Calumet Specialty Products Partners, L.P.
Form 10-K
March 06, 2017
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

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	35-1811116
(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 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
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No
Indicate by check mark 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.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting

company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $294.1 million on June 30, 2016, based on $4.90 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

On March 6, 2017, there were 76,691,864 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 expectations regarding annual EBITDA contributions from our multi-year, self-help program, (iii) 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, (iv) estimated costs of complying with the U.S. Environmental Protection Agency’s (“EPA”) Renewable Fuel Standard, including the prices paid for Renewable Identification Numbers (“RINs”), (v) our ability to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures and (vi) our access to capital to fund capital expenditures and our working capital needs and our ability to obtain debt or equity financing on satisfactory terms, 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 specialty and fuel products facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey and eastern Missouri. We own and lease oilfield services locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We own and lease additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States (“U.S.”). Our business is organized into three segments: specialty products, fuel products and oilfield services. 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, Bel-Ray, TruFuel and Quantum 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, and from time to time resell purchased crude oil to third party customers. Our oilfield services segment manufactures and markets products and provides oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry throughout the U.S. For the year ended December 31, 2016, approximately 34.8% of our sales and 82.8% of our gross profit were generated from our specialty products segment, approximately 61.7% of our sales and 11.8% of our gross profit were generated from our fuel products segment and approximately 3.5% of our sales and 5.4% of our gross profit were generated from our oilfield services segment.

Our Primary Operating Assets

Our primary operating assets consist of:

Refinery/Facility	Location	Year Acquired	Current 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
Great Falls	Montana	2012	25,000	Gasoline, diesel, jet fuel and asphalt
San Antonio	Texas	2013	21,000	Diesel, jet fuel, gasoline, other fuel products and solvents
Cotton Valley	Louisiana	1995	13,500	Specialty solvents used principally in the manufacture of paints, cleaners, automotive products and drilling fluids
Princeton	Louisiana	1990	10,000	Specialty lubricating oils, including process oils, base oils, transformer oils and refrigeration oils, and asphalt
Karns City	Pennsylvania	2008	5,500	Specialty white mineral oils, solvents, petrolatums, gelled hydrocarbons, cable fillers and natural petroleum sulfonates
Dickinson	Texas	2008	1,300	Specialty white mineral oils, compressor lubricants, natural petroleum sulfonates and biodiesel
Calumet Packaging	Louisiana	2012	N/A	Specialty products including premium industrial and consumer synthetic lubricants, fuels and solvents

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
Missouri	Missouri	2012	N/A	Specialty products including polyolester-based synthetic lubricants

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Drilling and Oilfield Services Assets. Anchor Drilling Fluids (as defined below) manufactures and markets specialty products and provides oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry. We design, manufacture and package these specialty products at our locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. These locations serve the great majority of major onshore oil fields in 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 provide us the ability to transport crude oil directly from the point of lease into our crude oil loading facilities, and then onto the Enbridge Pipeline System (“Enbridge Pipeline”) where it can be routed to our Superior refinery 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, West 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 12.9 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:

- Maintain Sufficient Levels of Liquidity. We are actively focused on maintaining sufficient liquidity to fund our operations and business strategies. In view of current volatility in market conditions and as part of a broader effort to maintain an adequate level of liquidity, the board of directors of our general partner unanimously voted to suspend the then-current quarterly cash distribution of $0.685 per unit, or $2.74 per unit on an annualized basis, effective beginning the quarter ended March 31, 2016.
- Concentrate on Stable Cash Flows. We intend to continue to focus on operating assets and businesses that generate stable cash flows. Approximately 34.8% of our sales and 82.8% of our gross profit in 2016 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 specialized products 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 61.7% of our sales and 11.8% of our gross profit in 2016, we seek to mitigate our exposure to fuel products margin volatility by generally maintaining a fuel products hedging program for crude oil basis differentials and fuel product crack spreads. In the future, we intend to shift more of our focus to our specialty products business to further reduce our exposure to commodity price volatility.
- 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 and services 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 have increased our focus on identifying opportunities to improve our existing asset base and to increase our throughput, profitability and cash flows. Historical examples include projects designed to maximize the profitability of our acquired assets, such as: (1) the enhancements at our San Antonio refinery completed in December 2013, which allowed us to blend finished gasoline and increased the refinery’s production capacity from 14,500 bpd to 18,000 bpd, (2) the more than doubling of esters production capacity at our Missouri facility completed in December 2015, and (3) the increase of production capacity at our Great Falls refinery from 10,000 bpd to 25,000 bpd, which was completed in February 2016. We intend to further increase the profitability of our existing asset base through various low capital requirement measures which may include changing

the product mix of our processing units, debottlenecking units as necessary to increase throughput, restarting idle assets and reducing costs by improving operations. We also are increasing our focus on optimizing current operations through improving reliability, product quality enhancements, product yield improvements and energy savings initiatives.

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- Disciplined Approach to Strategic and Complementary Acquisitions. Our senior management team is focused on acquiring assets and product lines where we can enhance operations and improve profitability. In the future, we intend to continue pursuing prudent, accretive acquisitions that will benefit our company over the long term. We intend to reduce our leverage over time and maintain sufficient liquidity to execute our acquisition strategy. We also may pursue 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 principally in our specialty products segment. In addition, we may pursue selected acquisitions. Since 2011 we have completed the following acquisitions to enhance and diversify our existing specialty products, fuel products and oilfield services 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”) — formerly known as TruSouth Oil, LLC, a specialty petroleum packaging and distribution company acquired in January 2012.
- Louisiana, Missouri, (“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 and greases acquired in July 2012.
- Montana Refining Company, Inc. (“Great Falls”) — a refinery that produces and sells gasoline, diesel, jet fuel and asphalt products acquired in October 2012.
- San Antonio, Texas, refinery (“San Antonio”) — a refinery that produces and sells diesel, gasoline, jet fuel, other fuel products and solvents acquired in January 2013.
- Crude oil logistics assets — 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 and greases acquired in December 2013.
- United Petroleum, LLC assets (“United Petroleum”) — a marketer and distributor of high performance lubricants acquired in February 2014.
- ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. (subsequently converted to Anchor Drilling Fluids, LLC (“Anchor Drilling Fluids”) — an independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry acquired in March 2014.
- Oilfield services assets — a full-service drilling fluids and solids control company with primary operations in the Eagle Ford, Marcellus and Utica shale formations acquired from Specialty Oilfield Services, Ltd. in August 2014.

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 approximately 3,500 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 4,400 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, 2016, 2015 and 2014.

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- 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 team’s extensive experience and contacts within the refining industry provide a strong foundation and focus for managing and enhancing our operations, accessing strategic asset portfolio opportunities and constructing and enhancing the profitability of new assets.

Potential Acquisition and Divestiture 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.

Our acquisition program targets properties that management believes will be financially accretive, and we intend to focus on targeted strategic acquisitions of specialty products assets that leverage an existing core competency and that have an identifiable competitive advantage we can exploit as the new owner.

As part of this strategy, we are in the process of evaluating our portfolio to identify potential divestiture candidates that are non-core to our business and which are worth more to a strategic buyer than to us, while seeking to maximize our return on invested capital. This strategy will allow us to focus on a portfolio of core specialty products assets with significant potential to increase our ability to generate stable to growing cash flows, optimize our assets, improve our operating efficiency and capture increased feedstock advantages.

As we continue to seek to optimize our asset portfolio, which may include the divestiture of certain non-core assets, we intend to redeploy capital into projects to develop assets that are better suited to our core specialty products business strategy. During the past five years, we have invested approximately $750 million in growth projects and joint ventures, some of which management believes in hindsight were not in line with our strategic objectives. For example, several growth projects, such as the Dakota Prairie Refining, LLC refinery joint venture, required significant upfront capital, which we financed, and had multiyear lead times, increasing our leverage and limiting our ability to grow our quarterly distributions to unitholders during that time. These projects were in process during periods in which market dynamics and return profiles changed dramatically. Going forward, we intend to tailor our approach toward owning businesses with stable to growing cash flows. As a result, we may pursue potential arrangements with third parties to divest certain non-core assets to enable us to further reduce the amount of our required capital commitments and potential capital expenditures. We expect that any potential divestitures of non-core assets could provide us with cash to reinvest in our business and repay debt, reducing our reliance on the capital markets for sources of financing. However, as we develop our strategy with respect to our non-core assets, any changes in our key assumptions regarding such assets may require us to record an impairment charge.

We typically do not announce a transaction until we have executed a definitive agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of an acquisition or divestiture until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition or divestiture can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive 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 or divestiture 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 6, 2017, we have 76,691,864 common units and 1,565,140 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."

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Our Operating Assets and Contractual Arrangements

General

The following table sets forth information about our combined operations, excluding the results of operations of our oilfield services segment. 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, and the resale of crude oil in our fuel products segment. The table includes the results of operations of our United Petroleum assets commencing February 28, 2014:

	Year Ended December 31,					
	2016	2015	% Change	2015	2014	% Change
	(In bpd)			(In bpd)		
Total sales volume [1]	140,180	126,216	11.1 %	126,216	122,852	2.7 %
Total feedstock runs [2]	134,163	123,051	9.0 %	123,051	117,427	4.8 %
Facility production: [3]						
Specialty products:						
Lubricating oils	14,697	13,325	10.3 %	13,325	11,836	12.6 %
Solvents	7,427	7,942	(6.5)%	7,942	8,934	(11.1)%
Waxes	1,571	1,460	7.6 %	1,460	1,510	(3.3)%
Packaged and synthetic specialty products [4]	2,074	1,584	30.9 %	1,584	1,754	(9.7)%
Other	1,553	1,355	14.6 %	1,355	1,829	(25.9)%
Total specialty products	27,322	25,666	6.5 %	25,666	25,863	(0.8)%
Fuel products:						
Gasoline	37,713	37,691	0.1 %	37,691	34,221	10.1 %
Diesel	34,808	30,204	15.2 %	30,204	27,074	11.6 %
Jet fuel	5,306	5,157	2.9 %	5,157	4,799	7.5 %
Asphalt, heavy fuel oils and other	29,780	24,077	23.7 %	24,077	22,189	8.5 %
Total fuel products	107,607	97,129	10.8 %	97,129	88,283	10.0 %
Total facility production [3]	134,929	122,795	9.9 %	122,795	114,146	7.6 %

(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 the production of finished products and volume loss.

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

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The following table sets forth information about our combined sales of principal products and services by segment. The table includes the results of operations of our United Petroleum assets commencing February 28, 2014, and Anchor Drilling Fluids commencing March 31, 2014:

	Year Ended December 31,					
	2016		2015		2014	
	(In millions)	% of Sales	(In millions)	% of Sales	(In millions)	% of Sales
Sales of specialty products:						
Lubricating oils	$538.7	15.0 %	$575.6	13.7 %	$748.4	12.9 %
Solvents	237.7	6.6 %	302.0	7.2 %	485.2	8.4 %
Waxes	128.7	3.6 %	136.9	3.2 %	144.1	2.5 %
Packaged and synthetic specialty products (1)	311.2	8.6 %	316.6	7.5 %	313.5	5.4 %
Other (2)	36.0	1.0 %	36.7	0.9 %	38.0	0.7 %
Total	1,252.3	34.8 %	1,367.8	32.5 %	1,729.2	29.9 %
Sales of fuel products:						
Gasoline	844.3	23.5 %	1,047.1	24.9 %	1,443.1	24.9 %
Diesel	808.4	22.4 %	894.8	21.2 %	1,197.4	20.7 %
Jet fuel	117.5	3.3 %	149.6	3.6 %	199.3	3.4 %
Asphalt, heavy fuel oils and other (3)	451.8	12.5 %	471.0	11.1 %	853.6	14.7 %
Total	2,222.0	61.7 %	2,562.5	60.8 %	3,693.4	63.7 %
Sales of oilfield services:	125.1	3.5 %	282.5	6.7 %	368.5	6.4 %
Consolidated sales	$3,599.4	100.0%	$4,212.8	100.0%	$5,791.1	100.0%

(1) Represents 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 Great Falls refineries and crude oil sales from the Montana, Superior and San Antonio refineries to third party customers.

Please read Note 17 “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 geographic 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 seventeen major processing units including hydrotreating, catalytic reforming and dewaxing units and 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.

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The following table sets forth historical information about production at our Shreveport refinery:

	Shreveport Refinery Year Ended December 31,		
	2016	2015	2014
	(In bpd)		
Crude oil throughput capacity	60,000	60,000	60,000
Total feedstock runs (1) (2)	40,845	40,726	35,140
Total refinery production (2) (3)	42,075	41,588	34,189

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

(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, Princeton and San Antonio 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 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. 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 fourteen major processing units including hydrotreating, catalytic reforming, fluid catalytic cracking and alkylation units and approximately 3.1 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:

	Superior Refinery Year Ended December 31,		
	2016	2015	2014
	(In bpd)		

Crude oil throughput capacity	45,000	45,000	45,000
Total feedstock runs [(1)] [(2)]	35,840	36,270	36,736
Total refinery production [(2)]	35,623	35,916	35,712

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

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(2) Total refinery production represents the barrels per day of fuel products yielded from processing crude oil. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the 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, South Dakota and Utah and through our Duluth terminal. The Superior wholesale fuel business also sells gasoline wholesale to Calumet 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 and pipeline service. 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.

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 the refinery 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 formation in North Dakota and from western Canada.

Great Falls Refinery

The Great Falls refinery, located on an 86 acre site in Great Falls, Montana, currently has aggregate crude oil throughput capacity of 25,000 bpd and processes light and heavy crude oil from Canada into fuel and asphalt products. In February 2016, we completed an expansion project which added 15,000 bpd of crude throughput capacity to the refinery.

The Great Falls refinery consists of fifteen major processing units including hydrotreating, catalytic reforming, hydrocracking, fluid catalytic cracking and alkylation units, approximately 1.1 million barrels of storage capacity in 75 tanks and related loading and unloading facilities and utilities.

The following table sets forth historical information about production at the Great Falls refinery:

	Great Falls Refinery Year Ended December 31,		
	2016	2015	2014
	(In bpd)		
Crude oil throughput capacity	25,000	10,000	10,000
Total feedstock runs [1] [2]	20,930	10,307	10,201
Total refinery production [2]	21,259	10,525	10,274

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

(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 the production of finished products and volume loss.

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

The Great Falls 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.

In February 2016, we completed an expansion project that increased production capacity at our Great Falls refinery by 15,000 bpd to 25,000 bpd. This project allows us to further capitalize on local access to cost-advantaged Bow River crude oil, while producing additional fuels and refined products for delivery into the regional market. The scope of this project included the installation of a new crude unit that can process up to 25,000 bpd of crude oil and other feedstocks, a hydrogen plant and a 20,000 bpd mild hydrocracker.

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San Antonio Refinery

The San Antonio refinery, located on a 32 acre site in San Antonio, Texas, has aggregate crude oil throughput capacity of 21,000 bpd and processes light crude oil from south Texas, including the Eagle Ford shale formation, into a variety of transportation fuels, petrochemical and refinery feedstocks, and aliphatic solvents. The San Antonio refinery consists of six major processing units including crude oil fractionation, naphtha hydrotreating, catalytic reforming, distillate hydrotreating, aromatic saturation and specialty fractionation. The refinery has approximately 200,000 barrels of storage capacity in 65 tanks and related loading and unloading facilities and utilities.

Currently, the San Antonio refinery produces diesel, jet fuel, gasoline, other fuel products and a variety of aliphatic 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 service. 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 San Antonio refinery has a long term agreement with TexStar Midstream Logistics, L.P. (“TexStar”) under which TexStar operates the Karnes North Pipeline System (“KNPS”), which transports crude oil from Karnes City, Texas, to Elmendorf. Currently, the San Antonio refinery receives at least 12,000 bpd of crude oil at the refinery through the KNPS-Elmendorf terminal supply route. Elmendorf has aggregate storage capacity of approximately 200,000 barrels.

Since acquiring the San Antonio refinery, we have expanded the refinery’s capabilities by adding 6,500 bpd of crude oil throughput capacity and adding additional processing and blending facilities which allow the San Antonio refinery to blend up to 6,000 bpd of finished gasoline. Additionally, we completed a project in December 2015 that provides us the capability to take a portion of the San Antonio refinery’s diesel and jet fuel production and convert it into up to 3,000 bpd of higher margin solvent products that meet customer requirements for low aromatic content. We are also beginning to integrate the San Antonio refinery into our other specialty products operations by producing intermediate feedstocks which our Shreveport refinery utilizes in the production of lubricating oils.

The following table sets forth historical information at our San Antonio refinery:

	San Antonio Refinery Year Ended December 31,		
	2016	2015	2014
	(In bpd)		
Crude oil throughput capacity	21,000	21,000	17,500
Total feedstock runs [(1)] [(2)]	17,374	16,442	14,617
Total refinery production [(2)] [(3)]	16,736	15,708	13,541

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

(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 the production of finished products and volume loss.

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

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 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.

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The following table sets forth historical information about production at our Cotton Valley refinery:

	Cotton Valley Refinery Year Ended December 31,		
	2016	2015	2014
	(In bpd)		
Crude oil throughput capacity	13,500	13,500	13,500
Total feedstock runs [(1)] [(2)]	6,021	6,413	6,580
Total refinery production [(2)] [(3)]	5,399	6,103	6,544

(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 the 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 tank truck and the Plains pipeline system. The Cotton Valley refinery's feedstock is primarily low sulfur and 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.

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 and asphalt. In addition, feedstock is made for the Shreveport refinery for further processing into ultra-low sulfur diesel. The asphalt produced at Princeton 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,		
	2016	2015	2014
	(In bpd)		
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs [(1)]	6,335	7,105	6,669
Total refinery production [(1)] [(2)]	5,242	5,851	5,420

(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 the production of finished products and volume loss.

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

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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 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, south Texas and north Louisiana, 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 truck, barge and railcar service.

Missouri Facility

The Missouri facility, located on a 22 acre site in Louisiana, Missouri, develops and produces polyolester synthetic lubricants for use in refrigeration compressors, commercial aviation and polyolester base stocks. In December 2015, we completed a project to double the production capacity of the facility from 35 million pounds to 75 million pounds per year. The facility has approximately 35,000 barrels of storage capacity in 64 tanks and related loading and unloading facilities and utilities. The facility receives its fatty acids and alcohol feedstocks and additives by truck and railcar under supply agreements or spot agreements with various suppliers.

The Missouri facility utilizes the latest batch esterification processes designed to ensure blending accuracy while maintaining production flexibility to meet customer needs.

Calumet Packaging

The Calumet Packaging facility, located on a 10 acre site in Shreveport, Louisiana, develops, blends and packages high performance synthetic lubricants, fuels and solvent products for use in industrial, commercial and automotive applications. The Calumet Packaging facility's processing capability includes state-of-the-art blending and packaging equipment. The facility has approximately 75,000 barrels of storage capacity and related loading and unloading facilities. The facility receives its base oil feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.

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 products for use in industrial, commercial and automotive applications. The Royal Purple facility's processing capability includes ten 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. The facility receives its base oil feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.

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 24 blending tanks and packaging production lines. In addition, the Bel-Ray facility has approximately 13,000 barrels of storage capacity in 63 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.

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These 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 "— Our 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,		
	2016	2015	2014
	(in bpd)		
Feedstock throughput capacity [(1)]	11,300	11,300	11,300
Total feedstock runs [(2)] [(3)]	6,483	5,515	6,651
Total production [(3)]	6,522	5,519	6,575

(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."

(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.

Anchor Drilling Fluids

We are an independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry. We design, manufacture and package drilling fluid products at our locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We service oil and gas resource plays in North America, including the Bakken, Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Marcellus, Niobrara, Permian, Piceance, Uinta and Utica shale formations.

We develop custom formulations and innovative solutions based on unique customer and well specifications. Through our extensive line of drilling and completion fluids, we deliver solutions that reduce drilling and completion time, help to control reservoir formation pressures and maximize oil and gas production, contributing to improved well economics for end-users.

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 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.

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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 provide 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 Superior refinery 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 and pipeline connected to its Elmendorf crude oil terminal
Cotton Valley	Local paraffinic crude oil	Plains Pipeline and tank truck
Great Falls	Canadian Heavy and Canadian Sour (e.g. Bow River)	Front Range Pipeline
Princeton	Local naphthenic crude oil	Tank truck, railcar and Plains Pipeline

In 2016, subsidiaries of Plains supplied us with approximately 39.3% of our total crude oil supply under term contracts and month-to-month evergreen crude oil supply contracts. In 2016, BP Products North America Inc. (“BP”) supplied us with approximately 25.2% of our total crude oil supply under a crude oil supply 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.

We have short-term and long-term contracts with our crude oil suppliers. For example, a majority of our crude oil supply contracts with Plains are currently month-to-month and terminable upon 90 days’ notice. Additionally, we have a crude oil supply agreement with BP which was amended and restated in December 2016 for a term ending March 2020 and automatically renews for successive one-year terms unless terminated by either party upon 90 days’ notice (“BP Purchase Agreement”). We also purchase foreign crude oil when its spot market price is attractive relative to the price of crude oil from domestic sources.

We have various long-term feedstock supply agreements with Phillips 66, 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 crude oil and feedstocks will continue to be available to us.

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.

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Our Products, Markets and Customers

Products

Specialty Products and Fuel 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 specialty products primarily as raw material components for basic industrial, consumer and automotive goods.

Oilfield Services. We are an independent provider and marketer of drilling fluids and completion fluids.

- Drilling fluids — Drilling fluids, often referred to as "drilling mud," are an essential and critical product of the drilling process for every oil and gas well. We provide three different types of drilling fluids including water-based mud, oil-based mud and synthetic-based mud.
- Completion fluids — Completion fluids replace drilling fluids during the final operations leading up to oil and gas production from a well. Completion fluids are critical products designed to control reservoir formation pressures and minimize formation damage in the event of a failure in down hole equipment.
- Solids control — Solids control is employed in drilling operations to filter out cuttings and clean the drilling fluid before it is pumped back into the well.

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	Oilfield Services	Other	Fuels & Fuel Related Products
15% (1)	7% (1)	4% (1)	8% (1)	3% (1)	1% (1)	62% (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	• 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 • Stains	• 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 • High performance industrial lubricants • High temperature chain lubricants • Food contact grade lubricants • Charcoal lighter fluids and other solvents	• Drilling fluids • Completion fluids • Solids control	• Roofing • Paving	• Gasoline • Diesel • Jet fuel • Marine fuel • Biodiesel • Ethanol • Ethanol free fuels • Fluid catalytic cracking feedstock • Asphalt vacuum residuals • Mixed butanes • Roofing • Paving • Heavy fuel oils

- Grease
- Automatic transmission fluid
- Animal feed dedusting
- Baby oils
- Bakery pan oils
- Catalyst carriers
- Gelatin capsule lubricants
- Sunscreen
- Engine treatment additives

(1) Based on the percentage of total sales for the year ended December 31, 2016. Except for the listed fuel products and certain packaged and synthetic specialty products, we do not produce any of these end-use products.

Marketing

Our salespeople regularly visit customers, and our marketing department works closely with both the laboratories at our production facilities 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 140 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:

- 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 (e.g., 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., 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 are 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 2016, 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 140 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 2,200 bpd of jet fuel. This contract is effective until March 2018 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 600 bpd of jet fuel. This contract is effective until March 2019.

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, 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, South Dakota and Utah 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 Calumet branded gas stations throughout the Upper Midwest, which are owned and operated by independent franchisees.

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Northwest Market (PADD 4)
Fuel products produced at our Great Falls refinery can be sold locally and in Missouri, Oklahoma, Texas, Arizona, North Dakota, South Dakota, Idaho, Oregon, Utah, Wyoming, Nevada, California and Canada. Seasonally, the Great Falls refinery transports fuel products to terminals in Washington.
We have a sales contract with the U.S. Department of Defense for approximately 150 bpd of jet fuel. This contract is effective until September 2017.
Oilfield Services. We sell oilfield products and services in the Bakken, Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Marcellus, Niobrara, Permian, Piceance, Uinta and Utica shale formations.
Customers
Specialty Products. We have a diverse customer base for our specialty products, with approximately 3,700 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 in our specialty products segment accounted for 10% or greater of consolidated sales in each of the three years ended December 31, 2016, 2015 and 2014.
Fuel Products. We have a diverse customer base for our fuel products, with approximately 500 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 Great Falls 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 in our fuel products segment represented 10% or greater of consolidated sales in each of the three years ended December 31, 2016, 2015 and 2014.
Oilfield Services. We have a diversified, established and unique customer base for our oilfield services, with approximately 200 active accounts. Our customers are companies operating in the domestic oil and gas exploration and production industry. No single customer in our oilfield services segment accounted for 10% or greater of consolidated sales in each of the three years ended December 31, 2016, 2015 and 2014.
Competition
Competition in our markets is from a combination of large, integrated petroleum companies, independent refiners, wax production companies and oilfield services 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 competitors in producing naphthenic lubricating oils include Ergon Refining, Inc., Cross Oil Refining and Marketing, Inc., San Joaquin Refining Co., Inc. and Martin Midstream Partners L.P.
Paraffinic Lubricating Oils. Our primary competitors in producing paraffinic lubricating oils include ExxonMobil Corporation, Motiva Enterprises, LLC, Phillips 66, Petro-Canada, HollyFrontier Corporation, Chevron Corporation, Sonneborn Refined Products and Royal Dutch Shell plc.
Paraffin Waxes. Our primary competitors in producing paraffin waxes include ExxonMobil, HollyFrontier Corporation, The International Group Inc. and Sonneborn Refined Products.
Solvents. Our primary competitors in producing solvents include CITGO Petroleum Corporation, ExxonMobil Chemical, Phillips 66 and Royal Dutch Shell plc.

Polyolester-Based Specialty Products. Our primary competitors in producing polyolester-based specialty products include Chemtura Corporation, BASF Corporation and JX Nippon Oil and Energy.
Packaged and Synthetic Specialty Products. Our primary competitors in retail and commercial packaged and synthetic specialty products include ExxonMobil (Mobil 1), Valvoline, Inc. and BP Lubricants USA (Castrol). Our primary competitors in industrial packaged and synthetic specialty products include ExxonMobil Corporation, Royal Dutch Shell plc and Chevron.

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Fuel Products and By-Products. Our primary competitors in producing fuel products in the local markets in which we operate include Delek US Holdings, Flint Hills Resources, Northern Tier Energy LP, ExxonMobil, Valero Energy Corporation, Phillips 66, Cenex, Alon USA and Marathon Petroleum Corporation.

Oilfield Services. Our primary competitors in servicing oilfields in the local markets in which we operate include Schlumberger, Halliburton, Newpark Resources and other regional competition.

Our ability to compete effectively depends on our responsiveness to customer needs and our ability to maintain competitive prices and product and service 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.

Governmental Regulation

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 ("IRS"), various state and local departments of revenue and the federal Occupational Safety and Health Administration ("OSHA"), as the result of audits or reviews of our business. In addition, we have property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to us.

Environmental and Occupational Health and Safety Matters

Environmental

We conduct crude oil and specialty hydrocarbon refining, blending and terminal operations in addition to providing oilfield services and products, which activities 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 for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial or corrective action obligations or the corresponding incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctive relief limiting or prohibiting our activities in a particular area. Moreover, 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 disposed of or released. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could significantly increase our operational or compliance expenditures, as discussed below in more detail.

Remediation of subsurface contamination is in process at certain of our refinery sites and is being overseen by the appropriate state agencies. Based on current investigative and remedial activities, we believe that the soil and 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.

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 deductible or 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. 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, pursuant to which Anadarko and Age Refining are obligated to assess and remediate certain contamination at the San Antonio refinery that predates our acquisition of the facility. We do not expect this pre-existing contamination at the San Antonio refinery to have a material adverse effect on our financial position or results of operations.

Great Falls Refinery

In connection with the acquisition of the Great Falls refinery from Connacher Oil and Gas Limited (“Connacher”), we became a party to an existing 2002 Refinery Initiative Consent Decree (the “Great Falls Consent Decree”) with the EPA and the Montana Department of Environmental Quality (the “MDEQ”). The material obligations imposed by the Great Falls Consent Decree have been completed. On September 27, 2012, Montana Refining Company, Inc., received a final Corrective Action Order on Consent, replacing the refinery’s previously held hazardous waste permit. This Corrective Action Order on Consent governs the investigation and remediation of contamination at the Great Falls refinery. We believe the majority of damages related to such contamination at the Great Falls refinery are covered by a contractual indemnity provided by HollyFrontier Corporation (“Holly”), the owner and operator of the Great Falls refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Great Falls refinery. Under this asset purchase agreement, Holly agreed to indemnify Connacher and Montana Refining Company, Inc., subject to timely notification, certain conditions and certain monetary baskets and caps, for environmental conditions arising under Holly’s ownership and operation of the Great Falls refinery and existing as of the date of sale to Connacher. During 2014, Holly provided us a notice challenging our position that Holly is obligated to indemnify our remediation expenses for environmental conditions to the extent arising under Holly’s ownership and operation of the refinery and existing as of the date of sale to Connacher, which expenses totaled approximately $18.7 million as of December 31, 2016, of which $14.6 million was capitalized into the cost of our recently completed expansion project and $4.1 million was expensed. We continue to believe that Holly is responsible to indemnify us for these remediation expenses disputed by Holly, and on September 22, 2015, we initiated a lawsuit against Holly and the sellers of the Great Falls refinery that were party to the asset purchase agreement. On November 24, 2015, Holly and such sellers filed a motion to dismiss the case pending arbitration. On February 10, 2016, the court ordered that all of the claims be addressed in arbitration. Arbitration is scheduled for early 2018. In the event we are unsuccessful in our legal dispute with Holly, we will be responsible for those remediation expenses. We expect that we may incur some costs to remediate other environmental conditions at the Great Falls refinery; however, we believe at this time that these other costs we may incur will not be material to our financial position or results of operations.

Superior Refinery

In connection with the acquisition of the Superior refinery, 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 must 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. We estimate costs of up to $5.0 million, as of December 31, 2016, to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform these required tasks under the Superior Consent Decree could result in the imposition of stipulated penalties, which could be material. We are currently assessing certain past actions at the refinery for compliance with the terms of the Superior Consent Decree, which actions may be subject to stipulated penalties under the Superior Consent Decree but, in any event, we do not currently believe that the imposition of such penalties for those actions, should they be imposed, would be material. In addition, we are pursuing certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in us incurring costs, which could be substantial. During 2016, we incurred less than $0.1 million for costs related to installing process equipment at the Superior refinery pursuant to the EPA fuel content regulations.

In June 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 that we provided to the EPA in response to an information request. The EPA alleges that the efficiency of the flares at the Superior refinery is lower than regulatory requirements. We are contesting the allegations and are in settlement discussions with the EPA to resolve this issue. We have not yet received formal action from the EPA. We do not believe that the resolution of these allegations will have a material adverse effect on our financial position or results of operations.

We are contractually indemnified by Murphy Oil Corporation (“Murphy Oil”) under an asset purchase agreement between Murphy Oil and us 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 contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums. 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 Murphy Oil and us 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 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, as amended ("CAA"), and federal Clean Water Act regulations that arose prior to December 23, 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 2016 and 2015, we incurred approximately $2.4 million and $6.8 million, respectively. The Global Settlement is substantially complete and any remaining capital investment requirements will be incorporated into our annual capital expenditures budget, and we do not expect any additional capital expenditures included in the Global Settlement to have a material adverse effect on our financial position or results of operations.

We are contractually indemnified by Shell Oil Company (“Shell”), as successor to Pennzoil-Quaker State Company, and Atlas Processing Company, under an asset purchase agreement between Shell and us, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to our acquisition of the facility. We believe the contractual indemnity is unlimited in amount and duration, but requires us to contribute $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, 2016, the trust fund contained approximately $0.5 million. In addition, Weston has 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 CAA, and comparable state and local laws. The CAA 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 CAA, facilities that emit regulated air pollutants are subject to stringent regulations, including requirements to install various levels of control technology on sources of pollutants. In addition, in recent years, the petroleum refining sector has become subject to stringent federal regulations that impose 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. Our refining and terminal operations that emit regulated air pollutants are also subject to air emissions permitting requirements that incorporate stringent control technology requirements for which we may incur significant capital expenditures. Any renewal of those air emissions permits or a need to modify existing or obtain new air emissions permits has the potential to delay the development of our projects. We can provide no assurance that future compliance with existing or any new laws, regulations or permit requirements will not have a material adverse effect on our business, financial position or results of operations. For example, on October 1, 2015, the EPA issued a final rule under the CAA that became effective on December 28, 2015, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA is required to make attainment and non-attainment designations for specific geographic locations under the review standards by October 1, 2017. With the EPA lowering the ground-level ozone standard, states may be required to implement more stringent regulations, which could apply to our operations. Also, in December 2015, the EPA published a final rule that amends three refinery standards already in effect, imposing additional or, in some cases, new emission control requirements on subject refineries. The final rule requires, among other things, the monitoring of air concentrations of benzene around the refinery fence line perimeter and submittal of the fence line monitoring data to the EPA on a quarterly basis; upgraded emissions controls for storage tanks, including controls for smaller capacity storage vessels and storage vessels storing materials with lower vapor pressures than previously regulated; enhanced performance requirements for flares including the use of a minimum of three pollution prevention measures, continuous monitoring of flares and pressure release devices and analysis and remedy of flare release events; and compliance with emissions standards for delayed coking units. These final rules and any other future air emissions rulemakings could impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business. From time to time the CAA 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 February 2000, the EPA published regulations limiting the sulfur content allowed in gasoline. These regulations, referred to as "Tier 2 Standards," 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 published 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, Great Falls and San Antonio refineries have implemented the sulfur standard with respect to produced gasoline and produced diesel meeting the ultra-low sulfur standard. In April 2014, the EPA published more stringent sulfur standards, referred to as “Tier 3 Standards,” including requiring that motor gasoline will not contain more than 10 ppm of sulfur on an annual average basis by January 1, 2017, except in those instances where refineries receive a “small refinery” exemption, in which event the deadline is extended to January 1, 2020. Our Shreveport, Superior, Great Falls and San Antonio refineries received small refinery exemptions and, thus will implement the 10 ppm sulfur standard with respect to produced gasoline by January 1, 2020. In addition, we are required to meet the MSAT II Standards adopted by the EPA to reduce the benzene content of motor gasoline produced at our facilities and have completed capital projects at our Shreveport, Superior, Great Falls and San Antonio refineries to comply with those fuel quality requirements.

The EPA has issued Renewable Fuel Standard (“RFS”) mandates, requiring refiners such as us to blend renewable fuels into the petroleum fuels they produce and sell in the U.S. We, and other refiners subject to RFS, may meet the RFS requirements by blending the necessary volumes of renewable transportation fuels produced by us or purchased from third parties. To the extent that refiners will not or cannot blend renewable fuels into the products they produce in the quantities required to satisfy their obligations under the RFS program, those refiners must purchase renewable credits, referred to as RINs, to maintain compliance. 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 RFS compliance or selling those RINs on the open market.

Under the RFS program, the volume of renewable fuels that obligated parties are required to blend into their finished petroleum fuels increases annually over time until 2022. Our Shreveport, Superior, Great Falls and San Antonio refineries are normally subject to compliance with the RFS mandates. However, the RFS program further provides for a small refinery to be granted a temporary exemption from its annual mandated volume of renewable fuels if such refinery can demonstrate that compliance with those mandated volumes would cause the refinery to suffer disproportionate economic hardship. The EPA granted certain of our refineries a “small refinery exemption” under the RFS for the 2013, 2014, 2015 and 2016 calendar years. Under these exemptions granted by the EPA, such refineries are not subject to the requirements of RFS as an “obligated party” for fuels produced at these refineries for the calendar years of 2013, 2014, 2015 and 2016.

On November 30, 2015, the EPA issued final multi-year volume mandates for 2014 to 2016 under RFS. While these volume mandates are generally lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. We have received a small refinery exemption for certain of our refineries for the full year 2016 and have applied for the small refinery exemption at selected other refineries for the full year 2016 and are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the 2017 calendar year. While we received a small refinery exemption for certain of our refineries for 2013, 2014, 2015 and 2016, there is no assurance that such an exemption will be obtained for any of our refineries for the 2016 year or in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2016 annual RINs obligation, which includes RINs that were required to be secured through either our own blending or through the purchase of RINs in the open market, was 112 million RINs for the 2016 calendar year.

On October 13, 2010, the EPA raised the maximum amount of ethanol content 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 between 2001 and 2006. 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, Great Falls and San Antonio refineries' fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make payments of our debt obligations.

Climate Change

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHG"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date but a number of states or grouping of states have already taken legal measures to reduce emissions of GHG, primarily through the planned development of

GHG emission inventories and/or GHG cap-and-trade programs. Additionally, the EPA has adopted regulations under existing provisions of the federal CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit program requiring reviews for GHG emissions from certain large stationary sources that are also potential major sources of criteria pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards. 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 ("NSPS") 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 and report upon GHG emissions at our facilities, where required. These EPA policies and rulemakings or any new administrative legal requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

On an international level, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. 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 that we produce. For example, in June 2016, the EPA published new source performance standards ("NSPS"), known as Subpart Quad OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued a final Information Collection Request ("ICR") seeking information about methane emissions from facilities and operators in the oil and natural gas industry that could be used in developing standards for existing sources in the oil and natural gas industry. 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 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. Historically, our environmental compliance costs under the existing requirements of RCRA and similar state and local laws have not had a material adverse effect on our results of operations, 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.

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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, in 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.

Remediation of subsurface contamination is in process at certain of our refinery sites and is being overseen by the appropriate state agencies. Based on current investigative and remedial activities, we believe that the soil and 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. The EPA retains jurisdiction over federal waters of the U.S. pursuant to the Clean Water Act and published a final rule in June 2015, that attempted to clarify this jurisdiction over such waters of the U.S.; however, this rule is alleged to have impermissibly broadened such jurisdiction and thus the rule is subject to various legal impediments, including formalized opposition, lawsuits and/or court stays. Historically, our environmental compliance costs under the existing requirements of the federal Clean Water Act and similar state laws have not had a material adverse effect on our results of operations.

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 as well as a variety of public and private damages from oil spills. Our past environmental compliance with OPA and similar state laws have not had a material adverse effect on our results of operations.

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. 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.

In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery’s PSM 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 financial position or results of operations.

Other Environmental and Maintenance Items

We perform preventive and normal maintenance on most, if not 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, generally follow seasonal demand trends. 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 the road construction and roofing industries we supply. Demand for gasoline and diesel 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 demand for natural gas as a heating fuel increases during the winter. 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 seasonality related to these and other products that we produce and sell.

The operating results for the oilfield services segment follow seasonal changes in weather and significant weather events can temporarily affect the performance and delivery of our oilfield services and products. The severity and duration of the winter can have a significant impact on drilling activity. Additionally, customer spending patterns for other oilfield services and products can result in lower activity in the fourth quarter.

Properties

We own and lease the principal properties which are listed below. The principal properties which we own, among others not listed below, 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.

Property	Business Segment(s)	Acres	Owned / Leased	Location
Shreveport refinery	Fuels and Specialty	240	Owned	Shreveport, Louisiana
Superior refinery	Fuels	675	Owned	Superior, Wisconsin
Great Falls refinery	Fuels	86	Owned	Great Falls, Montana
San Antonio refinery	Fuels and Specialty	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

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

Intellectual Property

Our patents relating to our refining operations are not material to us as a whole. Our products consist of composition patents which are integral to the formulas of our products. We own, have registered or applied for registration of a variety of tradenames, service marks and trademarks for us in our business. The trademarks, tradenames and design marks under which we conduct our branded business (including Royal Purple, Bel-Ray, TruFuel and Quantum) and other trademarks employed in the marketing of our products are integral to our marketing operations. We also license intellectual property rights from third parties. We are not aware of any facts as of the date of this filing which would negatively impact our continuing use of our tradenames, service marks or trademarks.

Office Facilities

In addition to our principal properties discussed above, as of December 31, 2016, we were a party to a number of cancelable and noncancelable leases for certain properties, including our corporate headquarters in Indianapolis, Indiana, and administrative offices in Houston, Texas. The corporate headquarters lease is for 58,501 square feet of office space. The lease term expires in August 2024. The Houston facility lease is for 24,025 square feet of office space. The lease term expires in August 2022. See Note 6 "Commitments and Contingencies" in Part II, Item 8 "Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements" of this Annual Report for additional information regarding our leases.

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 6, 2017, our general partner employs approximately 2,000 people who provide direct support to our operations. Of these employees, approximately 600 are covered by collective bargaining agreements.

Employees at the following locations are covered by the following separate collective bargaining agreements:

Facility/ Refinery	Union	Expiration Date
Superior	International Union of Operating Engineers	July 1, 2021
Cotton Valley	International Union of Operating Engineers	March 31, 2019
Princeton	International Union of Operating Engineers	October 31, 2017
Dickinson	International Union of Operating Engineers	March 31, 2019
Shreveport	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2019
Missouri	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2019
Karns City	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2019
Great Falls	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2019

None of the employees at the San Antonio refinery, Calumet Packaging facility, Royal Purple facility, Bel-Ray facility, Anchor or SOS locations 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, D.C., 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, following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay distributions to our unitholders.

In April 2016, we announced suspension of our quarterly cash distribution to unitholders. We may not have sufficient available cash from operations each quarter to enable us to resume payment of a distribution to unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- overall demand for specialty hydrocarbon products, fuel and other refined products;
- overall demand for oilfield products and services;
- the level of foreign and domestic production of crude oil and refined products;
- our ability to produce fuel products, specialty products and products used in oilfield services 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 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.

If we generate insufficient cash from our operations for a sustained period of time and/or forecasts demonstrate expectations of continued future insufficiencies, the board of directors of our general partner may determine not to reinstate our distribution to unitholders. Any such continued suspension or elimination in distributions may cause the trading price of our units to decline.

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.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

We had approximately $2.0 billion of outstanding indebtedness as of December 31, 2016, and availability for borrowings of $360.8 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 $900.0 million at any time, subject to borrowing base limitations, under our revolving credit facility. Our substantial indebtedness could adversely affect our results of operations, business and financial condition, and our ability to meet our debt obligations and resume payment of distributions to our unitholders. In addition, 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;
- our ability to execute our acquisition and divestiture strategy; 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.

Any of these factors could result in a material adverse effect on our business, financial conditions, results of operations, business prospects and ability to satisfy our obligations under our senior notes and revolving credit facility.

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 continuing the suspension of 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.

Refining margins are volatile and recently experienced a decline, and a continued 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 costs to acquire our feedstocks and the prices at which we can ultimately sell our refined products depend upon numerous factors beyond our control. When the margin between refined product prices and crude oil and other feedstock prices tightens, our earnings, profitability and cash flows are negatively impacted. 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 (“Gulf Coast 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 crack spread ranged from a high of $17.14 per barrel to a low of $6.89 per barrel during 2016 and averaged $12.33 per barrel during 2016 compared to an average of $17.96 in 2015 and $17.13 in 2014.

Our actual refining margins vary from the Gulf Coast 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 crack spread as an indicator of the volatility and general levels of fuels 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 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.

Refining margins are volatile, and we recently experienced a decline in our refining margins. There can be no assurance that our refining margins will improve. If our refining margins do not improve, it will adversely affect the amount of cash we have available for funding operations, for distributions to our unitholders and for payments of our debt obligations.

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, fuel products and their relationship with each other with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices and spreads. 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 New York Mercantile Exchange ("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 changed period to period, 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 on or redeem or repurchase our units or redeem or repurchase our subordinated debt and, in the case of the 2021 Secured Notes, our unsecured notes;
- 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 (a) 12.5% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $45.0 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 or the 2021 Secured Notes, foreclose on the collateral pledged pursuant to the terms of the revolving credit facility or indenture governing the 2021 Secured Notes, respectively.

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 accounts receivable, inventory and substantially all of our cash; our 2021 Secured Notes are secured by a first-priority lien on all of the fixed assets that secure our obligations under our secured hedge agreements; and our obligations under our master derivative contracts 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 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 Contracts" for additional information regarding our long-term debt.

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. From time to time, 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 or increases in crack spreads 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.

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We must make substantial capital expenditures on our refineries and other facilities to maintain their reliability and efficiency. If we are unable to complete capital projects at their expected costs and/or in a timely manner, or if the market conditions assumed in our project economics deteriorate, our financial condition, results of operations or cash flows, and our ability to make distributions to unitholders, could be adversely affected.

Delays or cost increases related to the engineering, procurement and construction of new facilities, or improvements and repairs to our existing facilities and equipment, could have a material adverse effect on our business, financial condition, results of operations or our ability to make distributions to our unitholders. Such delays or cost increases may arise as a result of unpredictable factors in the marketplace, many of which are beyond our control, including:

- denial or delay in obtaining regulatory approvals and/or permits;
- unplanned increases in the cost of equipment, materials or labor;
- disruptions in transportation of equipment and materials;
- severe adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of our vendors and suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project’s debt or equity financing costs; and/or
- nonperformance or declarations of force majeure by, or disputes with, our vendors, suppliers, contractors or sub-contractors.

Our refineries have been in operation for many years. Equipment, even if properly maintained, may require significant capital expenditures and expenses to keep it operating at optimum efficiency. For example, we incurred approximately $68.6 million in 2013 primarily associated with turnaround activities at our Great Falls and Superior refineries.

Any one or more of these occurrences noted above could have a significant impact on our business. If we were unable to make up the delays or to recover the related costs, or if market conditions change, it could materially and adversely affect our financial position, results of operations or cash flows and, as a result, our ability to make distributions.

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 and payments of our debt obligations.

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 2016, subsidiaries of Plains supplied us with approximately 39.3% of our total crude oil supplies under term contracts and month-to-month evergreen crude oil supply contracts. In 2016, BP supplied us with approximately 25.2% 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 on acceptable terms. We maintain short-term and long-term contracts with our suppliers. For example, the majority of our contracts with Plains are currently month-to-month and terminable upon 90 days’ notice, and our contract with BP was amended and restated in December 2016 for a term ending March 2020 and will automatically renew for successive one-year terms unless terminated by either party upon 90 days’ notice. We purchase all of our crude oil supply directly from third-party suppliers, generally under month-to-month evergreen supply contracts and on the spot market. 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 our existing credit ratings or perception of our creditworthiness or 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 gas 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.

Trends in crude oil and natural gas prices affect the level of exploration, development, and production activity of our customers and the demand for our oilfield services and products, which could adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations.

Demand for our oilfield services and products is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, crude oil and natural gas companies. The level of exploration, development, and production activity is directly affected by trends in oil and natural gas prices, which historically have been volatile and are likely to continue to be volatile.

Prices for crude oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other economic factors that are beyond our control. Any prolonged reduction in crude oil and natural gas prices will depress the immediate levels of exploration, development and production activity which could adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations. Even the perception of longer-term lower crude oil and natural gas prices by oil and natural gas companies can similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Factors affecting the prices of crude oil and natural gas include:

- the level of supply and demand for crude oil and natural gas, especially demand for natural gas in the U.S.;
- governmental regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- weather conditions and natural disasters;
- worldwide political, military, and economic conditions;
- the level of crude oil production by non-Organization of the Petroleum Exporting Countries (“OPEC”) countries and the available excess production capacity within OPEC;
- crude oil refining capacity and shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- the cost of producing and delivering crude oil and natural gas; and
- potential acceleration of the development of alternative fuels.

During 2015, the oil and natural gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the U.S. The decline in commodity prices and the global economic conditions continued during 2016. The duration and magnitude of the recent decline in crude oil and natural gas prices cannot be predicted, and low commodity prices may exist for an extended period. If commodity prices continue to decline or remain depressed, there could be a material adverse effect on our business, financial condition and results of operations.

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. 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 Great Falls refinery receives crude oil through the Front Range pipeline system via the Bow River Pipeline in Canada. Our San Antonio refinery receives crude oil through the Karnes North Pipeline System in Texas. 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.
For example, daily prices for natural gas as reported on the NYMEX ranged between $1.64 and $3.93 per million British thermal unit ("MMBtu"), in 2016 and between $3.23 and $1.76 per MMBtu in 2015. 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 12.6% and 11.5% of our total operating expenses included in cost of sales for the years ended December 31, 2016 and 2015, respectively. If our natural gas costs rise, they will adversely affect the amount of cash available for distribution to our unitholders and payments of our debt obligations.
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 experience 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.
We may incur significant environmental costs and liabilities in the operation of our refineries, terminals and related facilities and performance of our oilfield service activities.
The operation of our refineries, blending and packaging sites, terminals, and related facilities as well as performance of our oilfield service activities subject us to the risk of incurring significant environmental costs and liabilities due to our handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to our operations and activities, and as a result of historical operations and waste disposal practices at our facilities or in connection with our activities, some of which may have been conducted by prior owners or operators. We currently own or operate, or conduct oilfield services upon, properties that for many years have been used for industrial or oilfield activities, including refining and blending operations or terminal storage operations, sometimes by third parties over whom we had or continue to have 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 Great Falls refinery arising from a predecessor operators' handling of petroleum hydrocarbons and wastes. While we believe our costs in pursuing these investigatory and remedial activities are subject to reimbursement under a contractual indemnification right we received from the predecessor operator in the share purchase agreement transferring ownership of this refinery, this predecessor operator is currently disputing responsibility for reimbursement of certain of these remedial costs being incurred at our Great Falls refinery, which dispute has resulted in the filing of a suit by us against the predecessor operator and it is now in arbitration. Additionally, 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 or the owners of properties where we conduct oilfield services, 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 significant and not adequately secured or indemnified for, there could be a material adverse effect on our business, financial condition, and results of operations.

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

Our refining, blending and packaging site, terminal and related facility operations as well as our oilfield service activities 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 and packaging sites, terminals, and related facilities or with respect to our oilfield services, 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 oilfield services and to provide this information to employees, state and local government authorities, and local residents and the incurrence of significant costs and liabilities for pollution resulting from our operations and oilfield services 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 or the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects, and the issuance of injunctions limiting or preventing some or all of our operations.

On occasion, we receive notices of violation, other 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 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 in April 2013, for which a penalty of more than $0.1 million may result. In a further example, we have a pending proceeding 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 in June 2012, which included a proposed penalty amount of $0.1 million.

New worker safety and environmental 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, in April 2014, the EPA published its final Tier 3 fuel standards that require, among other things, a lower allowable sulfur level in gasoline to no more than 10 ppm by January 1, 2017. In two other examples, on October 1, 2015, the EPA issued a final rule under the CAA lowering the NAAQS for ground-level ozone to 70 parts per billion under both the primary and secondary standards, and on June 29, 2015, the EPA published a final rule that attempted to clarify the agency’s jurisdiction over waters of the U.S., but which rule is currently subject to various legal impediments, including lawsuits and court stays, as this rule is alleged to have impermissibly broadened the EPA’s jurisdiction over such waters. One or more of these regulatory initiatives or any new environmental laws or regulations could impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business, cash flows and results of operation. Please read Items 1 and 2 “Business and Properties — Environmental and Occupational Health and Safety Matters” for additional information.

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.

The EPA has issued RFS mandates, requiring refiners such as us to blend renewable fuels into the petroleum fuels they produce and sell in the U.S. We, and other refiners subject to RFS, may meet the RFS requirements by blending the necessary volumes of renewable transportation fuels produced by us or purchased from third parties. To the extent that refiners will not or cannot blend renewable fuels into the products they produce in the quantities required to satisfy their obligations under the RFS program, those refiners must purchase renewable credits, referred to as RINs, to maintain compliance. 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 RFS compliance or selling those RINs on the open market.

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Under RFS, the volume of renewable fuels that obligated parties are required to blend into their finished petroleum fuels increases annually over time until 2022. Our Shreveport, Superior, Great Falls and San Antonio refineries are normally subject to compliance with the RFS mandates. However, the EPA granted certain of our refineries a "small refinery exemption" under the RFS for the 2013, 2014, 2015 and 2016 calendar years, as provided under the CAA. Under these exemptions granted by the EPA, such exempt refineries were not subject to the requirements of RFS as an "obligated party" for fuels produced at these refineries for the calendar years 2013, 2014, 2015 and 2016.

On November 30, 2015, the EPA issued final multi-year volume mandates for 2014 to 2016. While these volume mandates are generally lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. We have received a small refinery exemption for certain of our refineries for the full year 2016 and have applied for the small refinery exemption at selected other refineries for the full year 2016 and are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the 2017 calendar year. While we received a small refinery exemption for certain of our refineries for 2013, 2014, 2015 and 2016, there is no assurance that such an exemption will be obtained for any of our refineries for the 2016 year or in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2016 annual RINs obligation, which includes RINs that were required to be secured through either our own blending or through the purchase of RINs in the open market, was 112 million RINs for the 2016 calendar year.

Existing laws, regulations or regulatory initiatives could change and, notwithstanding that the EPA's volume mandates for 2014 to 2016 may be relatively lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. 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 causes an increase in volume of our Shreveport, Superior, Great Falls and San Antonio refineries' fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make distributions to our unitholders. Moreover, despite a decline in RINs prices from levels during mid-2013, we cannot currently predict the future prices of RINs and, thus, the expenses related to acquiring RINs in the future could increase relative to the cost in prior years. The inability to receive an exemption under the RFS program for one or more of our refineries, any increase in the final minimum volumes of renewable fuels that must be blended with refined petroleum fuels, and/or any increase in the cost to acquire RINs may, individually or in the aggregate, have the potential to result in significant costs in connection with RIN compliance, which costs could be material. 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 RFS requirements. However, if any such RINs purchased by us on the open market are subsequently found to be invalid, then we may incur significant costs, penalties or other liabilities in connection with replacing such invalid RINs.

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 and payments of our debt obligations.

An impairment of our equity method investments, our long-lived assets or goodwill could reduce our earnings or negatively impact our financial condition and results of operations.

We continually monitor our business, the business environment and the performance of our operations to determine if an event has occurred that indicates that an equity method investment, a long-lived asset or goodwill may be impaired. If an event occurs, which is a determination that involves judgment, we may be required to utilize cash flow projections to assess our ability to recover the carrying value based on the ability to generate future cash flows. Under

GAAP, during the year ended December 31, 2015, we recognized an impairment charge on our equity method investment in Juniper GTL LLC of $24.3 million. Additionally, during the years ended December 31, 2016 and 2015, we recognized goodwill impairment charges of $34.8 million and $33.8 million, respectively. Our equity method investments, long-lived assets and goodwill impairment analyses are sensitive to changes in key assumptions used in our analysis, such as expected future cash flows, the degree of volatility in equity and debt markets and our unit price. If the assumptions used in our analysis are not realized, it is possible a material impairment charge may need to be recorded in the future. We cannot accurately predict the amount and timing of any impairment of long-lived assets or goodwill. Further, as we continue to develop our strategy regarding certain of our non-core assets, we will need to continue to evaluate the carrying value of those assets. Any additional impairment charges that we may take in the future could be material to our results of operations and financial condition.

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If we do not successfully execute growth strategies through acquisitions, our future growth and ability to reinstate 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 reinstate distributions to our unitholders may be limited. For example, as a result of the sustained decline in commodity prices during 2016 and the impact on our liquidity and access to capital, and in connection with our reduced operating budget for 2016, our ability to make acquisitions was limited in 2016. If commodity prices remain depressed, we expect that our ability to make acquisitions will be limited during 2017. 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;
- 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. Additionally, in February 2016 we completed an expansion project that increased production capacity at our Great Falls refinery by 15,000 bpd to 25,000 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.

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A decrease in the demand for our specialty products could adversely affect our ability to resume distributions to our unitholders and to make payments of our debt obligations.

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.

A decrease in demand for fuel products in the markets we serve could adversely affect our ability to resume distributions to our unitholders and to make payments of our debt obligations.

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 leads 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 many 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, Great Falls, Princeton, Cotton Valley, Karns City, Dickinson and Missouri facilities are employed under collective bargaining agreements. 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 impact our ability to make distributions to our unitholders and payments of our debt obligations. 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 ("LCM") 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. For example, due to the significant decrease in crude oil prices in 2015, we recorded an unfavorable LCM inventory adjustment of $81.8 million.

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 our 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 impact our ability to make distributions to our unitholders and payments of our debt obligations.

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, which in turn could impact our ability to make distributions to our unitholders and payments of our debt obligations.

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

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date but a number of states or grouping of states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. Additionally, the EPA has adopted rules under authority of the federal CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting “best available control technology” standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our producing customers’ operations. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rules with the new source performance standards.

On an international level, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs 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 that we produce. For example, in June 2016, the EPA published Subpart Quad OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued Subpart OOOO standards published by the EPA in 2012, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued a final ICR seeking information about methane emissions from facilities and operators in the oil and natural gas industry that could be used in developing standards for existing sources in the oil and natural gas industry. Finally, some scientists have concluded that increasing concentrations of GHG in the 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 operations and the operations of our customers.

Our business involves the shipping by rail of crude oil including from the Bakken Shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as regulatory changes that may adversely impact our business, financial condition or results of operations.

Our operations involve the purchasing of crude oil including from the Bakken Shale and shipping it by rail on railcars that we lease. Past derailments of trains transporting crude oil in the U.S. and Canada have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation of flammable materials by rail. Transportation safety regulators in the U.S. and Canada are concerned that crude oil from the Bakken Shale may be more flammable than crude oil from other producing regions and are investigating that issue. In May 2015, the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) adopted a final rule that, among other things, imposes a new tank car design standard, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as speed restrictions. The Canadian government's transportation department has also issued new regulations that align with the U.S. rule in many respects.

In August 2016, PHMSA released a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029. Additionally, in July 2016, PHMSA proposed a new rule that would expand the applicability of comprehensive oil spill response plans so that any railroad that transports a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train must have a current, comprehensive written plan. In response to a petition from the New York Attorney General, PHMSA issued an advance notice of proposed rulemaking ("ANPR") in January 2017 stating that it is considering revising the Hazardous Materials Regulations ("HMR") to establish vapor pressure limits for unrefined petroleum-based products and potentially all Class 3 flammable liquid hazardous materials that would apply during the transportation of the products or materials by any mode. In addition, in February 2016, the Federal Railroad Administration modified its accident and incident reports to gather additional data concerning rail cars carrying crude oil in any train involved in a Federal Railroad Agency-reportable accident. In addition to action taken or proposed by federal agencies, a number of states proposed or enacted laws in recent years that encourage safer rail operations or urge the federal government to strengthen requirements for these operations.

We have reviewed the final rule in detail to assess the expected impact on our business, including the potential impact on the tank cars that we lease to transport our products, and determined some of our tank cars could require upgrades or replacements. We are unable to predict what impact these or other regulatory changes may have, if any, on our business or the industry as a whole. As a result of the final rule, certain of our tank cars that we lease could be deemed unfit for further commercial use beginning in January 2018 or require retrofits or modifications, and the costs associated with any required retrofits or modifications could be substantial. In addition, the new tank car design requirements may result in significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. Such transportation capacity constraints could increase the cost of transporting crude oil by rail. We cannot assure that costs incurred to comply with any new standards and regulations, including those finalized by PHMSA in 2015 and 2016, will not be material to our business, financial condition or results of operations. In addition, any derailment involving crude oil that we have purchased or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot provide assurance that our policies will cover the entirety of any damages that may arise from such an event.

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 impact 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. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In its rulemaking under the Act, the CFTC has proposed new rules to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, their impact on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we believe that we qualify for the end-user exceptions to the mandatory clearing and trade execution requirements with respect to those swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

The Act and any new regulations could significantly increase the cost of derivative instruments, materially alter the terms of derivative instruments, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing derivatives contracts. 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.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

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 and payments of our debt obligations.

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 and payments of our debt obligations. 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. We have employment agreements in place with respect to Timothy Go, F. William Grube and R. Patrick Murray, II. 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, 2016, there were outstanding borrowings under our revolving credit facility of $10.2 million and $82.1 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 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 accounts receivable, inventory and substantially all of our cash; our 2021 Secured Notes are secured by a first-priority lien on all of the fixed assets that secure our obligations under our secured hedge agreements; and our obligations under our master derivatives contracts and the BP Purchase Agreement 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 forgoing (including proceeds of hedge agreements). If we are unable to repay our indebtedness under the revolving credit facility or the 2021 Secured Notes, satisfy 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 holders of our 2021 Secured Notes, the derivative counterparties under our master derivative contracts and BP, respectively, 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.

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 6, 2017, the families of our chairman, executive vice chairman, The Heritage Group and certain of their affiliates own an approximate 21.0% 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 6, 2017, the families of our chairman, executive vice chairman, The Heritage Group, and certain of their affiliates own an approximate 21.0% limited partner interest in us. In addition, The Heritage Group and the families of our chairman and executive 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 or payments from which will increase or decrease 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. Currently, The Heritage Group is an active marketer of asphalt products and has been engaged in this business for much longer than us. In certain geographical areas, there can be overlap where both The Heritage Group and we market asphalt.

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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 6, 2017, the owners of our general partner and certain of their affiliates own approximately 21.0% 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 6, 2017, our general partner and its affiliates own approximately 21.0% of our 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 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.

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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 and private letter rulings we have received with respect to certain aspects of our business, 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. 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 could 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 a material amount of 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 or interpretation 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 common 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 such substantive changes to the existing U.S. federal income tax laws that affect publicly-traded partnerships. Although there is no such current legislative proposal, a prior 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.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the “Final Regulations”) were published in the Federal Register. Although we are still studying the application of the Final Regulations to portions of our business, the Final Regulations reflect a number of changes from the proposed regulations that are responsive to our requests for clarifications to the proposed regulations. Although we anticipate that the vast majority of our income will qualify under new standards adopted by the Final Regulations, because of our private letter rulings portions of our income that may not qualify under the Final Regulations can be treated as qualifying throughout a ten-year transition period. However, there can be no assurance that there will not be further changes to the IRS’s interpretation of the qualifying income rules that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly-traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future changes could negatively impact the value of an investment 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 have requested and obtained a favorable private letter ruling from the IRS to the effect that, based on facts presented in the private letter ruling request, our income from refining, blending, processing, packaging, marketing and distribution of lubricants will constitute “qualifying income” within the meaning of Section 7704 of the Code.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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, including their share of income from the cancellation of debt.

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.

In response to current market conditions, we may engage in transactions to delever the Company and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases or modifications of our existing debt, could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD 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. 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. 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.

Furthermore, a substantial portion of the amount realized from the sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation and deductions and certain other items. Thus, our unitholders may recognize both ordinary income and capital loss from the sale of their units if the amount realized on a sale of such units is less than their adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which our unitholders sell their units, they may recognize ordinary income from our allocations of income and gain to them prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

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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 a U.S. federal tax return and pay tax on their share 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.

We have subsidiaries that are treated as a corporation for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for U.S. federal income tax purposes) are not subject to U.S. federal income tax, some of our operations are currently conducted through subsidiaries that are organized as a corporation for U.S. federal income tax purposes. The taxable income, if any, of such subsidiaries are subject to corporate-level U.S. federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries is fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

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 (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate gain or loss realized on a sale or other disposition of our assets or, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction on the Allocation Date. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The U.S. Department of the Treasury adopted final Treasury Regulations allowing a similar monthly simplifying convention but such regulations do not specifically authorize all aspects of our proration method. 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.

We have adopted certain valuation methodologies in determining unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely

affect the value of our common units.
In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.
A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of 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.

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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 jurisdictions 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 most 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 distribution per unit information 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)]
2015:			
First quarter	$20.65	$29.14	$ 0.685
Second quarter	$24.03	$28.49	$ 0.685
Third quarter	$18.26	$28.33	$ 0.685
Fourth quarter	$17.70	$27.88	$ 0.685
2016:			
First quarter	$7.80	$20.27	$ —
Second quarter	$3.42	$12.48	$ —
Third quarter	$4.36	$6.42	$ —
Fourth quarter	$2.79	$5.00	$ —

(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 6, 2017, there were approximately 40 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. As of March 6, 2017, there were 76,691,864 common units outstanding. The last reported sale price of our common units by NASDAQ on March 3, 2017, was $4.00.

Cash Distribution Policy

General. Within 45 days after the end of each quarter, we distribute our available cash (as defined in our partnership agreement), if any, 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.

Cash Distribution Policy. 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 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 2021 Secured Notes, 2021 Notes, 2022 Notes and 2023 Notes.

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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 a discussion of the restrictions in our debt instruments that restrict our ability to make distributions.

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 1,559,026 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 no incentive distribution rights during the year ended December 31, 2016. Our general partner earned incentive distribution rights of approximately $16.8 million during the year ended December 31, 2015.

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 %

Distribution Suspension

In April 2016 and effective beginning the first quarter 2016, the board of directors of our general partner suspended payment of our quarterly cash distribution. The board of directors of our general partner will continue to evaluate our ability to reinstate the distribution.

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, 2016, 2015, 2014, 2013 and 2012 includes the operations acquired as part of the acquisitions of Missouri, Calumet Packaging, Royal Purple, Great Falls, San Antonio, Bel-Ray, United Petroleum, Anchor Drilling Fluids and oilfield services assets from their respective dates of acquisition, January 3, 2012, January 6, 2012, July 3, 2012, October 1, 2012, January 2, 2013, December 10, 2013, February 28, 2014, March 31, 2014, and August 1, 2014.

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 (loss) and Net

cash provided by 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

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"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 Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions)				
Summary of Operations Data:					
Sales	$3,599.4	$4,212.8	$5,791.1	$5,421.4	$4,657.3
Cost of sales	3,191.1	3,618.2	5,261.4	5,011.4	4,144.1
Gross profit	408.3	594.6	529.7	410.0	513.2
Operating costs and expenses:					
Selling	110.7	146.0	149.6	62.6	41.6
General and administrative	110.6	135.5	98.3	82.1	60.9
Transportation	169.2	175.5	171.4	142.7	107.9
Taxes other than income taxes	20.1	17.7	13.4	14.2	9.1
Asset impairment	35.7	33.8	36.0	10.5	1.6
Other	1.7	11.1	14.2	6.3	6.2
Operating income (loss)	(39.7)	75.0	46.8	91.6	285.9
Other income (expense):					
Interest expense	(161.7)	(104.9)	(110.8)	(96.8)	(85.6)
Debt extinguishment costs	—	(46.6)	(89.9)	(14.6)	—
Realized gain (loss) on derivative instruments	(24.0)	8.1	43.8	(4.7)	9.5
Unrealized gain (loss) on derivative instruments	19.9	(39.5)	(0.6)	25.7	(3.8)
Loss from unconsolidated affiliates	(18.7)	(61.5)	(3.4)	(0.3)	—
Loss on sale of unconsolidated affiliates	(113.4)	—	—	—	—
Other	1.3	1.6	1.1	3.0	0.5
Total other expense	(296.6)	(242.8)	(159.8)	(87.7)	(79.4)
Net income (loss) before income taxes	(336.3)	(167.8)	(113.0)	3.9	206.5
Income tax expense (benefit)	(7.7)	(28.4)	(0.8)	0.4	0.8
Net income (loss)	$(328.6)	$(139.4)	$(112.2)	$3.5	$205.7

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except unit, per unit and operating data)				
Weighted average limited partner units outstanding:					
Basic	77,043,935	74,896,096	69,671,827	67,938,784	55,559,183
Diluted	77,043,935	74,896,096	69,671,827	67,938,784	55,676,741
Limited partners' interest basic net income (loss) per unit	$(4.18)	$(2.05)	$(1.80)	$(0.17)	$3.51
Limited partners' interest diluted net income (loss) per unit	$(4.18)	$(2.05)	$(1.80)	$(0.17)	$3.50
Cash distributions declared per limited partner unit	$0.685	$2.74	$2.74	$2.70	$2.30
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$1,678.0	$1,719.2	$1,464.4	$1,160.4	$986.9
Total assets	$2,725.2	$2,944.7	$3,085.1	$2,658.4	$2,223.6
Accounts payable	$295.5	$316.6	$419.9	$355.8	$332.6
Long-term debt	$1,997.2	$1,773.4	$1,678.8	$1,081.1	$834.1
Total partners' capital	$218.7	$603.9	$810.2	$1,062.8	$889.8
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$4.1	$376.4	$226.8	$39.1	$380.1
Investing activities	$(154.2)	$(389.0)	$(658.8)	$(370.3)	$(624.2)
Financing activities	$148.7	$9.7	$319.4	$420.1	$276.2
Other Financial Data:					
EBITDA	$(3.5)	$129.1	$226.3	$233.1	$383.7
Adjusted EBITDA	$158.2	$257.7	$305.9	$241.5	$404.6
Distributable Cash Flow	$(5.7)	$161.9	$146.3	$18.8	$281.1
Operating Data (bpd): [1]					
Total sales volume [2]	140,180	126,216	122,852	116,477	97,789