Pension assets are reported at fair value in the accompanying consolidated financial statements. At December 31, 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 12 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 Liability Awards are categorized as Level 1 because the fair value of the Company's Liability Awards are based on the Company's quoted closing unit price as of each balance sheet date. See Note 11 for further information on Liability Awards.

Renewable Identification Numbers Obligation

The Company's 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

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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 December 31, 2013 and December 31, 2012 were as follows (in millions):

	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$—	$—	$—	$—	$10.5	$10.5
Gasoline swaps	—	—	—	—	—	—	0.3	0.3
Diesel swaps	—	—	—	—	—	—	(7.9)	(7.9)
Jet fuel swaps	—	—	—	—	—	—	0.2	0.2
Total derivative assets	—	—	—	—	—	—	3.1	3.1
Pension plan investments	—	45.8	—	45.8	38.9	2.7	—	41.6
Total recurring assets at fair value	$—	$45.8	$—	$45.8	$38.9	$2.7	$3.1	$44.7
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$37.0	$37.0	$—	$—	$(35.8)	$(35.8)
Crude oil basis swaps	—	—	0.4	0.4	—	—	(3.4)	(3.4)
Gasoline swaps	—	—	(28.1)	(28.1)	—	—	(0.1)	(0.1)
Diesel swaps	—	—	(50.6)	(50.6)	—	—	(6.4)	(6.4)
Jet fuel swaps	—	—	(12.4)	(12.4)	—	—	(2.3)	(2.3)
Diesel crack spread collars	—	—	0.1	0.1	—	—	—	—
Natural gas swaps	—	—	(1.2)	(1.2)	—	—	—	—
Total derivative liabilities	—	—	(54.8)	(54.8)	—	—	(48.0)	(48.0)
RINs Obligation	—	(5.3)	—	(5.3)	—	(0.8)	—	(0.8)
Liability Awards	(3.7)	—	—	(3.7)	(2.2)	—	—	(2.2)
Total recurring liabilities at fair value	$(3.7)	$(5.3)	$(54.8)	$(63.8)	$(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 year ended December 31, 2013 and 2012 (in millions):

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	Derivative Instruments, Net For the Year Ended December 31,	
	2013	2012
Fair value at January 1,	$(44.9)	$14.9
Realized (gain) loss on derivative instruments	4.7	(9.5)
Unrealized gain (loss) on derivative instruments	25.7	(3.8)
Change in fair value of cash flow hedges	(36.9)	(215.1)
Settlements	(3.4)	168.6
Transfers in (out) of Level 3	—	—
Fair value at December 31,	$(54.8)	$(44.9)
Total gain (loss) included in net income attributable to changes in unrealized gain (loss) relating to financial assets and liabilities held as of December 31,	$25.7	$(3.8)

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 and cost of sales for crude oil derivatives in the consolidated statements of operations in the period that the hedged cash flow occurs. Any “ineffectiveness” associated with these derivative instruments are recorded in earnings in realized gain (loss) on derivative instruments in the consolidated statements of operations. All settlements from derivative instruments not designated as cash flow hedges are recorded in realized gain (loss) on derivative instruments in the 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 Company’s 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 consolidated financial statements. See Note 5 for further information on goodwill.

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including definite-lived intangible assets, indefinite-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 was required to measure and record such assets at fair value within its consolidated financial statements. See Note 2 and Note 5 for further information on long-lived assets.

Estimated Fair Value of Financial Instruments

Cash

The carrying value of cash is considered to be representative of its fair value.

Debt

The estimated fair value of long-term debt at December 31, 2013 and 2012 consists primarily of senior notes. The estimated aggregate fair value of the Company’s senior notes classified as Level 1 were based upon quoted market prices in an active market. The estimated aggregate fair value of the Company’s senior notes classified as Level 2 were based upon directly observable inputs. The carrying value of borrowings, if any, under the Company’s revolving credit facility and 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 December 31, 2013 and December 31, 2012 were as follows (in millions):

		December 31, 2013		December 31, 2012	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$863.6	$ 761.2	$658.8	$ 587.6
Senior notes	2	$353.9	$ 344.8	$301.8	$ 270.4
Revolving credit facility	3	$—	$ —	$—	$ —
Capital lease obligations	3	$4.8	$ 4.8	$5.5	$ 5.5

10. Partners' Capital

Units Outstanding

Of the 69,317,278 common units outstanding at December 31, 2013, 51,152,727 common units were held by the public, with the remaining 18,164,551 common units held by the Company's affiliates.

Significant information regarding rights of the limited partners includes the following:

- Rights to receive distributions of available cash within 45 days after the end of each quarter, to the extent the Company has sufficient cash from operations after the establishment of cash reserves.
- Limited partners have limited voting rights on matters affecting the Company's business. The general partner may consider only the interests and factors that it desires and has no duty or obligation to give any consideration of any interests of the Company's limited partners. Limited partners have no right to elect the board of directors of the Company's general partner.
- The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. Any holder, other than the general partner or the general partner's affiliates, that owns 20% or more of any class of units outstanding cannot vote on any matter.
- The Company may issue an unlimited number of limited partner interests without the approval of the limited partners.
- Limited partners may be required to sell their units to the general partner if at any time the general partner owns more than 80% of the issued and outstanding common units.

Distributions and Incentive Distribution Rights

The Company's general partner is entitled to incentive distributions if the amount it distributes to unitholders with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Per Common Unit Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98 %	2 %
First Target Distribution	up to $0.495	98 %	2 %
Second Target Distribution	above $0.495 up to $0.563	85 %	15 %
Third Target Distribution	above $0.563 up to $0.675	75 %	25 %
Thereafter	above $0.675	50 %	50 %

The Company's ability to make distributions is limited by its debt instruments. The revolving credit facility generally permits the Company to make cash distributions to unitholders as long as immediately after giving effect to such a cash distribution the Company has availability under the revolving credit facility at least equal to the greater of (i) 15% of the lesser of (a) the Borrowing Base (as defined in the revolving credit agreement) without giving effect to the LC Reserve (as defined in the revolving credit agreement) and (b) the revolving credit facility commitments then in effect and (ii) $45.0 million. The indentures governing the 2019 Notes, 2020 Notes and 2022 Notes provide that if the Company's fixed charge coverage ratio (as defined in the indentures) for the most recently ended four full fiscal quarters is not less than 1.75 to 1.0, the Company will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in the Company's partnership agreement) with respect to its preceding fiscal quarter, subject to certain customary adjustments described in the indentures. If the Company's fixed charge coverage ratio is less than 1.75 to 1.0, the Company will be able to pay distributions to its unitholders up to an amount equal to (i) a $70.0 million basket for the 2019 Notes, (ii) a $120.0 million basket for the 2020 Notes and (iii) a $210.0 million basket for the 2022 Notes, subject to certain customary adjustments described in the indentures.

The Company's distribution policy is as defined in its partnership agreement. For the years ended December 31, 2013, 2012 and 2011, the Company made distributions of $201.6 million, $132.4 million and $82.7 million, respectively, to its partners. For the years ended December 31, 2013, 2012 and 2011, the general partner was allocated $14.7 million, $5.5 million and $0.2 million, respectively, in incentive distribution rights.

Subordinated Unit Conversion

In February 2011, the Company satisfied the last of the earnings and distributions tests contained in its partnership agreement for the automatic conversion of all 13,066,000 outstanding subordinated units into common units on a one-for-one basis. The last of these requirements was met upon payment of the quarterly distribution paid on February 14, 2011. Two days following this quarterly distribution to unitholders, or February 16, 2011, all of the outstanding subordinated units automatically converted to common units.

Public Offerings of Common Units

During 2013, 2012 and 2011, the Company completed the following public offerings of its common units (in millions except unit and per unit data):

Closing Date	Number of Common Units Offered		Price per Unit	Net Proceeds (1)	General Partner Contribution (2)	Underwriting Discount	Use of Proceeds
February 24, 2011	4,500,000		$21.45	$92.3	$2.0	$ 3.9	Net proceeds were used to repay borrowings under the revolving credit facility.
September 8, 2011	11,750,000	(3)	$18.00	$202.4	$4.3	$ 8.4	Net proceeds were used to fund a portion of the purchase price of the Superior acquisition and repay borrowings under the revolving credit facility.
May 8, 2012	6,000,000		$25.50	$146.6	$3.1	$ 6.2	Net proceeds were used to repay borrowings under the revolving credit facility.
January 8, 2013	5,750,000	(4)	$31.81	$175.2	$3.8	$ 7.4	Net proceeds were used to repay borrowings under the revolving credit facility and for general partnership purposes.
April 1, 2013	6,037,500	(5)	$37.50	$217.3	$4.6	$ 9.1	Net proceeds were used for general partnership purposes.

(1) Proceeds are net of underwriting discounts, commissions and expenses but before its general partner's capital contribution.

(2) The Company's general partner contributions were made to retain its 2% general partner interest.

(3)

Includes the partial exercise of the overallotment option of 750,000 common units which closed on October 13, 2011.

(4) Includes the full exercise of the overallotment option of 750,000 common units which closed concurrently with the 5,000,000 firm units on January 8, 2013.

(5) Includes the full exercise of the overallotment option of 787,500 common units which closed on April 4, 2013.

11. Unit-Based Compensation

The Company's general partner originally adopted a Long-Term Incentive Plan on January 24, 2006, which was amended and restated effective January 22, 2009, for its employees, consultants and directors and its affiliates who perform services for the Company. The Long-Term Incentive Plan provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights ("DERs").

Subject to adjustment for certain events, an aggregate of 783,960 common units may be delivered pursuant to awards under the Long-Term Incentive Plan. Units withheld to satisfy the Company's general partner's tax withholding obligations are available for delivery pursuant to other awards. The Long-Term Incentive Plan is administered by the compensation committee of the Company's general partner's board of directors.

Non-employee directors of the Company's general partner have been granted phantom units under the terms of the Long-Term Incentive Plan as part of their director compensation package related to fiscal years 2011, 2012 and 2013. These phantom units have a four year service period with one-quarter of the phantom units vesting annually on each December 31 of the vesting period. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest, the recipients have DERs on these phantom units from the date of grant.

For the year ended December 31, 2012, named executive officers and certain employees were awarded phantom units under the terms of the Long-Term Incentive Plan, as part of the Company's achievement of specified levels of financial performance in the fiscal year. These phantom units are subject to time-vesting requirements whereby 25% of the units vest during the performance period, and the remainder will vest ratably over the next three years on each December 31. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest, the recipients have DERs on these phantom units from the date of grant.

The Company uses the market price of its common units on the grant date to calculate the fair value and related compensation cost of the phantom units. The Company amortizes this compensation cost to partners' capital and general and administrative expense in the consolidated statements of operations using the straight-line method over the service period, as it expects these units to fully vest.

Liability Awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units. Phantom unit Liability Awards are recorded in accrued salaries, wages and benefits in the consolidated balance sheets based on the vested portion of the fair value of the awards on the balance sheet date. The fair value of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to compensation expense within general and administrative expense in the consolidated statements of operations.

A summary of the Company's nonvested phantom units as of December 31, 2013, and the changes during the years ended December 31, 2013, 2012 and 2011, are presented below:

	Number of Phantom Units		Weighted-Average Grant Date Fair Value
Non-vested at January 1, 2011	105,492		$17.68
Granted	640,875		20.26
Vested	(183,671	)	20.29
Forfeited	—		—
Non-vested at December 31, 2011	562,696		$19.77
Granted	616,997		26.69
Vested	(286,976	)	21.16
Forfeited	(56,790	)	20.00
Non-vested at December 31, 2012	835,927		$27.57
Granted	483,044		27.73
Vested	(276,115	)	24.22
Forfeited	(354,600	)	30.60
Non-vested at December 31, 2013	688,256		$23.70

For the years ended December 31, 2013, 2012 and 2011, compensation expense of $4.8 million, $4.6 million and $3.0 million, respectively, was recognized in the consolidated statements of operations related to vested phantom unit grants, including $1.6 million and $2.2 million, attributable to Liability Awards for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, there was a total of $16.3 million and $23.0 million, respectively of unrecognized compensation costs related to nonvested phantom unit grants, including $12.4 million and $16.1 million, attributable to Liability Awards for the years ended December 31, 2013 and 2012, respectively. These costs are expected to be recognized over a weighted-average period of approximately two years. The total fair value of phantom units vested during the years ended December 31, 2013 and 2012, was $6.7 million and $6.1 million, respectively.

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12. Employee Benefit Plans

Defined Contribution Plan

The Company has a domestic defined contribution plan administered by its general partner for (i) all full-time employees that are eligible to participate in the plan ("401(k) Plan"). Participants in the 401(k) Plan are allowed to contribute 1% to 70% of their pre-tax earnings to the plan, subject to government imposed limitations. The Company matches 100% of each 1% of eligible compensation contributed by the participant up to 4% and 50% of each additional 1% of eligible compensation contributed up to 6%, for a maximum contribution by the Company of 5% of eligible compensation contributed per participant. The plan also includes a profit-sharing component for eligible employees. Contributions under the profit-sharing component are determined by the board of directors of the Company's general partner and are discretionary. The funding policy is consistent with funding requirements of applicable laws and regulations.

The Company recorded the following 401(k) Plan matching contribution and profit sharing expenses in the consolidated statement of operations for the years ended December 31, 2013, 2012 and 2011 (in millions):

	Year Ended December 31,		
	2013	2012	2011
401(k) Plan matching contribution expense	$4.1	$3.2	$2.3
Profit sharing expense	0.9	2.5	1.4

Defined Pension Plan

The Company has domestic noncontributory defined benefit plans for those salaried employees as well as those employees represented by either the United Steelworkers ("USW") or the International Union of Operating Engineers ("IUOE"); who (i) were formerly employees of Penreco and became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 ("Penreco Pension Plan"), (ii) were formerly employees of Murphy Oil represented by the IUOE and who became employees of the Company as a result of the Superior Acquisition on September 30, 2011 (the "Superior Pension Plan") or (iii) were formerly employees of Montana Refining and who became employees of the Company as a result of the Montana Acquisition on October 1, 2012 (the "Montana Pension Plan" and together with the Penreco Pension Plan and the Superior Pension Plan, the "Pension Plan"). During 2013, the Company made contributions of $3.4 million to its Pension Plan and expects to make contributions in 2014 of approximately $1.6 million to its Pension Plan.

Under the Penreco Pension Plan, benefits are based primarily on years of service for USW and IUOE represented employees and the employee's final 60 months' average compensation for salaried employees. In 2009, the Company amended the Penreco Pension Plan, which curtailed Penreco employees from accumulating additional benefits subsequent to December 31, 2009.

Under the Superior Pension Plan, benefits are based primarily on years of service for IUOE represented employees and the employee's three highest consecutive calendar years within the last 10 years of service. Effective July 1, 2012, the Company amended the Superior Pension Plan, which curtailed Superior employees from accumulating additional benefits subsequent to December 31, 2012. For the year ended December 31, 2012, the Company recorded a $0.2 million curtailment gain.

Under the Montana Pension Plan, benefits are based primarily on years of service and the employees' 36 months' highest average compensation for salaried employees. Effective October 1, 2012, the date of the Montana Acquisition, the Company amended the Montana Pension Plan, which curtailed only the Montana salaried employees from accumulating additional benefits subsequent to October 31, 2012.

Defined Benefit Other Plans

The Company also has domestic contributory defined benefit post retirement medical plans and contributory life insurance plans for (i) those salaried employees, as well as those employees represented by either the International Brotherhood of Teamsters ("IBT"), USW or IUOE, who were formerly employees of Penreco and who became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 ("Penreco Other Plan") or (ii) employees represented by the IUOE, who were formerly employees of Murphy Oil and who became employees of the Company as a result of the Superior acquisition on September 30, 2011 ("Superior Other Plan" and together with the Penreco Other Plan, the "Other Plan"). The funding policy is consistent with funding requirements of applicable laws and regulations.

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Effective 2009, the Company amended the Penreco Other Plan, which curtailed employees from accumulating additional benefits subsequent to February 29, 2009. Effective July 1, 2012, the Company amended the Superior Other Plan, which curtailed Superior employees from accumulating additional benefits subsequent to December 31, 2012. For the year ended December 31, 2012, the Company recorded a $7.0 million curtailment gain.

All information presented below has been adjusted for these curtailments for the Pension Plan and Other Plan. The change in the benefit obligations, change in the plan assets, funded status and amounts recognized in the consolidated balance sheets were as follows (in millions):

	Year Ended December 31,			
	2013		2012	
	Pension Plan	Other Plan	Pension Plan	Other Plan
Change in projected benefit obligation:				
Benefit obligation at beginning of year	$65.3	$0.3	$55.3	$7.7
Projected benefit obligation attributable to acquisitions	—	—	4.9	—
Service cost	0.4	—	1.1	0.3
Interest cost	2.4	—	2.4	0.2
Plan curtailments	—	—	(3.7)	(7.9)
Benefits paid	(2.3)	—	(2.6)	(0.1)
Actuarial (gain) loss	(8.5)	—	7.9	0.1
Administrative expense	(0.1)	—	—	—
Plan amendments	—	—	—	(0.1)
Employee contributions	—	—	—	0.1
Benefit obligation at end of year	$57.2	$0.3	$65.3	$0.3
Change in plan assets:				
Fair value of plan assets at beginning of year	$41.6	$—	$36.0	$—
Fair value of pension assets attributable to acquisitions	—	—	3.2	—
Benefit payments	(2.3)	—	(2.6)	(0.1)
Actual return on assets	3.2	—	1.9	—
Administrative expense	(0.1)	—	—	—
Employee contributions	—	—	—	0.1
Employer contribution	3.4	—	3.1	—
Fair value of plan assets at end of year	$45.8	$—	$41.6	$—
Funded status — benefit obligation in excess of plan assets	$(11.4)	$(0.3)	$(23.7)	$(0.3)
Reconciliation of amounts recognized in the consolidated balance sheets:				
Accrued benefit obligation, long-term	$(11.4)	$(0.3)	$(23.7)	$(0.3)
Prior service credit	—	(0.2)	—	(0.2)
Unrecognized net actuarial (gain) loss	2.3	(0.2)	11.9	(0.2)
Accumulated other comprehensive (income) loss	2.3	(0.4)	11.9	(0.4)
Net amount recognized at end of year	$(9.1)	$(0.7)	$(11.8)	$(0.7)

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The accumulated benefit obligation for the Pension Plan was $56.7 million and $63.4 million as of December 31, 2013 and 2012, respectively. Selected information for the Company’s pension plans with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31,	
	2013	2012
Accumulated benefit obligation	$52.9	$63.4
Fair value of plan assets	41.8	41.6

Selected information for the Company’s Pension Plan with projected benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31,	
	2013	2012
Projected benefit obligation	$57.2	$65.3
Fair value of plan assets	$45.8	$41.6

The components of net periodic pension cost and other post retirement benefits cost (income) for 2013, 2012 and 2011 were as follows (in millions):

	Pension Plan Year Ended December 31,			Other Plan Year Ended December 31,		
	2013	2012	2011	2013	2012	2011
Service cost	$0.4	$1.1	$0.3	$—	$0.3	$0.1
Interest cost	2.4	2.4	1.6	—	0.2	0.1
Expected return on assets	(2.9)	(1.7)	(1.2)	—	—	—
Amortization of net loss	0.8	0.6	0.2	—	—	—
Curtailment gain recognized	—	(0.2)	—	—	(7.0)	—
Settlement gain recognized	—	—	—	—	(0.2)	—
Net periodic benefit cost (income)	$0.7	$2.2	$0.9	$—	$(6.7)	$0.2

The components of changes recognized in other comprehensive (income) loss for the Pension Plan and Other Plan for 2013, 2012 and 2011 were as follows (in millions):

	Pension Plan Year Ended December 31,			Other Plan Year Ended December 31,		
	2013	2012	2011	2013	2012	2011
Changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net (gain) loss	$(8.8)	$4.3	$3.3	$—	$0.1	$0.6
New prior service cost	—	—	—	—	(0.1)	—
Amounts recognized as a component of net periodic benefit cost:						
Amortization or settlement recognition of net loss	(0.8)	(0.6)	(0.2)	—	(0.8)	—
Amortization or curtailment recognition of prior service credit	—	—	—	—	0.1	—
	$(9.6)	$3.7	$3.1	$—	$(0.7)	$0.6

Total recognized in other
comprehensive (income) loss

The portion relating to the Pension Plan and Other Plan classified in accumulated other comprehensive loss is $1.9 million and $11.5 million as of December 31, 2013 and 2012, respectively. In 2014, the estimated amount that will be amortized from accumulated other comprehensive loss includes a net loss of $0.3 million for the Pension Plan.

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All pension and other post retirement plans have a December 31 measurement date. The significant weighted average assumptions used to determine the benefit obligations for the years ended December 31, 2013 and 2012 were as follows:

	Benefit Obligations Assumptions			
	2013		2012	
Pension Plan:				
Discount rate for Penreco Pension Plan	4.78	%	3.86	%
Discount rate for Superior Pension Plan	4.66	%	3.75	%
Discount rate for Montana Pension Plan	4.97	%	4.03	%
Rate of compensation increase for Montana Pension Plan	3.00	%	3.00	%
Other Plan:				
Discount rate for Penreco Other Plan	4.29	%	3.33	%
Immediate trend rate for Penreco Other Plan (1)	7.50	%	7.70	%
Ultimate trend rate for Penreco Other Plan (1)	4.50	%	4.50	%
Year that the rate reaches ultimate trend rate for Penreco Other Plan (1)	2029		2029	

(1) For measurement purposes, an annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease by 0.20% per year for an ultimate rate of 4.50% in 2029 for the Penreco Other Plan and remain at that level thereafter.

The significant weighted average assumptions used to determine the net periodic benefit cost (income) for the years ended December 31, 2013 and 2012 were as follows:

	Net Periodic Benefit Cost (Income) Assumptions					
	2013		2012		2011	
Pension Plan:						
Discount rate for Penreco Pension Plan	3.86	%	4.63	%	5.50	%
Discount rate for Superior Pension Plan	3.75	%	4.55	%	4.71	%
Discount rate for Montana Pension Plan	4.03	%	3.89	%	N/A	
Expected return on plan assets for Penreco Pension Plan (1)	6.75	%	6.00	%	6.50	%
Expected return on plan assets for Superior Pension Plan (1)	6.75	%	3.00	%	6.50	%
Expected return on plan assets for Montana Pension Plan (1)	6.75	%	6.00	%	N/A	
Rate of compensation increase for Superior Pension Plan	N/A		3.75	%	3.75	%
Rate of compensation increase for Montana Pension Plan	3.00	%	3.00	%	N/A	
Other Plan:						
Discount rate for Penreco Other Plan	3.33	%	4.04	%	4.54	%
Discount rate for Superior Other Plan	N/A		4.65	%	4.82	%
Immediate trend rate (2)	7.70	%	8.00	%	8.20	%
Ultimate trend rate for Penreco Other Plan (2)	4.50	%	4.50	%	4.50	%
Ultimate trend rate for Superior Other Plan (2)	N/A		4.50	%	5.00	%
Year that the rate reaches ultimate trend rate for Penreco Other Plan (2)	2029		2029		2029	
Year that the rate reaches ultimate trend rate for Superior Other Plan (2)	N/A		2029		2020	

(1) The Company considered the historical returns and the future expectation for returns for each asset class, as well as the target asset allocation of the Pension Plan portfolio which was developed in accordance with the Company's Statement of Investment Policy, to develop the expected long-term rate of return on plan assets.

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(2) For measurement purposes, an annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease by 0.20% per year for an ultimate rate of 4.50% for 2029 for the Penreco Other Plan and remain at that level thereafter.

An increase or decrease by one percentage point in the assumed healthcare cost trend rates would have less than $0.1 million effect on the post retirement benefit obligation and service and interest cost components of benefit costs for the Other Plan as of December 31, 2013.

Investment Policy

The Defined Benefit Plan Investment Committee (the "Committee") is responsible for the overall management of the Pension Plan assets, whose responsibilities encompass establishing the investment strategies and policies, monitoring the management of plan assets, reviewing the asset allocation mix on a regular basis, monitoring the performance of the Pension Plan assets to determine whether the investments objectives are met and guidelines followed and taking the appropriate action if objectives are not followed. The Company uses different investment managers with various asset management objectives to eliminate any significant concentration of risk. The Committee believes there are no significant concentrations of risks associated with the investment assets. The Company's investment manager will assist in the continual assessment of assets and the potential reallocation of certain investments and will evaluate the selection of investment managers for the Pension Plan assets based on such factors as organizational stability, depth of resources, experience, investment strategy and process, performance expectations and fees.

Long-term strategic investment objectives utilize a diversified mix of equity and fixed income securities to preserve the funded status of the trusts, and balance risk and return in relationship to the respective liabilities. The primary investment strategy currently employed is a dynamic de-risking strategy that periodically rebalances among various investment categories depending on the current funded position and maximizes the effectiveness of the Pension Plan asset allocation strategy. This program is designed to actively move from return-seeking investments (such as equities) toward liability-hedging investments (such as fixed income) as funding levels improve.

Effective June 2013, all of the Pension Plan assets were invested in a Master Trust. Trust assets in the Pension Plan are invested subject to the policy restriction that the average quality of the fixed income portfolio must be rated at least investment grade by both Moody's and S&P. These assets are invested in accordance with prudent expert standards as mandated by the Employee Retirement Income Security Act ("ERISA"). The Pension Plan's target asset allocation is currently comprised of the following:

Asset Class	Range of Asset Allocation	Target Allocation	
Domestic equities	0 — 50%	25	%
Foreign equities	0 — 50%	25	%
Fixed income	50 — 100%	50	%

Investment Fund Strategies

Domestic equities 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.

The Company’s Pension Plan asset allocations, as of December 31, 2013 and 2012 by asset category, are as follows:

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	2013		2012	
Cash and cash equivalents (1)	—	%	46	%
Domestic equities	23	%	14	%
Foreign equities	23	%	6	%
Fixed income	54	%	20	%
Commingled fund	—	%	7	%
Balanced fund	—	%	7	%
	100	%	100	%

(1) The Superior Pension Plan assets were included in cash and cash equivalents in 2012 and such assets were invested in 2013 based upon the current investment policy.

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

	Fair Value of Pension Assets at December 31,			
	2013		2012	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$—	$—	$19.3	$—
Domestic equities	—	10.6	5.9	—
Foreign equities	—	10.6	2.3	—
Fixed income	—	24.6	8.4	—
Commingled fund	—	—	—	2.7
Balanced fund	—	—	3.0	—
	$—	$45.8	$38.9	$2.7

The following benefit payments for the Pension Plans, which reflect expected future service, as appropriate, are expected to be paid in the years indicated as of December 31, 2013 (in millions):

	Pension Benefits
2014	$2.5
2015	2.6
2016	2.7
2017	2.8
2018	3.0
2019 to 2023	17.1
Total	$30.7

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13. Accumulated Other Comprehensive Loss

The table below sets forth a summary of changes in accumulated other comprehensive loss by component for the year ended December 31, 2013 (in millions):

	Derivatives	Defined Benefit Pension And Retiree Health Benefit Plans	Foreign Currency Translation Adjustment	Total
Accumulated other comprehensive loss at December 31, 2012	$(14.0)	$(11.5)	$—	$(25.5)
Other comprehensive income (loss) before reclassifications	(36.9)	8.8	(0.1)	(28.2)
Amounts reclassified from accumulated other comprehensive loss	(0.5)	0.8	—	0.3
Net current period other comprehensive income (loss)	(37.4)	9.6	(0.1)	(27.9)
Accumulated other comprehensive loss at December 31, 2013	$(51.4)	$(1.9)	$(0.1)	$(53.4)

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive loss in the Company’s consolidated statements of operations for the year ended December 31, 2013 (in millions):

Components of Accumulated Other Comprehensive Loss	Amount Reclassified From Accumulated Other Comprehensive Loss	Location of Gain (Loss)
Derivative gains (losses) reflected in gross profit		
	$(3.1)	Sales
	3.6	Cost of sales
	$0.5	Total
Amortization of defined benefit pension benefit plans:		
Amortization of net loss	$(0.8)	(1)
	$(0.8)	Total

(1) This accumulated other comprehensive loss component is included in the computation of net periodic pension cost. See Note 12 for additional information.

14. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended December 31, 2013, 2012 and 2011 (in millions, except unit and per unit data):

	Year Ended December 31,		
	2013	2012	2011
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$3.5	$205.7	$43.0
Less:			
General partner's interest in net income	0.1	4.1	0.9
General partner's incentive distribution rights	14.7	5.5	0.2
Nonvested share based payments	0.2	1.1	—
Net income (loss) available to limited partners	$(11.5)	$195.0	$41.9
Denominator for basic and diluted earnings per limited partner unit:			
Basic weighted average limited partner units outstanding	67,938,784	55,559,183	42,598,876
Effect of dilutive securities:			
Participating securities — phantom units	—	117,558	45,210
Diluted weighted average limited partner units outstanding (1)	67,938,784	55,676,741	42,644,086
Limited partners' interest basic net income (loss) per unit	$(0.17)	$3.51	$0.98
Limited partners' interest diluted net income (loss) per unit	$(0.17)	$3.50	$0.98

(1) Total diluted weighted average limited partner units outstanding excludes 0.2 million potentially dilutive phantom units for the year ended December 31, 2013.

15. Transactions with Related Parties

During the years ended December 31, 2013, 2012 and 2011, the Company had product sales to related parties owned by a limited partner of $9.7 million, $9.3 million and $16.5 million, respectively. Trade accounts and other receivables from related parties at December 31, 2013 and 2012 were $0.2 million and $0.1 million, respectively. The Company also had purchases from related parties owned by a limited partner, excluding crude purchases related to the Legacy Resources Co., L.P. ("Legacy Resources") and director's and officers' liability insurance premiums discussed below, during the years ended December 31, 2013, 2012 and 2011 of $9.0 million, $7.2 million and $1.8 million, respectively. Accounts payable to related parties, excluding accounts payable related to the Legacy Resources agreements discussed below, at December 31, 2013 and 2012 were $4.3 million and $2.2 million, respectively.

Legacy Resources is owned in part by one of the Company's limited partners, an affiliate of the Company's general partner, the Company's chief executive officer and vice chairman of the board of the Company's general partner, F. William Grube, and the Company's president and chief operating officer, Jennifer G. Straumins.

From May 2008 to May 2011, the Company purchased all of its crude oil requirements for its Princeton refinery on a just in time basis utilizing a market-based pricing mechanism from Legacy Resources (the "Legacy Princeton Agreement"). In addition, in January 2009, the Company entered into an agreement with Legacy Resources to begin purchasing certain of its crude oil requirements for its Shreveport refinery utilizing a market-based pricing mechanism from Legacy Resources (the "Master Crude Oil Purchase and Sale Agreement"). In September 2009, the Company entered into a crude oil supply agreement with Legacy Resources (the "Legacy Shreveport Agreement"). Under the Legacy Shreveport Agreement, Legacy Resources supplied the Company's Shreveport refinery with a portion of its crude oil requirements on a just in time basis utilizing a market-based pricing mechanism.

On May 31, 2011, the Company terminated the Legacy Princeton Agreement and the Legacy Shreveport Agreement and did not incur any material early termination penalties in connection with their termination. With the termination of these agreements, the Company has one remaining crude oil supply agreement with Legacy Resources, the Master Crude Oil Purchase and Sale Agreement. No crude oil is currently being purchased by the Company under this agreement. During the years ended December 31, 2013 and 2012 and 2011, the Company had crude oil purchases of

$1.2 million, $1.1 million and $229.8 million, respectively, from Legacy Resources. Accounts payable to Legacy Resources at December 31, 2013 and 2012 were $0.1 million and $0.1 million, respectively.

Nicholas J. Rutigliano, a member of the board of directors of the Company's general partner, founded Tobias Insurance Group, Inc. ("Tobias"), a commercial insurance brokerage business, which was acquired by Assured Partners, LLC. Mr. Rutigliano continues to serve as president of Tobias. Tobias has historically placed the Company's directors' and officers' liability insurance. The total premiums paid to Tobias by the Company for the years ended December 31, 2013, 2012 and 2011 were $0.7 million, $0.5 million and $0.6 million, respectively. With the exception of its directors' and officers' liability insurance which were placed with this commercial insurance brokerage company, the Company placed its insurance requirements with third parties during the years ended December 31, 2013, 2012 and 2011.

16. Segments and Related Information

a. Segment Reporting

The Company manages its business in multiple operating segments, which are grouped on the basis of similar product, market and operating factors into the following reportable segments:

- Specialty Products. The Specialty Products segment produces a variety of lubricating oils, solvents, waxes, synthetic lubricants and other products which are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. Specialty products also include synthetic lubricants used in manufacturing, mining and automotive applications.
- Fuel Products. The Fuel Products segment produces primarily gasoline, diesel fuel, jet fuel and asphalt which are primarily sold to customers located in PADD 2, PADD 3 and PADD 4 areas within the U.S.

During the fourth quarter 2013, the Company realigned its reportable segments for financial reporting purposes as a result of significant growth in the Company. The change primarily represents reporting the operating results of asphalt produced at the Shreveport, Superior and Montana refineries within the fuel products segment. Prior to this change, asphalt was reported as part of the specialty products segment. While this reporting change did not impact the Company's consolidated results, segment data for previous years has been restated and is consistent with the current year presentation throughout the financial statements and the accompanying notes.

The accounting policies of the reporting segments are the same as those described in Note 2, except that the disaggregated financial results for the reporting segments have been prepared using a management approach, which is consistent with the basis and manner in which management internally disaggregates financial information for the purposes of assisting internal operating decisions. The Company evaluates performance based upon Adjusted EBITDA. The Company defines 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.

Through September 30, 2013, the Company's management believed that income from operations was a meaningful measure of performance and it was used by management to analyze the Company and stand-alone operating segment performance. During the fourth quarter 2013, the Company's management determined that Adjusted EBITDA is the key performance measure for planning and forecasting purposes and discontinued the use of income from operations as a measure of performance. Segment Adjusted EBITDA should not be considered a substitute for results prepared in accordance with U.S. GAAP and should not be considered alternatives to net income, which is the most directly comparable financial measure to Adjusted EBITDA that is in accordance with U.S. GAAP. Segment Adjusted EBITDA, as determined and measured by the Company, should also not be compared to similarly titled measures reported by other companies.

The Company manages its assets on a total company basis, not by segment. Therefore, management does not review any asset information by segment and, accordingly, the Company does not report asset information by segment.

Reportable segment information is as follows (in millions):

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Year Ended December 31, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,774.9	$3,646.5	$5,421.4	$—	$5,421.4
Intersegment sales	—	77.3	77.3	(77.3)	—
Total sales	$1,774.9	$3,723.8	$5,498.7	$(77.3)	$5,421.4
Adjusted EBITDA	$194.5	$47.0	$241.5	—	$241.5
Reconciling items to net income:					
Depreciation and amortization	66.6	67.1	133.7	—	133.7
Realized loss on derivatives, not reflected in net income	(0.5)	(1.3)	(1.8)	—	(1.8)
Unrealized gain on derivatives					(25.7)
Interest expense					96.8
Debt extinguishment costs					14.6
Non-cash equity based compensation and other non-cash items					20.0
Income tax expense					0.4
Net income					$3.5

Year Ended December 31, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,849.9	$2,807.4	$4,657.3	$—	$4,657.3
Intersegment sales	—	50.2	50.2	(50.2)	—
Total sales	$1,849.9	$2,857.6	$4,707.5	$(50.2)	$4,657.3
Adjusted EBITDA	$283.2	$121.4	$404.6	—	$404.6
Reconciling items to net income:					
Depreciation and amortization	55.8	49.2	105.0	—	105.0
Realized loss on derivatives, not reflected in net income	(1.9)	(3.1)	(5.0)	—	(5.0)
Unrealized loss on derivatives					3.8
Interest expense					85.6
Non-cash equity based compensation and other non-cash items					8.7
Income tax expense					0.8
Net income					$205.7

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Year Ended December 31, 2011	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,630.5	$1,504.4	$3,134.9	$—	$3,134.9
Intersegment sales	—	45.8	45.8	(45.8)	—
Total sales	$1,630.5	$1,550.2	$3,180.7	$(45.8)	$3,134.9
Adjusted EBITDA	$280.6	$(69.6)	$211.0	$—	$211.0
Reconciling items to net income:					
Depreciation and amortization	43.2	31.3	74.5	—	74.5
Realized gain on derivatives, not reflected in net income	2.5	8.4	10.9	—	10.9
Unrealized loss on derivatives					10.4
Interest expense					48.7
Debt extinguishment costs					15.1
Non-cash equity based compensation and other non-cash items					7.4
Income tax expense					1.0
Net income					$43.0

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three years ended December 31, 2013, 2012 and 2011. As of December 31, 2013 and 2012, substantially all of the Company's long-lived assets are domestically located.

c. Product Information

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

	Year Ended December 31,					
	2013		2012		2011	
Specialty products:						
Lubricating oils	$848.8	15.7 %	$1,007.9	21.6 %	$947.8	30.2 %
Solvents	511.7	9.4 %	491.1	10.5 %	495.9	15.8 %
Waxes	141.0	2.6 %	142.8	3.1 %	143.1	4.6 %
Packaged and synthetic specialty products	233.6	4.3 %	161.7	3.5 %	—	— %
Other	39.8	0.7 %	46.4	1.0 %	43.7	1.4 %
Total	1,774.9	32.7 %	1,849.9	39.7 %	1,630.5	52.0 %
Fuel products:						
Gasoline	1,409.4	26.0 %	1,174.9	25.2 %	619.6	19.8 %
Diesel	1,259.2	23.3 %	941.0	20.2 %	513.3	16.4 %
Jet fuel	191.4	3.5 %	184.0	4.0 %	148.0	4.7 %
Asphalt, heavy fuel oils and other	786.5	14.5 %	507.5	10.9 %	223.5	7.1 %
Total	3,646.5	67.3 %	2,807.4	60.3 %	1,504.4	48.0 %
Consolidated sales	$5,421.4	100.0 %	$4,657.3	100.0 %	$3,134.9	100.0 %

d. Major Customers

During the years ended December 31, 2013, 2012 and 2011, the Company had no customer that represented 10% or greater of consolidated sales.

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e. Major Suppliers
During the years ended December 31, 2013, 2012 and 2011, the Company had two suppliers that supplied approximately 54.1%, 65.0% and 55.2%, respectively, of its crude oil supply.

17. Quarterly Financial Data (Unaudited)
The table below sets forth selected quarterly financial data for each of the last two fiscal years (in millions, except unit and per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total (1)
2013					
Sales	$1,318.6	$1,354.2	$1,505.5	$1,243.1	$5,421.4
Gross profit	134.4	101.0	62.1	112.5	410.0
Net income (loss)	46.0	7.8	(34.8)	(15.5)	3.5
Net income (loss) available to limited partners	41.7	3.8	(37.9)	(19.0)	(11.5)
Limited partners’ interest basic net income (loss) per unit	$0.67	$0.05	$(0.54)	$(0.27)	$(0.17)
Limited partners’ interest diluted net income (loss) per unit	$0.66	$0.05	$(0.54)	$(0.27)	$(0.17)
Weighted average limited partner units outstanding — basic	62,831,155	69,571,855	69,626,650	69,635,865	
Weighted average limited partner units outstanding — diluted	63,017,869	69,769,536	69,626,650	69,635,865	

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total (1)
2012					
Sales	$1,169.6	$1,087.0	$1,179.8	$1,220.9	$4,657.3
Gross profit	84.2	128.8	158.4	141.8	513.2
Net income	51.9	65.7	42.4	45.7	205.7
Net income available to limited partners	50.1	62.9	39.7	42.3	195.0
Limited partners’ interest basic net income per unit	$0.97	$1.14	$0.69	$0.73	$3.51
Limited partners’ diluted net income per unit	$0.97	$1.14	$0.69	$0.73	$3.50
Weighted average limited partner units outstanding — basic	51,684,741	55,027,786	57,745,806	57,745,881	
Weighted average limited partner units outstanding — diluted	51,736,396	55,074,265	57,825,603	57,898,207	

(1) The sum of the four quarters may not equal the total year due to rounding.

18. Subsequent Events
On January 24, 2014, 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 December 31, 2013. The distribution was paid on February 14, 2014 to unitholders of record as of the close of business on February 4, 2014. This quarterly distribution of $0.685 per unit equates to $2.74

per unit, 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 $56.0 million subsequent to December 31, 2013 to a net asset of approximately $1.0 million. The fair value of the Company's long-term debt, excluding capital leases, has increased by approximately $40.0 million subsequent to December 31, 2013.

On February 28, 2014, the Company completed the acquisition of substantially all of the assets of United Petroleum, LLC, a marketer and distributor of high-performance lubricants, for aggregate consideration of approximately $10.4 million. United Petroleum, LLC markets and distributes an array of high-end specialty lubricants. The Company believes the acquisition increases its sales in the specialty lubricants market, expands its geographic reach and increases its asset diversity.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure
None.
Item 9A. Controls and Procedures
Evaluation of Disclosure Controls and Procedures
As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") 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 Annual 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 December 31, 2013 at the reasonable assurance level. See Management's Report on Internal Control Over Financial Reporting included in Item 8 "Financial Statements and Supplementary Data."
Changes in Internal Control over Financial Reporting
There have been no changes to our internal controls over financial reporting during the fourth quarter of fiscal year 2013 that have materially affected, or are reasonably likely to materially affect, our 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 twelve months ended December 31, 2013 to ensure ongoing reliability of our financial reporting.
On December 10, 2013, we completed the Bel-Ray Acquisition, which includes certain existing information systems and internal controls over financial reporting that previously existed. In conducting our evaluation of effectiveness of our internal control over financial reporting, we have elected to exclude the Bel-Ray Acquisition from our evaluation, as permitted under existing SEC rules. We are currently in the process of evaluating and integrating the Bel-Ray Acquisition's historical internal controls over financial reporting with ours. We expect to complete the integration of the Bel-Ray Acquisition in 2014.
See Management's Report on Internal Control Over Financial Reporting included in Item 8 "Financial Statements and Supplemental Data."
Item 9B. Other Information
None.

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PART III

Item 10. Directors, Executive Officers of Our General Partner and Corporate Governance

Management of Calumet Specialty Products Partners, L.P. and Director Independence

Our general partner, Calumet GP, LLC, manages our operations and activities. Unitholders are limited partners and are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. Our general partner owes a fiduciary duty to our unitholders, as limited by the various provisions of our partnership agreement modifying and restricting the fiduciary duties that might otherwise be owed by our general partner to our unitholders.

The directors of our general partner oversee our operations. The owners of our general partner have appointed seven members to our general partner's board of directors. The directors of our general partner are generally elected by a majority vote of the owners of our general partner on an annual basis. However, as long as our chief executive officer and vice chairman of our general partner, F. William Grube, or trusts established for the benefit of his family members, continue to own at least 30% of the membership interests in our general partner, Mr. Grube (or in certain specified instances, his designee or transferee) has the right to serve as a director of our general partner. The directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified.

Pursuant to Section 4360 of the NASDAQ Stock Market, LLC Marketplace Rules ("NASDAQ Rules"), a listed limited partnership like us is not required to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/governance committee. However, three of our general partner's seven directors are "independent" as that term is defined in the NASDAQ Rules and Rule 10A-3 of the Exchange Act. In determining the independence of each director, our general partner has adopted standards that incorporate the NASDAQ Rules and Exchange Act standards. Our general partner's independent directors as determined in accordance with those standards are: James S. Carter, Robert E. Funk and George C. Morris III.

The officers of our general partner manage the day-to-day affairs of our business. Officers serve at the discretion of the board of directors.

Directors and Executive Officers

The following table shows information regarding the directors and executive officers of Calumet GP, LLC as of March 3, 2014.

Name	Age	Position with Calumet GP, LLC
Fred M. Fehsenfeld, Jr.	63	Chairman of the Board
F. William Grube	66	Chief Executive Officer and Vice Chairman of the Board
Jennifer G. Straumins	40	President and Chief Operating Officer
R. Patrick Murray, II	42	Senior Vice President, Chief Financial Officer and Secretary
Timothy R. Barnhart	54	Senior Vice President — Operations
James S. Carter	65	Director
William S. Fehsenfeld	63	Director
Robert E. Funk	68	Director
George C. Morris III	58	Director
Nicholas J. Rutigliano	66	Director

Each director's biographical information set forth below includes the particular experience and qualifications that led the board of directors to conclude that the director is qualified to serve in such capacity.

Fred M. Fehsenfeld, Jr. has served as the chairman of the board of our general partner since September 2005. Mr. Fehsenfeld also served as the vice chairman of the board of our Predecessor from 1990 until our initial public offering. Mr. Fehsenfeld has worked for The Heritage Group in various capacities since 1977 and has served as its managing trustee since 1980. Mr. Fehsenfeld received his B.S. in Mechanical Engineering from Duke University and his M.S. in Management from the Massachusetts Institute of Technology Sloan School.

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As co-founder of our Predecessor, Mr. Fehsenfeld has an extensive knowledge base regarding the Company’s operations and has participated in all major strategic decision making for the Company and our Predecessor since their inception. In his role as managing trustee of The Heritage Group, Mr. Fehsenfeld serves in lead executive roles, including the role of chairman and chief executive officer, for a multitude of different companies within The Heritage Group, providing breadth of experience in leadership and management across a wide variety of industries, including energy. Since 2008, Mr. Fehsenfeld has served as chairman of the board of directors of Heritage-Crystal Clean, Inc., a publicly-traded environmental services company which is owned in part by The Heritage Group.

F. William Grube has served as the chief executive officer and vice chairman of the board of our general partner since January 2011. From September 2005 through December 2010, Mr. Grube served as chief executive officer, president and director of our general partner. Mr. Grube has also served as president and chief executive officer of our Predecessor from 1990 until our initial public offering. From 1973 to 1989, Mr. Grube served as executive vice president of Rock Island Refining Corporation. Mr. Grube received his B.S. in Chemical Engineering from Rose-Hulman Institute of Technology and his M.B.A. from Harvard University. Mr. Grube is the father of Jennifer G. Straumins, president and chief operating officer of our general partner.

As co-founder of our Predecessor and through his role as the chief executive officer since inception, Mr. Grube possesses unique experience relative to the management of the Company on a day-to-day basis over a significant time period and across all functional areas of the Company. Mr. Grube has significant technical expertise in refining developed over the course of his career, with both the Company and our Predecessor, as well as another refining company which specialized in the production of fuel products.

Jennifer G. Straumins has served as president and chief operating officer of our general partner since January 2011. From December 2009 through December 2010, Ms. Straumins served as executive vice president and chief operating officer of our general partner. From February 2007 through December 2009, Ms. Straumins served as senior vice president of our general partner. From January 2006 through February 2007, Ms. Straumins served as vice president — investor relations of our general partner. Ms. Straumins served in various capacities in financial planning and economics for our Predecessor from 2002 until our initial public offering. Prior to joining our Predecessor, Ms. Straumins held financial planning positions with Great Lakes Chemical Company and Exxon Chemical Company. Ms. Straumins received a B.E. in Chemical Engineering from Vanderbilt University and her M.B.A. from the University of Kansas. Ms. Straumins is the daughter of F. William Grube, the chief executive officer and vice chairman of the board of our general partner.

R. Patrick Murray, II has served as senior vice president, chief financial officer and secretary of our general partner since January 2013. From September 2005 through December 2012, Mr. Murray served as vice president, chief financial officer and secretary of our general partner. Mr. Murray served as the vice president and chief financial officer of our Predecessor from 1999 until our initial public offering and served as its controller from 1998 to 1999. From 1993 to 1998, Mr. Murray was a senior auditor with Arthur Andersen LLP. Mr. Murray received his B.B.A. in Accountancy from the University of Notre Dame.

Timothy R. Barnhart has served as senior vice president — operations of our general partner since January 2013. From December 2009 to December 2012, Mr. Barnhart served as vice president — operations of our general partner. Mr. Barnhart served as the plant manager of our Karns City facility from January 2008 to December 2009. Prior to joining Calumet in 2008 upon our acquisition of Penreco, Mr. Barnhart held various engineering, supervisory and management positions at Penreco and Pennzoil Products Company since 1981. Mr. Barnhart received his B.S. in Engineering from Grove City College.

James S. Carter has served as a member of the board of directors of our general partner since January 2006. Mr. Carter served as U.S. regional director of Exxon Mobil Fuels Company, the fuels subsidiary of Exxon Mobil Corporation, from 1999 until his retirement in 2003. Mr. Carter received his B.S. in Mechanical Engineering from Clemson University and his M.B.A. in Finance and Accounting from Tulane University.

Mr. Carter brings extensive marketing and managerial experience with one of the largest integrated energy companies in the world. He possesses a broad background in petroleum products marketing, with specific experience in the marketing of fuel products.

William S. Fehsenfeld has served as a member of the board of directors of our general partner since January 2006. Mr. Fehsenfeld is chairman of the board and has served as an officer of Schuler Books, Inc., the independent bookstore company he founded with his wife, since 1982. He has also served as a trustee of The Heritage Group from 2003 to the present. Mr. Fehsenfeld received his B.G.S. from the University of Michigan and his M.B.A. from Grand Valley State University. He is also a first cousin of the chairman of the board of our general partner, Fred M. Fehsenfeld, Jr.

In his role as a trustee of The Heritage Group, which held the controlling interest in our Predecessor, Mr. Fehsenfeld has extensive knowledge of the Company and its operations over time and has been involved in strategic decision making for the

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Company during his tenure. His role as a trustee of The Heritage Group provides significant breadth of oversight experience of a multitude of companies across various industry sectors, including energy. As a founder and owner of a successful independent bookselling business, Mr. Fehsenfeld also brings executive management and entrepreneurial skills to the board of directors.

Robert E. Funk has served as a member of the board of directors of our general partner since January 2006. Mr. Funk previously served as vice president-corporate planning and economics of CITGO Petroleum Corporation, a refiner and marketer of transportation fuels, lubricants, petrochemicals, refined waxes, asphalt and other industrial products, from 1997 until his retirement in December 2004. Mr. Funk previously served CITGO or its predecessor, Cities Services Company, as general manager-facilities planning from 1988 to 1997, general manager-lubricants operations from 1983 to 1988 and manager-refinery east, Lake Charles refinery from 1982 to 1983. Mr. Funk received his B.S. in Chemical Engineering from the University of Kansas.

Mr. Funk has extensive refining industry experience including planning, operations and managerial roles for a large multinational refining company. His broad background of experience provides helpful insight to the Company in its implementation of strategic initiatives and its refinery operations in general.

George C. Morris III has served as a member of the board of directors of our general partner since May 2009. Mr. Morris has served as president of Morris Energy Advisors, Inc. since March 2009 and most recently served as a managing director at Merrill Lynch & Co. from December 2006 until his retirement in March 2009. Mr. Morris served as a managing director of investment banking at Petrie Parkman & Co. until its acquisition by Merrill Lynch in December 2006 and also served as a managing director of investment banking at Simmons & Company International and as a director of investment banking at First Boston Corporation. Mr. Morris holds B.B.A. and M.B.A. degrees from the University of Texas and a J.D. from Southern Methodist University. Mr. Morris is also a member of the board of directors of Arch Coal, Inc., a public company which produces thermal and metallurgical coal from surface and underground mines.

Mr. Morris' long tenure in the investment banking industry with a focus on the energy sector provides unique breadth of experience to the board of directors in areas of finance and capital markets. In his role as a financial advisor to the Company prior to joining the board of directors, Mr. Morris gained significant insight into the Company's operations and strategy.

Nicholas J. Rutigliano has served as a member of the board of directors of our general partner since January 2006. Mr. Rutigliano served as president of Tobias Insurance Group, Inc., a commercial insurance brokerage business he founded, since 1973 to 2012 prior to it being acquired by Assured Partners, LLC. Mr. Rutigliano now serves as president of Assured Partners of Indiana, LLC. He has also served as a trustee of The Heritage Group from 1980 to the present and as a trustee of the University of Evansville. Mr. Rutigliano received his B.S. in Business from the University of Evansville. He is also the brother-in-law of the chairman of the board of our general partner, Fred M. Fehsenfeld, Jr.

In his role as a trustee of The Heritage Group, which held the controlling interest in our Predecessor, Mr. Rutigliano has extensive knowledge of the Company and its operations over time and has been involved in strategic decision making for the Company from the inception of the Company's Predecessor. His role as a trustee of The Heritage Group provides significant breadth of oversight experience of a multitude of companies across various industry sectors, including energy. As the founder and chief executive officer of a successful commercial insurance brokerage business, Mr. Rutigliano brings unique risk management, executive management and entrepreneurial skills to the board of directors.

Board of Directors Committees

Conflicts Committee

Two members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be owners, officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by NASDAQ and the Exchange Act to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. The two independent board members who serve on the conflicts committee are Messrs. James S. Carter and Robert E. Funk. Mr. Carter serves as the chairman of the conflicts committee.

Compensation Committee

The board of directors of our general partner also has a compensation committee which, among other responsibilities, has overall responsibility for evaluating and either approving or recommending to the board of directors the director, chief executive officer and senior executive compensation plans, policies and programs of the Company. NASDAQ does not require a limited partnership like us to have a compensation committee comprised entirely of independent directors. Accordingly, Messrs. Fred M. Fehsenfeld, Jr. and F. William Grube serve as members of our compensation committee. Mr. Fehsenfeld serves as the chairman of the compensation committee.

The board of directors has adopted a written charter for the compensation committee which defines the scope of the committee's authority. The committee may form and delegate some or all of its authority to subcommittees comprised of committee members when it deems appropriate. The committee is responsible for reviewing and recommending to the board of directors for its approval the annual salary and other compensation components for the chief executive officer. The committee reviews and makes recommendations to the board of directors for its approval any of the Company's equity compensation-based plans, including the Long-Term Incentive Plan, or any cash bonus or incentive compensation plans or programs. Also, the committee reviews and approves all annual salary and other compensation arrangements and components for the senior executives of the Company. Further, the compensation committee periodically reviews and makes a recommendation to the board of directors for changes in the compensation of all directors. The committee has the authority to retain and terminate any compensation consultant to assist it in the evaluation of director and senior executive compensation and to obtain independent advice and assistance from internal and external legal, accounting and other advisors.

See Item 11 "Executive and Director Compensation — Compensation Discussion and Analysis — Peer Group and Compensation Targets" for additional discussion regarding the results of this executive compensation review.

Audit Committee

The board of directors of our general partner has an audit committee comprised of three directors, Messrs. James S. Carter, Robert E. Funk and George C. Morris III, each of whom the board of directors of our general partner has determined meets the independence and experience standards established by NASDAQ and the SEC. In addition, the board of directors of our general partner has determined that Mr. Morris is an "audit committee financial expert" as defined by the SEC. Mr. Morris serves as the chairman of the audit committee.

The board of directors has adopted a written charter for the audit committee. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approves all auditing services and related fees and the terms thereof and pre-approves any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all directors, officers and employees. Available on our website at www.calumetspecialty.com are copies of our board of directors committee charters and Code of Business Conduct and Ethics, all of which also will be provided to unitholders without charge upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, IN 46214.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires Calumet's directors and certain executive officers, as well as beneficial owners of ten percent or more of Calumet's common units, to report their holdings and transactions in Calumet's securities. Based on information furnished to Calumet and contained in reports filed pursuant to Section 16(a), as well as written representations that no other reports were required for 2013, Calumet's directors and executive officers filed all reports required by Section 16(a).

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Item 11. Executive and Director Compensation
Compensation Discussion and Analysis
Overview
For purposes of this Compensation Discussion and Analysis and the compensation tables that follow, the names and positions of our named executive officers for the 2013 year were:

- F. William Grube - Chief Executive Officer and Vice Chairman of the Board
- Jennifer G. Straumins - President and Chief Operating Officer
- R. Patrick Murray, II - Senior Vice President and Chief Financial Officer
- Timothy R. Barnhart - Senior Vice President - Operations

The compensation committee of the board of directors of our general partner oversees our compensation programs. Our general partner maintains compensation and benefits programs designed to allow us to attract, motivate and retain the best possible employees to manage us, including executive compensation programs designed to reward the achievement of both short-term and long-term goals necessary to promote growth and generate positive unitholder returns. Our general partner's executive compensation programs are based on a pay-for-performance philosophy, including measurement of our performance against a specified financial target, namely distributable cash flow. Our executive compensation programs include both long-term and short-term compensation elements which, together with base salary and employee benefits, constitute a total compensation package intended to be competitive with similar companies.
Under their collective authority, the compensation committee and the board of directors maintain the right to develop and modify compensation programs and policies as they deem appropriate. Factors they may consider in making decisions to materially increase or decrease compensation include our overall financial performance, our growth over time, our changes in complexity as well as individual executive job scope, complexity, performance and changes in competitive compensation practices in our defined labor markets. In determining any forms of compensation other than the base salary for the senior executives, or in the case of the chief executive officer, the recommendation to the board of directors of the forms of compensation for the chief executive officer, the compensation committee considers our financial performance and relative unitholder return, the value of similar incentive awards to senior executives at comparable companies and the awards given to senior executives in past years.
Financial Performance Metric Used in Compensation Programs
Our primary business objective is to generate cash flows to make distributions to our unitholders. As a result, our distributable cash flow is the primary measurement of performance taken into account in setting policies and making compensation decisions, as we believe this represents the most comprehensive measurement of our ability to generate cash flows. Both short-term and long-term forms of executive compensation are specifically structured on our achievement relative to annual distributable cash flow goals and, as such, determination of related awards, as well as their grant or payment, occurs subsequent to the end of each fiscal year upon final determination of distributable cash flow. We believe that including this financial objective as the primary performance measurement to determine compensation awards for all of our executive officers recognizes the integrated and collaborative effort required by the full executive team to maximize performance. Distributable cash flow is a non-GAAP measure that we define, consistent with the terms of our revolving credit agreement and senior notes indentures, as our Adjusted EBITDA less replacement capital expenditures, cash interest expense, turnaround costs and income tax expense. Please refer to Part II, Item 6 "Selected Financial Data — Non-GAAP Financial Measures" for our definition of Adjusted EBITDA.
Peer Group and Compensation Targets
To evaluate all areas of executive compensation, the compensation committee seeks the additional input of outside compensation consultants and available comparative information to validate that the compensation programs established for our executives are consistent with the philosophy of compensating our executives at ranges that approximate within 15% of the median of market for companies of similar size to us. In 2012, the compensation committee retained Buck Consultants, LLC ("Buck Consultants") as an independent consultant to review our general partner's executive compensation programs. Buck Consultants reported directly to the compensation committee and

did not provide any additional services to our general partner. The scope of this engagement included the following:

- review of a peer group of publicly-traded master limited partnerships for executive compensation comparisons;
- analysis of market pay levels and trends for our named executive officers, other officers and key employees from peer companies including base salary, annual incentives and long-term incentives; and

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- assessment of Calumet's executive pay levels relative to overall market levels.

The following master limited partnerships and corporation were included by Buck Consultants in the peer group for the compensation review: Atlas Pipeline Partners, L.P., Boardwalk Pipeline Partners, LP, Buckeye Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., DCP Midstream Partners, LP, Energy Transfer Partners, L.P., Genesis Energy, L.P., Inergy, L.P., Kinder Morgan Energy Partners, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., PVR Partners, L.P., Regency Energy Partners LP, Suburban Propane Partners, L.P., Targa Resources Partners LP and Williams Partners, L.P. Peer group companies were validated and selected based on their comparability of EBITDA (a non-GAAP measurement), sales and market capitalization to those of Calumet. Market data compiled from public disclosures of the peer group companies were used in the review to compare our compensation of the key executive group against the market. Buck Consultants provided a presentation of its findings to the compensation committee in October 2012 that assisted us in making the compensation decisions described below for the 2013 year.

The compensation committee used the findings of the Buck Consultants executive compensation review to validate the total competitiveness of compensation for our key executives, including each named executive officer. Specifically, the Buck Consultants review indicated that aggregate target total direct compensation of our key executives, which includes all the major elements of our executive compensation program, including base salary, short-term incentives and long-term compensation, was below the median of market by approximately 15%, driven primarily by long-term compensation, whereas total cash compensation, which includes aggregate base salaries and aggregate short-term incentives for the key executives, assuming the target levels of such incentives are achieved, fall above the median of the expanded peer group by less than 5%. Long-term incentives for the key executives fall below the 25th percentile of the peer group by approximately 10%, which the compensation committee deemed appropriate given our smaller size relative to certain master limited partnerships included in the peer group, with an expectation by the compensation committee that with future achievement of strategic goals and further growth in financial performance, such long-term incentive opportunities should migrate toward the median level of the peer group. As of this filing, we have not made any material changes to our compensation program for the 2014 year.

Review of Named Executive Officer Performance

The compensation committee reviews, on an annual basis, each compensation element for a named executive officer. In each case, the compensation committee takes into account the scope of responsibilities and experience and balances these against competitive salary levels. The compensation committee has the opportunity to meet with the named executive officers at various times during the year, which allows the compensation committee to form its own assessment of each individual's performance.

Objectives of Compensation Programs

Our executive compensation programs are designed with the following primary objectives:

- reward strong individual performance that drives our positive financial results;
- make incentive compensation a significant portion of an executive's total compensation, designed to balance short-term and long-term performance;
- align the interests of our executives with those of our unitholders; and
- attract, develop and retain executives with a compensation structure that is competitive with other publicly-traded partnerships of similar size.

Elements of Executive Compensation

The compensation committee believes the total compensation and benefits program for our named executive officers should consist of the following:

- base salary;
- annual incentive plan which includes short-term cash awards and also includes an optional deferred compensation element;
- long-term incentive compensation, including unit-based awards;
- retirement, health and welfare benefits; and
- perquisites.

These elements are designed to constitute an integrated executive compensation structure meant to incentivize a high level of individual executive officer performance in line with our financial and operating goals.

Base Salary

Design. Salaries provide executives with a base level of monthly income as consideration for fulfillment of certain roles and responsibilities. The salary program assists us in achieving our objective of attracting and retaining the services of quality individuals who are essential for the growth and profitability of Calumet. Generally, changes in the base salary levels for our named executive officers are determined on an annual basis by the compensation committee of the board of directors and are effective at the beginning of the following fiscal year. In the case of Mr. Grube, his initial base salary was established under his employment agreement, which provides that the amount of his annual salary increase must be at least equal to the average of the percentage increases of all salaried employees of Calumet's general partner.

Results. Mr. Grube's salary increase for 2013 was 3.7%, which was equivalent to the average of the percentage increases of all salaried employees for 2013. With respect to our other executive officers, the 2013 base salaries for Ms. Straumins, Mr. Murray and Mr. Barnhart were $350,000, $320,000 and $300,000, respectively. These 2013 base salaries for Ms. Straumins, Mr. Murray and Mr. Barnhart compare to $297,500, $292,000 and $271,000, respectively, in 2012.

The levels of increases in the base salaries for these executives were based on increased job complexity due to the growth of our business and in the case of each of Mr. Murray and Mr. Barnhart, the increases take into account their respective promotions to senior vice president and chief financial officer and senior vice president — operations effective January 1, 2013.

Compensation Changes for 2014. Mr. Grube's salary increase for 2014 was 3.0%, based on the same formula described above. With respect to our other named executive officers, the compensation committee approved increased salaries as part of its annual salary review process. Effective January 1, 2014, the base salaries for Ms. Straumins, Mr. Murray and Mr. Barnhart are $360,500, $329,600 and $309,000, respectively. The levels of increases in the base salaries for these executives were based on the same formula as above. The compensation committee also considered the increases to base salary to be appropriate based on comparisons against our peer group of publicly traded partnerships in an effort to ensure that base salaries were closer to the market median of our peer group.

Short-Term Cash Awards

Design. Under the Cash Incentive Compensation Plan (the "Cash Incentive Plan"), short-term cash awards are designed to aid us in retaining and motivating executives to assist us in meeting our financial performance objectives on an annual basis. Short-term cash awards are granted to named executive officers and certain other management employees based on our achievement of performance targets on our distributable cash flow, thereby establishing a direct link between executive compensation and our financial performance.

The compensation committee establishes minimum, target and stretch incentive opportunities for each executive officer and other key employees expressed as a percentage of base salary. The amount that is paid out is based on our achievement of a minimum, target or stretch level of distributable cash flow for the fiscal year. At the recommendation of the compensation committee, the board of directors approves distributable cash flow targets for each fiscal year based on budgets prepared by management. When making the annual determination of the minimum goal, target goal and stretch goal levels of distributable cash flow, the compensation committee and the board of directors consider the specific circumstances facing us during the relevant year. Generally, the compensation committee seeks to set the minimum goal, target goal and stretch goal levels such that the relative challenge of achieving each level is consistent from year to year. The expectation that management will achieve the minimum goal level is very high, while meaningful additional effort would be required to achieve the target goal and considerable additional effort would be required to achieve the stretch goal.

Generally, no awards are paid under the Cash Incentive Plan unless we achieve at least the minimum distributable cash flow goal. If the minimum, target or stretch level distributable cash flow goal is achieved, participants in the plan will receive their minimum, target or stretch cash award opportunity, respectively. If our distributable cash flow is between specified goal levels, participants are eligible to receive a prorated percentage of their cash award opportunity based on where the actual distributable cash flow amount falls between the levels.

Results. For fiscal year 2013, the minimum distributable cash flow goal was $175.3 million, the target goal was $246.8 million and the stretch goal was $357.6 million. For the reasons described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations — 2013 Update,” we did not meet our minimum goal with 2013 distributable cash flow of $18.5 million and no awards were paid out for the 2013 year.

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The following table summarizes the levels of cash award opportunity for each named executive officer and the actual percentage earned by them in 2013:

	Cash Incentive Award Opportunity as a Percentage of Base Salary			
	Minimum	Target	Stretch	Actual Payout
F. William Grube	50 %	100 %	200 %	— % (1)
Jennifer G. Straumins, R. Patrick Murray, II and Timothy R. Barnhart	50 %	100 %	200 %	— %

(1) Mr. Grube's employment agreement guarantees him a potential award that is at least 150% of the amount of the next highest potential award paid to any other executive officer of our general partner, which would have been the maximum potential award for Ms. Straumins.

The compensation committee determined these percentages of base salary at levels, when combined with both base salary and potential long-term, unit-based awards, to develop a total direct compensation structure for the named executive officers which is intended to be within approximately 15% of the median of our peer group, while placing significant emphasis on the achievement of our distributable cash flow goals.

For 2013, the target goal for distributable cash flow was set at the budgeted amount, a level that the board of directors believed reflected the reasonable expectations management had for our financial performance during the fiscal year and likely to be achieved given actual distributable cash flow achieved for the 2012 fiscal year. The board of directors set the stretch cash flow goal at 45% above the budgeted amount, a level which they believed would be attained only with higher levels of performance relative to the reasonable expectations management had for our financial performance and therefore not likely to be achieved. The minimum goal was set at approximately 29% below the budgeted amount. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — 2013 Update," for a discussion of the factors that impacted our results, including our lower gross profit per barrel sold of both specialty products and fuel products, the primary drivers that hindered us from meeting our distributable cash flow targets. The following table reflects our historical minimum, target and stretch distributable cash flow goals:

Distributable Cash Flow (In millions)

Fiscal Year	Actual		Minimum Goal	Target Goal	Stretch Goal
2013	$18.5		$175.3	$246.8	$357.6
2012	$281.1		$123.0	$138.5	$169.3
2011	$126.4	(1)(2)	$79.4	$89.6	$110.0

(1) As adjusted. When assessing our 2010 performance with respect to our distributable cash flow targets, the compensation committee determined it was appropriate to include an interim payment of certain insurance proceeds. Such amounts were excluded from distributable cash flow for 2011.

(2) For 2011, we adjusted the calculation of Distributable Cash Flow to reflect calculations contained in our debt instruments. For additional information please read Part II, Item 6 "Selected Financial Data — Non-GAAP Financial Measures" for our definition of Distributable Cash Flow. For 2011 and 2010 Distributable Cash Flow calculations, please refer to our 2011 and 2010 Annual Reports.

Compensation Changes for 2014. Upon the recommendation of the compensation committee, the board of directors has approved new distributable cash flow targets for the 2014 fiscal year based on budgets prepared by management. We do not disclose our confidential 2014 targets, which, if disclosed, would put us at a competitive disadvantage. However, we believe that the targets set for the 2014 year will be difficult to achieve and that there is no guarantee that our named executive officers will receive an award related to the 2014 year.

For further description of this compensation program, please see "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Cash Incentive Plan."

Executive Deferred Compensation Plan

Design. The compensation committee allows for the participation of the executive officers in the Calumet Specialty Products Partners, L.P. Executive Deferred Compensation Plan (the “Deferred Compensation Plan”) to encourage the officers to save for retirement and to assist us in retaining our officers. The Deferred Compensation Plan is intended to promote

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retention by giving employees an opportunity to save in a tax-efficient manner. The terms governing the retirement benefit under this plan for the executive officers are the same as those available for other eligible employees in the U.S. Pursuant to the Deferred Compensation Plan, a select group of management, including the named executive officers, and all of the non-employee directors are eligible to participate by making an annual irrevocable election to defer, in the case of management, all or a portion of their annual cash incentive award under the Cash Incentive Plan, and, in the case of non-management directors, all or none of their annual cash retainer. The deferred amounts are credited to participants' accounts in the form of phantom units, with each such phantom unit representing a notional unit that entitles the holder to receive either an actual common unit or the cash value of a common unit (determined by using the fair market value of a common unit at the time a determination is needed). The phantom units credited to each participant's account also receive distribution equivalent rights ("DERs"), which are credited to the participant's account in the form of additional phantom units. In our sole discretion, we may make matching contributions of phantom units or purely discretionary contributions of phantom units, in amounts and at times as the compensation committee recommends and the board of directors approves.

Results. On February 28, 2013, we made discretionary matching contributions of phantom units to the accounts of those participants in the Deferred Compensation Plan, including certain of the named executive officers, who elected to defer all or a portion of their annual cash incentive award related to the 2012 fiscal year. These contributions, which were subject to continued service vesting requirements, were made as a reward for prior service and future efforts toward our success and growth, as well as an incentive for continued participation through elective deferrals into the Deferred Compensation Plan allowing participants to save in a tax-efficient manner knowing that we, in our discretion, may make such matching contributions. Please see "Nonqualified Deferred Compensation" for a more detailed disclosure of the value of contributions into this plan, as well as the DERs associated with such contributions.

Long-Term, Unit-Based Awards

Design. Long-term unit-based awards may consist of phantom units, restricted units, unit options, substitution awards and DERs. These awards are granted to employees, consultants and directors of our general partner under the provisions of our Long-Term Incentive Plan, as amended, originally adopted on January 24, 2006 and administered by the compensation committee. These awards aid Calumet in retaining and motivating executives to assist us in meeting our financial performance objectives.

In fiscal year 2013, the annual unit award opportunity to named executive officers consisted of the contingent right to receive phantom units. Under the Long-Term Incentive Plan, phantom units are granted only upon our achievement of specified levels of distributable cash flow. When granted, phantom units are subject to further time-based vesting criteria specified in the grant. Upon satisfaction of the time-based vesting criteria specified in the grant, phantom units convert into common units (or cash equivalent). Accordingly, these awards established a direct link between executive compensation and our financial performance. This component of executive compensation, when coupled with an extended ratable vesting period as compared to cash awards, further aligns the interests of executives with our unitholders in the longer-term and reinforces unit ownership levels among executives.

Results. The following table provides the annual unit award opportunity for each named executive officer. Our general objective when determining the size of the phantom unit awards is to provide our named executive officers with long-term incentive opportunities targeted within approximately 10% of the 25th percentile of peer practices for long-term equity based awards for similarly situated executive officers. The following table reflects the number of phantom units that would be awarded to our named executive officers depending on whether we achieved the distributable cash flow minimum, target and stretch goals discussed above in "Short-Term Cash Awards":

	2013 Phantom Unit Award Opportunity			Phantom Units Granted
	Minimum	Target	Stretch	
F. William Grube	10,800	21,600	32,400	—
Jennifer G. Straumins, R. Patrick Murray, II and Timothy R. Barnhart	7,200	14,400	21,600	—

We did not grant any phantom units from the Long-Term Incentive Plan during the 2013 year due to our performance results for the year. Phantom units granted, if any, would have been subject to a time-vesting requirement, whereby 25% of the units would vest immediately at grant and the remainder would vest ratably over three years on each December 31. These phantom units would have also included DERs, which would be paid in the form of cash.

For further description of this compensation program, please see “Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Long-Term Incentive Plan.”

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Health and Welfare Benefits

We offer a variety of health and welfare benefits to all eligible employees of our general partner. These benefits are consistent with the types of benefits provided by our peer group and provided so as to ensure that we are able to maintain a competitive position in terms of attracting and retaining executive officers and other employees. In addition, the health and welfare programs are intended to protect employees against catastrophic loss and encourage a healthy lifestyle. The named executive officers generally are eligible for the same benefit programs on the same basis as the rest of our employees. Our health and welfare programs include medical, pharmacy, dental, life insurance and accidental death and dismemberment. In addition, certain employees are eligible for long-term disability coverage. Coverage under long-term disability offers benefits specific to the named executive officers. We provide the named executive officers with a compensation allowance, which is grossed up for the payment of taxes to allow them to purchase long-term disability coverage on an after-tax basis at no net cost to them. As structured, these long-term disability benefits will pay 60% of monthly earnings, as defined by the policy, up to a maximum of $6,000 per month during a period of continuing disability up to normal retirement age, as defined by the policy. Executive officers and other key employees are also eligible to obtain executive physical examinations which are paid for by Calumet. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

Retirement Benefits

We provide the Calumet GP, LLC Retirement Savings Plan (the “401(k) Plan”) to assist our eligible officers and employees in providing for their retirement. Named executive officers participate in the same retirement savings plan as other eligible employees subject to ERISA limits. We match 100% of each 1% of eligible compensation contribution by the participant up to 4% and 50% of each additional 1% of eligible compensation contribution up to 6%, for a maximum contribution by us of 5% of eligible compensation contributions per participant. These contributions are provided as a reward for prior contributions and future efforts toward our success and growth.

The 401(k) Plan also includes a discretionary profit-sharing component. Determination of annual contributions is subjectively made by the compensation committee based on our overall profitability. The board of directors approved a discretionary profit sharing contribution to the 401(k) Plan for all eligible participants equivalent to 1% of their eligible compensation for the 2013 fiscal year. The value of our contributions to the retirement savings plan for named executive officers is included in the Summary Compensation Table. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

Although we have not historically maintained a traditional pension plan for our employees, we continued to maintain the Penreco Pension Plan after our acquisition of Penreco in 2008 for the employees that were participating in the plan at that time. Only one of our named executive officers, Mr. Barnhart, was and is a participant in the Penreco Pension Plan. While the plan was frozen in 2009, Mr. Barnhart still holds an account in that plan. Please see the “Pension Benefits” section below for additional details.

Perquisites

We provide executive officers with perquisites and other personal benefits that we believe are reasonable and consistent with our overall compensation programs and philosophy. These benefits are provided in order to enable us to attract and retain these executives. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

All named executive officers are provided with all, or certain of, the following benefits as a supplement to their other compensation:

- Use of Company Vehicles: In order to assist them in conducting our daily affairs, we provide each named executive officer with a company vehicle that may be used for personal use as well as business use. Personal use of a company vehicle is treated as taxable compensation to the named executive officer.
- Executive Physical Program: Generally on an annual basis, we pay for a complete and professional personal physical exam for each named executive officer appropriate for his or her age to improve their health and productivity.

- Spousal Travel: On an occasional basis, we pay expenses related to travel of the spouses of our named executive officers in order to accompany the named executive officer to business-related events.
- Long-Term Disability Insurance: We provide compensation to allow each named executive officer to purchase long-term disability insurance on an after-tax basis at no net cost to them.
- Use of Company Aircraft: On an occasional basis, our named executive officers may be eligible to use a leased aircraft for personal use and the incremental cost to us is treated as and reflected in the tables below as compensation to

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the applicable officer for purposes of these disclosures. The items that we use to determine the incremental cost to us of these flights include the variable costs for personal use of aircraft that were charged to us by the vendor that operates the leased aircraft for contracted hourly costs, fuel charges, and taxes.

The compensation committee periodically reviews the perquisite program to determine if adjustments are appropriate and did not make any material changes to the program during the 2013 year.

Other Compensation Related Matters

Tax Implications of Executive Compensation

Because we are not an entity taxable as a corporation, many of the tax issues associated with executive compensation that face publicly traded corporations do not directly affect us. Internal Revenue Code Section 409A (“Section 409A”) provides that amounts deferred under nonqualified deferred compensation plans are includible in a participant’s income when vested, unless certain requirements are met. If these requirements are not met, participants are also subject to an additional income tax and interest. All of our awards under our Long-Term Incentive Plan, severance arrangements and other nonqualified deferred compensation plans presently meet these requirements. As a result, employees will be taxed when the deferred compensation is actually paid to them. We will be entitled to a tax deduction at that time.

Executive Ownership of Units

While we have not adopted any security ownership requirements or policies for our executives, our executive compensation programs foster the enhancement of executives’ equity ownership through long-term, unit-based awards under the Long-Term Incentive Plan. Further, in 2006 several executives purchased a significant number of our common units as participants in a directed unit program in conjunction with our initial public offering. For a listing of security ownership by our named executive officers, refer to Item 12 “Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.”

The board of directors has adopted the Insider Trading Policy of Calumet GP, LLC and Calumet Specialty Products Partners, L.P. (the “Insider Trading Policy”), which provides guidelines to employees, officers and directors with respect to transactions in our securities. Pursuant to Calumet’s Insider Trading Policy, all executive officers and directors must confer with our Chief Financial Officer before effecting any put or call options for our securities. Further, the Insider Trading Policy states that we strongly discourage all such transactions by officers, directors and all other employees and consultants. The Insider Trading Policy is available on our website at www.calumetspecialty.com or a copy will be provided at no cost to unitholders upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, IN 46214.

Employment Agreement with F. William Grube

We have entered into an employment agreement with our chief executive officer and vice chairman of the board, F. William Grube, to ensure he will perform his role for an extended period of time given his position and value to us. For a discussion of the major terms of Mr. Grube’s employment agreement, please refer to “Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Employment Agreement with F. William Grube.”

Under his employment agreement, Mr. Grube is entitled to receive severance compensation if his employment is terminated under certain conditions, such as termination by Mr. Grube for “good reason” or by us without “cause,” each as defined in the agreement and further described in “Potential Payments Upon Termination or Change in Control — Employment Agreement with F. William Grube.”

Our employment agreement with Mr. Grube and the related severance provisions are designed to meet the following objectives:

- Change in Control: In certain scenarios, the potential for merger or being acquired may be in the best interests of our unitholders. We provide the potential for severance compensation to Mr. Grube in the event of a change in control transaction to promote his ability to act in the best interests of our unitholders even though his employment could be terminated as a result of the transaction.
- Termination without Cause: We believe severance compensation in such a scenario is appropriate because Mr. Grube is bound by confidentiality, nonsolicitation and noncompetition provisions covering one year after

termination and because we and Mr. Grube have mutually agreed to a severance package that is in place prior to any termination event. This provides us with more flexibility to make a change in this executive position if such a change is in our and our unitholders' best interests.

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The salary multiple of the change of control benefits, use of the single trigger change of control benefits and the amount of the severance payout were determined through negotiation with Mr. Grube at the time that we entered into his employment agreement. Relative to the overall value to us, the compensation committee believes these potential benefits are reasonable.

Report of the Compensation Committee for the Year Ended December 31, 2013

The compensation committee of our general partner has reviewed and discussed our Compensation Discussion and Analysis with management. Based upon such review, the related discussion with management and such other matters deemed relevant and appropriate by the compensation committee, the compensation committee has recommended to the board of directors that our Compensation Discussion and Analysis be included in the Company's Annual Report on Form 10-K.

Members of the Compensation Committee:
Fred M. Fehsenfeld, Jr., Chairman
F. William Grube

Summary Compensation Table

The following table sets forth certain compensation information of our named executive officers for the years ended December 31, 2013, 2012 and 2011:

Summary Compensation Table for 2013

Name and Principal Position	Year	Salary	Unit Awards (1)	Non-Equity Incentive Plan Compensation (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (3)	All Other Compensation (4)	Total
F. William Grube	2013	$428,281	$68,711	$—	$ —	$6,098	$503,090
Chief Executive Officer	2012	413,000	698,289	892,500	—	40,608	2,044,397
and Vice Chairman of the Board	2011	398,000	935,597	692,400	—	19,760	2,045,757
Jennifer G. Straumins	2013	350,000	39,030	—	—	17,483	406,513
President and Chief	2012	297,500	427,751	595,000	—	19,428	1,339,679
Operating Officer	2011	288,500	506,130	577,000	—	19,381	1,391,011
R. Patrick Murray, II	2013	320,000	52,641	—	—	18,263	390,904
Senior Vice President and	2012	292,000	493,475	525,600	—	19,409	1,330,484
Chief Financial Officer	2011	283,500	545,094	510,300	—	19,363	1,358,257
Timothy R. Barnhart	2013	300,000	139,743	—	—	6,564	446,307
Senior Vice President —	2012	271,000	683,380	325,200	54,848	19,334	1,353,762
Operations	2011	263,000	614,752	420,800	64,866	19,290	1,382,708

(1) The amounts include the aggregate grant date fair value of (i) discretionary matching phantom unit awards granted during the 2013 fiscal year (with respect to amounts deferred by the executives with respect to the 2012 year) and (ii) DERs granted in the form of phantom units, each pursuant to the Deferred Compensation Plan. The amounts reflect the aggregate grant date fair value computed in accordance with FASB ASC Topic 718. See Note 11 to our consolidated financial statements for the fiscal year ending December 31, 2013 for a discussion of the assumptions used to determine the FASB ASC Topic 718 value of the awards.

(2)

Represents amounts earned under our Cash Incentive Plan and not deferred into the Deferred Compensation Plan. Please read “Compensation Discussion and Analysis — Elements of Executive Compensation — Short-Term Cash Awards” for further details.

(3) Represents aggregate change in the actuarial present value of accumulated benefits under the Penreco Pension Plan. The actuarial present value of accumulated benefits under the Penreco Pension Plan decreased $48,079 in 2013 for Mr. Barnhart. Please read “Pension Benefits” for further details.

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(4) The following table provides the aggregate “All Other Compensation” information for each of the named executive officers, except that it excludes perquisites or other personal benefits received by Mr. Grube and Mr. Barnhart in 2013, as such amounts for these named executive officers were each less than $10,000 in aggregate.

	401(k) Plan Matching Contributions	Vehicle	Spousal Travel	Long-Term Disability Insurance	Term Life Insurance	Total
F. William Grube	$ 5,172	$—	$—	$ —	$926	$6,098
Jennifer G. Straumins	6,009	9,335	—	900	1,239	17,483
R. Patrick Murray, II	5,759	9,447	1,024	900	1,133	18,263
Timothy R. Barnhart	5,592	—	—	—	972	6,564

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Grants of Plan-Based Awards

The following table sets forth grants of plan-based awards to our named executive officers for the year ended December 31, 2013:

Grants of Plan-Based Awards Table for the Year Ended December 31, 2013

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Minimum ($)	Target ($)	Maximum ($)	Estimated Possible Payouts Under Equity Incentive Plan Awards (2) Minimum (#)	Target (#)	Maximum (#)	All Other Unit Awards: Number of Units (3) (#)	Grant Date Fair Value of Unit Awards ($)
F. William Grube		262,500	525,000	1,050,000					
					10,800	21,600	32,400		
	2/14/2013							438	14,016
	5/15/2013							468	17,382
	8/14/2013							561	18,911
	11/14/2013							584	18,402
Jennifer G. Straumins		175,000	350,000	700,000					
					7,200	14,400	21,600		
	2/14/2013							248	7,936
	5/15/2013							266	9,879
	8/14/2013							319	10,754
	11/14/2013							332	10,461
R. Patrick Murray, II		160,000	320,000	640,000					
					7,200	14,400	21,600		
	2/14/2013							182	5,824
	2/28/2013							507	19,449
	5/15/2013							235	8,728
	8/14/2013							280	9,439
	11/14/2013							292	9,201
Timothy R. Barnhart		150,000	300,000	600,000					
					7,200	14,400	21,600		
	2/14/2013							323	10,336
	2/28/2013							1,884	72,270
	5/15/2013							489	18,162
	8/14/2013							586	19,754
	11/14/2013							610	19,221

(1) Estimated possible payouts under non-equity incentive plan awards represent the ranges of potential cash incentive awards granted under our Cash Incentive Plan related to fiscal year 2013, although we did not pay these awards for the 2013 year. For a description of this plan and available awards please read "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Cash Incentive Plan."

(2) Estimated possible payouts under equity incentive plan awards represent the ranges of potential unit based awards earned under the 2013 Phantom Unit Program as part of the Long-Term Incentive Plan, although we did not pay these awards for the 2013 year. For a description of this plan and available awards under the 2013 Phantom Unit

Program please read “Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Long-Term Incentive Plan.”

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(3) All other unit awards represent discretionary matching contributions made by us in fiscal year 2013, in connection with the named executive officer's deferral of a portion of his or her cash incentive award under our Cash Incentive Plan from the 2012 year into the Deferred Compensation Plan. See "Nonqualified Deferred Compensation" for additional discussion of this plan. Also included are DERs credited in the form of phantom units earned on discretionary phantom unit grants, deferred cash incentive awards and discretionary matches on such deferred cash incentive awards.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

Description of Cash Incentive Plan

Annual distributable cash flow goals are recommended by the compensation committee to the board of directors and are based upon our annual forecast of financial performance for the upcoming fiscal year, and such goals are reviewed and approved by the board of directors. Three increasing distributable cash flow goals are established to calculate awards under the Cash Incentive Plan: minimum, target and stretch. Under the Cash Incentive Plan, if our actual performance meets at least the minimum distributable cash flow goal for the fiscal year, executives and certain other management employees may receive incentive awards ranging from 20% to 50% of base salary, depending on the employee's position with the general partner. If financial performance exceeds the minimum distributable cash flow goal, the cash incentive award paid as a percentage of base salary may be larger, ultimately reaching an upper range of 60% to 200% of base salary, if distributable cash flow for the fiscal year reaches the stretch goal. Cash incentive awards are prorated if actual performance falls between the defined minimum and stretch cash flow goals. If distributable cash flow falls below the minimum goal, no cash incentive awards are paid under the Cash Incentive Plan. The compensation committee can recommend to the full board of directors, however, that cash awards be given notwithstanding the fact that we failed to achieve at least the minimum distributable cash flow goal. Awards earned, if any, under this plan are generally paid in the first quarter of the following fiscal year after finalizing the calculation of our performance relative to the distributable cash flow targets. The following table summarizes the levels of awards available to participants in the Cash Incentive Plan:

	Cash Incentive Award Calculated as a Percentage of Base Salary		
Incentive Level (1)	Minimum	Target	Stretch
1	50%	100%	200%
2	50%	100%	150%
3	20%	40%	80%
4	20%	40%	60%

(1) Mr. Grube, Ms. Straumins, Mr. Murray and Mr. Barnhart participate in the Cash Incentive Plan at Incentive Level 1.

Participants in the Cash Incentive Plan are eligible to defer all or a portion of their award, if any, under the Cash Incentive Plan into the Deferred Compensation Plan, which was adopted by the board of directors on December 18, 2008 and effective as of January 1, 2009. See "Compensation Discussion and Analysis — Elements of Executive Compensation — Executive Deferred Compensation Plan" for additional discussion of this plan.

Description of Long-Term Incentive Plan

Following is a summary of the Long-Term Incentive Plan and the material terms relating to phantom units that we may grant pursuant to the Long-Term Incentive Plan:

General. The Long-Term Incentive Plan provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of DERs. Subject to adjustment for certain events, an aggregate of 783,960 common units may be delivered pursuant to awards under the Long-Term Incentive Plan. Units withheld to satisfy our general partner's tax withholding obligations are available for delivery pursuant to other awards. Our general partner's board of directors, in its discretion, may terminate the Long-Term Incentive Plan at any time with respect to the common units for which a grant has not theretofore been made. The Long-Term Incentive Plan will automatically terminate on the earlier of the 10th anniversary of the date it was initially approved by the board of directors of our general partner or when common units are no longer available for delivery pursuant to awards under the Long-Term Incentive Plan. Our general partner's board of directors have the right to alter or amend the Long-Term Incentive Plan or any part of it from time to time and the compensation committee may amend any award; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant. Subject to unitholder approval, if required by the rules of the principal national securities exchange upon which the common units are traded, the board of directors of our general partner may increase the number of common units that may be delivered with respect to awards under the Long-Term Incentive Plan.

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Phantom Units. We have historically granted phantom units pursuant to the Long-Term Incentive Plan, but during the 2013 year, we did not grant any awards to any named executive officer, including phantom units pursuant to the Long-Term Incentive Plan. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equal to the fair market value of a common unit. The compensation committee may make grants of phantom units under the Long-Term Incentive Plan to eligible individuals containing such terms, consistent with the Long-Term Incentive Plan, as the compensation committee may determine, including the period over which phantom units granted will vest. The compensation committee may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the phantom units will vest automatically upon a change of control (as defined in the Long-Term Incentive Plan) of us or our general partner, subject to any contrary provisions in the award agreement.

If a grantee's employment, consulting or membership on the board of directors terminates for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the grant agreement or the compensation committee provides otherwise. Common units to be delivered with respect to these awards may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units with respect to these awards, the total number of common units outstanding will increase. Any outstanding restricted unit or phantom unit awards fully vest upon the occurrence of certain events including, but not limited to, change of control, death, disability and normal retirement.

DERs are rights that entitle the grantee to receive, with respect to a phantom unit, cash equal to the cash distributions made by us on a common unit. The compensation committee, in its discretion, may grant tandem DERs with phantom units on such terms as it deems appropriate.

Participants do not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our general partner will receive remuneration for the units delivered with respect to these awards.

2013 Phantom Unit Program. In addition to the features described above, potential awards under our 2013 Phantom Unit Program ranged from 1,800 to 10,800 phantom units for achievement of the minimum distributable cash flow goal, 3,600 to 21,600 phantom units for achievement of the target distributable cash flow goal and from 5,400 to 32,400 phantom units for achievement of the stretch distributable cash flow goal. Awards are not prorated for actual distributable cash flow that is achieved between the minimum, target and stretch levels. Phantom units that would have been granted under this program would be subject to a time-vesting requirement, whereby 25% of the units would vest immediately at grant and the remainder would vest ratably over three years on each December 31. At the election of the general partner, phantom unit awards may be settled in either cash or common units. Phantom units also receive DERs, which are paid in the form of cash.

The following table summarizes the levels of phantom unit awards that would have been available to participants in the 2013 program:

	Phantom Unit Award Opportunity		
Incentive Level (1)	Minimum	Target	Stretch
1	10,800	21,600	32,400
2	7,200	14,400	21,600
3	5,400	10,800	16,200
4	3,600	7,200	10,800
5	1,800	3,600	5,400

(1) Mr. Grube is the only employee and named executive officer who was eligible for a long-term unit-based award under Incentive Level 1. Ms. Straumins, Mr. Murray and Mr. Barnhart were the only employees and named

executive officers who were eligible for a long-term unit-based award under Incentive Level 2.

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Description of Employment Agreement with F. William Grube

We have an employment agreement with F. William Grube, our chief executive officer and vice chairman of the board, dated as of January 31, 2006 (the "Effective Date"). The initial term of the employment agreement was five years and would have expired on January 31, 2011 (the "Employment Period"), but for the automatic extensions of an additional twelve months added to the Employment Period beginning on the third anniversary of the Effective Date, and on every anniversary of the Effective Date thereafter, unless either party notifies the other of non-extension at least ninety days prior to any such anniversary date. As neither we nor Mr. Grube provided notice of a non-renewal of the agreement within the ninety day period prior to January 31, 2013, the effective term now extends to at least January 31, 2016.

The agreement provides for an initial annual base salary of approximately $333,000, subject to various annual adjustments by the board of directors of our general partner that have been made following the Effective Date, as well as the right to participate in the Long-Term Incentive Plan, other bonus plans, our retirement, health and welfare benefit plans, and the use of an automobile. Mr. Grube will generally be entitled to receive a payout or distribution of at least 150% of the amount of any cash, equity or other payout or distribution that may be made to any other executive officer under the terms of these plans. Mr. Grube's employment agreement may be terminated at any time by either party with proper notice. The potential severance benefits provided within the employment agreement are described in greater detail in the "Potential Payments Upon Termination or Change in Control" section below. For the term of the employment agreement and for the one-year period following the termination of employment, Mr. Grube is prohibited from engaging in competition (as defined in the employment agreement) with us and soliciting our customers and employees.

Salary in Proportion to Total Compensation

The following table sets forth the percentage of each named executive officer's total compensation that we paid in the form of salary for 2013.

Salary Percentage for 2013

Name	Percentage of Total Compensation
F. William Grube	85%
Jennifer G. Straumins	86%
R. Patrick Murray, II	82%
Timothy R. Barnhart	67%

Outstanding Equity Awards at Fiscal Year-End

Our named executive officers had the following outstanding equity awards at December 31, 2013.

Outstanding Equity Awards at December 31, 2013

	Unit Awards	
Name	Number of Units That Have Not Vested	Market Value of Units That Have Not Vested (1)
F. William Grube (2)	28,134	$732,047
Jennifer G. Straumins (3)	17,212	$447,856
R. Patrick Murray, II (4)	17,968	$467,527
Timothy R. Barnhart (5)	20,524	$534,034

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price of $26.02 of our common units at December 31, 2013 (the last trading day of the fiscal year) by the number of units.

(2) 8,100 phantom units vest on December 31, 2014; 16,200 phantom units vest ratably over two years on each of December 31, 2014 and 2015; 609 phantom units vest on July 1, 2014; 1,131 phantom units vest ratably over two

years on each of July 1, 2014 and 2015 and 2,094 phantom units vest ratably over three years on each of July 1, 2014, 2015 and 2016.

(3) 5,400 phantom units vest on December 31, 2014; 10,800 phantom units vest ratably over two years on each of December 31, 2014 and 2015; 587 phantom units vest on July 1, 2014 and 425 phantom units vest ratably over two years on each of July 1, 2014 and 2015.

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(4) 5,400 phantom units vest on December 31, 2014; 10,800 phantom units vest ratably over two years on each of December 31, 2014 and 2015; 268 phantom units vest on July 1, 2014; 277 phantom units vest ratably over two years on each of July 1, 2014 and 2015; 682 phantom units vest ratably over three years on each of July 1, 2014, 2015 and 2016 and 541 phantom units vest ratably over four years on each of July 1, 2014, 2015, 2016 and 2017.

(5) 5,400 phantom units vest on December 31, 2014; 10,800 phantom units vest ratably over two years on each of December 31, 2014 and 2015; 399 phantom units vest on July 1, 2014; 647 phantom units vest ratably over two years on each of July 1, 2014 and 2015; 1,270 phantom units vest ratably over three years on each of July 1, 2014, 2015 and 2016 and 2,008 phantom units vest ratably over four years on each July 1, 2014, 2015, 2016 and 2017.

Options Exercises and Stock Vested

Our named executive officers exercised no options and had a total of 71,754 phantom units related to the Deferred Compensation Plan and the Long-Term Incentive Plan vest during the year ended December 31, 2013. The vested units related to the Deferred Compensation Plan will remain in the Deferred Compensation Plan until the earlier of the date specified by each participant and the participant's termination of employment.

Unit Awards Vested During Year Ended December 31, 2013

Name	Unit Awards Number of Units Vested	Value Realized on Vesting (1)
F. William Grube	20,968	$577,948
Jennifer G. Straumins	14,626	404,263
R. Patrick Murray, II	15,219	431,838
Timothy R. Barnhart	20,941	646,209

(1) Market value of phantom units reported in this column is calculated by multiplying the closing market price of our common units on the vesting date by the number of units vesting on such date.

Pension Benefits

Executive	Plan Name	Number of Years of Credited Service (1)	Present Value of Accumulated Benefits (2)	Payments During 2013
Timothy R. Barnhart	Penreco Pension Plan	26.3205	$311,246	$—

(1) Mr. Barnhart's "Number of Years Credited Service" is computed using the same pension plan measurement dates used for our financial statement reporting purposes with respect to our audited consolidated financial statements for the 2013 fiscal year; a further description can be found in Note 11 to such statements included in this Annual Report. This column contemplates Mr. Barnhart's previous employment with Penreco, as well as our decision to freeze account benefit accumulation for all salaried participants as of January 31, 2009.

(2) In addition to the assumptions noted within Note 11 to our audited consolidated financial statements for the 2013 fiscal year, the assumptions used to calculate the amounts shown in the "Present Value of Accumulated Benefits" column above are as follows: (a) payments under the Pension Plan were assumed to begin for Mr. Barnhart at age 65; (b) the December 31, 2013 Financial Accounting Standards ("FAS") disclosure weighted average discount rate of 4.78% was used; and (c) payments assumed to be made following age 65 were also discounted using the FAS disclosure mortality assumption (no mortality was assumed prior to age 65).

We acquired Penreco from ConocoPhillips and M.E. Zukerman Specialty Oil Corporation on January 3, 2008. In connection with this acquisition, we also took over the Penreco Pension Plan, a noncontributory defined benefit plan, in which both salaried and union employees were entitled to participate (the "Pension Plan"). However, while we agreed to maintain and continue administration of the Pension Plan, we froze the plan as in effect for salaried employees effective January 31, 2009. "Freezing" this portion of the Pension Plan meant that no more salaried employees were permitted to join the plan following January 31, 2009, and the accounts of current participants were not permitted to accrue further benefits following January 31, 2009.

Mr. Timothy R. Barnhart, as a former salaried Penreco employee, participates in the Pension Plan. Salaried employees such as Mr. Barnhart were eligible to participate in the plan following one year of completed service. The Pension Plan is

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intended to provide a “normal” pension benefit to participants upon their “normal” retirement age of 65. A normal retirement benefit is equal to the greater of: (1) the sum of (a) one and one-sixth percent of the participant’s “final average compensation” multiplied by his years of service prior to 1974, plus (b) one and one-tenth percent of a participant’s “final average compensation” multiplied by his years of service after 1973, plus (c) five-tenths percent of the amount of the participant’s monthly “final average compensation” in excess of the participant’s final “covered compensation” in the year of retirement, multiplied by his years of service after 1973; or (2) $40 multiplied by a participant’s years of service; or (3) the accrued pension amount as determined under the terms of the Pension Plan as in effect on June 30, 2003. Once the greatest of these three options is determined, a normal pension will then be calculated by subtracting the pension benefit determined under two of the various superseded and prior plans, or the pension benefit as calculated under the union employee portion of the Pension Plan if the participant was previously a participant in that portion of the Pension Plan.

The “average final compensation” is the highest monthly “considered compensation” of a participant during the 60 consecutive months immediately prior to January 31, 2009. A participant’s “considered compensation” under the Pension Plan consists of all of the compensation actually provided to a participant in consideration of his performance of services to his employer that is considered taxable wages, excluding any compensation received from the exercise of stock options, from distributions of any other employee benefit plan accounts, or amounts paid by his employer for life insurance policies; this amount will be limited to the amount as noted in Code section 401(a)(17)(B) for an applicable year (which was $255,000 for the 2013 year). However, due to our freezing of benefits in 2009, no amount of compensation earned after January 31, 2009 shall be deemed “considered compensation” for purposes of the Pension Plan. “Covered compensation” under the Pension Plan means the average taxable wage base during the 35 years immediately prior to the date the participant reaches the social security retirement age.

Other than a “normal” retirement, there are various events that would require or allow the distribution of Pension Plan accounts. Participants may receive an “early” retirement benefit upon reaching the age of 55 but prior to reaching age 65. In the event that a participant suffers a “disability” prior to normal retirement, the participant will be eligible to receive a disability pension benefit upon reaching the age of 65. If a participant works past the age of 65, his Pension Plan benefit will not be calculated differently than if calculated at age 65. If a participant separates from service prior to retirement, the retirement benefit will be calculated based upon years of service completed at the separation date, although payments will not begin until the participant reaches a normal or early retirement age. As of December 31, 2013, Mr. Barnhart was not yet eligible to receive an “early” or a “normal” retirement benefit pursuant to the Pension Plan. Any participant in the Pension Plan as of January 31, 2009 was also considered fully vested in his or her account, thus Mr. Barnhart is 100% vested in all portions of his Pension Plan account.

A normal form of payment will be distributed in a monthly annuity payment, but a participant may also elect a different monthly benefit amount prior to normal retirement, which would allow the participant to receive a reduced pension amount while continuing to provide for a surviving spouse upon his death, known as a joint and survivor annuity benefit. This will typically provide a 50% benefit as a retirement benefit and 50% will be deferred until it is needed for surviving spouse support, although the participant and his spouse may make written elections to alter these percentages during the participant’s service.

Nonqualified Deferred Compensation

The Deferred Compensation Plan became effective as of January 1, 2009. The Deferred Compensation Plan is an unfunded arrangement intended to be exempt from the participation, vesting, funding and fiduciary requirements set forth in Title I of the Employee Retirement Income Security Act of 1974, as amended, and to comply with Section 409A of the Code. Our obligations under the Deferred Compensation Plan will be general unsecured obligations to pay deferred compensation in the future to eligible participants in accordance with the terms of the Deferred Compensation Plan from our general assets. The compensation committee of our general partner’s board of directors acts as the plan administrator.

Nonqualified Deferred Compensation Table for 2013

Name	Executive Contributions	Company Contributions	Aggregate Earnings	Aggregate Withdrawals/	Aggregate Balance at end

	in 2013 (1)	in 2013 (2)	in 2013 (3)	Distributions in 2013	of 2013 (4)
F. William Grube	$—	$—	$68,711	$—	$782,083
Jennifer G. Straumins	—	—	39,030	—	491,544
R. Patrick Murray, II	—	—	33,192	—	398,193
Timothy R. Barnhart	—	—	67,473	—	806,880

(1) No executive contributions were made with respect to the 2013 year. Executive contributions in 2013 would have represented phantom units granted to certain of our named executive officers based on their individual elections to defer

all or a portion of their cash incentive award under the Cash Incentive Plan related to the 2013 fiscal year into the Deferred Compensation Plan.

(2) No company contributions were made with respect to the 2013 year. Our contributions for the 2013 would have reflected discretionary matching contributions made in the form of phantom units granted to our named executive officers based on their individual elections to defer all or a portion of their cash award under the Cash Incentive Plan related to the 2013 fiscal year into the Deferred Compensation Plan.

(3) Aggregate earnings in 2013 represent additional phantom units earned through DERs in the applicable named executive officer's Deferred Compensation Plan account on phantom units granted under the discretionary matching contribution on February 28, 2013, as well as phantom units granted in fiscal years 2012, 2011, 2010 and 2009. These amounts, which represent the fair value of the phantom units earned on the corresponding dates of our distributions to our unitholders in fiscal year 2013, are included as compensation in 2013 under "Unit Awards" in the Summary Compensation Table.

(4) While the aggregate balance of each participant's Deferred Compensation Plan account at the end of the fiscal year is comprised of the phantom units related to the executive and discretionary matching contributions as well as the phantom units attributable to aggregate earnings accumulated during the 2013 year, the dollar amount of each participant's account as of December 31, 2013 was determined by multiplying all phantom units deemed to be included in the participant's account by the closing price of our common units on December 31, 2013, which was $26.02. The phantom units associated with each executive's account as of December 31, 2013 were as follows: Mr. Grube, 30,057; Ms. Straumins, 18,891; Mr. Murray, 15,331 and Mr. Barnhart, 31,010. Subject to the executive's continued employment with us, these phantom units will become vested over a four year period (except for phantom units associated with executive contributions, which are fully vested at the time of cash incentive deferral), but such vesting applies to the number of phantom units credited to the participant's account, and not the value of the account at any given time. The value of the executives' accounts will fluctuate due to the fact that the value of their phantom units will track the value of our common units. Also, please keep in mind that the executives' accounts are not currently fully vested; subject to the forfeiture provisions described below, these amounts do not reflect the payout amount that an executive would receive if he or she voluntarily left our service prior to vesting. The amounts in this column also include amounts that were previously reported as compensation in the Summary Compensation Table during previous years as follows: (a) for 2009, Mr. Grube, $113,348; Ms. Straumins, $109,362; Mr. Murray, $49,354; and Mr. Barnhart, $74,939 (b) for 2010, Mr. Grube, $115,373; Ms. Straumins, $43,590; Mr. Murray, $28,553 and Mr. Barnhart, $66,178 (c) for 2011, Mr. Grube, $160,800; Mr. Murray, $52,664 and Mr. Barnhart, $97,726 and (d) for 2012, Mr. Murray, $58,384 and Mr. Barnhart, $216,811.

The named executive officers, as well as other officers and key employees, participate in the Deferred Compensation Plan by making an annual irrevocable election to defer all or a portion of their annual cash incentive award for the year. The deferred amounts will be credited to the participants' accounts in the form of phantom units, and will receive DERs to be credited in the form of additional phantom units to the participants' account. We have the discretion to make matching contributions of phantom units or purely discretionary contributions of phantom units, in amounts and at times as the compensation committee determines appropriate. For the 2013 year, the compensation committee authorized matching contributions of deferred amounts related to the 2012 fiscal year. For each equivalent three phantom units credited to a participant's account at the time the 2012 cash incentive award was paid during the first quarter of 2013, we matched with one additional phantom unit credited to the participant's account. Participants will at all times be 100% vested in amounts they have deferred; however, amounts we have contributed may be subject to a vesting schedule, as determined appropriate by the compensation committee. The 2013 matching contributions related to fiscal year 2012 will vest ratably over four years on each July 1 beginning July 1, 2014. The participants' accounts are adjusted at least quarterly to determine the fair market value of our phantom units, as well as any DERs that may have been credited in that time period. Distributions from the Deferred Compensation Plan are payable on the earlier of the date specified by each participant and the participant's termination of employment. Death, disability, normal retirement or our change of control (as such terms are defined within the Long-Term Incentive Plan) require automatic distribution of the Deferred Compensation Plan benefits, and will also accelerate at that time the vesting of any portion of a participant's account that has not already become vested. Benefits will be distributed to participants in the form of our common units, cash or a combination of common units and cash at the election of the compensation committee. In the event that accounts are paid in common units, such units will be distributed pursuant to the Long-Term Incentive Plan. Unvested portions of a participant's account will be forfeited in the event that a distribution was due to a participant's voluntary resignation or a termination for cause. To ensure compliance with Section 409A of the Code, distributions to participants that are considered "key employees" (as defined in Code Section 409A of the Code) may be delayed for a period of six months following such key employees' termination of employment with us.

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Potential Payments Upon Termination or Change in Control

Employment Agreement with F. William Grube

Following is a description of our obligations, including potential payments to Mr. Grube, upon termination of Mr. Grube's employment under various termination scenarios. We have assumed for purposes of quantifying Mr. Grube's potential payments that his termination occurred on December 31, 2013, and earned salary and bonus amounts are paid current. The amounts are our best estimates as to the potential payout he would have received upon December 31, 2013, but the amounts Mr. Grube would receive upon an actual termination of employment could only be calculated with certainty upon a true termination of employment.

In consideration for any potential severance Mr. Grube may receive pursuant to his employment agreement, he will not compete or solicit our employees for a period of one year following a termination of employment. Prior to receipt of any potential severance payments or the acceleration of any outstanding equity awards, Mr. Grube will be required to sign, and not revoke, a full waiver and release in our favor. Following such release and waiver's period of revocability, Mr. Grube will be eligible to receive payments as soon as administratively possible, though if Code Section 409A would subject Mr. Grube to additional taxes upon receipt of the payments, we will delay the payment of these amounts for a period of six months and provide for interest to accrue on such delayed amounts at the maximum nonusurious rate from the date of the originally scheduled payment date. Mr. Grube is also eligible to receive an additional sum from us in the event that any termination payments we provide to him are considered "parachute" payments pursuant to Section 280G of the Internal Revenue Code of 1986, as amended (the "Code"); a parachute payment could occur in connection with a change in control or a termination of employment that was also in connection with a change in control, but such a payment would not occur in the event of a termination of Mr. Grube's employment that is not in connection with a change in control. This additional payment, if necessary, would equal the amount necessary to place Mr. Grube in the same after-tax position he would have been in absent the additional excise taxes imposed by Section 280G of the Code.

Termination of Employment Due to Death or Disability

Upon the termination of Mr. Grube's employment due to his disability or death:

a. We will pay him or his beneficiary a lump sum equal to his earned annual base salary through the date of termination to the extent not theretofore paid;

b. We will pay him or his beneficiary a lump sum equal to any compensation incentive awards payable in cash with respect to fiscal years ended prior to the year that includes the date of termination to the extent not theretofore paid;

c. We will pay him or his beneficiary a lump sum cash payment with respect to his participation in any plans, programs, contracts or other arrangements that may result in a cash payment for the fiscal year that includes the date of termination on a prorated basis considering the date of termination relative to the full fiscal year; and

d. Any equity awards held by Mr. Grube shall immediately vest and become fully exercisable or payable, as the case may be.

For this purpose, Mr. Grube will be deemed to have a "disability" if he is unable to perform his duties under the employment agreement by reason of mental or physical incapacity for 90 consecutive calendar days during the Employment Period, provided that we will not have the right to terminate his employment for disability if in the written opinion of a qualified physician reasonably acceptable to us is delivered to the us within 30 days of our delivery to Mr. Grube of a notice of termination (as defined in the employment agreement) that it is reasonably likely that Mr. Grube will be able to resume his duties on a regular basis within 90 days of the notice of termination and Mr. Grube does resume such duties within such time.

If Mr. Grube's employment were to have been terminated on December 31, 2013, due to death or disability (as defined in the employment agreement), we estimate that the value of the payments and benefits described in clauses (a), (b), (c) and (d) above he would have been eligible to receive is as follows: (a) $0; (b) $0; (c) $782,083; and (d) $1,088,937, with an aggregate value of $1,871,020.

Termination of Employment by Mr. Grube for Good Reason or by Us Without Cause

Upon the termination of Mr. Grube's employment by him for good reason or by us without cause:

a. We will pay him a lump sum cash payment in an amount equal to three times his annual base salary then in effect;
b. We will pay him a lump sum equal to his earned annual base salary through the date of termination to the extent not theretofore paid;

c. We will pay him a lump sum equal to any compensation incentive awards payable in cash with respect to fiscal years ended prior to the year that includes the date of termination to the extent not theretofore paid;
d. We will pay him a lump sum cash payment with respect to his participation in any plans, programs, contracts or other arrangements that may result in a cash payment for the fiscal year that includes the date of termination on a prorated basis considering the date of termination relative to the full fiscal year;
e. All equity-based awards (including phantom unit awards) held by Mr. Grube shall immediately vest in full (at their target levels, if applicable) and become fully exercisable or payable, as the case may be.
“Good reason” as defined in the employment agreement includes: (i) any material breach by us of the employment agreement; (ii) any requirement by us that Mr. Grube relocate outside of the metropolitan Indianapolis, Indiana area; (iii) failure of any successor to us to assume the employment agreement not later than the date as of which it acquires substantially all of the equity, assets or business of us; (iv) any material reduction in Mr. Grube’s title, authority, responsibilities, or duties (including a change that causes him to cease being a member of the board of directors or reporting directly and solely to the board of directors); or (v) the assignment of Mr. Grube any duties materially inconsistent with his duties as our chief executive officer.
“Cause” as defined in the employment agreement includes: (i) Mr. Grube’s willful and continuing failure (excluding as a result of his mental or physical incapacity) to perform his duties and responsibilities with us; (ii) Mr. Grube’s having committed any act of material dishonesty against us or any of its affiliates as defined in the employment agreement; (iii) Mr. Grube’s willful and continuing breach of the employment agreement; (iv) Mr. Grube’s having been convicted of, or having entered a plea of nolo contendre to any felony; or (v) Mr. Grube’s having been the subject of any final and non-appealable order, judicial or administrative, obtained or issued by the Securities and Exchange Commission, for any securities violation involving fraud.
If Mr. Grube’s employment were to have been terminated by him for good reason or by us without cause on December 31, 2013, we estimate that the value of the payments and benefits described in clauses (a), (b), (c), (d) and (e) above he would have been eligible to receive is as follows: (a) $1,284,843 (or three times $428,281); (b) $0; (c) $0; (d) $782,083; and (e) $1,088,937, with an aggregate value of $3,155,863.
Termination of Employment by Mr. Grube Without Good Reason or by Us for Cause
Upon the termination of employment by Mr. Grube without good reason or by us with cause:
a. We will pay him a lump sum equal to his earned annual base salary through the date of termination to the extent not theretofore paid;
b. We will pay him a lump sum equal to any compensation incentive awards payable in cash with respect to fiscal years ended prior to the year that includes the date of termination to the extent not theretofore paid; and
c. We will pay him a lump sum cash payment with respect to his participation in any plans, programs, contracts or other arrangements that may result in a cash payment for the fiscal year that includes the date of termination on a prorated basis considering the date of termination relative to the full fiscal year.
If Mr. Grube’s employment were to have terminated by him without good reason or by us for cause on December 31, 2013, we estimate that the value of the payments and benefits described in clauses (a), (b) and (c) above he would have been eligible to receive is as follows: (a) $0; (b) $0; and (c) $782,083, with an aggregate value of $782,083.
Termination or Change of Control Pursuant to Long-Term Incentive Plan
Unless specifically provided otherwise in the named executive officer’s individual award agreement, upon a Change of Control all outstanding awards granted pursuant to the Long-Term Incentive Plan shall automatically vest and be payable at their maximum target level or become exercisable in full, as the case may be, or any restricted periods connected to the award shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. We provide these “single-trigger” change of control benefits because we believe such benefits are important retention tools for us, as providing for accelerated vesting of awards under the Long-Term Incentive Plan upon a Change of Control enables employees, including the named executive officers, to realize value from these awards in the event that we go through a change of control transaction. In addition, we believe that it is important to provide the named executive officers with a sense of stability, both in the middle of transactions that may create uncertainty regarding their future employment and post-termination as they seek future employment. Whether or not a

change of control results in a termination of our officers' employment with us or a successor entity, we want to provide our officers with certain guarantees regarding the importance of equity incentive compensation awards they were granted prior to that change of control. Further, we believe that change of control protection allows management to focus their attention and energy on the business transaction at hand without any distractions regarding the effects of a change of control. Also, we believe that such protection maximizes unitholder value by encouraging the named

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executive officers to review objectively any proposed transaction in determining whether such proposed transaction is in the best interest of our unitholders, whether or not the executive will continue to be employed.

For purposes of the Long-Term Incentive Plan, a Change of Control shall be deemed to have occurred upon one or more of the following events: (i) any person or group, other than a person or group who is our affiliate, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of fifty percent (50%) or more of the voting power of our outstanding equity interests; (ii) a person or group, other than our general partner or one of our general partner's affiliates, becomes our general partner; or (iii) the sale or other disposition, including by liquidation or dissolution, of all or substantially all of our assets or the assets of our general partner in one or more transactions to any person or group other than an a person or group who is our affiliate. However, in the event that an award is subject to Code Section 409A, a Change of Control shall have the same meaning as such term in the regulations or other guidance issued with respect to Code Section 409A for that particular award.

Under the Long-Term Incentive Plan, the awards will also accelerate upon a termination due to death, disability or a normal retirement upon or after reaching the age of 66. The Board has the final authority to determine if a disability is permanent or of a long term duration resulting in termination from us. A "disability" per the terms of the Long-Term Incentive Plan grant means (i) a participant's inability to engage in any substantial gainful activity by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, or (ii) the participant is, by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, receiving income replacement benefits for a period of not less than 3 months under one of our accident and health plans. We have determined that providing acceleration of the Long-Term Incentive Plan awards upon a death or disability is appropriate because the termination of a participant's employment with us due to such an occurrence is often an unexpected event, and it is our belief that providing an immediate value to the participant or his or her family, as appropriate, in such a situation is a competitive retention tool. We also believe that providing for acceleration upon a normal retirement is appropriate due to the fact that the definition of a normal retirement requires an executive to remain employed with us until late in his or her career, and the acceleration of their equity awards upon such an event provides the executives with a reassurance that they will receive value for their awards at the end of their career. We have determined that it is in the unitholders' best interest to provide such retention tools with respect to our equity compensation awards due to the fact that we strive to retain a high level of executive talent while competing in a very aggressive industry.

The following table discloses the amount each executive could receive as of December 31, 2013 under the Long-Term Incentive Plan upon a termination of employment or a Change of Control:

	Potential Payments from the Long-Term Incentive Plan (1)	
Name	Change of Control	Termination due to Death, Disability or Normal Retirement
F. William Grube	$1,088,937	$1,088,937
Jennifer G. Straumins	725,928	725,928
R. Patrick Murray, II	725,928	725,928
Timothy R. Barnhart	725,928	725,928

(1) All amounts assume that the executives received full vesting of equity awards due to the applicable termination or Change of Control event, and the value of all phantom units pursuant to equity awards under the Long-Term Incentive Plan were valued at our December 31, 2013 closing common unit price of $26.02. As required pursuant to Section 409A of the Code, in the event that any of the executives are also "key employees" as defined in Section 409A of the Code at the time a settlement would become due, we would delay the settlement of such an executive's equity awards until the first day of the seventh month following the applicable event requiring settlement of equity awards under the Long-Term Incentive Plan.

Termination or Change of Control with Respect to Deferred Compensation Plan Participants

The Deferred Compensation Plan provides the executives with the opportunity to defer all or a portion of their eligible compensation each year. At the time of their deferral election, the executive may choose a day in the future in which a payout from the plan will occur with regard to their vested account balance, or, if earlier, the payout of vested accounts will occur upon the executive's termination from service for any reason. Despite the executive's payout election date, however, the Deferred Compensation Plan accounts will also receive accelerated vesting and a pay out in the event of the executive's termination from service due to death, disability or normal retirement, or upon the occurrence of a Change of Control.

A “disability” under the Deferred Compensation Plan means (i) a participant’s inability to engage in any substantial gainful activity by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, or (ii) the participant is, by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, receiving income replacement benefits for a period of not less than 3 months under one of our accident and health plans. A “normal retirement” means a participant’s termination of employment on or after the date that he or she reaches the age of 66.

There are various connections between the Deferred Compensation Plan and the Long-Term Incentive Plan. A “Change of Control” for the Deferred Compensation Plan shall have the same definition as that term within the Long-Term Incentive Plan noted above. Our compensation committee also has the discretion to pay Deferred Compensation Plan accounts in either cash or our common units. In the event that a Deferred Compensation Plan account is settled in our common units, those units will be issued pursuant to the Long-Term Incentive Plan. For purposes of this disclosure we have assumed that the compensation committee would determine to settle the Deferred Compensation Plan accounts solely in our common units, meaning that the amounts below would reflect the fair market value of common units that could be issued pursuant to the Long-Term Incentive Plan in connection with a termination of employment or a Change of Control. Please note that the compensation committee’s decision regarding such a settlement could not be determined with any certainty until such an event actually occurred.

The following table discloses the amount each executive could receive as of December 31, 2013 under the Deferred Compensation Plan upon a termination of employment or a Change of Control:

	Potential Payments from the Deferred Compensation Plan (1)	
Name	Change of Control	Termination due to Death, Disability or Normal Retirement
F. William Grube	$782,083	$782,083
Jennifer G. Straumins	491,544	491,544
R. Patrick Murray, II	398,193	398,193
Timothy R. Barnhart	806,880	806,880

(1) All amounts assume that the executives received full vesting of the accounts due to the applicable termination or Change of Control event, and the value of all phantom units held in the Deferred Compensation Plan accounts was valued at our December 31, 2013 closing common unit price of $26.02. As required pursuant to Section 409A of the Code, in the event that any of the executives are also “key employees” as defined in Section 409A of the Code at the time a settlement would become due, we would delay the settlement of such an executive’s account until the first day of the seventh month following the applicable event requiring settlement of the Deferred Compensation Plan account.

Compensation of Directors

Officers or employees of our general partner who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each director who is not an officer or employee of our general partner receives an annual fee as well as compensation for attending meetings of the board of directors and board committee meetings. Non-employee director compensation for 2013 consists of the following:

- an annual fee of $50,000, payable in quarterly installments;
- an annual award of 2,200 restricted or phantom units;
- an audit committee chair annual fee of $8,000, payable in quarterly installments;
- a non-chair audit committee member annual fee of $4,000, payable in quarterly installments;
- all other committee chair annual fee of $5,000, payable in quarterly installments; and
- all other committee member annual fee of $2,500, payable in quarterly installments.

In addition, we reimburse each non-employee director for his out-of-pocket expenses incurred in connection with attending meetings of the board of directors or board committees. Under certain circumstances, we will also indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

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The following table sets forth certain compensation information of our non-employee directors for the year ended December 31, 2013:

Director Compensation Table for 2013

Name	Fees Earned or Paid in Cash	Unit Awards (1)	Total
Fred M. Fehsenfeld, Jr.	$55,000	$123,122	$178,122
James S. Carter	59,000	130,310	189,310
William S. Fehsenfeld	50,000	62,392	112,392
Robert E. Funk	56,500	100,464	156,964
George C. Morris III	58,000	101,836	159,836
Nicholas J. Rutigliano	50,000	120,438	170,438

(1) The amounts in this column are calculated based on the aggregate grant date fair value of (i) annual phantom unit awards to all non-employee directors, (ii) matching phantom unit awards granted to those non-employee directors who deferred all of the fees they earned in 2013 pursuant to the Deferred Compensation Plan and (iii) DERs credited in the form of phantom units earned on deferred fees and discretionary matches on such deferred fees. Please see "Compensation Discussion and Analysis — Elements of Executive Compensation — Executive Deferred Compensation Plan" for a discussion of how we calculated these values. The amounts reflect the aggregate grant date fair value computed in accordance with FASB ASC Topic 718. See Note 11 to our consolidated financial statements for the fiscal year ending December 31, 2013 for a discussion of the assumptions used to determine the FASB ASC Topic 718 value of the awards.

Annual Phantom Unit Awards

On November 6, 2013, each non-employee director was granted 2,200 phantom units with a grant date fair value of $62,392. With respect to this award, 25% of the phantom units vested on December 31, 2013, entitling the director to receive an equal number of common units, with an additional 25% vesting on December 31 of each of the three successive years. As of December 31, 2013, each non-employee director had 3,287 unvested phantom units outstanding with a market value of $85,528 related to annual equity awards from 2011, 2012 and 2013. Related to these annual equity awards made to non-employee directors, an aggregate of 19,722 unvested phantom units with a market value of $513,166 were outstanding as of December 31, 2013.

Deferred Compensation Plan

Messrs. F. Fehsenfeld, Jr., Carter, Morris and Rutigliano each elected to defer all of their fees earned related to fiscal year 2013 into the Deferred Compensation Plan. These deferred amounts are credited to the participant's account in the form of phantom units, and will receive DERs to be credited to the participant's account in the form of additional phantom units on the corresponding dates of our distributions to our unitholders. The compensation committee recommended, and the board of directors approved, a matching contribution of one phantom unit for each equivalent three phantom units deferred for those fees earned related to fiscal year 2013. Phantom units credited to a participant's account pursuant to matching contributions also carry DERs to be credited to the participant's account in the form of additional phantom units. The matching contribution for each participant for fiscal year 2013 was made on a quarterly basis as of the date of our quarterly board meetings related to fiscal year 2013.

The following table summarizes the aggregate balance of each director's Deferred Compensation Plan account at the end of the fiscal year:

Director Nonqualified Deferred Compensation Table for 2013

Name	Number of Units	Aggregate Balance at end of 2013 (1)
Fred M. Fehsenfeld, Jr.	19,971	$519,645
James S. Carter	22,916	$596,274
Robert E. Funk	15,430	$401,489

George C. Morris III	9,241	$240,451
Nicholas J. Rutigliano	19,659	$511,527

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(1) The dollar amount of each director's account as of December 31, 2013 was determined by multiplying all phantom units deemed to be included in the participant's account by the closing price of our common units on December 31, 2013, which was $26.02.

Compensation Committee Interlocks and Insider Participation

The members of our compensation committee are F. William Grube and Fred M. Fehsenfeld, Jr. Mr. Grube is our chief executive officer and vice chairman of the board of our general partner. Mr. F. Fehsenfeld, Jr. is the chairman of the board of our general partner. Please read Item 13 "Certain Relationships and Related Transactions and Director Independence — Specialty Product Sales and Related Purchases" for descriptions of our transactions in fiscal year 2013 with certain entities related to Messrs. Grube and F. Fehsenfeld, Jr. No executive officer of our general partner served as a member of the compensation committee of another entity that had an executive officer serving as a member of our board of directors or compensation committee.

Risk Considerations in our Overall Compensation Program

Our compensation policies and practices are designed to provide rewards for high levels of financial performance. Currently, our incentive compensation programs are based on performance, at the Company level, relative to goals we set for distributable cash flow. In our assessment of risk related to such use of a single financial performance metric, we considered the relative difficulty for any employee to engage in an undue amount of risk-taking activity with a result that would be reasonably likely to have a material adverse effect on us due to the breadth and scope of activities, both operational and financial, across that organization that are captured in the calculation of distributable cash flow. Also, we considered the current approval controls that exist to mitigate against excessive risk-taking that might impact distributable cash flow and, in turn, our compensation programs. For example, we have specific approval policies related to the entry into derivative instruments, material commercial agreements and significant capital expenditures. Also, our full board of directors, as well as through the actions of its various committees, regularly assesses our key risk areas to monitor the impacts of such risks on our financial performance. Further, we considered the design of our incentive compensation programs, noting that the inclusion of both shorter-term cash incentive awards and longer-term unit awards further align the interest our employees and its unitholders. As a result of these considerations, we have concluded that the risks arising from our compensation policies and practices for our employees are not reasonably likely to have a material adverse effect on us.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units as of March 3, 2014 held by:

- each person who beneficially owns 5% or more of our outstanding units;
- each director of our general partner;
- each named executive officer of our general partner; and
- all directors, and executive officers of our general partner as a group.

The amounts and percentages of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

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Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. The address for the beneficial owners listed below, other than The Heritage Group and Calumet, Incorporated, is 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana 46214.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Total Units Beneficially Owned	
The Heritage Group (1) (2)	11,867,533	17.12	%
Calumet, Incorporated (2)	1,934,287	2.79	%
F. William Grube (3)(4)(5)	1,403,497	2.02	%
Jennifer G. Straumins (6)	1,349,151	1.95	%
Fred M. Fehsenfeld, Jr. (1)(2)(7)(8)	675,525	*	
R. Patrick Murray, II	32,814	*	
Timothy R. Barnhart	31,198	*	
George C. Morris III (9)	90,914	*	
William S. Fehsenfeld (1)(8)(10)	77,863	*	
Nicholas J. Rutigliano (1)(8)(11)	60,457	*	
James S. Carter	44,482	*	
Robert E. Funk	39,857	*	
All directors and executive officers as a group (10 persons)	3,805,758	5.49	%

* = less than 1 percent.

(1) Thirty grantor trusts indirectly own all of the outstanding general partner interests in The Heritage Group, an Indiana general partnership. The direct or indirect beneficiaries of the grantor trusts are members of the Fehsenfeld family. Each of the grantor trusts has five trustees, Fred M. Fehsenfeld, Jr., James C. Fehsenfeld, Nicholas J. Rutigliano, William S. Fehsenfeld and Amy M. Schumacher, each of whom exercises equivalent voting rights with respect to each such trust. Each of Fred M. Fehsenfeld, Jr., Nicholas J. Rutigliano and William S. Fehsenfeld, who are directors of our general partner, disclaims beneficial ownership of all of the common units owned by The Heritage Group, and none of these units are shown as being beneficially owned by such directors in the table above. The address for The Heritage Group is 5400 W. 86th St., Indianapolis, Indiana 46268. Of these common units, 367,197 are owned by The Heritage Group Investment Company, LLC ("Investment LLC"). Investment LLC is under common ownership with The Heritage Group. The Heritage Group, although not the owner of the common units, serves as the Manager of Investment LLC, and in that capacity has sole voting and investment power over the common units. The Heritage Group disclaims beneficial ownership of the common units owned by Investment LLC except to the extent of its pecuniary interest therein.

(2) The common units of Calumet, Incorporated are indirectly owned 45.8% by The Heritage Group and 5.1% by Fred M. Fehsenfeld, Jr. personally. Fred M. Fehsenfeld, Jr. is also a director of Calumet, Incorporated. Accordingly, 885,294 of the common units owned by Calumet, Incorporated are also shown as being beneficially owned by The Heritage Group in the table above, and 97,971 of the common units owned by Calumet, Incorporated are also shown as being beneficially owned by Fred M. Fehsenfeld, Jr. in the table above. The Heritage Group and Fred M. Fehsenfeld, Jr. disclaim beneficial ownership of all of the common units owned by Calumet, Incorporated in excess of their respective pecuniary interests in such units. The address of Calumet, Incorporated is 5400 W. 86th St., Indianapolis, Indiana 46268.

(3) Includes 775,000 common units that are owned by AEG Associates II, LLC, an Indiana limited liability company ("AEG II"). F. William Grube has sole voting and investment power over the common units. AEG II is co-owned by F. William Grube, William F. Grube, Jennifer G. Straumins, one grantor retained annuity trust for which Jennifer G. Straumins serves as sole trustee, and one grantor retained annuity trust for which Janet K. Grube, the spouse of

F. William Grube, serves as sole trustee. F. William Grube disclaims beneficial ownership of the common units owned by AEG II except to the extent of his pecuniary interest therein.

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(4) Includes common units that are owned by a grantor retained annuity trust for which Janet K. Grube, the spouse of F. William Grube, serves as sole trustee. Janet K. Grube and her two children are the beneficiaries of such trust. F. William Grube disclaims beneficial ownership of the common units owned by the trust.

(5) Includes common units that are owned by the spouse of F. William Grube, for which he disclaims beneficial ownership.

(6) Includes common units that are owned by the children of Jennifer G. Straumins, for which she disclaims beneficial ownership.

(7) Includes common units that are owned by the spouse and certain children of Fred M. Fehsenfeld, Jr., for which he disclaims beneficial ownership.

(8) Does not include a total of 1,979,804 common units owned by two trusts, the direct or indirect beneficiaries of which are members of the Fred M. Fehsenfeld, Jr. family. Each of the trusts has five trustees, Fred M. Fehsenfeld, Jr., James C. Fehsenfeld, Nicholas J. Rutigliano, William S. Fehsenfeld and Amy M. Schumacher, each of whom exercises equivalent voting rights with respect to each such trust. Each of Fred M. Fehsenfeld, Jr., Nicholas J. Rutigliano and William S. Fehsenfeld, who are directors of our general partner, disclaims beneficial ownership of all of the common units owned by the trusts, and none of these units are shown as being beneficially owned by such directors in the table above.

(9) Includes common units that are owned by the spouse of George C. Morris III, for which he disclaims beneficial ownership.

(10) Includes common units that are owned by the spouse of William S. Fehsenfeld, for which he disclaims beneficial ownership.

(11) Includes common units that are owned by the spouse of Nicholas J. Rutigliano, for which he disclaims beneficial ownership.

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Equity Compensation Plan Information

The following table summarizes information about our equity compensation plans as of December 31, 2013:

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (1) (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by unitholders	—	$—	—
Equity compensation plans not approved by unitholders	783,960	—	—
Total	783,960	$—	—

(1) The Long-Term Incentive Plan contemplates the issuance or delivery of up to 783,960 common units to satisfy awards under the plan. The number of units presented in column (a) assumes that all outstanding grants may be satisfied by the issuance of new units or the purchase of existing units on the open market upon vesting. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become "available for future issuance" under Column (c). For more information on our Long-Term Incentive Plan, which did not require approval by our limited partners, refer to Item 11 "Executive and Director Compensation — Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Long-Term Incentive Plan."

Item 13. Certain Relationships and Related Transactions and Director Independence

Distributions and Payments to Our General Partner and its Affiliates

Owners of our general partner and their affiliates own 18,164,551 common units representing a 26.2% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of \$0.495 (\$1.98 annualized) per unit, 25% of the amounts we distribute in excess of \$0.563 (\$2.25 annualized) per unit and 50% of amounts we distribute in excess of \$0.675 (\$2.70 annualized) per unit. Please refer to Part II, Item 5 "Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities — Market Information" for a summary of cash distribution levels of the Company during the year ended December 31, 2013 and for additional information related to incentive distribution rights.

Our general partner does not receive any management fee or other compensation for its management of our partnership; however, our general partner and its affiliates are reimbursed for all expenses incurred on our behalf. These expenses include the cost of employee, officer and director compensation and benefits properly allocable to us and all other expenses necessary or appropriate to the conduct of our business and allocable to us. The partnership agreement provides that our general partner determines the expenses that are allocable to us. There is no limit on the amount of expenses for which our general partner and its affiliates may be reimbursed.

Omnibus Agreement

We entered into an omnibus agreement, dated January 31, 2006, with The Heritage Group and certain of its affiliates pursuant to which The Heritage Group and its controlled affiliates agreed not to engage in, whether by acquisition or otherwise, the business of refining or marketing specialty lubricating oils, solvents and wax products as well as gasoline, diesel and jet fuel products in the continental U.S. ("restricted business") for so long as The Heritage Group controls us. This restriction does not apply to:

- any business owned or operated by The Heritage Group or any of its affiliates as of January 31, 2006;
- the refining and marketing of asphalt and asphalt-related products and related product development activities;
- the refining and marketing of other products that do not produce "qualifying income" as defined in the Internal Revenue Code;

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- the purchase and ownership of up to 9.9% of any class of securities of any entity engaged in any restricted business;
- any restricted business acquired or constructed that The Heritage Group or any of its affiliates acquires or constructs that has a fair market value or construction cost, as applicable, of less than $5.0 million;
- any restricted business acquired or constructed that has a fair market value or construction cost, as applicable, of $5.0 million or more if we have been offered the opportunity to purchase it for fair market value or construction cost and we decline to do so with the concurrence of the conflicts committee of the board of directors of our general partner; and
- any business conducted by The Heritage Group with the approval of the conflicts committee of the board of directors of our general partner.

Insurance Brokerage

Nicholas J. Rutigliano, a member of the board of directors of our general partner, served as president of Tobias Insurance Group, Inc., a commercial insurance brokerage business he founded, prior to it being acquired by Assured Partners, LLC. Mr. Rutigliano continues to serve as president of Tobias. Tobias has historically placed a portion of our insurance underwriting and surety/performance bond requirements, including our general liability, automobile liability, excess liability, workers' compensation as well as directors' and officers' liability and issuance of surety/performance bonds. The total premiums and fees paid by us through Mr. Rutigliano's firm for 2013 were approximately $0.7 million and were related to our directors' and officers' liability insurance. We believe these premiums are comparable to the premiums we would pay for such insurance from a non-affiliated third party and we have assessed our other insurance brokerage options to confirm this belief. We have transitioned the majority of the aforementioned insurance underwriting requirements to a non-affiliated third party commercial insurance broker.

Crude Oil Purchases

Since May 2008, we have purchased a portion of our crude oil supplies from Legacy Resources Co., L.P. ("Legacy Resources"), an exploration and production company owned in part by The Heritage Group, our chief executive officer and vice chairman of the board of our general partner, F. William Grube, and Jennifer G. Straumins, our president and chief operating officer. Mr. Grube and Ms. Straumins serve as members of the board of directors of Legacy Resources. The total purchases made by us from Legacy Resources in 2013 were approximately $1.2 million, which represented purchases based upon standard, index-based market rates.

From May 2008 to May 2011 we purchased all of our crude oil requirements for our Princeton refinery on a just in time basis utilizing a market-based pricing mechanism from Legacy Resources. Based on historical usage, the estimated volume of crude oil sold by Legacy Resources and purchased by us for the Princeton refinery was approximately 7,000 barrels per day. This agreement was terminated in May 2011.

On January 26, 2009, we entered into a Master Crude Oil Supply Agreement with Legacy Resources (the "Master Crude Oil Supply Agreement"). Under this agreement, Legacy Resources may supply our Shreveport refinery with a portion of its crude oil requirements that are received via common carrier pipeline. Pricing for the crude oil purchased under each confirmation will be mutually agreed to by the parties and set forth in such confirmation and will include a market-based premium as determined and agreed to by the parties. The agreement was effective as of January 26, 2009 and will continue to be in effect until terminated by either party by written notice. Based on historical usage, the estimated volume of crude oil to be sold by Legacy Resources and purchased by us under this Agreement is up to 15,000 barrels per day. This agreement is active but is not currently in use.

From September 2009 to May 2011, we purchased crude oil under a Crude Oil Supply Agreement (the "Shreveport Crude Oil Supply Agreement") with Legacy Resources. Under the Agreement, Legacy Resources supplied our Shreveport refinery with a portion of its crude oil requirements on a just in time basis utilizing a market-based pricing mechanism. Based on historical usage, the estimated volume of crude oil to be sold by Legacy Resources and purchased by us under this Agreement was up to 20,000 barrels per day. This agreement was terminated in May 2011.

With the termination of the agreements, we have one remaining crude oil supply agreement with Legacy Resources, the Master Crude Oil Purchase and Sale Agreement, that was entered into on January 26, 2009. No crude oil is currently being purchased by the Company under this agreement.

Because Legacy Resources is owned in part by one of our limited partners, an affiliate of our general partner, our chief executive officer and vice chairman of the board of directors of our general partner, F. William Grube, and our president and chief operating officer, Jennifer G. Straumins, the terms of the aforementioned agreements were reviewed by the conflicts committee of the board of directors of our general partner, which consists entirely of independent directors. The conflicts committee approved the agreements after determining that the terms of the agreements are fair and reasonable to us.

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Product Sales and Related Purchases

During 2013, we made ordinary course sales of certain specialty products to Johann Haltermann, Ltd. (“Haltermann”), a specialty chemical company owned in part by The Heritage Group and a Grube family trust for which Janet K. Grube is sole trustee. The total sales made by us to Haltermann in 2013 were approximately $1.9 million. As of December 31, 2013 there was no balance due us from Haltermann related to these products sales. We anticipate that we will continue to sell products to Haltermann in the future. We believe that the product sales prices and credit terms offered to Haltermann are comparable to prices and terms offered to non-affiliated third party customers.

During 2013, we made ordinary course sales of certain specialty products to Heritage-Crystal Clean Inc. (“Crystal Clean”), a cleaning and waste removal company owned in part by The Heritage Group and Fred M. Fehsenfeld, Jr. as an individual. The total sales made by us to Crystal Clean in 2013 were approximately $0.2 million. As of December 31, 2013, there was no balance due us from Crystal Clean related to these products sales. We anticipate that we will continue to sell products to Crystal Clean in the future. The total purchases made by us from Crystal Clean in 2013 for cleaning and waste removal services were approximately $8.4 million. As of December 31, 2013, there was a $1.3 million balance due from us to Crystal Clean related to these purchases. We believe that the product sales prices and credit terms offered to Crystal Clean are comparable to prices and terms offered to non-affiliated third party customers.

During 2013, we made ordinary course purchases from Heritage Environmental Services (“Heritage Environmental”), a cleaning and waste removal company owned in part by The Heritage Group and Fred M. Fehsenfeld, Jr. as an individual. Total purchases made by us from Heritage Environmental in 2013 for cleaning and waste removal services were approximately $0.6 million. As of December 31, 2013, there was a $0.1 million balance due from us to Heritage Environmental related to these purchases.

During 2013, we made payments to Asphalt Materials, Inc., an affiliate of The Heritage Group (“Asphalt Materials”), for expenses related to the business use of The Heritage Group’s company plane by our senior executive officers and for environmental consulting services provided to us by Asphalt Materials. The aggregate payments for these services made by us to Asphalt Materials in 2013 were approximately $0.5 million. As of December 31, 2013, there was an immaterial amount due from us to Asphalt Materials related to these services. We believe that the costs of the services provided to us by Asphalt Materials are comparable to costs charged by non-affiliated third-party suppliers of similar services. During 2013, we made ordinary course sales of certain fuel products to Asphalt Materials of $7.6 million. As of December 31, 2013, there was a $0.2 million balance due us from Asphalt Materials related to these products sales. We also reimburse Asphalt Materials for ordinary course purchases made by us under a procurement card program administered by Asphalt Materials. As of December 31, 2013, there was approximately $2.9 million payable by us to Asphalt Materials related to the reimbursement of these ordinary course purchases. With the exception of the procurement card program, we expect that we will continue to utilize each of these services from Asphalt Materials in the future.

Calumet Packaging Acquisition

On January 6, 2012, we completed the acquisition of all of the outstanding membership interests of TruSouth Oil, LLC which was renamed Calumet Packaging, LLC in 2013 for aggregate consideration of approximately $26.9 million. Immediately prior to its acquisition, Calumet Packaging was owned in part by Fred M. Fehsenfeld, Jr.; the spouse of F. William Grube; and other members of the Fehsenfeld and Grube families, who also own our general partner. The terms of the agreement were reviewed by the conflicts committee of the board of directors of our general partner, which consists entirely of independent directors. The conflicts committee approved the agreement after determining that the terms of the agreement were fair and reasonable to us.

Procedures for Review and Approval of Related Person Transactions

Effective February 9, 2007, to further formalize the process by which related person transactions are analyzed and approved or disapproved, the board of directors of our general partner has adopted the Calumet Specialty Products Partners, L.P. Related Person Transactions Policy (the “Policy”) to be followed in connection with all related person transactions (as defined by the Policy) involving the Company and its subsidiaries. The Policy was adopted to provide guidelines and procedures for the application of the partnership agreement to related person transactions and to further

supplement the conflicts resolutions policies already set forth therein.
The Policy defines a “related person transaction” to mean any transaction since the beginning of the Company’s last fiscal year (or any currently proposed transaction) in which: (i) the Company or any of its subsidiaries was or is to be a participant; (ii) the amount involved exceeds $120,000 (including any series of similar transactions exceeding such amount on an annual basis); and (iii) any related person (as defined in the Policy) has or will have a direct or indirect material interest. Under the terms of the policy, our general partner’s chief executive officer (“CEO”) has the authority to approve a related person transaction (considering any and all factors as the CEO determines in his sole discretion to be relevant, reasonable or appropriate under the circumstances) so long as it is:

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(a) in the normal course of the Company's business;
(b) not one in which the CEO or any of his immediate family members has a direct or indirect material interest; and
(c) on terms no less favorable to the Company than those generally being provided to or available from unrelated third parties or fair to the Company, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Company).

The CEO does not have the authority to approve the issuances of equity or grants of awards under the Company's Long-Term Incentive Plan, except as provided in that plan. Pursuant to the Policy, any other related person transaction must be approved by the conflicts committee acting in accordance with the terms and provisions of its charter.

A copy of the Policy is available on our website at www.calumetspecialty.com and will be provided to unitholders without charge upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway E. Drive, Suite 200, Indianapolis, IN 46214.

Please see Item 10 "Directors, Executive Officers of Our General Partner and Corporate Governance" for a discussion of director independence matters.

Item 14. Principal Accounting Fees and Services

The following table details the aggregate fees billed for professional services rendered by our independent auditor during 2013 and 2012 (in millions).

	Year Ended December 31,	
	2013	2012
Audit fees	$5.4	$2.9
Audit-related fees	0.2	0.6
Tax fees	0.2	0.1
Total	$5.8	$3.6

"Audit fees" above include those related to our annual audit, audit of our general partner and quarterly review procedures.

"Audit-related fees" primarily relate to procedures related to due diligence related to acquisitions, accounting consultations and audits in connection with acquisitions and attest services related to financial reporting that are not required for the audit.

"Tax fees" are related to due diligence and domestic compliance matters.

Pre-Approval Policy

The audit committee of our general partner's board of directors has adopted an audit committee charter, which is available on our website at http://www.calumetspecialty.com. The charter requires the audit committee to pre-approve all audit and non-audit services to be provided by our independent registered public accounting firm. The audit committee does not delegate its pre-approval responsibilities to management or to an individual member of the audit committee. Services for the audit, tax and all other fee categories above were pre-approved by the audit committee.

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PART IV

Item 15. Exhibits
(a)(1) Consolidated Financial Statements
The consolidated financial statements of Calumet Specialty Products Partners, L.P. are included in Part II, Item 8 "Financial Statements and Supplementary Data."
(a)(2) Financial Statement Schedules
All schedules are omitted because they are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.
(a)(3) Exhibits
The following documents are filed as exhibits to this Annual Report:

Exhibit Number		Description
2.1	—	Unit Purchase Agreement, dated as of June 5, 2012, by and among Calumet Lubricants Co., Limited Partnership, Royal Purple, Inc. and the shareholders of Royal Purple, Inc. named therein (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Commission on June 8, 2012 (File No. 000-51734)).
2.2	—	Share Purchase Agreement, dated as of August 14, 2012, among Calumet Specialty Products Partners, L.P. and Connacher Oil and Gas Limited (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Commission on August 20, 2012 (File No. 000-51734)).
3.1	—	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	—	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	—	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	—	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	—	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	—	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
4.1	—	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 3.7 to the Registrant's Quarterly Report on Form 10-Q filed with the Commission on November 4, 2010 (File No. 000-51734).
4.2	—	Indenture, dated April 21, 2011, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association (as successor by merger to Wilmington Trust FSB), as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the

		Commission on April 26, 2011 (File No. 000-51734)).
4.3	—	Indenture, dated September 19, 2011, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on September 21, 2011 (File No. 000-51734)).

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Exhibit Number		Description
4.4	—	Indenture, dated June 29, 2012, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 5, 2012 (File No. 000-51734)).
4.5	—	Indenture, dated November 26, 2013, by and among Calumet Specialty Products, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on November 26, 2013 (File No. 000-51734)).
10.1	—	LVT Unit Agreement, effective January 1, 2008, between ConocoPhillips Company and Calumet Penreco, LLC (incorporated by reference to Exhibit 10.11 to the Registrant's Annual Report on Form 10-K filed with the Commission on March 4, 2008 (File No. 000-51734)). Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
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10.4	—	Amended Crude Oil Sale Contract, effective April 1, 2008, between Plains Marketing, L.P. and Calumet Shreveport Fuels, LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on March 20, 2008 (File No. 000-51734)).
10.5*	—	Calumet Specialty Products Partners, L.P. Executive Deferred Compensation Plan, dated December 18, 2008 and effective January 1, 2009 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on December 22, 2008 (File No. 000-51734)).
10.6*	—	Form of Phantom Unit Grant Agreement (incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed with the Commission on January 28, 2009 (File No. 000-51734)).
10.7*	—	F. William Grube Employment Contract (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
10.8	—	Omnibus Agreement (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
10.9*	—	Form of Unit Option Grant (incorporated by reference to Exhibit 10.4 to the Registrant's Registration Statement on Form S-1/A filed with the Commission on November 16, 2005 (File No. 333-128880)).
10.10*	—	Amended and Restated Long-Term Incentive Plan, dated and effective January 22, 2009 (incorporated by reference to Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed with the Commission on March 4, 2009 (File No. 000-51734).
10.11*	—	Reaffirmation Agreement, General Release and Covenant Not to Sue, dated December 22, 2010 and effective as of December 29, 2010, between Calumet GP, LLC and Allan A. Moyes III

		(incorporated by reference to Exhibit 10.26 to the Registrant's Current Report on Form 8-K filed with the Commission on January 4, 2011 (File No. 000-51734)).
10.12	—	Amended and Restated Credit Agreement, dated as June 24, 2011, by and among Calumet Specialty Products Partners, L.P. and its subsidiaries as Borrowers, the Lenders, Bank of America, N.A., as Agent and Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC and Wells Fargo Capital Finance, LLC as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on June 30, 2011 (File No. 000-51734)).
10.13	—	First Amendment to Amended and Restated Credit Agreement, dated December 28, 2011, by and among Calumet Specialty Products Partners, L.P. and its subsidiaries as Borrowers, the Lenders and Bank of America, N.A., as Agent (incorporated by reference to Exhibit 10.27 to the Registrant's Annual Report on Form 10-K filed with the Commission on February 29, 2012 (File No. 000-51734)).
10.14	—	Collateral Trust Agreement, as amended, dated as of April 21, 2011, among Calumet Lubricants Co., Limited Partnership, the guarantors party thereto, the secured hedge counterparties thereto and Bank of America, N.A. (incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed with the Commission on August 8, 2011 (File No. 000-51734)).

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10.15	—	Amendment No. 2 to Collateral Trust Agreement, effective as of September 30, 2011, by and among Calumet Lubricants Co., Limited Partnership, the guarantors party thereto, the secured hedge counterparties thereto and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on October 6, 2011 (File No. 000-51734)).
10.16	—	Crude Oil Purchase Agreement effective as of October 1, 2011, by and between BP Products North America Inc. and Calumet Superior, LLC (incorporated by reference to Exhibit 10.30 to the Registrant's Annual Report on Form 10-K filed with the Commission on February 29, 2012 (File No. 000-51734)). Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
10.17	—	Amended and Restated Crude Oil Purchase Agreement, dated April 1, 2012 by and between BP Products North America Inc. and Calumet Superior, LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the Commission on August 9, 2012 (File No. 000-51734)). Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
12.1**	—	Statement regarding computation of ratios.
21.1**	—	List of Subsidiaries of Calumet Specialty Products Partners, L.P.
23.1**	—	Consent of Ernst & Young, LLP, independent registered public accounting firm.
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***	—	Sarbanes-Oxley Section 906 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.
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101.LAB**	—	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	—	XBRL Taxonomy Extension Presentation Linkbase Document.

* Identifies management contract and compensatory plan arrangements.
** Filed herewith.
*** Furnished herewith.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, 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

By: /s/ F. William Grube
F. William Grube
Chief Executive Officer

Date: March 3, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title		Date
/s/ F. William Grube F. William Grube	Chief Executive Officer, Director and Vice Chairman of the Board of Calumet GP, LLC (Principal Executive Officer)	Date:	March 3, 2014
/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)	Date:	March 3, 2014
/s/ Fred M. Fehsenfeld, Jr. Fred M. Fehsenfeld, Jr.	Director and Chairman of the Board of Calumet GP, LLC	Date:	March 3, 2014
/s/ James S. Carter James S. Carter	Director of Calumet GP, LLC	Date:	March 3, 2014
/s/ William S. Fehsenfeld William S. Fehsenfeld	Director of Calumet GP, LLC	Date:	March 3, 2014
/s/ Robert E. Funk Robert E. Funk	Director of Calumet GP, LLC	Date:	March 3, 2014
/s/ Nicholas J. Rutigliano Nicholas J. Rutigliano	Director of Calumet GP, LLC	Date:	March 3, 2014
/s/ George C. Morris III George C. Morris III	Director of Calumet GP, LLC	Date:	March 3, 2014

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Index to Exhibits

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2.1	—	Unit Purchase Agreement, dated as of June 5, 2012, by and among Calumet Lubricants Co., Limited Partnership, Royal Purple, Inc. and the shareholders of Royal Purple, Inc. named therein (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Commission on June 8, 2012 (File No. 000-51734)).
2.2	—	Share Purchase Agreement, dated as of August 14, 2012, among Calumet Specialty Products Partners, L.P. and Connacher Oil and Gas Limited (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Commission on August 20, 2012 (File No. 000-51734)).
3.1	—	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	—	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	—	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	—	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	—	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	—	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
4.1	—	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 3.7 to the Registrant's Quarterly Report on Form 10-Q filed with the Commission on November 4, 2010 (File No. 000-51734).
4.2	—	Indenture, dated April 21, 2011, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association (as successor by merger to Wilmington Trust FSB), as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 26, 2011 (File No. 000-51734)).
4.3	—	Indenture, dated September 19, 2011, by and among Calumet Specialty Products Partners, L.P., Calumet Finance Corp., certain subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on September 21, 2011 (File No. 000-51734)).
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** Filed herewith.
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