Calumet Specialty Products Partners, L.P.
Form 10-K
April 02, 2018
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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, 2017
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

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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 $256.5 million on June 30, 2017, based on $4.25 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

On April 2, 2018, there were 76,905,657 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE.

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Annual Report”) includes certain “forward-looking statements.” These statements can be identified by the use of forward-looking terminology including “may,” “intend,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” or other similar words. The statements regarding (i) estimated capital expenditures as a result of required audits or required operational changes or other environmental and regulatory liabilities, (ii) our anticipated levels of, use and effectiveness of derivatives to mitigate our exposure to crude oil price changes, natural gas price changes and fuel products price changes, (iii) estimated costs of complying with the U.S. Environmental Protection Agency’s (“EPA”) Renewable Fuel Standard, including the prices paid for Renewable Identification Numbers (“RINs”), (iv) our ability to meet our financial commitments, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures, (v) 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, (vi) our access to inventory financing under our supply and offtake agreements, (vii) our ability to remediate the identified material weaknesses and further strengthen the overall controls surrounding information systems and (viii) the future effectiveness of our new enterprise resource planning (“ERP”) system to further enhance operating efficiencies and provide more effective management of our business operations, 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 as of the date hereof 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 acquisition or disposition transactions. 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, northern Montana, western Pennsylvania, Texas, New Jersey and eastern Missouri. We own and lease additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("U.S."). Our business is organized into two segments: specialty products and fuel products. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple, 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. As a result of the sale of Anchor Drilling Fluids USA, LLC ("Anchor") in November 2017, we classified its results of operations for all periods presented to reflect Anchor as a discontinued operation and classified the assets and liabilities of Anchor as discontinued operations. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services. For the year ended December 31, 2017, approximately 64.1% of our continuing operations gross profit and approximately 59.3% of our continuing operations Adjusted EBITDA were generated from our specialty products segment and approximately 35.9% of our continuing operations gross profit and approximately 40.7% of our continuing operations Adjusted EBITDA were generated from our fuel products segment. We consider our specialty products segment our core business.

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
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

Storage, Distribution and Logistics Assets. We own and operate product terminals in Burnham, Illinois (“Burnham”) and Elmendorf, Texas (“Elmendorf”) with aggregate storage capacities of approximately 150,000 barrels and 200,000 barrels, respectively. The Burnham terminal, as well as additional owned and leased facilities throughout the U.S., facilitate the distribution of products in the Upper Midwest, West Coast and Mid-Continent regions of the U.S. and Canada. The Elmendorf terminal is a key supply hub for the San Antonio refinery and provides reliable access to high quality crude oil from Texas, primarily the Eagle Ford shale formation.

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We also use approximately 2,200 leased railcars to receive crude oil or distribute our products throughout the U.S. and Canada. In total, we have approximately 8.7 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. 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 64.1% of our continuing operations gross profit and 59.3% of our continuing operations Adjusted EBITDA in 2017 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 35.9% of our continuing operations gross profit and 40.7% of our continuing operations Adjusted EBITDA in 2017, 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 the increase of production capacity at our Great Falls refinery from 10,000 bpd to 25,000 bpd, which was completed in February 2016 and during 2017, the expansion of our TruFuel packaging line through the installation of a new filler line dedicated to filling gallon containers. Prior to the TruFuel packaging line expansion, we had only one filler line which required the line to be shut down prior to converting from quarts to gallons which reduced total run time on the line. Both filler lines are now utilized and we are able to meet customer demand and avoid substantial downtime encountered with the previous packaging line. 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 self-help initiatives and organic growth projects including improving reliability, product quality enhancements, product yield improvements and energy savings initiatives.
- 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.

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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 3,700 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. Many of these relationships involve lengthy approval processes or certifications that may make switching to a different supplier more difficult. Our customer base includes more than 4,000 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, 2017, 2016 and 2015.
- 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 in particular on strategic acquisitions of specialty products assets that leverage existing core competencies and/or that have an identifiable competitive advantage we can exploit as the new owner.

As part of our portfolio strategy, we continuously evaluate our portfolio which allows an objective assessment of potential divestiture candidates that are non-core to our business and which are worth more to a strategic buyer than to us. The combination of acquisition and divestment activity intends to maximize our return on invested capital by creating and maintaining a portfolio of core assets with significant potential to generate more stable and 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. In the past, we have invested 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 ("Dakota Prairie") 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.

During 2016 and 2017, we completed the following divestitures:

- In November 2017, we sold the Superior, Wisconsin refinery ("Superior Refinery") and associated inventories, the Superior Refinery's wholesale marketing business and related assets, including certain owned and leased product terminals, and certain crude gathering assets and line space in North Dakota for total consideration of $533.1 million. See Note 4 "Divestitures" under Part II, Item 8 "Financial Statements and Supplementary Data" for additional information.

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- In November 2017, we sold Anchor, for total consideration of approximately $89.6 million. We have classified the results of operations for Anchor as discontinued operations for all periods presented. See Note 3 "Discontinued Operations" under Part II, Item 8 "Financial Statements and Supplementary Data" for additional information.
- In June 2016, we sold our 50% equity interest in Dakota Prairie for total of consideration of $28.5 million, which was offset by our repayment of $36.0 million in borrowings under Dakota Prairie's revolving credit facility. See Note 5 "Investment in Unconsolidated Affiliates" under Part II, Item 8 "Financial Statements and Supplementary Data" for additional information.

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 April 2, 2018, we have 76,905,657 common units and 1,569,503 general partner units outstanding. Our general partner owns 2% of the Company and all incentive distribution rights and has sole responsibility for conducting our business and managing our operations. For more information about our general partner's board of directors and executive officers, please read Part III, Item 10 "Directors, Executive Officers of Our General Partner and Corporate Governance."

Our Operating Assets and Contractual Arrangements

General

The following table sets forth information about our combined operations from continuing operations. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, and the resale of crude oil in our fuel products segment. The operations of Superior are included through the effective date of the sale, November 7, 2017.

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	Year Ended December 31,					
	2017	2016	% Change	2016	2015	% Change
	(In bpd)			(In bpd)		
Total sales volume [1]	132,082	140,180	(5.8)%	140,180	126,216	11.1 %
Total feedstock runs [2]	128,624	134,163	(4.1)%	134,163	123,051	9.0 %
Facility production: [3]						
Specialty products:						
Lubricating oils	14,606	14,697	(0.6)%	14,697	13,325	10.3 %
Solvents	7,761	7,427	4.5 %	7,427	7,942	(6.5)%
Waxes	1,423	1,571	(9.4)%	1,571	1,460	7.6 %
Packaged and synthetic specialty products [4]	2,206	1,777	24.1 %	1,777	1,321	34.5 %
Other	1,811	1,850	(2.1)%	1,850	1,618	14.3 %
Total specialty products	27,807	27,322	1.8 %	27,322	25,666	6.5 %
Fuel products:						
Gasoline	35,713	37,713	(5.3)%	37,713	37,691	0.1 %
Diesel	33,277	34,808	(4.4)%	34,808	30,204	15.2 %
Jet fuel	5,368	5,306	1.2 %	5,306	5,157	2.9 %
Asphalt, heavy fuel oils and other	29,396	29,780	(1.3)%	29,780	24,077	23.7 %
Total fuel products	103,754	107,607	(3.6)%	107,607	97,129	10.8 %
Total facility production [3]	131,561	134,929	(2.5)%	134,929	122,795	9.9 %

(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 and Calumet Packaging facilities.

The following table sets forth information about our combined sales of principal products by segment:

	Year Ended December 31,					
	2017		2016		2015	
	(In millions)	% of Sales	(In millions)	% of Sales	(In millions)	% of Sales
Sales of specialty products:						
Lubricating oils	$584.2	15.5 %	$538.7	15.5 %	$575.6	14.6 %
Solvents	274.4	7.3 %	237.7	6.8 %	302.0	7.7 %
Waxes	117.2	3.1 %	128.7	3.7 %	136.9	3.5 %
Packaged and synthetic specialty products [1]	260.7	6.9 %	244.7	7.0 %	261.5	6.7 %
Other [2]	63.9	1.7 %	102.5	3.0 %	91.8	2.3 %
Total	1,300.4	34.5 %	1,252.3	36.0 %	1,367.8	34.8 %
Sales of fuel products:						
Gasoline	948.5	25.2 %	844.3	24.3 %	1,047.1	26.6 %
Diesel	877.9	23.4 %	808.4	23.3 %	894.8	22.8 %

Jet fuel	135.0	3.6 %	117.5	3.4 %	149.6	3.8 %
Asphalt, heavy fuel oils and other (3)	502.0	13.3 %	451.8	13.0 %	471.0	12.0 %
Total	2,463.4	65.5 %	2,222.0	64.0 %	2,562.5	65.2 %
Consolidated sales	$3,763.8	100.0%	$3,474.3	100.0%	$3,930.3	100.0%

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

(2) Represents (a) 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 and (b) polyolester synthetic lubricants produced at the Missouri facility.

(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 and San Antonio refineries to third party customers.

Please read Note 19 "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 ("Shreveport"), located on a 240 acre site in Shreveport, Louisiana, 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.

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

	Shreveport Refinery Year Ended December 31,		
	2017	2016	2015
	(In bpd)		
Crude oil throughput capacity	60,000	60,000	60,000
Total feedstock runs (1) (2)	37,853	40,845	40,726
Total refinery production (2) (3)	40,741	42,075	41,588

(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. The Plains pipeline also connects to a Plains terminal in Longview, TX, which gives the refinery access to crude oil in west Texas and access to the Cushing, Oklahoma storage hub. 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

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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.

Great Falls Refinery

The Great Falls refinery ("Great Falls"), 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,		
	2017	2016	2015
	(In bpd)		
Crude oil throughput capacity	25,000	25,000	10,000
Total feedstock runs [(1)] [(2)]	24,511	20,930	10,307
Total refinery production [(2)]	24,948	21,259	10,525

(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.

San Antonio Refinery

The San Antonio refinery ("San Antonio"), 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 Elmendorf crude oil terminal, 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.

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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 7,000 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,		
	2017	2016	2015
	(In bpd)		
Crude oil throughput capacity	21,000	21,000	21,000
Total feedstock runs (1) (2)	16,463	17,374	16,442
Total refinery production (2) (3)	15,782	16,736	15,708

(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 ("Cotton Valley"), located on a 77 acre site in Cotton Valley, Louisiana, 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.

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

	Cotton Valley Refinery Year Ended December 31,		
	2017	2016	2015
	(In bpd)		
Crude oil throughput capacity	13,500	13,500	13,500
Total feedstock runs (1) (2)	6,920	6,021	6,413
Total refinery production (2) (3)	6,466	5,399	6,103

(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. 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 ("Princeton"), located on a 208 acre site in Princeton, Louisiana, 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,		
	2017	2016	2015
	(In bpd)		
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs (1)	6,606	6,335	7,105
Total refinery production (1) (2)	5,396	5,242	5,851

(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.

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 ("Missouri"), 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 ("Calumet Packaging"), 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 ("Royal Purple"), 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 ("Bel-Ray"), 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 ("Karns City"), located on a 225 acre site in Karns City, Pennsylvania, 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 ("Dickinson"), located on a 28 acre site in Dickinson, Texas, has aggregate base oil throughput capacity of 1,300 bpd and processes white mineral oils, compressor lubricants and natural petroleum sulfonates. 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.

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,		
	2017	2016	2015
	(in bpd)		
Feedstock throughput capacity (1)	11,300	11,300	11,300

Total feedstock runs (2) (3)	5,896	6,483	5,515
Total production (3)	5,932	6,522	5,519

(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,

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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.

Other Logistics Assets

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. In addition to the below terminal, we own and lease additional facilities, primarily related to distribution of finished products, throughout the U.S. We operate the following terminal:

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, supplying lube base oils, food grade white oils and aliphatic solvents, as well as viscosity index additives and tackifiers.

We use approximately 2,200 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
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	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 2017, subsidiaries of Plains supplied us with approximately 11.6% of our total crude oil supply under term contracts and month-to-month evergreen crude oil supply contracts. In 2017, BP Products North America Inc. ("BP") supplied us with approximately 54.1% 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

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read Part II, Item 7A “Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk — Derivative Instruments” for a discussion of our hedging program.

Our Products, Markets and Customers

Products

We produce a full line of specialty products, including lubricating oils, solvents, waxes, packaged and synthetic specialty products, other by-products, as well as a variety of fuel and fuel related products, asphalt and heavy fuel oils. Our customers purchase specialty products primarily as raw material components for basic industrial, consumer and automotive goods.

The following table depicts a representative sample of the diversity of end-use applications for the products we produce:

Representative Sample of End-Use Applications by Product (1)

Lubricating Oils	Solvents	Waxes	Packaged and Synthetic Specialty Products	Other	Fuels & Fuel Related Products
16%	7%	3%	7%	2%	65%
• Hydraulic oils • Passenger car motor oils • Railroad engine oils • Cutting oils • Compressor oils • Metalworking fluids • Transformer oils • Rubber process oils • Industrial lubricants • Gear oils • Grease • Automatic transmission fluid •	• 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 • Engine treatment additives	• Roofing • Paving • Refrigeration compressor oils • Positive displacement and roto-dynamic compressor oils	• 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

- Animal feed dedusting
- Baby oils
- Bakery pan oils
- Catalyst carriers
- Gelatin capsule lubricants
- Sunscreen

(1) Based on the percentage of total sales for the year ended December 31, 2017. 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.

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

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- 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 2,200 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 international shipments, which accounted for less than 10% of our consolidated sales in 2017, 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.

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.

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 and Utah.

Customers

Specialty Products. We have a diverse customer base for our specialty products, with approximately 3,600 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, 2017, 2016 and 2015.

Fuel Products. We have a diverse customer base for our fuel products, with approximately 400 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. 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, 2017, 2016 and 2015.

Competition

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

Naphthenic Lubricating Oils. Our primary 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.

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, Andeavor, ExxonMobil, Valero Energy Corporation, Phillips 66, Cenex, Alon USA and Marathon Petroleum Corporation.

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 U.S. 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, 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: and 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, amendment 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 cost to control or remediate the soil and groundwater contamination at these refineries will not have 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.

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San Antonio Refinery

In connection with the acquisition of our San Antonio refinery from NuStar, 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, 2017, of which $14.6 million was capitalized into the cost of our recently completed expansion project and $2.4 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. The first phase of the arbitration is scheduled for July 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.

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 2017 and 2016, we incurred approximately $0.7 million and $2.4 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. We have recorded the $1.0 million liability within other current liabilities in the consolidated balance sheets.

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

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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, in October 2015, the EPA issued a final rule under the CAA 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 published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue attainment or non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. Also, in 2015, the EPA published a final rule that amended 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, 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, 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, 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, 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 2017 and certain prior calendar years. Under these exemptions granted by the

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EPA, such "small" refineries are not subject to the requirements of RFS as an "obligated party" for fuels produced at these refineries for those calendar years.

Under the RFS program, the EPA sets mandates for the production of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel volume that applies to all gasoline and diesel produced or imported during each year. Most recently, the EPA published final volume mandates in December 2017 for RFS program years 2018 (relating to conventional renewable fuel volumes such as corn ethanol) and 2019 (relating to biomass-based diesel). The EPA's December 2017 final volume mandates maintain the conventional (i.e., corn ethanol) renewable fuel volume at 15 billion gallons, the statutory level, which remains the same as the level for 2017. The EPA slightly increased the advanced biofuels volume slightly from the 2017 RFS mandate, from 4.28 billion gallons to 4.29 billion gallons. The final 2018 cellulosic biofuel volume is set at 288 million gallons, which represents a reduction from the 2017 level of 311 million gallons. The EPA also set a separate biodiesel volume for 2019 at 2.1 billion gallons, unchanged from the mandate previously finalized for 2018.

In the past, we received a small refinery exemption under the RFS program for certain of our refineries. We have received small refinery exemptions for our fuel products refineries for the full year 2016 and 2017. While we received a small refinery exemption for certain of our refineries in past years, there is no assurance that such an exemption will be obtained for any of our refineries in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2017 annual RINs obligation ("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 113 million RINs for the 2017 calendar year.

The EPA's implementation of the RFS program has been subject to numerous court challenges. For example, the D.C. Circuit remanded the 2016 final volume mandate to the EPA, and challenges to the 2017 remain pending in that court as well. Additional lawsuits have been filed by refiners attempting to move the point of compliance for the RFS program from refiners to importers and blenders of fuels. We cannot predict the outcome of these matters or whether they may result in increased RFS program compliance costs. Moreover, the price of RINs remains subject to extreme volatility, with the potential for significant increases in price. There also continues to be a shortage of advanced biofuel production resulting in increased difficulties meeting RFS program mandates. It is possible we could find ourselves unable to blend sufficient quantities of ethanol and biodiesel to meet our requirements and would, therefore, have to purchase an increasing number of RINs. It is not possible at this time to predict with certainty what those volumes or costs may be, but given the potential increase in volumes and the volatile price of RINs, increases in renewable volume requirements could have an adverse impact on our results of operations. 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, 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, governmental 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, the EPA entered a settlement agreement with environmental groups in December 2010 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.

In June 2016, the EPA published 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. However, the Quad OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a

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period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

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. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, 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. In August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities and result in decreased production of oil, which indirectly could have an adverse impact on our operations. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. 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 costs to control or remediate the soil and groundwater contamination at these refineries will not have 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. In July 2017, the EPA issued a questionnaire soliciting data from nine petroleum refining companies related to their wastewater characteristics. The request pertains to the types of processing units, wastewater treatment technologies, and related information. The EPA will use the data collected in this request to evaluate water use, wastewater generation, pollution prevention, and wastewater management, treatment, and disposal. 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 but these laws and their implementing regulations are subject to change and there can be no assurance that such future costs will not be material.

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.

Properties

We own and lease the principal properties which are listed below. The principal properties which we own, as well as 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
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
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

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, 2017, 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 7 “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.

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Employees

As of April 2, 2018, our general partner employs approximately 1,600 people who provide direct support to our operations. Of these employees, approximately 500 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
Cotton Valley	International Union of Operating Engineers	March 31, 2019
Princeton	International Union of Operating Engineers	October 31, 2020
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 or at the Burnham 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;
- the level of foreign and domestic production of crude oil and refined products;
- our ability to produce fuel products and specialty products that meet our customers' unique and precise specifications;
- the marketing of alternative and competing products;
- the extent of government regulation;
- results of our hedging activities; and
- overall economic and local market conditions.

In addition, the actual amount of cash we 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, 2017, and availability for borrowings of approximately $252.0 million under our senior secured revolving credit facility, in addition to $164.3 million of unrestricted cash. We continue to have the ability to incur additional debt, including the ability to borrow up to an aggregate principal amount of $600.0 million at any time, subject to borrowing base limitations, under our revolving credit facility. A tranche of the revolving credit facility includes a $25.0 million senior secured first loaned in and last to be repaid out ("FILO") 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;

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- 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 in general.

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 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 $32.86 per barrel to a low of $10.47 per barrel during 2017 and averaged $16.76 per barrel during 2017 compared to an average of $12.33 in 2016 and $17.96 in 2015.

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 have experienced fluctuations in our refining margins. There can be no assurance that our refining margins will not deteriorate. If our refining margins deteriorate, 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.

We have identified three material weaknesses in our internal control over financial reporting which, if not remediated, could result in material misstatements in our financial statements.

As of December 31, 2017, we have identified material weaknesses in internal control over financial reporting that pertain to (1) the ineffective design and implementation of effective controls with respect to the implementation of our ERP system consistent with our financial reporting requirements, (2) the design and maintenance of information technology general controls for information systems that are relevant to the preparation of financial statements and (3) untimely and insufficient operation of controls in the financial statement close process, specifically lack of timely account reconciliation, analysis and review related to all financial statement accounts. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

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Although we have developed and are implementing a plan to remediate these material weaknesses and believe, based on our evaluation to date, that these material weaknesses will be remediated in a timely fashion, we cannot assure you that this will occur within a specific timeframe. These material weaknesses will not be remediated until all necessary internal controls have been implemented, tested and determined to be operating effectively. In addition, we may need to take additional measures to address the material weaknesses or modify the planned remediation steps, and we cannot be certain that the measures we have taken, and expect to take, to improve our internal controls will be sufficient to address the issues identified, to ensure that our internal controls are effective or to ensure that the identified material weaknesses will not result in a material misstatement of our consolidated financial statements. Moreover, we cannot assure you that we will not identify additional material weaknesses in our internal control over financial reporting in the future.

If we are unable to remediate the material weaknesses, our ability to record, process and report financial information accurately, and to prepare financial statements within the time periods specified by the rules and forms of the Securities and Exchange Commission, could be adversely affected. This failure could negatively affect the market price and trading liquidity of our common units, cause investors to lose confidence in our reported financial information, subject us to civil and criminal investigations and penalties and generally materially and adversely impact our business and financial condition.

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;

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- 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 sum of the amount of FILO loans outstanding plus the greater of (a) 10% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $35.0 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 until availability under the revolving credit facility exceeds the greater of the foregoing amounts for 30 consecutive days.

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

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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. Furthermore, our borrowing base may be subject to decreases due to the sale of inventories and accounts as part of a divestiture. 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.

Implementation of our new enterprise resource planning system has adversely impacted and could continue to negatively affect our business.

We rely extensively on information systems and technology to manage our business and summarize our operating results. We have implemented a new enterprise resource planning (“ERP”) system to further enhance operating efficiencies and provide more effective management of our business operations, including processing sales orders and invoicing, inventory control, purchasing and supply chain management, human resources, and financial reporting. The new ERP system was deployed for use throughout our company in the third quarter of 2017. Implementing a new ERP system is costly, and has required, and will continue to require, the investment of significant personnel and financial resources. In addition, a new ERP system involves risks inherent in the conversion to a new system, including loss of information, disruption to our normal operations, changes in accounting procedures and internal control over financial reporting, as well as problems achieving accuracy in the conversion of electronic data. In particular, the implementation of our ERP system has resulted in operating and reporting disruptions, including limitations on our ability to ship and bill customers, project our inventory requirements, manage our supply chain, maintain current and complete books and records, maintain an effective internal control environment and meet external reporting deadlines. Management is executing a plan to resolve these issues. However, failure to properly or adequately address any issues with the new system could result in increased costs, the diversion of management’s and employees’ attention and resources and could materially adversely affect our operating results, internal controls over financial reporting and ability to manage our business effectively. While the ERP system is intended to further improve and enhance our information systems, large scale implementation of a new information system exposes us to the risks of starting up the new system and integrating that system with our existing systems and processes, including possible continued disruption of our financial reporting, which could lead to a failure to make required filings under the federal securities laws on a timely basis.

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.

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 2017, subsidiaries of Plains supplied us with approximately 11.6% of our total crude oil supplies under term contracts and month-to-month evergreen crude oil supply contracts. In 2017, BP supplied us with approximately 54.1% 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. Finding comparable suppliers 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.

From time to time, we may seek to divest portions of our business that are no longer core to our strategy, which could materially affect our results of operations and result in disruption to other parts of the business.

As demonstrated in 2016 with the disposition of our 50% equity interest in Dakota Prairie and in 2017 with the dispositions of the Superior Refinery and Anchor, we may continue to dispose of portions of our current business or assets, based on a variety of factors and strategic considerations, consistent with our strategy of preserving liquidity and streamlining our business to better focus on the advancement of our core business. These dispositions, together with any other future dispositions we make, may involve risks and uncertainties, including disruption to other parts of our business, potential loss of employees, customers or revenue, exposure to unanticipated liabilities or result in ongoing obligations and liabilities to us following any such divestiture. For example, in connection with a disposition, we may enter into transition services agreements or other strategic relationships, which may result in additional expense. In addition, in connection with a disposition, we may be required to make representations about the business and financial affairs of the business or assets. We may also be required to indemnify the purchasers to the extent that our representations turn out to be inaccurate or with respect to certain potential liabilities. These indemnification obligations may require us to pay money to the purchasers as satisfaction of their indemnity claims. It may also take us longer than expected to fully realize the anticipated benefits of these transactions, and those benefits may ultimately be smaller than anticipated or may not be realized at all, which could adversely affect our business and operating results. Further, such divestitures may result in proceeds to us in an amount less than we expect or less than our assessment of the value of those assets. Any of the foregoing could adversely affect our financial condition and results of operations.

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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 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. 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 $3.42 and $2.56 per million British thermal unit (“MMBtu”) in 2017, and between $1.64 and $3.93 per MMBtu in 2016. 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 14.6% and 12.6% of our total operating expenses included in cost of sales for the years ended December 31, 2017 and 2016, 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. 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, 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, but not limited to, 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 affect our financial condition and 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.

The operation of our refineries, blending and packaging sites, terminals, and related facilities 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 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

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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 had resulted in the filing of a suit by us against the predecessor operator and the matter is currently 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, 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 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, the expenditure of significant monies in the application of specific health and safety criteria addressing worker protection, the requirement to maintain information about hazardous materials used or produced in our operations and to provide this information to employees, state and local government authorities, and local residents and the incurrence of significant costs and liabilities for pollution resulting from our operations or from those of prior owners or operators of our facilities. Numerous federal governmental authorities, such as the EPA and OSHA as well as state agencies, such as the LDEQ, TCEQ and the MDEQ, 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.

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 another example, 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. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue attainment or non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our and our customers' operations. 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.

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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.

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. Each year until 2022, the EPA sets mandates for the production of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel volume that applies to all gasoline and diesel produced or imported during the applicable year. Most recently, the EPA published final volume mandates in December 2017 for RFS program years 2018 (relating to conventional renewable fuel volumes such as corn ethanol) and 2019 (relating to biomass-based diesel). The EPA’s December 2017 final volume mandates maintain the conventional (i.e., corn ethanol) renewable fuel volume at 15 billion gallons, the statutory level, which remains the same as the level for 2017. The EPA slightly increased the advanced biofuels volume slightly from the 2017 RFS mandate, from 4.28 billion gallons to 4.29 billion gallons. The final 2018 cellulosic biofuel volume is set at 288 million gallons, which represents a reduction from the 2017 level of 311 million gallons. EPA also set a separate biodiesel volume for 2019 at 2.1 billion gallons, unchanged from the mandate previously finalized for 2018.

Our Shreveport, Great Falls and San Antonio refineries are normally subject to compliance with the RFS mandates. However, the EPA granted our fuel products refineries a “small refinery exemption” under the RFS in the past years including, most recently, in the 2016 calendar year, 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 “small” refineries for those calendar years. While we received a small refinery exemption for certain of our refineries in past years, there is no assurance that such an exemption will be obtained for any of our refineries in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2017 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 113 million RINs for the 2017 calendar year.

The EPA’s implementation of the RFS program has been subject to numerous court challenges. For example, the D.C. Circuit remanded the 2016 final volume mandate to the EPA, and challenges to the 2017 remain pending in that court as well. Additional lawsuits have been filed by refiners attempting to move the point of compliance for the RFS program from refiners to importers and blenders and of fuels. We cannot predict the outcome of these matters or whether they may result in increased RFS program compliance costs. Moreover, the price of RINs remains subject to extreme volatility, with the potential for significant increases in price. There also continues to be a shortage of advanced biofuel production resulting in increased difficulties meeting RFS program mandates. It is possible we could find ourselves unable to blend sufficient quantities of ethanol and biodiesel to meet our requirements and would, therefore, have to purchase an increasing number of RINs. It is not possible at this time to predict with certainty what those volumes or costs may be, but given the potential increase in volumes and the volatile price of RINs, increases in renewable volume requirements could have an adverse impact on our results of operations.

Existing laws, regulations or regulatory initiatives could change and, notwithstanding that the EPA’s volume mandates for 2018 and 2019 may be relatively lower than the statutory mandates, 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, 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. 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, there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties and, while we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFS requirements, 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.

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Our arrangement with Macquarie exposes us to Macquarie-related credit and performance risk.

On March 31, 2017, we entered into several agreements with Macquarie to support the operations of the Great Falls refinery (the "Great Falls Supply and Offtake Agreements"). On June 19, 2017, we entered into several agreements with Macquarie to support the operations of the Shreveport refinery (the "Shreveport Supply and Offtake Agreements", and together with the Great Falls Supply and Offtake Agreements, the "Supply and Offtake Agreements"). We have Supply and Offtake Agreements with Macquarie, pursuant to which Macquarie will intermediate crude oil supplies and refined product inventories at our Great Falls and Shreveport refineries. Macquarie will own all of the crude oil in our tanks and substantially all of our refined product inventories prior to our sale of the inventories. Upon termination of the Supply and Offtake Agreements, which may be terminated by Macquarie with nine months' notice any time prior to June 2019, we are obligated in certain scenarios to repurchase all crude oil and refined product inventories then owned by Macquarie and located at the specified storage facilities at then current market prices. Relying on Macquarie's ability to honor its supply and offtake obligations exposes us to Macquarie's credit and business risks. An adverse change in Macquarie's business, results of operations, liquidity or financial condition could adversely affect its ability to perform its obligations, which could consequently have a material adverse effect on our business, results of operations or liquidity and, as a result, our business and operating results. In addition, we may be required to use substantial capital to repurchase crude oil and refined product inventories from Macquarie upon termination of the agreements, which could have a material adverse effect on our business, results of operations or financial condition. The repurchase obligations under the Supply and Offtake Agreements may be at substantially higher cost than which we sold the inventory.

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, 2017 and 2016, we recognized goodwill impairment charges of $0.7 million and $34.8 million, respectively. In 2017, we recorded impairment on long-lived assets primarily at our San Antonio refinery and Missouri facility totaling $206.6 million. 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.

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 involved 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, and 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.

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, among others:

- 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, 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 increase in crude oil prices in 2016, we recorded a favorable LCM inventory adjustment of $38.4 million.

Inadequate liquidity could materially and adversely affect our business operations in the future.
If our cash flow and capital resources are insufficient to fund our obligations, we may be forced to reduce our capital expenditures, seek additional equity or debt capital or restructure our indebtedness. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. Our liquidity is constrained by our need to satisfy our obligations under our credit agreements and our Supply and Offtake Agreements. The availability of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, the crack spread, natural gas and crude oil prices, our credit ratings, interest rates, market perceptions of us or the industries in which we operate, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these or other sources when the need arises.
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.
Our Supply and Offtake Agreements with Macquarie include provisions for early termination and could represent a refinancing risk.
When we executed the Supply and Offtake Agreements, the inventories associated with such agreements were taken out of our revolving credit facility borrowing base. As such, these inventories are not part of our revolving credit facility. Should Macquarie choose to exercise its option to terminate the Supply and Offtake Agreements by giving nine months' notice any time prior to June 2019 of such termination, we would need to seek alternative sources of financing, including putting the inventory back into our revolving credit facility, to meet our obligation to repurchase the inventory at then current market prices. In addition, the cost of repurchasing the inventory may be at higher prices than we sold the inventory. Currently, the price of crude oil is well above the price at which we sold the inventory, so unless the price of crude oil falls, we will have to pay more for the inventory than the price we sold the inventory for. Should we be unable to include the inventory in our borrowing base, we could suffer significant reductions in liquidity when Macquarie terminates the Supply and Offtake Agreements and we have to repurchase the inventories.
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, 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, governmental 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.

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. However, the Quad OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

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. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; while 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. In August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities and result in decreased production of oil, which indirectly could have an adverse impact on our operations.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. 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, 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 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. 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.

On December 13, 2017, PHMSA announced that it would initiate a rulemaking to rescind the May 2015 rule's requirement regarding electronically controlled pneumatic brakes. 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. PHMSA has not yet issued a final version of the rule. 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. PHMSA has not yet issued a final version of the rule. 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-

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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 re-proposed 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 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.

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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.

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 and F. William Grube. 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, 2017, there were outstanding borrowings under our revolving credit facility of $0.2 million and $67.3 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, our Collateral Trust Agreement and our Supply and Offtake Agreements.

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, our Collateral Trust Agreement and our Supply and Offtake Agreements. 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, the senior notes and Supply and Offtake Agreements 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, our Collateral Trust Agreement or our Supply and Offtake Agreements.

We are subject to cybersecurity risks and other cyber incidents resulting in disruption.

Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. We depend on information technology systems. In addition, our use of the internet, cloud services and other public networks exposes our business and that of other third parties with whom we do business to cyber-attacks that attempt to gain unauthorized access to data and systems, intentional or inadvertent releases of confidential information, corruption of data and disruption of critical systems and operations. Despite the security measures we have in place and any additional measures we may implement in the future, our facilities and systems, and those of our third-party service providers, could be vulnerable to security breaches, computer viruses, lost or misplaced data, programming errors, human errors, acts of vandalism or other events. Any disruption of our systems or security breach or event resulting in the misappropriation, loss or other unauthorized disclosure of confidential information, whether by us directly or our third-party service providers, could damage our reputation, expose us to the risks of litigation and liability, disrupt our business or otherwise affect our results of operations. In addition, as cyber-attacks continue to evolve in magnitude and sophistication, and our reliance on digital technologies continues to grow, we may be required to expend

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additional resources in order to continue to enhance our cyber security measures and to investigate and remediate any digital systems, related infrastructure, technologies and network security vulnerabilities.

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 April 2, 2018, 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 April 2, 2018, 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.

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 April 2, 2018, 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.

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 common units or 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 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 April 2, 2018, 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 or failure to provide such 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.

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

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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 and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders’ behalf.

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 information statement 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 and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. 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 de-lever and manage our liquidity, which 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.

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.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after

December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

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Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a 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.

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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.

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 7 "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
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	$ —
2017:			
First quarter	$3.55	$4.70	$ —
Second quarter	$3.40	$4.93	$ —
Third quarter	$4.00	$9.10	$ —
Fourth quarter	$6.10	$9.95	$ —

As of April 2, 2018, there were approximately 37 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. As of April 2, 2018, there were 76,905,657 common units outstanding. The last reported sale price of our common units by NASDAQ on March 29, 2018, was $7.05.

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, since April 2016, we have not paid, and there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. See "— Distribution Suspension." 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. 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 1,569,503 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

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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 for the years ended December 31, 2017 and 2016. 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, 2017, 2016, 2015, 2014 and 2013. The operations of Superior are included through the effective date of the sale, November 7, 2017. The operations acquired as part of the acquisitions of San Antonio, Bel-Ray and United Petroleum, LLC (“United Petroleum”) are included from their respective dates of acquisition, January 2, 2013, December 10, 2013 and February 28, 2014. On November 21, 2017, we completed the sale of Anchor. As a result, effective in fourth quarter of fiscal 2017, we classified Anchor as a discontinued operation in accordance with GAAP.

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 (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with U.S. generally accepted accounting principles (“GAAP”), please read “—Non-GAAP Financial Measures.”

We derived the information in the following table from, and the information should be read together with, and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included in Item 8 “Financial Statements and Supplementary Data” except for operating data, such as sales volume, feedstock runs and facility production. The following table also should be read together with Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions)				
Summary of Operations Data:					
Sales	$3,763.8	$3,474.3	$3,930.3	$5,422.6	$5,421.4
Cost of sales	3,265.6	3,088.0	3,393.9	5,014.9	5,011.4
Gross profit	498.2	386.3	536.4	407.7	410.0
Operating costs and expenses:					
Selling	65.7	69.8	71.8	80.6	62.6
General and administrative	138.7	105.8	125.9	94.2	82.1
Transportation	137.1	154.3	153.6	143.3	142.7
Taxes other than income taxes	24.1	19.3	17.1	13.0	14.2
Asset impairment	207.3	35.7	—	—	10.5
Gain on sale of business, net	(236.0)	—	—	—	—
Other	3.3	1.7	10.8	14.1	6.3
Operating income (loss)	158.0	(0.3)	157.2	62.5	91.6
Other income (expense):					
Interest expense	(183.1)	(161.7)	(104.9)	(110.8)	(96.8)
Debt extinguishment costs	—	—	(46.6)	(89.9)	(14.6)
Gain (loss) on derivative instruments	(9.6)	(4.1)	(31.4)	43.2	21.0
Loss from unconsolidated affiliates	—	(18.3)	(61.1)	(3.2)	(0.3)
Loss on sale of unconsolidated affiliates	—	(113.4)	—	—	—
Other	3.3	1.2	1.6	1.4	3.0
Total other expense	(189.4)	(296.3)	(242.4)	(159.3)	(87.7)
Net income (loss) from continuing operations before income taxes	(31.4)	(296.6)	(85.2)	(96.8)	3.9
Income tax expense (benefit) from continuing operations	(0.1)	0.2	0.2	0.6	0.4
Net income (loss) from continuing operations	(31.3)	(296.8)	(85.4)	(97.4)	3.5
Net loss from discontinued operations, net of income taxes	(72.5)	(31.8)	(54.0)	(14.8)	—
Net income (loss)	$(103.8)	$(328.6)	$(139.4)	$(112.2)	$3.5

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	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions, except unit, per unit and operating data)				
Weighted average limited partner units outstanding:					
Basic and diluted	77,598,950	77,043,935	74,896,096	69,671,827	67,938,784
Limited partners' interest basic and diluted net loss per unit:					
From continuing operations	$(0.40)	$(3.77)	$(1.34)	$(1.59)	$(0.17)
From discontinued operations	(0.91)	(0.41)	(0.71)	(0.21)	—
Limited partners' interest	$(1.31)	$(4.18)	$(2.05)	$(1.80)	$(0.17)
Cash distributions declared per limited partner	$—	$0.685	$2.74	$2.74	$2.70
Balance Sheet Data (at period end):[1]					
Property, plant and equipment, net	$1,159.2	$1,632.4	$1,665.0	$1,407.2	$1,160.4
Total assets	$2,688.8	$2,571.3	$2,752.6	$2,715.3	$2,658.4
Accounts payable	$282.3	$275.9	$300.0	$360.4	$355.8
Total long-term debt	$1,992.3	$1,997.2	$1,773.4	$1,678.8	$1,081.1
Total partners' capital	$119.9	$218.7	$603.9	$810.2	$1,062.8
Cash Flow Data:[5]					
Net cash flow provided by (used in):					
Operating activities	$(26.5)	$4.1	$376.4	$226.8	$39.1
Investing activities	$453.4	$(154.2)	$(389.0)	$(658.8)	$(370.3)
Financing activities	$83.2	$148.7	$9.7	$319.4	$420.1
Other Financial Data:[5]					
EBITDA	$246.7	$(3.5)	$82.5	$136.4	$218.5
Adjusted EBITDA	$317.2	$158.2	$257.7	$305.9	$241.5
Distributable Cash Flow	$89.3	$(5.7)	$161.9	$146.3	$18.8
Operating Data (bpd): [1]					
Total sales volume [2]	132,082	140,180	126,216	122,852	116,477
Total feedstock runs [3]	128,624	134,163	123,051	117,427	110,237
Total facility production [4]	131,561	134,929	122,795	114,146	106,592

(1) Balance sheet and operating data exclude discontinued operations.

(2) 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.

(3) 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.

(4) 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.

(5) Cash flow and other financial data are reflective of continuing and discontinued operations.

Non-GAAP Financial Measures

We include in this Annual Report the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. We provide reconciliations of EBITDA, Adjusted EBITDA and Distributable Cash Flow to Net income (loss), our most directly comparable financial performance measure. We also provide a reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by (used in) operating activities, our most directly comparable liquidity measure. Both Net income (loss) and Net cash provided by (used in) operating activities are calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP").

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

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

Management believes that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay interest costs and distributions. However, the indentures governing our senior notes contain covenants that, among other things, restrict our ability to pay distributions. We believe that excluding these transactions allows investors to meaningfully analyze trends and performance of our core cash operations.

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

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

We define Distributable Cash Flow for any period as Adjusted EBITDA less replacement and environmental capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense), income (loss) from unconsolidated affiliates, net of cash distributions and income tax expense (benefit).

We define Adjusted EBITDA Margin as Adjusted EBITDA divided by sales.

The definition of Adjusted EBITDA presented in this Annual Report is consistent with the calculation of "Consolidated Cash Flow" contained in the indentures governing our 2021 Secured, 2021, 2022 and 2023 Notes (as defined in this Annual Report). We are required to report Consolidated Cash Flow to the holders of our 2021 Secured, 2021, 2022 and 2023 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. 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 details regarding the covenants governing our debt instruments.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to Net income (loss), Operating income (loss), Net cash provided by (used in) operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted

EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA and Adjusted EBITDA do not reflect our obligations for the payment of income taxes, interest expense or other obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of several measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner.
The following tables present a reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow; Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by (used in) operating activities and Segment

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Adjusted EBITDA to EBITDA and Net income (loss), and our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions)				
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:					
Net income (loss)	$(103.8)	$(328.6)	$(139.4)	$(112.2)	$3.5
Add:					
Interest expense	183.1	161.7	104.9	110.8	96.8
Depreciation and amortization	168.5	171.1	145.4	138.6	117.8
Income tax expense (benefit)	(1.1)	(7.7)	(28.4)	(0.8)	0.4
EBITDA	$246.7	$(3.5)	$82.5	$136.4	$218.5
Add:					
Unrealized (gain) loss on derivatives	$(3.6)	$(19.9)	$39.5	$0.6	$(25.7)
Realized gain (loss) on derivatives, not included in net income (loss) or settled in a prior period	—	(6.4)	(10.0)	6.6	(1.8)
Debt extinguishment costs	—	—	46.6	89.9	14.6
Amortization of turnaround costs	24.3	33.2	29.0	24.5	15.9
Impairment charges [1]	207.3	35.9	58.1	36.0	10.5
Loss on sale of unconsolidated affiliate	—	113.9	—	—	—
Gain on the sale of businesses, net	(173.4)	—	—	—	—
Non-cash equity-based compensation and other items	15.9	5.0	12.0	11.9	9.5
Adjusted EBITDA	$317.2	$158.2	$257.7	$305.9	$241.5
Less:					
Replacement and environmental capital expenditures [2]	$42.0	$29.3	$44.2	$31.8	$64.2
Cash interest expense [3]	172.9	152.1	98.2	104.4	89.8
Turnaround costs	14.5	8.7	19.3	27.6	68.6
Loss from unconsolidated affiliates	(0.4)	(18.5)	(37.5)	(3.4)	(0.3)
Income tax expense (benefit)	(1.1)	(7.7)	(28.4)	(0.8)	0.4
Distributable Cash Flow	$89.3	$(5.7)	$161.9	$146.3	$18.8

(1) Impairment charges for 2017 primarily relate to $59.2 million of long-lived asset impairment charges related to the specialty products segment and $147.0 million of long-lived asset impairment charges related to the fuel products segment.

Impairment charges for 2016 include $34.8 million of goodwill impairment charges related to the specialty products and fuel products segments, $0.9 million of long-lived assets impairment charges related to the specialty products and fuel products segments, and a $0.2 million impairment charge related to one of our equity method investments.

Impairment charges for 2015 include a $33.8 million goodwill impairment charge related to the prior oilfield services segment and $24.3 million impairment charge related to our investment in Juniper GTL LLC ("Juniper").

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

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

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	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions)				
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by (used in) operating activities:					
Distributable Cash Flow	$89.3	$(5.7)	$161.9	$146.3	$18.8
Add:					
Replacement and environmental capital expenditures (1)	42.0	29.3	44.2	31.8	64.2
Cash interest expense (2)	172.9	152.1	98.2	104.4	89.8
Turnaround costs	14.5	8.7	19.3	27.6	68.6
Loss from unconsolidated affiliates	(0.4)	(18.5)	(37.5)	(3.4)	(0.3)
Income tax expense (benefit)	(1.1)	(7.7)	(28.4)	(0.8)	0.4
Adjusted EBITDA	$317.2	$158.2	$257.7	$305.9	$241.5
Less:					
Unrealized (gain) loss on derivatives	$(3.6)	$(19.9)	$39.5	$0.6	$(25.7)
Realized gain (loss) on derivatives, not included in net income (loss) or settled in a prior period	—	(6.4)	(10.0)	6.6	(1.8)
Debt extinguishment costs	—	—	46.6	89.9	14.6
Amortization of turnaround costs	24.3	33.2	29.0	24.5	15.9
Impairment charges (3)	207.3	35.9	58.1	36.0	10.5
Gain on sale of businesses, net	(173.4)	—	—	—	—
Loss on sale of unconsolidated affiliate	—	113.9	—	—	—
Non-cash equity-based compensation and other items	15.9	5.0	12.0	11.9	9.5
EBITDA	$246.7	$(3.5)	$82.5	$136.4	$218.5
Add:					
Unrealized (gain) loss on derivatives	$(3.6)	$(19.9)	$39.5	$0.6	$(25.7)
Cash interest expense (2)	(172.9)	(152.1)	(98.2)	(104.4)	(89.8)
Gain on sale of businesses, net	(173.4)	—	—	—	—
Asset impairment	207.3	35.7	33.8	36.0	10.5
Lower of cost or market inventory adjustment	(30.6)	(39.2)	81.8	74.1	(2.1)
Equity-based compensation	11.6	5.6	9.8	6.5	4.8
Loss from unconsolidated affiliates	0.4	18.7	61.5	3.4	0.3
Loss on sale of unconsolidated affiliates	—	113.4	—	—	—
Amortization of turnaround costs	24.3	33.2	29.0	24.5	15.9
Income tax (expense) benefit	1.1	7.7	28.4	0.8	(0.4)
Non-cash debt extinguishment costs	—	—	9.1	19.0	3.4
Changes in assets and liabilities:					
Accounts receivable	(200.7)	(28.4)	138.0	(0.4)	(32.3)
Inventories	(18.1)	49.6	47.3	43.9	16.4
Other current assets	(0.5)	(3.5)	3.4	3.9	6.8
Turnaround costs	(14.5)	(8.7)	(19.3)	(27.6)	(68.6)
Derivative activity	(0.5)	(19.0)	(7.0)	6.7	(1.8)
Other assets	(0.5)	(0.6)	—	—	(0.1)
Accounts payable	94.1	21.4	(119.9)	(13.1)	6.8
Accrued interest payable	0.9	21.4	(6.5)	15.1	(1.0)
Accrued income taxes payable	—	—	—	—	(27.6)
Other current liabilities	(5.3)	(31.1)	84.2	(2.1)	2.7
Other	7.7	3.4	(21.0)	3.5	2.4

Net cash provided by (used in) operating activities	$(26.5)	$4.1	$376.4	$226.8	$39.1

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

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

(3) Impairment charges for 2017 primarily relate to $59.2 million of long-lived asset impairment charges related to the specialty products segment and $147.0 million of long-lived asset impairment charges related to the fuel products segment.

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Impairment charges for 2016 include $34.8 million of goodwill impairment charges related to the specialty products and fuel products segments, $0.9 million of long-lived assets impairment charges related to the specialty products and fuel products segments, and a $0.2 million impairment charge related to one of our equity method investments. Impairment charges for 2015 include a $33.8 million goodwill impairment charge related to the prior oilfield services segment and $24.3 million impairment charge related to our investment in Juniper.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions)				
Reconciliation of Segment Adjusted EBITDA to EBITDA and Net income (loss):					
Segment Adjusted EBITDA:					
Specialty products Adjusted EBITDA	$186.5	$188.9	$201.7	$220.8	$194.5
Fuel products Adjusted EBITDA	127.8	(10.1)	81.9	50.0	47.0
Discontinued operations Adjusted EBITDA	2.9	(20.6)	(25.9)	35.1	—
Total segment Adjusted EBITDA	$317.2	$158.2	$257.7	$305.9	$241.5
Less:					
Unrealized (gain) loss on derivatives	$(3.6)	$(19.9)	$39.5	$0.6	$(25.7)
Realized gain (loss) on derivatives, not included in net income (loss) or settled in a prior period	—	(6.4)	(10.0)	6.6	(1.8)
Debt extinguishment costs	—	—	46.6	89.9	14.6
Amortization of turnaround costs	24.3	33.2	29.0	24.5	15.9
Impairment charges	207.3	35.9	58.1	36.0	10.5
Gain on sale of businesses, net	(173.4)	—	—	—	—
Loss on sale of unconsolidated affiliate	—	113.9	—	—	—
Non-cash equity-based compensation and other items	15.9	5.0	12.0	11.9	9.5
EBITDA	$246.7	$(3.5)	$82.5	$136.4	$218.5
Less:					
Interest expense	$183.1	$161.7	$104.9	$110.8	$96.8
Depreciation and amortization	168.5	171.1	145.4	138.6	117.8
Income tax expense (benefit)	(1.1)	(7.7)	(28.4)	(0.8)	0.4
Net income (loss)	$(103.8)	$(328.6)	$(139.4)	$(112.2)	$3.5

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

The historical consolidated financial statements included in this Annual Report reflect all of the assets, liabilities and results of operations of the Company. The following discussion analyzes the financial condition and results of operations of the Company for the years ended December 31, 2017, 2016 and 2015. In addition, as discussed in Note 3 and Note 4 to the Consolidated Financial Statements, we closed the Superior Transaction and the Anchor Transaction on November 8, 2017 and November 21, 2017, respectively. The historical results of operations of the Superior Refinery are contained in our financial position and results through November 7, 2017. As a result of the Anchor Transaction, we classified its results of operations and the assets and liabilities of Anchor for all periods presented to reflect Anchor as a discontinued operation. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services. Unitholders should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with the historical consolidated financial statements and notes of the Company included elsewhere in this Annual Report.

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana, and own specialty and fuel products facilities primarily located in northwest Louisiana, northern Montana, western Pennsylvania, Texas, New Jersey and eastern Missouri. We own and lease additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("U.S."). Our business is organized into two segments: specialty products and fuel products. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple, 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.

2017 Update

Outlook and Trends

Commodity markets and corresponding refined product margins were volatile during 2016 and 2017, with the average price per barrel of New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") crude oil decreasing approximately 11% during 2016 and increasing approximately 17% during 2017. We expect this volatility to continue into 2018. Below are factors that have impacted our results of operations during 2017:

- We realized record profit contribution from certain specialty product lines, primarily attributable to the continued growth of our brand-named products such as Royal Purple, Bel-Ray and TruFuel. We are committed to continued growth in our specialty products segment, and we continue to work on new products to introduce to the market. Specialty products margins have remained relatively stable and are expected to remain stable in the near term.
- We continue to consider our specialty products segment our core business over the long term, and we plan to seek appropriate ways to invest in our specialty products segment while divesting non-core businesses. Accordingly, we continue to evaluate opportunities to divest non-core businesses and assets in line with our strategy of preserving liquidity and streamlining our business to better focus on the advancement of our core business. However, there can be no assurance as to the timing or success of any such potential transaction, or any other transaction, or that we will be able to sell these assets or non-core businesses on satisfactory terms, if at all. In addition, our acquisition program targets assets 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.
- We continued to focus on improving operations in 2017. Our average feedstock runs were 128,624 barrels per day ("bpd") in 2017, compared to 134,163 bpd in 2016. The decrease is primarily attributable to the Superior Transaction partially offset by strong specialty products feedstock runs. We hope to see modest improvement in our utilization rates in the future as we continue to seek to minimize unplanned downtime at our facilities.

- Refined fuel product margins have widened in 2017 as compared to 2016 with the Gulf Coast crack spread (defined below) increasing 42% to $17 per barrel, while the Western Canadian Select (“WCS”) discount versus NYMEX WTI remained flat at $13 per barrel below NYMEX WTI. The WCS discount to NYMEX WTI widened in the fourth quarter of 2017 and into 2018. We have increased our use of WCS crude oil and other heavy crude oils to capture the higher margins associated with refining heavier crude oils. Canadian heavy sour crude oil discounts are expected to remain wide over the long term as Canadian sour crude oil remains oversupplied. Processing heavy sour crude oil in our refining system results in a lower overall delivered cost of crude oil.
- Environmental regulations continue to affect our margins in the form of Renewable Identification Numbers (“RINs”). To the extent we are unable to blend biofuels, we must purchase RINs in the open market to satisfy our annual requirement.

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It is not possible to predict what future volumes or costs may be, but given the volatile price of RINs, we continue to anticipate that RINs have the potential to remain a significant expense for our fuel products segment, assuming current market prices for RINs continue, inclusive of the favorable impact of any exemptions received from the EPA.

Financial Results

We reported a net loss from continuing operations of $31.3 million in 2017, versus a net loss from continuing operations of $296.8 million in 2016. We reported Adjusted EBITDA from continuing operations (as defined in Item 6 “Selected Financial Data — Non-GAAP Financial Measures”) of $314.3 million in 2017, versus $178.8 million in 2016.

Our net loss from continuing operations for the full-year 2017 includes the impact of seven items: (1) a net gain on sale of Superior of $236.0 million, (2) asset impairment charges of $207.3 million, (3) a favorable lower of cost or market (“LCM”) inventory adjustment of $30.6 million, (4) realized hedging losses of $13.2 million, (5) $3.7 million of losses related to liquidation of last-in, first-out (“LIFO”) inventory layers, (6) $18.6 million of enterprise resource planning (“ERP”) costs and (7) $6.1 million of bad debt expense.

Please read Item 6 “Selected Financial Data — Non-GAAP Financial Measures” for a reconciliation of EBITDA and Adjusted EBITDA to Net income (loss), our most directly comparable financial performance measure calculated and presented in accordance with U.S. GAAP.

Commodity markets remained volatile in 2017, contributing to fluctuations in refined product margins. The average price of NYMEX WTI crude oil averaged approximately $51 per barrel in 2017 compared to approximately $43 per barrel in 2016. With respect to the average price differential per barrel between WCS and NYMEX WTI, WCS averaged $13 per barrel below NYMEX WTI, in both 2017 and 2016. Given our access to cost-advantaged, heavy Canadian crude oil in our Great Falls refinery, we have embarked on a multi-year plan to increase our ability to process this crude oil grade. In the full-year 2017, we processed 36,500 bpd of heavy Canadian crude oil, versus 35,000 bpd in the full-year 2016.

Gross profit per barrel for our specialty products segment was $33.93 in 2017, versus $34.57 in the prior year. Specialty products segment Adjusted EBITDA was $186.5 million in 2017 compared to $188.9 million in the prior year. Specialty products segment Adjusted EBITDA Margin was 14.3% in 2017, compared to 15.1% in 2016. Specialty products segment Adjusted EBITDA decreased slightly due to consistently rising feedstock costs throughout 2017, decreased sales volumes and increased ERP implementation costs, partially offset by stronger market conditions, record volume and profit performance in the higher-margin packaged and synthetic specialty products and record feestock runs at the Cotton Valley refinery. 2017 results were impacted by a $10.9 million favorable LCM inventory adjustment and a $3.0 million loss related to the liquidation of LIFO inventory layers. Specialty products represented approximately 21.0% of total production in 2017, compared to 20.0% in 2016.

Gross profit per barrel for our fuel products segment was $4.61 per barrel in 2017, versus $0.96 per barrel in the prior year. Fuel products segment Adjusted EBITDA was $127.8 million in 2017, a significant increase versus the prior year, despite increased ERP implementation costs. Fuel products segment results for fiscal year 2017 were positively impacted by an improvement in the benchmark Gulf Coast crack spread, lower Renewable Fuel Standard (“RFS”) compliance costs, improvement in fuels profitability at the Shreveport refinery and record production and record Canadian feedstock runs at the Great Falls refinery. 2017 results were impacted by a $19.7 million favorable LCM inventory adjustment and a $0.7 million loss related to the liquidation of LIFO inventory layers. Fuel products represented approximately 79.0% of total production during the year. Total fuel products segment sales volumes decreased 6.6% during 2017, when compared to the full-year 2016 primarily as a result of the Superior Transaction.

During the fourth quarter of 2017, we identified impairment indicators that suggested the carrying values of long-lived assets at the Missouri and San Antonio reporting units within the specialty products and fuel products segments, respectively, may not be recoverable. The primary impairment indicators included recently completed projections of future cash flows and the associated impact on the long-range strategic plan forecasts, lower than expected cash flows attributed to these reporting units and poor local market conditions. Undiscounted cash flow tests performed for these reporting units indicated that the long-lived assets were not recoverable. As a result, we recorded impairment on long-lived assets primarily at our San Antonio refinery and Missouri facility totaling $206.6 million.

For benchmarking purposes, we compare our per barrel refined fuel products margin to the U.S. Gulf Coast 2/1/1 crack spread ("Gulf Coast crack spread"). The Gulf Coast crack spread represents the approximate gross margin per barrel that results from processing two barrels of crude oil into one barrel of gasoline and one barrel of ultra-low sulfur diesel fuel. The Gulf Coast crack spread is calculated using the near-month futures price of NYMEX WTI crude oil, the price of U.S. Gulf Coast Pipeline 87 Octane Conventional Gasoline and the price of U.S. Gulf Coast Pipeline Ultra-Low Sulfur Diesel ("ULSD").

During 2017, the Gulf Coast crack spread averaged approximately $17 per barrel, versus approximately $12 per barrel in 2016, an approximate 42.0% increase. The Gulf Coast ULSD crack spread averaged approximately $17 per barrel during 2017, compared to approximately $12 per barrel in the prior year. The Gulf Coast gasoline crack spread averaged approximately $16 per barrel during 2017, compared to approximately $13 per barrel in the prior year. Between 2016 and 2017, the average WCS discount versus NYMEX WTI remained flat at $13 per barrel.

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Included within our fuel products segment gross profit per barrel calculation are the realized cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and process materials. Our gross profit per barrel calculation may not be comparable to similar calculations published by our competitors.

There are several factors that impact our refined product margin when compared to the benchmark crack spread. For example, several of our fuel products refineries produce asphalt and other residual products that may carry an average sales price below that of U.S. Gulf Coast gasoline or U.S. Gulf Coast ULSD. Alternatively, many of our fuel products refineries purchase select quantities of crude oil at a discount to NYMEX WTI, which helps support a higher capture rate, relative to the crack spread benchmark. Finally, our Shreveport refinery produces both fuel and specialty products; given that our specialty products facilities generally operate at lower utilization rates than our fuel products facilities, facilities producing specialty products may incur higher operating expenses when compared to refineries that produce fuels exclusively, such as our Great Falls refinery. Based on our system-wide crude purchasing behaviors and overall production slate, we believe the Gulf Coast crack spread remains a meaningful indicator in tracking directional shifts in our refined product margins.

On September 1, 2017, we implemented the first phase of our new enterprise resource planning (“ERP”) system, to provide better information and enable us to manage our business operations more effectively, including processing sales orders and invoicing, inventory control, purchasing and supply chain management and financial reporting. However, the implementation of our ERP system resulted in operating and reporting disruptions, including limitations on our ability to ship product and bill customers, project our inventory requirements, manage our supply chain, maintain current and complete books and records, maintain an effective internal control environment and meet external reporting deadlines. We expect that we will continue to incur costs related to our ERP system in 2018 as we stabilize the system and then embark on a number of enhancements to achieve the expected results for the implementation.

Divestitures

On November 8, 2017, we completed the sale of all of the issued and outstanding membership interests in Calumet Superior, LLC, which owns the Superior, Wisconsin refinery (“Superior Refinery”). The sale included the associated working capital, the Superior Refinery’s wholesale marketing business and related assets, including certain owned or leased product terminals, and certain crude gathering assets and line space in North Dakota to Husky Superior Refining Holding Corp. (“Husky”) (the “Superior Transaction”). Total consideration was $533.1 million which consisted of a base price of $435.0 million and $98.1 million for net working capital and reimbursement of certain capital spending. The Superior Refinery is included in the Company’s fuel products segment. We recognized a net gain of $236.0 million in gain on sale of business in the consolidated statements of operations for the year ended December 31, 2017.

On November 21, 2017, we completed the sale to a subsidiary of Q’Max Solutions Inc. (“Q’Max”) of all of the issued and outstanding membership interests in Anchor Drilling Fluids USA, LLC, (“Anchor”), for total consideration of approximately $89.6 million including a base price of $50.0 million ($8.0 million of which will be paid at various times over the next year), $14.2 million to be paid at various times over the 24 month period following the closing of the transaction for net working capital and other items, and 10% equity ownership in Fluid Holding Corp., the parent company of Q’Max (the “Anchor Transaction”). Effective in fourth quarter of 2017, we classified its results of operations for all periods presented to reflect Anchor as a discontinued operation and classified the assets and liabilities of Anchor as discontinued operations. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services.

We received over $500 million in cash (excluding any receivables recorded for post-closing adjustments) for the Superior Transaction and the Anchor Transaction combined in 2017. On March 8, 2018, we issued a notice to call the 2021 Secured Notes (defined below) with a close date of April 9, 2018. A portion of the proceeds from the Superior Transaction and the Anchor Transaction will be used to fund the redemption of the 2021 Secured Notes. In addition, we have used the proceeds from these divestitures for general partnership purposes including capital expenditures.

2018 Capital Spending Forecast

We currently anticipate total capital expenditures to range between $80 million and $90 million in 2018. Included in the forecast is maintenance capital, expected turnaround activity at the Great Falls and Shreveport refineries and smaller growth capital projects.

Liquidity Update

On December 31, 2017, we had availability under our revolving credit facility of approximately $252.0 million, based on a borrowing base of approximately $319.0 million, $67.3 million in outstanding standby letters of credit and $0.2 million in outstanding borrowings. In addition, we had $164.3 million of cash on hand as of December 31, 2017 (excluding $350.0 million of restricted cash). We believe we will continue to have sufficient liquidity from cash on hand, cash flow from operations, borrowing capacity and other means by which to meet our financial commitments, debt service obligations, contingencies and anticipated

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capital expenditures. On a continuous basis, we focus on various initiatives, including working capital initiatives, to further enhance our liquidity over time, given current market conditions.

Renewable Fuel Standard Update

We, along with the broader refining industry, remain subject to compliance costs under the RFS. Under the regulation of the Environmental Protection Agency ("EPA"), the RFS provides annual requirements for the total volume of renewable transportation fuels which are mandated to be blended into finished petroleum fuels. If a refiner does not meet its required annual Renewable Volume Obligation ("RVO"), the refiner can purchase blending credits in the open market, referred to as RINs.

For the year ended December 31, 2017, our RINs gain was $41.2 million, as compared to a RINs gain for the year ended December 31, 2016 of approximately $5.5 million. Our gross RINs Obligation, which includes RINs that are required to be secured through either blending or through the purchase of RINs in the open market, was 113 million RINs in 2017. For the full-year 2018, we anticipate our gross RINs obligation will decrease to approximately 85 million RINs reflecting the sale of our Superior Refinery.

During 2016, the EPA granted our fuel products refineries a "small refinery exemption" under the RFS for the full-year 2014 and 2015 as provided for under the federal Clean Air Act, as amended ("CAA"). In granting those exemptions, the EPA determined that for the full-year 2014 and 2015, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

During 2017, the EPA granted our fuel product refineries a "small refinery exemption" under the RFS for the full-year 2016, as provided for under the CAA. In granting those exemptions, the EPA determined that for the full-year 2016, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

We continue to anticipate that expenses related to RFS compliance have the potential to remain a significant expense for our fuel products segment, assuming current market prices for RINs. Estimated RINs Obligations remain subject to fluctuations in fuels production volumes during the full-year 2018.

Key Performance Measures

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

Our primary raw materials are crude oil and other specialty feedstocks, and our primary outputs are specialty petroleum products and fuel products. The prices of crude oil, specialty products and fuel products are subject to fluctuations in response to changes in supply, demand, market uncertainties and a variety of additional factors beyond our control. We monitor these risks and enter into derivative instruments designed to help mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically hedge our cash flow exposure to commodity price risk so that we can meet our debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please read Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk" and Note 10 — "Derivatives" under Part II, Item 8 "Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements."

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

- sales volumes;
- production yields;
- segment gross profit;
- segment Adjusted EBITDA; and
- selling, general and administrative expenses.

Sales volumes. We view the volumes of specialty products and fuel products sold as an important measure of our ability to effectively utilize our operating assets. Our ability to meet the demands of our customers is driven by the volumes of crude oil and feedstocks that we run at our facilities. Higher volumes improve profitability both through

the spreading of fixed costs over greater volumes and the additional gross profit achieved on the incremental volumes.
Production yields. In order to maximize our gross profit and minimize lower margin products, we seek the optimal product mix for each barrel of crude oil we refine, or feedstocks we, or third parties, process, which we refer to as production yield.
Segment gross profit. Specialty products and fuel products gross profit are important measures of our ability to maximize the profitability of our specialty products and fuel products segments. We define gross profit as sales less the cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities,

contract services, maintenance, depreciation and processing materials. We use gross profit as an indicator of our ability to manage our business during periods of crude oil and natural gas price fluctuations, as the prices of our specialty products and fuel products generally do not change immediately with changes in the price of crude oil and natural gas. The increase or decrease in selling prices typically lags behind the rising or falling costs, respectively, of crude oil feedstocks for specialty products. Other than plant fuel, production-related expenses generally remain stable across broad ranges of specialty products and fuel products throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.

Our fuel products segment gross profit per barrel may differ from standard U.S. Gulf Coast, PADD 4 Billings, Montana or 3/2/1 and 2/1/1 market crack spreads due to many factors, including derivative activities to hedge both our fuel products segment sales and the cost of crude oil reflected in gross profit, our fuel products mix as shown in our production table being different than the ratios used to calculate such market crack spreads, LCM inventory adjustments reflected in gross profit, operating costs including fixed costs, actual crude oil costs differing from market indices and our local market pricing differentials for fuel products in the Shreveport, Louisiana; San Antonio, Texas and Great Falls, Montana vicinities as compared to U.S. Gulf Coast and PADD 4 Billings, Montana postings.

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

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Results of Operations

The following table sets forth information about our combined operations from continuing operations. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, and the resale of crude oil in our fuel products segment. The operations of Superior are included through the effective date of the sale, November 7, 2017.

	Year Ended December 31,		
	2017	2016	2015
	(In bpd)		
Total sales volume [1]	132,082	140,180	126,216
Total feedstock runs [2]	128,624	134,163	123,051
Facility production: [3]			
Specialty products:			
Lubricating oils	14,606	14,697	13,325
Solvents	7,761	7,427	7,942
Waxes	1,423	1,571	1,460
Packaged and synthetic specialty products [4]	2,206	1,777	1,321
Other	1,811	1,850	1,618
Total specialty products	27,807	27,322	25,666
Fuel products:			
Gasoline	35,713	37,713	37,691
Diesel	33,277	34,808	30,204
Jet fuel	5,368	5,306	5,157
Asphalt, heavy fuel oils and other	29,396	29,780	24,077
Total fuel products	103,754	107,607	97,129
Total facility production [3]	131,561	134,929	122,795

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, as components of finished fuel products in our fuel products segment sales.

The decrease in total sales volume in 2017 compared to 2016 is due primarily to decreased sales volumes of fuel products primarily as a result of turnaround activities at the Superior Refinery during the second quarter of 2017 and the sale of the Superior Refinery in November 2017. Specialty products volumes were adversely impacted by the temporary disruptions in the supply chain as a result of Hurricane Harvey and the implementation of our ERP system in 2017. These declines were partially offset by continued growth in our packaged and synthetic specialty products and increases in solvents production.

The increase in total sales volume in 2016 compared to 2015 is due primarily to increased sales volume of lubricating oils, diesel and asphalt as a result of market conditions and increased production at the Great Falls refinery from the expansion project completed in the first quarter 2016.

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

The decrease in total feedstock runs in 2017 compared to 2016 is due primarily to decreased feedstock runs at the Superior Refinery as a result of turnaround activities completed in the second quarter 2017 and the sale of the Superior Refinery in November 2017, partially offset by increased feedstock runs at the Great Falls refinery as a result of the expansion completed in the first quarter of 2016 and increased specialty products feedstock runs as a result of improved reliability.

The increase in total feedstock runs in 2016 compared to 2015 is due primarily to increased feedstock runs at the Great Falls refinery from the expansion project completed in the first quarter 2016 and improved operational reliability, partially offset by scheduled turnaround activity in 2016.

(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.
The changes in total facility production in 2017 over 2016 and 2016 over 2015 are due primarily to the operational items discussed above in footnote 2 of this table.

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

The following table reflects our consolidated results of operations and includes the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to Net income (loss) and Net cash provided by (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP, please read Item 6 “Selected Financial Data — Non-GAAP Financial Measures.”

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Sales	$3,763.8	$3,474.3	$3,930.3
Cost of sales	3,265.6	3,088.0	3,393.9
Gross profit	498.2	386.3	536.4
Operating costs and expenses:			
Selling	65.7	69.8	71.8
General and administrative	138.7	105.8	125.9
Transportation	137.1	154.3	153.6
Taxes other than income taxes	24.1	19.3	17.1
Asset impairment	207.3	35.7	—
Gain on sale of business, net	(236.0)	—	—
Other	3.3	1.7	10.8
Operating income (loss)	158.0	(0.3)	157.2
Other income (expense):			
Interest expense	(183.1)	(161.7)	(104.9)
Debt extinguishment costs	—	—	(46.6)
Loss on derivative instruments	(9.6)	(4.1)	(31.4)
Loss from unconsolidated affiliates	—	(18.3)	(61.1)
Loss on sale of unconsolidated affiliates	—	(113.4)	—
Other	3.3	1.2	1.6
Total other expense	(189.4)	(296.3)	(242.4)
Net loss from continuing operations before income taxes	(31.4)	(296.6)	(85.2)
Income tax expense (benefit) from continuing operations	(0.1)	0.2	0.2
Net loss from continuing operations	(31.3)	(296.8)	(85.4)
Net loss from discontinued operations, net of income taxes	(72.5)	(31.8)	(54.0)
Net loss	$(103.8)	$(328.6)	$(139.4)
EBITDA	$246.7	$(3.5)	$82.5
Adjusted EBITDA	$317.2	$158.2	$257.7
Distributable Cash Flow	$89.3	$(5.7)	$161.9

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Year Ended December 31, 2017, Compared to Year Ended December 31, 2016

Sales. Sales from continuing operations increased $289.5 million, or 8.3%, to $3,763.8 million in 2017 from $3,474.3 million in 2016. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2017	2016	% Change
	(In millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$584.2	$ 538.7	8.4 %
Solvents	274.4	237.7	15.4 %
Waxes	117.2	128.7	(8.9)%
Packaged and synthetic specialty products (1)	260.7	244.7	6.5 %
Other (2)	63.9	102.5	(37.7)%
Total specialty products	$1,300.4	$ 1,252.3	3.8 %
Total specialty products sales volume (in barrels)	9,407,000	9,779,000	(3.8)%
Average specialty products sales price per barrel	$138.24	$ 128.06	7.9 %
Fuel products:			
Gasoline	$948.5	$ 844.3	12.3 %
Diesel	877.9	748.7	17.3 %
Jet fuel	135.0	117.5	14.9 %
Asphalt, heavy fuel oils and other (3)	502.0	451.8	11.1 %
Hedging activities	—	59.7	(100.0)%
Total fuel products	$2,463.4	$ 2,222.0	10.9 %
Total fuel products sales volume (in barrels)	38,803,000	41,527,000	(6.6)%
Average fuel products sales price per barrel (excluding hedging activities)	$63.48	$ 52.07	21.9 %
Average fuel products sales price per barrel (including hedging activities)	$63.48	$ 53.51	18.6 %
Total sales	$3,763.8	$ 3,474.3	8.3 %
Total specialty and fuel products sales volume (in barrels)	48,210,000	51,306,000	(6.0)%

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

(2) Represents (a) 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 and (b) polyolester synthetic lubricants produced at the Missouri facility.

(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 and San Antonio refineries to third party customers.

The components of the $48.1 million specialty products segment sales increase in 2017 were as follows:

	Dollar Change (In millions)
Sales price	$ 95.8
Volume	(47.7)
Total specialty products segment sales increase	$ 48.1

Specialty products segment sales for 2017 increased $48.1 million, or 3.8%, primarily due to an increase in the average selling price per barrel, partially offset by lower sales volume. Sales increased $95.8 million compared to 2016 due to a 7.9% increase in the average selling price per barrel primarily as a result of increased lubricating oils and solvents average selling prices due to market conditions, while the average cost of crude oil per barrel increased 16.6%. The decrease in sales volume is due to

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lower sales volumes in all product lines except packaged and synthetic specialty products as a result of market conditions and temporary disruptions in the supply chain as a result of Hurricane Harvey and the implementation of our ERP system in 2017.

The components of the $241.4 million fuel products segment sales increase in 2017 were as follows:

	Dollar Change (In millions)
Sales price	$ 444.2
Divestiture impact	(109.0)
Hedging activities	(59.7)
Volume	(34.1)
Total fuel products segment sales increase	$ 241.4

Fuel products segment sales for 2017 increased $241.4 million, or 10.9%, due primarily to an increase in the average selling price per barrel, partially offset by the sale of the Superior Refinery in November 2017, a $59.7 million decrease in realized derivative gains recorded in sales on our fuel products and decreased sales volume. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) increased $11.41, or 21.9%, resulting in a $444.2 million increase in sales, compared to a 21.5% increase in the average cost of crude oil per barrel. The increase in the average selling price per barrel was in all product lines, primarily due to market conditions. Sales volume decreased 6.6% as a result of decreases in all product lines, primarily due to market conditions and sale of the Superior Refinery in November 2017.

Gross Profit. Gross profit from continuing operations increased $111.9 million, or 29.0%, to $498.2 million in 2017 from $386.3 million in 2016. Gross profit for our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2017	2016	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$319.2	$338.1	(5.6)%
Percentage of sales	24.5 %	27.0 %	
Specialty products gross profit per barrel	$33.93	$34.57	(1.9)%
Fuel products:			
Gross profit excluding hedging activities	$179.0	$39.8	349.7 %
Hedging activities	—	8.4	(100.0)%
Gross profit	$179.0	$48.2	271.4 %
Percentage of sales	7.3 %	2.2 %	
Fuel products gross profit per barrel (excluding hedging activities)	$4.61	$0.96	380.2 %
Fuel products gross profit per barrel (including hedging activities)	$4.61	$1.16	297.4 %
Total gross profit	$498.2	$386.3	29.0 %
Percentage of sales	13.2 %	11.1 %	

The components of the $18.9 million decrease in the specialty products segment gross profit for 2017 were as follows:

	Dollar Change (In millions)
2016 reported gross profit	$ 338.1

Cost of materials	(91.0)
Volume	(20.2)
Operating costs	(9.0)
LCM inventory adjustment	(0.3)
Sales price	95.8
LIFO inventory layer adjustment	5.8
2017 reported gross profit	$ 319.2

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The decrease in specialty products segment gross profit of $18.9 million year-over-year was primarily due to a $91.0 million increase in cost of materials, decreased sales volume and a $9.0 million increase in operating costs, partially offset by a $95.8 million increase in sales price. Sales price and cost of materials, net, increased gross profit by $4.8 million, as the average selling price per barrel increased by 7.9%, while the average cost of crude oil per barrel increased 16.6%. The increase in operating costs was primarily due to increased depreciation expense and increased utility costs. Gross profit was also positively impacted by decreased losses of $5.8 million related to the liquidation of LIFO inventory layers.

The components of the $130.8 million increase in the fuel products segment gross profit for 2017 were as follows:

	Dollar Change (In millions)
2016 reported gross profit	$ 48.2
Sales price	444.2
RINs expense	38.2
LIFO inventory layer adjustment	19.0
Divestiture impact	0.1
Volume	(6.2)
Hedging activities	(8.4)
LCM inventory layer adjustment	(7.5)
Operating costs	(10.9)
Cost of materials	(337.7)
2017 reported gross profit	$ 179.0

The increase in fuel products segment gross profit of $130.8 million year-over-year was primarily due to widening crack spreads, a $38.2 million decrease in RINs compliance costs and a $19.0 million decrease in LIFO inventory liquidation losses, partially offset by a $7.5 million decrease in the favorable LCM inventory adjustment, increased operating costs, an $8.4 million decrease in realized derivative gains and decreased sales volume. During 2017, crack spreads widened as the average cost of crude oil per barrel increased 21.5% and the average selling price per barrel increased by 21.9%. The $38.2 million decrease in RINs expense primarily resulted from a reduction of the RINs liability as a result of an approval from the EPA of the small refinery exemption from the requirements of the RFS for the 2016 calendar year, decreased RINs market pricing and decreased production. The increase in operating costs was due primarily to increased depreciation expense and increased repairs and maintenance costs.

Selling. Selling expenses from continuing operations decreased $4.1 million, or 5.9%, to $65.7 million in 2017 from $69.8 million in 2016. The decrease was due primarily to a $3.4 million decrease in advertising expense, a $2.3 million decrease in depreciation and amortization, a $1.9 million decrease in salaries and benefits primarily as a result of workforce reductions, a $1.7 million decrease in travel and entertainment expense and a $0.6 million decrease in professional fees, partially offset by a $5.7 million increase in bad debt expense.

General and administrative. General and administrative expenses from continuing operations increased $32.9 million, or 31.1%, to $138.7 million in 2017 from $105.8 million in 2016. The increase was due primarily to a $26.9 million increase in incentive compensation costs, a $3.3 million increase in professional fees expense largely related to the implementation of our new ERP system and a $3.8 million increase in salaries and benefits, partially offset by a $1.5 million decrease in depreciation and amortization.

Transportation. Transportation expenses from continuing operations decreased $17.2 million, or 11.1%, to $137.1 million in 2017 from $154.3 million in 2016. This decrease is due primarily to decreased freight rates, decreased sales of specialty products and asphalt and optimization of our transportation logistics system.

Asset impairment. Asset impairment from continuing operations increased $171.6 million, or 480.7% to $207.3 million in 2017 from $35.7 million in 2016. The increase was primarily related to long-lived assets including property, plant and equipment impairment charges on the Missouri reporting unit of $59.2 million and on the San Antonio reporting unit of $147.0 million as a result of lowered projections of future cash flows. The 2016 fuel products segment goodwill impairment charge of $33.4 million was primarily a result of the reduced outlook on crack spreads. The 2016 specialty products segment goodwill impairment charge of $1.4 million was the result of a significant reduction in orders from a customer of significance. For a further discussion regarding the factors underlying these impairments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Critical Accounting Policies and Estimates" and Item 8. Financial Statements and Supplementary Data, Note 2.

Gain on sale of business, net. Gain on sale of business, net from continuing operations was $236.0 million in 2017, due to the Superior Transaction with no comparable activity in 2016.

Interest expense. Interest expense from continuing operations increased $21.4 million, or 13.2%, to $183.1 million in 2017 from $161.7 million in 2016. The increase is due primarily to an increase in the amount of our outstanding long-term debt, higher

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interest rates on senior secured notes issued in April 2016 compared to other outstanding long-term debt, an increase in interest related to the Supply and Offtake Agreements (defined below) and decreased capitalized interest as a result of decreased capital spending.

Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2017 and 2016:

	Year Ended December 31,	
	2017	2016
	(In millions)	
Derivative gain reflected in sales	$—	$59.7
Derivative loss reflected in cost of sales	—	(53.3)
Derivative gain reflected in gross profit	$—	$6.4
Realized loss on derivative instruments	$(13.2)	$(24.0)
Unrealized gain on derivative instruments	3.6	19.9
Total derivative gain (loss) reflected in the consolidated statements of operations	$(9.6)	$2.3
Total loss on commodity derivative settlements	$(13.2)	$(24.0)

Loss on derivative instruments. Loss on derivative instruments from continuing operations increased $5.5 million to a loss of $9.6 million in 2017 from a loss of $4.1 million in 2016. The change was primarily due to decreased unrealized gains of approximately $11.9 million on crack spreads, crude oil and natural gas swaps used to economically hedge purchases and sales, further impacted by increased unrealized losses of $4.4 million on embedded derivatives associated with our Supply and Offtake Agreements and decreased realized losses of approximately $10.8 million related to settlements of derivative instruments used to economically hedge crack spreads, crude oil and natural gas.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates from continuing operations was $18.3 million in 2016, due primarily to the sale of Dakota Prairie Refining, LLC (“Dakota Prairie”) in June 2016, with no comparable activity in 2017.

Loss on sale of unconsolidated affiliates. Loss on sale of unconsolidated affiliates from continuing operations was $113.4 million in 2016. The loss on sale of unconsolidated affiliates was primarily due to the $113.9 million loss on sale of Dakota Prairie in June 2016, with no comparable activity in 2017.

Net loss from discontinued operations. Net loss from discontinued operations was $72.5 million in 2017 compared to $31.8 million in 2016. In November 2017, we completed the divestiture of Anchor. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services. As a result, effective in the fourth quarter of 2017, we classified our results of operations for all periods presented to reflect Anchor as a discontinued operation. We recorded a net loss on the sale of Anchor of $62.6 million. Increases in crude oil and natural gas prices resulted in increases in drilling and production activities, which had a favorable impact on the net loss. In addition, income tax benefit decreased due to a $7.8 million income tax refund in 2016. Refer to Note 3 - “Discontinued Operations” in Part II, Item 8 “Financial Statements and Supplementary Data” for additional information.

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Year Ended December 31, 2016, Compared to Year Ended December 31, 2015

Sales. Sales from continuing operations decreased $456.0 million, or 11.6%, to $3,474.3 million in 2016 from $3,930.3 million in 2015. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2016	2015	% Change
	(In millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$538.7	$ 575.6	(6.4)%
Solvents	237.7	302.0	(21.3)%
Waxes	128.7	136.9	(6.0)%
Packaged and synthetic specialty products[1]	244.7	261.5	(6.4)%
Other [2]	102.5	91.8	11.7 %
Total specialty products	$1,252.3	$ 1,367.8	(8.4)%
Total specialty products sales volume (in barrels)	9,779,000	9,200,000	6.3 %
Average specialty products sales price per barrel	$128.06	$ 148.67	(13.9)%
Fuel products:			
Gasoline	$844.3	$ 1,002.4	(15.8)%
Diesel	748.7	773.2	(3.2)%
Jet fuel	117.5	136.5	(13.9)%
Asphalt, heavy fuel oils and other [3]	451.8	471.0	(4.1)%
Hedging activities	59.7	179.4	(66.7)%
Total fuel products	$2,222.0	$ 2,562.5	(13.3)%
Total fuel products sales volume (in barrels)	41,527,000	36,869,000	12.6 %
Average fuel products sales price per barrel (excluding hedging activities)	$52.07	$ 64.64	(19.4)%
Average fuel products sales price per barrel (including hedging activities)	$53.51	$ 69.50	(23.0)%
Total sales	$3,474.3	$ 3,930.3	(11.6)%
Total specialty and fuel products sales volume (in barrels)	51,306,000	46,069,000	11.4 %

[1] Represents packaged and synthetic specialty products at the Royal Purple, Bel-Ray and Calumet Packaging.

[2] Represents (a) 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 and (b) polyolester synthetic lubricants produced at the Missouri facility.

[3] Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, San Antonio and Great Falls refineries and crude oil sales from the San Antonio refinery to third party customers.

The components of the $115.5 million specialty products segment sales decrease in 2016 were as follows:

	Dollar Change (In millions)
Sales price	$(201.7)
Volume	86.2
Total specialty products segment sales decrease	$(115.5)

Specialty products segment sales for 2016 decreased $115.5 million, or 8.4%, primarily due to a decrease in the average selling price per barrel, partially offset by higher sales volume. Sales decreased $201.7 million compared to 2015 due to a 13.9% decrease in the average selling price per barrel primarily as a result of decreased lubricating oils, solvents and packaged and synthetic specialty products average selling prices due to market conditions, while the average cost of crude oil per barrel decreased 10.7%. The increase in sales volume is primarily due to higher sales volume of lubricating oils and packaged and synthetic specialty products, partially offset by decreased sales volume of solvents and waxes due to market conditions.

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The components of the $340.5 million fuel products segment sales decrease in 2016 were as follows:

	Dollar Change (In millions)
Sales price	$ (521.9)
Hedging activities	(119.7)
Volume	301.1
Total fuel products segment sales decrease	$ (340.5)

Fuel products segment sales for 2016 decreased $340.5 million, or 13.3%, due primarily to a decrease in the average selling price per barrel and a $119.7 million decrease in realized derivative gains recorded in sales on our fuel products cash flow hedges, partially offset by increased sales volume. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $12.57, or 19.4%, resulting in a $521.9 million decrease in sales, compared to a 14.1% decrease in the average cost of crude oil per barrel. The decrease in the average selling prices per barrel is primarily due to market conditions. Sales volume increased 12.6% primarily due to increased sales volume of diesel and asphalt as a result of the Great Falls refinery expansion project completed in 2016, partially offset by decreased sales volume of gasoline due to market conditions.

Gross Profit. Gross profit from continuing operations decreased $150.1 million, or 28.0%, to $386.3 million in 2016 from $536.4 million in 2015. Gross profit for our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2016	2015	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$338.1	$370.2	(8.7)%
Percentage of sales	27.0 %	27.1 %	
Specialty products gross profit per barrel	$34.57	$40.24	(14.1)%
Fuel products:			
Gross profit (loss) excluding hedging activities	$39.8	$157.1	(74.7)%
Hedging activities	8.4	9.1	(7.7)%
Gross profit	$48.2	$166.2	(71.0)%
Percentage of sales	2.2 %	6.5 %	
Fuel products gross profit per barrel (excluding hedging activities)	$0.96	$4.26	(77.5)%
Fuel products gross profit per barrel (including hedging activities)	$1.16	$4.51	(74.3)%
Total gross profit	$386.3	$536.4	(28.0)%
Percentage of sales	11.1 %	13.6 %	

The components of the $32.1 million decrease in the specialty products segment gross profit for 2016 were as follows:

	Dollar Change (In millions)
2015 reported gross profit	$ 370.2
Sales price	(201.7)
Operating costs	(4.9)
Cost of materials	89.3
LCM inventory adjustment	47.4
Volume	35.3

LIFO inventory layer liquidation	2.5
2016 reported gross profit	$ 338.1

The decrease in specialty products segment gross profit of $32.1 million year-over-year was primarily due to a decrease in the average selling price per barrel and a $4.9 million increase in operating costs, partially offset by decreased cost of materials, a $47.4 million decrease in the unfavorable LCM inventory adjustment and increased sales volume. Sales price and cost of materials, net, lowered gross profit by $112.4 million, as the average selling price per barrel decreased 13.9%, while the average cost of crude oil per barrel decreased 10.7%. The increase in operating costs was primarily due to increased depreciation expense, partially offset by decreased natural gas costs. Gross profit was also positively impacted by decreased losses of $2.5 million related to the liquidation of LIFO inventory layers.

The components of the $118.0 million decrease in the fuel products segment gross profit for 2016 were as follows:

	Dollar Change (In millions)
2015 reported gross profit	$ 166.2
Sales price	(521.9)
Operating costs	(39.4)
LIFO inventory layer adjustment	(5.9)
Hedging activities	(0.7)
Cost of materials	285.5
Volume	65.1
LCM inventory layer liquidation	58.0
RINs expense	41.3
2016 reported gross profit	$ 48.2

The decrease in fuel products segment gross profit of $118.0 million year-over-year was primarily due to narrowing crack spreads, a $39.4 million increase in operating costs and increased losses of $5.9 million related to the liquidation of LIFO inventory layers, partially offset by increased sales volume, a $58.0 million decrease in the unfavorable LCM inventory adjustment and decreased RINs compliance costs. During 2016, crack spreads narrowed as the average cost of crude oil per barrel decreased 14.1% and the average selling price per barrel decreased by 19.4%. The $41.3 million decrease in RINs expense primarily resulted from a reduction of the RINs liability as a result of an approval from the EPA of the small refinery exemption from the requirements of the RFS for certain of our refineries for the 2014 and 2015 calendar years, partially offset by increased RINs market pricing and increased production. The increase in operating costs was due primarily to increased depreciation expense, utility costs and salaries and benefits expense, partially offset by decreased repairs and maintenance expense.

Selling. Selling expenses from continuing operations decreased $2.0 million, or 2.8%, to $69.8 million in 2016 from $71.8 million in 2015. The decrease was due primarily to a $4.3 million decrease in advertising expense and a $2.8 million decrease in depreciation and amortization expense, partially offset by an increase in salaries and benefits of $2.3 million, an increase in travel expenses of $1.0 million, an increase in commissions of $0.9 million and an increase in bad debt expense of $0.5 million.

General and administrative. General and administrative expenses from continuing operations decreased $20.1 million, or 16.0%, to $105.8 million in 2016 from $125.9 million in 2015. The decrease was due primarily to a $23.1 million decrease in incentive compensation costs, a $3.6 million decrease in professional fees expense and a $2.1 million decrease in severance expense, partially offset by an $8.0 million increase in salaries and benefits and a $1.1 million increase in information technology equipment.

Asset impairment. During 2016, we recorded asset impairment charges from continuing operations of $35.7 million primarily related to goodwill in the fuel products segment and specialty products segment. The 2016 fuel products segment goodwill impairment charge of $33.4 million was primarily a result of the reduced outlook on crack spreads. The 2016 specialty products segment goodwill impairment charge of $1.4 million was the result of a significant reduction in orders from a customer of significance. There was no asset impairment from continuing operations in 2015. For a further discussion regarding the factors underlying these impairments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Critical Accounting Policies and Estimates" and Item 8. Financial Statements and Supplementary Data, Note 2.

Other operating costs and expenses. Other operating costs and expenses from continuing operations decreased $9.1 million, or 84.3%, to $1.7 million in 2016 from $10.8 million in 2015. The decrease is due primarily to decreased environmental remediation expense, decreased profit sharing expense related to a profit share agreement and gains from fixed asset sales.

Interest expense. Interest expense from continuing operations increased $56.8 million, or 54.1%, to $161.7 million in 2016 from $104.9 million in 2015. The increase is due primarily to an increase in the amount of our outstanding long-term debt, higher interest rates on senior secured notes issued in April 2016 compared to other outstanding long-term debt and decreased capitalized interest.

Debt extinguishment costs. Debt extinguishment costs from continuing operations were $46.6 million in 2015. Debt extinguishment costs were due primarily to the redemption of the 9.625% senior notes due 2020 (“2020 Notes”) with a portion of the net proceeds from the issuance of the 2023 Notes in 2015 period, with no comparable activity in the 2016 period.

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Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2016 and 2015:

	Year Ended December 31,	
	2016	2015
	(In millions)	
Derivative gain reflected in sales	$59.7	$179.4
Derivative loss reflected in cost of sales	(53.3)	(167.3)
Derivative gain reflected in gross profit	$6.4	$12.1
Realized gain (loss) on derivative instruments	$(24.0)	$8.1
Unrealized gain (loss) on derivative instruments	19.9	(39.5)
Total derivative gain (loss) reflected in the consolidated statements of operations	$2.3	$(19.3)
Total gain (loss) on commodity derivative settlements	$(24.0)	$10.2

Loss on derivative instruments. Loss on derivative instruments from continuing operations decreased $27.3 million to $4.1 million in 2016 from $31.4 million in 2015. The change was primarily due to decreased unrealized losses related to derivative instruments used to economically hedge crack spreads and crude oil purchases, partially offset by decreased realized gains of approximately $32.1 million related to settlements of derivative instruments used to economically hedge crack spreads and crude oil.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates from continuing operations decreased $42.8 million to $18.3 million in 2016 from $61.1 million in 2015, due primarily to a $24.3 million other-than-temporary impairment charge related to Juniper (defined below) in the 2015 period and the sale of Dakota Prairie in June 2016.

Net loss from discontinued operations. Net loss from discontinued operations decreased $22.2 million, or 41.1%, to $31.8 million in 2016 compared to $54.0 million in 2015. The decrease in net loss from discontinued operations was primarily due to a $33.8 million goodwill impairment charge in 2015 and a $15.6 million decrease in the unfavorable LCM inventory adjustment, partially offset by decreased sales volume in 2016 driven by a decline in rig count. Volatility in crude oil and natural gas prices resulted in a significant reduction in drilling and production activities, which had an unfavorable impact on net loss. In addition, 2016 included a $7.8 million income tax refund. Refer to Note 3 - “Discontinued Operations” in Part II, Item 8 “Financial Statements and Supplementary Data” for additional information.

Liquidity and Capital Resources

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity offerings, proceeds from notes offerings and bank borrowings. Principal uses of cash have included capital expenditures, acquisitions, distributions to our limited partners and general partner and debt service. We expect that our principal uses of cash in the future will be for debt service, replacement and environmental capital expenditures and capital expenditures related to internal growth projects.

We received over $500 million in cash (excluding any receivables recorded for post-closing adjustments) for the Superior Transaction and the Anchor Transaction combined in 2017. On March 8, 2018, we issued a notice to call the 2021 Secured Notes (defined below) with a close date of April 9, 2018. A portion of the proceeds from the Superior Transaction and the Anchor Transaction will be used to fund the redemption of the 2021 Secured Notes. In addition, we have used the proceeds from these divestitures for general partnership purposes including capital expenditures.

We expect to fund planned capital expenditures in 2018 of $80 million and $90 million with cash on hand, cash flows from operations, borrowings under our revolving credit facility and by accessing capital markets as necessary. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowing availability under our revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs. However, our credit ratings were downgraded in April 2016 which could adversely affect our ability to obtain new financing and increase the costs of our financing. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

The borrowing base on our revolving credit facility decreased from approximately $453.1 million as of December 31, 2016, to approximately $319.0 million at December 31, 2017, resulting in a corresponding decrease in our borrowing availability from approximately $360.8 million at December 31, 2016, to approximately $252.0 million at December 31, 2017. The decrease in our

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borrowing base and borrowing availability was primarily related to a decrease in accounts receivable and inventory as a result of the Superior Transaction and Anchor Transaction.

Cash Flows from Operating, Investing and Financing Activities

We believe that we have sufficient liquid assets, cash flow from operations, borrowing capacity and adequate access to capital markets to meet our financial commitments, debt service obligations and anticipated capital expenditures. We continue to seek to lower our operating costs, selling expenses and general and administrative expenses as a means to further improve our cash flow from operations with the objective of having our cash flow from operations support all of our capital expenditures and interest payments. However, we are subject to business and operational risks that could materially adversely affect our cash flows. A material decrease in our cash flow from operations including a significant, sudden decrease in crude oil prices would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially our ability to comply with the covenants under our revolving credit facility. A significant, sudden increase in crude oil prices, if sustained, would likely result in increased working capital requirements which would be funded by borrowings under our revolving credit facility. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from derivative instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive income (loss), but may impact operating cash flow in the period settled. Gains and losses from derivative instruments that do not qualify as hedges are recorded in unrealized gain (loss) until settlement and will impact operating cash flow in the period settled.

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

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Net cash provided by (used in) operating activities	$(26.5)	$4.1	$376.4
Net cash provided by (used in) investing activities	453.4	(154.2)	(389.0)
Net cash provided by financing activities	83.2	148.7	9.7
Net increase (decrease) in cash and cash equivalents	$510.1	$(1.4)	$(2.9)

Operating Activities. Operating activities used cash of $26.5 million during 2017 compared to providing cash of $4.1 million during 2016. The decrease in cash provided by operating activities is primarily due to increased working capital requirements of $97.3 million, a $166.7 million decrease in non-cash and other adjustment items and decreased operating cash flow from discontinued operations of $32.1 million, partially offset by decreased net loss from continuing operations of $265.5 million. Working capital increases were primarily driven by increased accounts receivable and increased accounts payable related to timing as a result of our ERP implementation, increased inventory as a result of higher crude oil prices and increased accrued salaries, wages and benefits related to increased incentive compensation costs.

Operating activities provided cash of $4.1 million during 2016 compared to $376.4 million during 2015. The decrease in cash provided by operating activities is primarily due to increased net loss from continuing operations of $211.4 million, increased working capital requirements of $75.7 million, decreased operating cash flow from discontinued operations of $44.9 million and a $40.3 million decrease in non-cash and other adjustment items. Working capital increases were primarily driven by increased accounts receivable due to timing of payments, decreased other liabilities due to decreased RINs costs and increased accrued salaries, wages and benefits, partially offset by decreased accounts payable.

Investing Activities. Cash provided by investing activities increased to $453.4 million in 2017 compared to using cash of $154.2 million in 2016. The increase is primarily due to proceeds from the Superior Transaction of $484.5 million in 2017 and $38.6 million in cash provided by discontinued operations primarily as a result of the proceeds from the Anchor Transaction, decreased capital expenditures of $69.2 million and decreased joint venture contributions of $45.7 million, partially offset by proceeds of $29.0 million mainly related to the sale of Dakota Prairie in 2016.

Cash used in investing activities decreased to $154.2 million in 2016 compared to $389.0 million in 2015. The decrease is primarily due to a decrease in capital expenditures of $192.9 million mainly due to the completion of several capital improvement projects, proceeds of $29.0 million mainly related to the sale of Dakota Prairie, decreased cash flow from discontinued operations of $6.8 million and a decrease in net joint venture investments of $4.5 million.
Financing Activities. Financing activities provided cash of $83.2 million during 2017 compared to $148.7 million during 2016. This decrease is primarily due to decreased net proceeds from the private placement of senior notes in 2016 of $393.1 million, partially offset by net proceeds from inventory financing agreements of $97.9 million in 2017 with no comparable activity in 2016, decreased distributions of $57.4 million and decreased repayments on the revolving credit facility and the related party debt of $165.8 million.

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Financing activities provided cash of $148.7 million during 2016 compared to $9.7 million during 2015. This increase is primarily due to the redemption of the 2020 Notes of $275.0 million in 2015 with no comparable activity in 2016, decreased distributions of $167.2 million, increased net proceeds from the private placement of senior notes of $65.6 million and increased proceeds of $11.0 million from other financing activities. Partially offsetting these increases are decreased net proceeds from public offerings of common units (including our general partner's contributions) of $167.4 million, increased payments on the revolving credit facility of $100.8 million in 2016 compared to repayments of $39.8 million in 2015 and $75.0 million in repayments of a related party note in 2016.

Supply and Offtake Agreements

On March 31, 2017, we entered into several agreements with Macquarie to support the operations of the Great Falls refinery, ("Great Falls Supply and Offtake Agreements"). The Great Falls Supply and Offtake Agreements expire on October 31, 2019. On July 27, 2017, we amended the Great Falls Supply and Offtake Agreements to provide Macquarie the option to terminate the Great Falls Supply and Offtake Agreements with nine months' notice any time prior to June 2019.

On June 19, 2017, we entered into several agreements with Macquarie to support the operations of the Shreveport refinery, ("Shreveport Supply and Offtake Agreements", and together with the Great falls Supply and Offtake Agreements, the "Supply and Offtake Agreements"). The Shreveport Supply and Offtake Agreements expire on June 30, 2020; however, Macquarie has the option to terminate the Shreveport Supply and Offtake Agreements with nine months' notice any time prior to June 2019.

At the commencement of the Great Falls Supply and Offtake Agreements, we sold to Macquarie inventory comprised of 652,000 barrels of crude oil and refined products valued at $32.2 million.

At the commencement of the Shreveport Supply and Offtake Agreements, we sold to Macquarie inventory comprised of 987,000 barrels of crude oil and refined products valued at $54.8 million.

In addition, we incurred approximately $3.1 million of costs related to the Supply and Offtake Agreements.

The Supply and Offtake Agreements are subject to minimum and maximum inventory levels. The agreements also provide for the lease to Macquarie of crude oil and certain refined product storage tanks located at the Great Falls and Shreveport refineries. Following expiration or termination of the agreements, Macquarie has the option to require us to purchase the crude oil and refined product inventories then owned by Macquarie and located at the leased storage tanks at then current market prices. Our obligations under the agreements are secured by the inventory included in these agreements.

Joint Ventures

Dakota Prairie Refining, LLC

On June 27, 2016, we consummated the sale of our 50% equity interest in Dakota Prairie to joint venture partner WBI Energy, Inc. ("WBI"), a wholly owned subsidiary of MDU. Concurrent with the sale of our equity interest in Dakota Prairie to WBI, Tesoro Refining & Marketing Company LLC ("Tesoro") acquired 100% of Dakota Prairie from WBI in a separate transaction that closed on June 27, 2016.

Under the terms of the definitive agreement with WBI, we received consideration of $28.5 million, which was offset by our repayment of $36.0 million in borrowings under Dakota Prairie's revolving credit facility. In addition, our $39.4 million letter of credit supporting the Dakota Prairie revolving credit facility was terminated. As part of the transaction, MDU and WBI released us from all liabilities arising out of or related to Dakota Prairie. Further, Tesoro and Dakota Prairie released us from all liabilities arising out of the organization, management and operation of Dakota Prairie, subject to certain limited exceptions. Also, WBI agreed to indemnify us from all liabilities arising out of or related to Dakota Prairie, subject to certain limited exceptions. As a result of the sale of Dakota Prairie, we recorded a loss on sale of unconsolidated affiliate of $113.9 million during the year ended December 31, 2016.

Pacific New Investment Limited

On August 5, 2015, we and The Heritage Group, a related party, formed Pacific New Investment Limited ("PACNIL") for the purpose of investing in a joint venture with Shandong Hi-Speed Materials Group Corporation and China Construction Installation Engineering Co., Ltd. to construct, develop and operate a solvents refinery in mainland China. The joint venture is named Shandong Hi-Speed Hainan Development Co., Ltd. ("Hi-Speed"). We invested $4.8

million in June 2016 and $4.8 million in October 2016. As of December 31, 2016 and 2017, we had an investment of $9.6 million in PACNIL, we owned an equity interest of approximately 23.8% in PACNIL, and through that ownership we owned an equity interest of approximately 6% in Hi-Speed. PACNIL wishes to exit its investment in Hi-Speed. We and PACNIL believe we will fully recover our investment in Hi-Speed.

Capital Expenditures

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

The following table sets forth our capital improvement expenditures, replacement capital expenditures, environmental capital expenditures, turnaround capital expenditures and joint venture contributions for continuing operations and discontinued operations in each of the periods shown (including capitalized interest):

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Capital improvement expenditures	$23.4	$67.6	$311.7
Replacement capital expenditures	30.5	20.0	28.9
Environmental capital expenditures	11.5	9.3	15.3
Turnaround capital expenditures	14.5	8.7	19.3
Joint venture contributions, net [1]	—	16.7	50.2
Total	$79.9	$122.3	$425.4

[1] Includes proceeds from sale of unconsolidated affiliates and return of capital.

The decrease in capital expenditures from 2016 to 2017 is due primarily to the completion of capital improvement projects and decreased joint venture contributions. The decrease in capital expenditures from 2015 to 2016 due to the completion of several projects including the Great Falls refinery expansion.

We estimate our capital expenditures will be between $80 million and $90 million in 2018. We anticipate that capital expenditure requirements will be provided primarily through cash flow from operations, cash on hand, available borrowings under our revolving credit facility and by accessing capital markets as necessary. If future capital expenditures require expenditures in excess of our then-current cash flow from operations and borrowing availability under our revolving credit facility, we may be required to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Debt and Credit Facilities

As of December 31, 2017, our primary debt and credit instruments consisted of:

- a $900.0 million senior secured revolving credit facility maturing in July 2019, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect with the consent of the Agent (as defined in the revolving credit agreement) (“revolving credit facility”). On February 23, 2018, we entered into a $600.0 million amended and restated senior secured revolving credit facility maturing in February 2023, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $300.0 million, which amount may be increased to 90% of revolver commitments in effect with the consent of the Agent (as defined in the amended and restated revolving credit agreement);
- $900.0 million of 6.50% senior notes due 2021 (“2021 Notes”);
- $350.0 million of 7.625% senior notes due 2022 (“2022 Notes”);
- $325.0 million of 7.75% senior notes due 2023 (“2023 Notes”); and
- $400.0 million of 11.50% senior secured notes due 2021 (“2021 Secured Notes”).

We were in compliance with all covenants under our debt instruments in place as of December 31, 2017, and believe we have adequate liquidity to conduct our business.

On March 8, 2018, we issued a notice to call the 2021 Secured Notes with a close date of April 9, 2018.

Short-Term Liquidity

As of December 31, 2017, our principal sources of short-term liquidity were (i) approximately $252.0 million of availability under our revolving credit facility and (ii) $164.3 million of cash. Borrowings under our revolving credit facility can be used for, among other things, working capital, capital expenditures, and other lawful partnership purposes including acquisitions. In addition, we have restricted cash of $350.0 million generated from the Superior Transaction. Under the indentures governing our senior

notes, proceeds from Asset Sales (as defined in the indentures) can only be used for, among other things, to repay, redeem or repurchase debt; to make certain acquisitions or investments; and to make capital expenditures.
Borrowings under our revolving credit facility are limited by a borrowing base that is determined based on advance rates of percentages of Eligible Accounts and Eligible Inventory (as defined in the revolving credit agreement). As such, the borrowing base can fluctuate based on changes in selling prices of our products and our current material costs, primarily the cost of crude oil. On December 31, 2017, we had availability on our revolving credit facility of approximately $252.0 million, based on a borrowing base of approximately $319.0 million, $67.3 million in outstanding standby letters of credit and $0.2 million of outstanding borrowings. The borrowing base cannot exceed the revolving credit facility commitments then in effect. The lender group under our revolving credit facility is comprised of a syndicate of nine lenders with total commitments of $600.0 million. The lenders under our revolving credit facility have a first priority lien on our accounts receivable, inventory and substantially all of our cash.
Amounts outstanding under our revolving credit facility fluctuate materially during each quarter mainly due to cash flow from operations, normal changes in working capital, capital expenditures and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supply on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended December 31, 2017, were $90.0 million. Our availability on our revolving credit facility during the peak borrowing days of the quarter has been ample to support our operations and service upcoming requirements. During the quarter ended December 31, 2017, availability for additional borrowings under our revolving credit facility was approximately $210.8 million at its lowest point.
The revolving credit facility currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option which margin ranges between 50 basis points and 100 basis points for base rate loans and 150 basis points to 200 basis points for LIBOR loans, depending on our average availability for additional borrowings for the preceding quarter. The margin applicable to loans under the FILO tranche of the revolving credit facility range from 150 to 200 basis points for base rate FILO loans and 250 to 300 basis points for LIBOR based FILO loans. As of December 31, 2017, this margin was 50 basis points for prime and 150 basis points for LIBOR; however, the margin can fluctuate quarterly based on our average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter.
In addition to paying interest on outstanding borrowings under the revolving credit facility, we are required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to either 0.250% or 0.375% per annum depending on the average daily available unused borrowing capacity for the preceding month. We also pay a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.
Our revolving credit facility contains various covenants that limit, among other things, our ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates; and enter into a merger, consolidation or sale of assets. The revolving credit facility generally permits us to make cash distributions to our unitholders as long as immediately after giving effect to such a cash distribution we have cash and availability under the revolving credit facility totaling at least equal to the sum of the amount of FILO loans outstanding plus the greater of (i) 15% of the Borrowing Base (as defined in the credit agreement) then in effect and (ii) $60.0 million. Further, the revolving credit facility contains one springing financial covenant which provides that only if our availability under the revolving credit facility falls below the sum of the amount of FILO loans outstanding plus the greater of (a) 10% of the Borrowing Base (as defined in the credit agreement) then in effect and (b) $35.0 million, we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the credit agreement) of at least 1.0 to 1.0 until availability under the revolving credit facility exceeds the greater of the foregoing amounts for 30 consecutive days.
If an event of default exists under the revolving credit facility, the lenders will be able to accelerate the maturity of the revolving credit facility and exercise other rights and remedies. An event of default includes, among other things, the nonpayment of principal, interest, fees or other amounts; failure of any representation or warranty to be true and

correct when made or confirmed; failure to perform or observe covenants in the revolving credit facility or other loan documents, subject, in limited circumstances, to certain grace periods; cross-defaults in other indebtedness if the effect of such default is to cause, or permit the holders of such indebtedness to cause, the acceleration of such indebtedness under any material agreement; bankruptcy or insolvency events; monetary judgment defaults; asserted invalidity of the loan documentation; and a change of control.

As of December 31, 2017, we were in compliance with all covenants under the revolving credit facility.

For additional information regarding our revolving credit facility, see Note 9 “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data.” We amended and restated our revolving credit agreement on February 23, 2018. For information regarding our amended and restated revolving credit agreement, see Note 21 “Subsequent Events” in Part II, Item 8 “Financial Statements and Supplementary Data.”

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Long-Term Financing

In addition to our principal sources of short-term liquidity listed above, subject to market conditions, we may meet our cash requirements (other than distributions of Available Cash (as defined in our partnership agreement) to our common unitholders) through the issuance of debt or equity.

From time to time we issue long-term debt securities, referred to as our senior notes. All of our outstanding senior notes, other than the 2021 Secured Notes, are unsecured obligations that rank equally with all of our other senior debt obligations to the extent they are unsecured. As of December 31, 2017 and December 31, 2016, we had $400.0 million in 2021 Secured Notes, $900.0 million in 2021 Notes, $350.0 million in 2022 Notes and $325.0 million in 2023 Notes outstanding. On March 8, 2018, we issued a notice to call the 2021 Secured Notes with a close date of April 9, 2018.

The indentures governing our senior notes contain covenants that, among other things, restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets; (ii) pay distributions on or redeem or repurchase our common units or redeem or repurchase our subordinated debt and, in the case of the 2021 Secured Notes, our unsecured notes; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates, and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the senior notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's") or S&P's Global Ratings ("S&P") and no Default or Event of Default, each as defined in the indentures governing the senior notes, has occurred and is continuing, many of these covenants will be suspended. As of December 31, 2017, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes) was 1.7.

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

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

We are subject, however, to conditions in the equity and debt markets for our common units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our common units and/or senior notes in the future. If we are unable or unwilling to issue additional common units, we may be required to either restrict capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. For additional information regarding our credit ratings, see "Credit Ratings" below.

For additional information regarding our senior notes, see Note 9 "Long-Term Debt" in Part II, Item 8 "Financial Statements and Supplementary Data."

Master Derivative Contracts and Collateral Trust Agreement

Under our credit support arrangements, our payment obligations under all of our master derivatives contracts for commodity hedging generally are secured by a first priority lien on our and our subsidiaries' real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). We had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 2017. Our master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on our operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements. For financial reporting purposes, we do not offset the collateral provided to a counterparty against the fair value of our obligation to that counterparty. Any outstanding collateral is released to us upon settlement of the related derivative instrument liability.

All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads or interest rates to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads or interest rates to significantly impact our liquidity. Additionally, we have a collateral trust agreement (the “Collateral Trust Agreement”) which governs how the holders of the 2021 Secured Notes and secured hedging counterparties share collateral pledged as security for the payment obligations owed by us to the holders of the 2021 Secured Notes and secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $150.0 million the extent to which forward purchase contracts for physical commodities are covered by, and secured under, the Collateral Trust Agreement and the Parity Lien Security Documents (as defined in the Collateral Trust Agreement). There is no such limit on financially settled derivative instruments used for commodity hedging.

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Subject to certain conditions set forth in the Collateral Trust Agreement, we have the ability to add secured hedging counterparties from time to time. On March 8, 2018, we issued a notice to call the 2021 Secured Notes with a close date of April 9, 2018.

Credit Ratings

In April 2016, our senior unsecured notes ratings and partnership ratings were downgraded by credit rating agencies. Our senior unsecured notes ratings decreased to Caa2 from B3 and CCC+ from B by Moody's and S&P, respectively. Our partnership rating decreased to Caa1 from B2 and B- from B by Moody's and S&P, respectively. This downgrade in our credit ratings could adversely affect our ability to obtain new financing and increase the costs of our financing and, in turn, adversely affect our financial results.

Equity Transactions

We entered into an Equity Placement Agreement with various sales agents under which we issued and sold, from time to time, common units representing limited partner interests, having an aggregate offering price of up to $300.0 million through one or more sales agents. The Equity Placement Agreement expired in May 2016. The net proceeds from any sales under this agreement were used for general partnership purposes, which included, among other things, repayment of indebtedness, working capital and capital expenditures. Our general partner contributed its proportionate capital contribution to retain its 2% general partner interest. For the years ended December 31, 2017 and December 31, 2016, we did not have any sales of our common units under the Equity Placement Agreement.

During 2017, 2016 and 2015, we completed the following marketed public offerings of common units (in millions, except unit and per unit data):

Closing Date	Number of Common Units Offered	Price per Unit	Net Proceeds (1)	General Partner Contribution(2)	Underwriting Discount	Use of Proceeds
March 13, 2015	6,000,000	$26.75	$ 153.9	$ 3.3	$ 6.4	Net proceeds were used to redeem a portion of the 2020 Notes and to repay borrowings under the revolving credit facility.

(1) Proceeds are net of underwriting discounts, commissions and expenses but before our general partner's capital contribution.

(2) Our general partner contributions were made to retain its 2% general partner interest.

In April 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. During 2017, 2016, 2015 and through February 2018, we made the following cash distributions on all outstanding common units (including our general partner's incentive distribution rights) (in millions except per unit data):

Quarter Ended	Declaration Date	Record Date	Distribution Date	Quarterly Distribution per Unit	Aggregate Quarterly Distribution
December 31, 2015	January 19, 2016	February 2, 2016	February 12, 2016	$ 0.685	$ 57.4

Seasonality Impacts on Liquidity

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.

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Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of December 31, 2017, at current maturities is as follows:

	Payments Due by Period				
	Total	Less Than 1 Year	1–3 Years	3–5 Years	More Than 5 Years
	(In millions)				
Operating Activities:					
Interest on long-term and short-term debt at contractual rates and maturities [(1)]	$706.1	$167.1	$326.8	$154.3	$ 57.9
Operating lease obligations [(2)]	97.4	31.4	38.4	16.8	10.8
Letters of credit [(3)]	67.3	67.3	—	—	—
Purchase commitments [(4)]	571.5	297.5	147.8	42.0	84.2
Employment agreements [(5)]	0.9	0.9	—	—	—
Financing Activities:					
Obligations under inventory financing agreements	105.5	105.5	—	—	—
Capital lease obligations	44.0	2.7	2.2	2.2	36.9
Long-term debt obligations, excluding capital lease obligations	1,981.8	351.4	3.1	1,302.3	325.0
Total obligations	$3,574.5	$1,023.8	$518.3	$1,517.6	$ 514.8

(1) Interest on long-term and short-term debt at contractual rates and maturities relates primarily to interest on our senior notes, revolving credit facility interest and fees, and interest on our capital lease obligations, which excludes the adjustment for the interest rate swap agreement.

(2) We have various operating leases primarily for railcars, the use of land, storage tanks, compressor stations, equipment, precious metals and office facilities that extend through July 2055.

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

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

(5) Certain employment agreements may be terminated under certain circumstances or at certain dates prior to expiration. We expect our contracts will be renewed or replaced with similar agreements upon their expiration. Amounts due under the contracts assume the contracts are not terminated prior to their expiration.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of ten years. This agreement was extended for 90 days subsequent to December 31, 2017. Based upon this minimum supply quantity, we expect to purchase $11.4 million of feedstock for the LVT unit in the term of the agreement extension based on pricing estimates as of December 31, 2017. This amount is not included in the table above.

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

Off-Balance Sheet Arrangements

We did not enter into any material off-balance sheet debt or operating lease transactions during fiscal year 2017.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements for the years ended December 31, 2017, 2016 and 2015. These consolidated financial statements have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in those financial statements. On an ongoing basis, we evaluate estimates and base our estimates on historical experience and assumptions believed to be reasonable under the circumstances. Those estimates form the basis for our judgments that affect the amounts reported in the financial statements. Actual results could differ from our estimates under different assumptions or conditions. Our significant accounting policies, which may be affected by our estimates and assumptions, are more fully described in Note 2 "Summary of Significant Accounting Policies" in Part II, Item 8 "Financial Statements and Supplementary Data." We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Inventory

The cost of inventory is recorded using the LIFO method. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Such write downs are subject to reversal in subsequent periods, not to exceed LIFO cost, if prices recover. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. Accordingly, interim LIFO calculations are based on management's estimates of expected year-end inventory levels and are subject to the final year-end LIFO inventory valuation.

Significant Estimates and Assumptions

Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our inventory. Because crude oil and refined products are essentially commodities, we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market, 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 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.

Sensitivity Analysis

We have not made any material changes in the accounting methodology we use to establish our markdown or inventory loss adjustments during the past three fiscal years.

The replacement cost of our inventory, based on current market values, would have been $4.6 million lower and $15.7 million lower at December 31, 2017 and 2016, respectively. During the years ended December 31, 2017 and 2016, we recorded decreases in cost of sales in the consolidated statements of operations of $30.6 million and $38.4 million, respectively, due to the LCM inventory valuation. During the years ended December 31, 2017 and 2016, we recorded $3.7 million and $28.5 million, respectively, of increases in cost of sales in the consolidated statements of operations due to the liquidation of higher cost LIFO inventory layers.

Valuation of Definite Long-Lived Assets

Property, plant and equipment and intangible assets with finite lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. If the estimated undiscounted future cash flows related to the asset are less than the carrying value, we recognize a loss equal to the difference between the carrying value and the estimated fair value, usually determined by the estimated discounted future cash flows of the asset. When a decision has been made to dispose of property and equipment prior to the end of the previously estimated useful life, depreciation estimates are revised to reflect the use of the asset over the shortened estimated useful life.

Significant Estimates and Assumptions

Estimated undiscounted future cash flows are used for the purpose of testing our definite long-lived assets for impairment. Fair values calculated for the purpose of measuring impairments on definite long-lived assets are estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in estimating undiscounted future cash flows and performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- Future margins on products produced and sold. Our estimates of future product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, capital expenditures and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews.

- Future capital requirements. These are based on authorized spending and internal forecasts.
- Discount rate commensurate with the risks involved. We apply a discount rate to our cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.

We base our estimated undiscounted future cash flows and fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

2017 Impairment Charge

During the fourth quarter of 2017, we identified impairment indicators that suggested the carrying values of long-lived assets at the Missouri and San Antonio reporting units within the specialty products and fuel products segments, respectively, may not be recoverable. The primary impairment indicators included recently completed projections of future cash flows and the associated impact on the long-range strategic plan forecasts, lower than expected cash flows attributed to these reporting units and poor local market conditions. Undiscounted cash flow tests performed for these reporting units indicated that the long-lived assets were not recoverable. The fair value of the reporting units was established using a discounted cash flow method which utilized Level 3 inputs in the fair value hierarchy. The principal parameters used to establish fair values included estimates of future margins on products produced and sold, future commodity prices, future capital expenditures and discount rates. As a result of the long-lived asset impairment assessment performed, we recorded property, plant and equipment impairment charges on our Missouri reporting unit of $59.2 million and on our San Antonio reporting unit of $147.0 million.

The discount rates used for our Missouri and San Antonio reporting units were approximately12.5% and 14.5%, respectively, per year. Revenue growth rates assumed for our Missouri reporting unit were approximately 12.6% for 2018 and 2.0% to 6.0% for 2019 and beyond. Revenue growth rates assumed for our San Antonio reporting unit were approximately 42.2% for 2018 and 2.0% to 6.0% for 2019 and beyond.

Sensitivity Analysis

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g., pricing, volumes and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Valuation of Goodwill

We review goodwill for impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable in accordance with ASC 350, Intangibles — Goodwill and Other (Topic 350): Testing Goodwill for Impairment (“ASU 2011-08”). Under ASU 2011-08, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the impairment test is unnecessary.

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

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

When performing the quantitative assessment, as required in the impairment test, the fair value of the reporting unit is determined using the income approach. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation, and risks associated with the reporting unit. If the carrying value of a reporting unit is in excess of its fair value, an impairment would be recognized in an amount equal to the excess that the carrying value exceeded the estimated fair value, limited to the total amount of goodwill.

Inputs used to estimate the fair value of the Company's reporting units are considered Level 3 inputs of the fair value hierarchy and include the following:

- The Company's financial projections for its reporting units are based on its analysis of various supply and demand factors which include, among other things, industry-wide capacity, its planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in the Company's planning and capital investment reviews and include recent historical prices and published forward prices.
- The discount rate used to measure the present value of the projected future cash flows is based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible.

For Level 3 measurements, significant increases or decreases in long-term growth rates or discount rates in isolation or in combination could result in a significantly lower or higher fair value measurement.

2016 Impairment Charge

In April 2016, the board of directors of our general partner determined to suspend payment of our quarterly cash distribution to unitholders. The suspension of the quarterly cash distribution caused a sustained decrease in our common unit price. As a result, we determined that these events constituted a triggering event that required us to update our financial projections and our goodwill impairment assessment as of April 30, 2016. The discount rates used for our Great Falls and San Antonio reporting units where impairment was recognized were approximately 13.0% and 13.5%, respectively, per year. Revenue growth rates assumed for our Great Falls reporting unit where impairment was recognized were approximately 41.1% for 2016 and (2.6)% to 39.9% for 2017 and beyond. Revenue growth rates assumed for our San Antonio reporting unit where impairment was recognized were approximately (8.5)% for 2016 and (1.0)% to 27.4% for 2017 and beyond. An impairment charge of $33.4 million related to the fuel products segment was recorded for goodwill as a result of the step 2 analysis.

In December 2016, the Missouri reporting unit experienced a significant reduction in orders from a customer of significance, which is expected to have an adverse impact on the business. As a result, we determined that this event constituted a triggering event that required us to update our financial projections and our goodwill impairment assessment in December 2016. An impairment charge of $1.4 million for goodwill related to the specialty products segment was recorded in the consolidated statements of operations within asset impairment.

A significant decline in our revenue and earnings or a significant decline in the price of our common units could result in an impairment charge related to the remaining specialty products segment goodwill of $171.4 million in the future.

Significant Estimates and Assumptions

Fair values calculated for the purpose of testing our goodwill for impairment are estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- Future margins on products produced and sold. Our estimates of future product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews and include recent historical prices and published forward prices.
- Discount rate commensurate with the risks involved. We apply a discount rate to our cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.

- Future capital requirements. These are based on authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

Sensitivity Analysis

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g., pricing, volumes and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Derivative Instruments

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

The increase in the fair market value of our outstanding derivative instruments from a net liability of $14.0 million as of December 31, 2016, to a net liability of $10.4 million as of December 31, 2017, was due primarily to decreases in the forward market values of crude oil and fuel products margins, or crack spreads, relative to our hedged products margins and settlements of derivatives in 2017 that resulted in realized losses and the $4.4 million embedded derivative related to our Supply and Offtake Agreements. We recorded realized losses of $13.2 million and unrealized gains of $3.6 million on derivative instruments for the year ended December 31, 2017.

The increase in the fair market value of our outstanding derivative instruments from a net liability of $33.9 million as of December 31, 2015, to a net liability of $14.0 million as of December 31, 2016, was due primarily to decreases in the forward market values of crude oil and fuel products margins, or crack spreads, relative to our hedged products margins and settlements of derivatives in 2016 that resulted in realized losses. We recorded realized losses of $24.0 million and unrealized gains of $19.9 million on derivative instruments for the year ended December 31, 2016.

Significant Estimates and Assumptions

Our derivative instruments consist of over-the-counter contracts, which are not traded on a public exchange. Substantially all of our derivative instruments are with counterparties that have long-term credit ratings of at least A3 and BBB+ by Moody’s and S&P, respectively.

To estimate the fair values of our derivative instruments, we use the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. Various analytical tests are performed to validate the counterparty data. The fair values of our derivative instruments are adjusted for nonperformance risk and creditworthiness of the hedging entities through our credit valuation adjustment (“CVA”). The CVA is calculated at the transaction level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. We use the counterparty’s marginal default rate and our survival rate when we are in a net asset position at the payment date and use our marginal default rate and the counterparty’s survival rate when we are in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2017, our net liabilities changed by an immaterial amount. As a result of applying the CVA at December 31, 2016, our net assets were increased by less than $0.1 million and our net liabilities were reduced by approximately $0.5 million.

Observable inputs utilized to estimate the fair values of our derivative instruments were primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, we have categorized these derivative instruments as Level 3. Significant increases (decreases) in any of those unobservable inputs in isolation would result in a significantly lower (higher) fair value measurement. We believe we have obtained the most accurate information available for the types of derivative instruments we hold. See Note 10 “Derivatives” in Part II, Item 8 “Financial Statements and Supplementary Data” for further information on derivative instruments.

Sensitivity Analysis

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

instruments and pension assets we hold.
We believe that the fair values of our derivative instruments may diverge materially from the amounts currently recorded at fair value at settlement due to the volatility of commodity prices. Holding all other variables constant, we expect a $1.00 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of December 31, 2017:

	In millions
Gasoline crack spread swaps	$ (0.8)
Diesel crack spread swaps	$ (0.8)

Recent Accounting Pronouncements
For a summary of recently issued and adopted accounting standards applicable to us, see Note 2 “Summary of Significant Accounting Policies” in Part II, Item 8 “Financial Statements and Supplementary Data.”
Item 7A. Quantitative and Qualitative Disclosures About Market Risk
Commodity Price Risk
Derivative Instruments
We are exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in our fuel products segment), natural gas and precious metals. We use various strategies to reduce our exposure to commodity price risk. We do not attempt to eliminate all of our risk as the costs of such actions are believed to be too high in relation to the risk posed to our future

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cash flows, earnings and liquidity. The strategies we use to reduce our risk utilize both physical forward contracts and financially settled derivative instruments, such as swaps, collars and options, to attempt to reduce our exposure with respect to:

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

We manage our exposure to commodity markets, credit, volumetric and liquidity risks to manage our costs and volatility of cash flows as conditions warrant or opportunities become available. These risks may be managed in a variety of ways that may include the use of derivative instruments. Derivative instruments may be used for the purpose of mitigating risks associated with an asset, liability and anticipated future transactions and the changes in fair value of our derivative instruments will affect our earnings and cash flows; however, such changes should be offset by price or rate changes related to the underlying commodity or financial transaction that is part of the risk management strategy. We do not speculate with derivative instruments or other contractual arrangements that are not associated with our business objectives. Speculation is defined as increasing our natural position above the maximum position of our physical assets or trading in commodities, currencies or other risk bearing assets that are not associated with our business activities and objectives. Our positions are monitored routinely by a risk management committee and discussed with the board of directors of our general partner quarterly to ensure compliance with our stated risk management policy and documented risk management strategies. All strategies are reviewed on an ongoing basis by our risk management committee, which will add, remove or revise strategies in anticipation of changes in market conditions and/or in risk profiles. These changes in strategies are to position us in relation to our risk exposures in an attempt to capture market opportunities as they arise.

The following table provides a summary of the implied crack spreads of gasoline swaps, diesel swaps, gasoline crack spread swaps and diesel crack spread swaps on a combined basis as of December 31, 2017 in our fuel products segment:

Crack Spread Swap Contracts by Expiration Dates	Barrels	BPD	Average Implied Crack Spread ($/Bbl)
First Quarter 2018	1,680,000	18,667	$ 14.92
Total	1,680,000		
Average price			$ 14.92

The following tables provide a summary of crude oil swaps as of December 31, 2017, in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2018	28,000	311	$ 48.25
Total	28,000		
Average price			$ 48.25

Please read Note 10 "Derivatives" in the notes to our consolidated financial statements under Part II, Item 8 "Financial Statements and Supplementary Data" for a discussion of the accounting treatment for the various types of derivative instruments, for a further discussion of our hedging policies and for more information relating to our implied crack spreads of crude oil, diesel, and gasoline derivative instruments.

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

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

	Sales		Cost of Sales	
	Year Ended December 31,		Year Ended December 31,	
	2017	2016	2017	2016
	(In millions)			
Specialty Products:				
$1.00 change in per barrel price of crude oil [1]	$—	$—	$9.4	$9.8
$0.50 change in MMBtu (one million British Thermal Units) of natural gas [2]	$—	$—	$6.6	$7.2
Fuel Products:				
$1.00 change in per barrel price of crude oil [1]	$—	$—	$28.1	$29.8
$1.00 change in per barrel selling price of gasoline, diesel and jet fuel [1]	$28.1	$29.8	$—	$—

(1) Based on our 2017 and 2016 sales volumes.
(2) Based on our results for the years ended December 31, 2017 and 2016.

Revolving Credit Facility

Borrowings under the revolving credit facility are limited by a borrowing base that is determined based on advance rates of percentages of Eligible Accounts and Eligible Inventory (as defined in the revolving credit agreement). As such, the borrowing base can fluctuate based on changes in inventory and accounts receivable, as well as selling prices of our products and our current material costs, primarily the cost of crude oil. Our inventory is based on local crude oil prices at period end, which can materially fluctuate period to period.

Pension Assets Volatility and Investment Policy

Our Pension Plan assets are also subject to volatility that can be caused by fluctuation in general economic conditions. Plan assets are invested by the Plan’s fiduciaries, which direct investments according to specific policies. Our consolidated statement of operations is currently shielded from volatility in plan assets due to the way accounting standards are applied for pension plans, although favorable or unfavorable investment performance over the long term will impact our pension expense if it deviates from our assumption related to the future rate of return. Please read Note 14 “Employee Benefit Plans” under Part II, Item 8 “Financial Statements and Supplementary Data” for a further discussion of our investment policies.

Compliance Price Risk

Renewable Identification Numbers

We are exposed to market risks related to the volatility in the price of credits needed to comply with governmental programs. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, we are required to blend biofuels into the fuel products we produce at a rate that will meet the EPA’s annual quota. To the extent we are unable to blend biofuels at that rate, we must purchase RINs in the open market to satisfy the annual requirement. We have not entered into any derivative instruments to manage this risk, but we have purchased RINs when the price of these instruments is deemed favorable.

Holding other variables constant (RINs requirements), a $1.00 change in the price of RINs as of December 31, 2017, would be expected to have an impact on net income for 2017 of approximately $113.1 million.

Interest Rate Risk

We use various strategies to reduce our exposure to interest rate risk, including the use of financially settled derivative instruments, such as interest rate swaps and options, to minimize significant unplanned fluctuations in earnings that are caused by interest rate volatility. Our goal is to manage interest rate sensitivity by modifying the pricing characteristics of certain debt instruments so that earnings are not adversely affected by movement in interest rates.

During 2014, we entered into an interest rate swap agreement that converted a portion of our senior notes from a fixed interest rate to a variable rate that fluctuates based on changes in the one-month London Interbank Offered Rate (“LIBOR”). During the first quarter 2015, we terminated this interest rate swap agreement. We have disclosed this interest rate swap designated as a fair value hedge in Note 10 “Derivatives” under Part II, Item 8 “Financial Statements and Supplementary Data.”

Our exposure to interest rate changes is limited to the fair value of the debt issued, which would not have a material impact on our earnings or cash flows. The following table provides information about the fair value of our fixed rate debt obligations as

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of December 31, 2017 and 2016, which we disclose in Note 9 “Long-Term Debt” and Note 11 “Fair Value Measurements” under Part II, Item 8 “Financial Statements and Supplementary Data.”

	December 31, 2017		December 31, 2016	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2021 Unsecured Notes	$896.4	$ 892.5	$763.9	$ 890.2
2022 Unsecured Notes	$352.4	$ 344.8	$296.0	$ 343.7
2023 Unsecured Notes	$327.7	$ 319.1	$274.2	$ 318.3
2021 Secured Notes	$456.4	$ 387.6	$458.8	$ 384.5

For our variable rate debt, if any, changes in interest rates generally do not impact the fair value of the debt instrument, but may impact our future earnings and cash flows. We had a $900.0 million revolving credit facility as of December 31, 2017, with borrowings bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. Borrowings under this facility are variable. We had $0.2 million of variable rate debt as of December 31, 2017. Holding other variables constant (such as debt levels), a 100 basis point change in interest rates on our variable rate debt as of December 31, 2017, would be expected to have an immaterial impact on net income and cash flows for 2017. We had $10.2 million of variable rate debt outstanding as of December 31, 2016.

Foreign Currency Risk

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

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Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Calumet GP, LLC
General Partner and the Partners of Calumet Specialty Products Partners, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Calumet Specialty Products Partners, L.P. ("the Company") as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive loss, partners' capital and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with US generally accepted accounting principles.

We did not audit the financial statements of Dakota Prairie Refining, LLC a company in which Calumet Specialty Products Partners, L.P. had a 50% interest during the year ended December 31, 2015. Calumet Specialty Products Partners, L.P.'s equity in the net loss of Dakota Prairie Refining, LLC is stated at $36.1 million for the year ended December 31, 2015. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the 2015 amounts included for Dakota Prairie Refining, LLC, is based solely on the report of the other auditors.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated April 2, 2018 expressed an adverse opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 2002.
Indianapolis, Indiana
April 2, 2018

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

	Year Ended December 31,	
	2017	2016
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$164.3	$4.2
Restricted cash	350.0	—
Accounts receivable, net:		
Trade, less allowance for doubtful accounts of $7.0 million and $0.9 million, respectively	265.4	182.7
Other	88.7	22.2
	354.1	204.9
Inventories	314.4	357.8
Derivative assets	—	0.8
Prepaid expenses and other current assets	8.7	10.6
Discontinued operations, current assets	—	62.6
Total current assets	1,191.5	640.9
Property, plant and equipment, net	1,159.2	1,632.4
Investment in unconsolidated affiliates	35.0	9.6
Goodwill	171.4	177.2
Other intangible assets, net	107.9	133.5
Other noncurrent assets, net	23.8	40.3
Discontinued operations, noncurrent assets	—	91.3
Total assets	$2,688.8	$2,725.2
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$282.3	$275.9
Accrued interest payable	52.5	52.5
Accrued salaries, wages and benefits	35.9	11.1
Other taxes payable	16.1	20.4
Obligations under inventory financing agreements	103.1	—
Other current liabilities	73.7	99.6
Current portion of long-term debt	354.1	3.5
Derivative liabilities	6.0	14.8
Discontinued operations, current liabilities	2.0	20.4
Total current liabilities	925.7	498.2
Pension and postretirement benefit obligations	3.1	11.3
Other long-term liabilities	1.9	3.3
Long-term debt, less current portion	1,638.2	1,993.7
Total liabilities	2,568.9	2,506.5
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (76,788,801 units and 76,392,258 units, issued and outstanding at December 31, 2017 and 2016, respectively)	113.3	211.2
General partner's interest	13.8	15.8

Accumulated other comprehensive loss	(7.2)	(8.3)
Total partners' capital	119.9	218.7
Total liabilities and partners' capital	$2,688.8	$2,725.2

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2017	2016	2015
	(In millions, except unit and per unit data)		
Sales	$3,763.8	$3,474.3	$3,930.3
Cost of sales	3,265.6	3,088.0	3,393.9
Gross profit	498.2	386.3	536.4
Operating costs and expenses:			
Selling	65.7	69.8	71.8
General and administrative	138.7	105.8	125.9
Transportation	137.1	154.3	153.6
Taxes other than income taxes	24.1	19.3	17.1
Asset impairment	207.3	35.7	—
Gain on sale of business, net	(236.0)	—	—
Other	3.3	1.7	10.8
Operating income (loss)	158.0	(0.3)	157.2
Other income (expense):			
Interest expense	(183.1)	(161.7)	(104.9)
Debt extinguishment costs	—	—	(46.6)
Loss on derivative instruments	(9.6)	(4.1)	(31.4)
Loss from unconsolidated affiliates	—	(18.3)	(61.1)
Loss on sale of unconsolidated affiliates	—	(113.4)	—
Other	3.3	1.2	1.6
Total other expense	(189.4)	(296.3)	(242.4)
Net loss from continuing operations before income taxes	(31.4)	(296.6)	(85.2)
Income tax expense (benefit) from continuing operations	(0.1)	0.2	0.2
Net loss from continuing operations	(31.3)	(296.8)	(85.4)
Net loss from discontinued operations, net of income taxes	(72.5)	(31.8)	(54.0)
Net loss	$(103.8)	$(328.6)	$(139.4)
Allocation of net loss:			
Net loss	$(103.8)	$(328.6)	$(139.4)
Less:			
General partner’s interest in net loss	(2.1)	(6.6)	(2.8)
General partner’s incentive distribution rights	—	—	16.8
Net loss available to limited partners	$(101.7)	$(322.0)	$(153.4)
Weighted average limited partner units outstanding:			
Basic and diluted	77,598,950	77,043,935	74,896,096
Limited partners’ interest basic and diluted net loss per unit:			
From continuing operations	$(0.40)	$(3.77)	$(1.34)
From discontinued operations	(0.91)	(0.41)	(0.71)
Limited partners’ interest	$(1.31)	$(4.18)	$(2.05)
Cash distributions declared per limited partner unit	$—	$0.685	$2.74

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Net loss	$(103.8)	$(328.6)	$(139.4)
Other comprehensive income (loss):			
Cash flow hedges:			
Cash flow hedge gain reclassified to net loss	—	(6.4)	(12.1)
Change in fair value of cash flow hedges	—	—	(7.3)
Defined benefit pension and retiree health benefit plans	1.1	(0.3)	4.7
Foreign currency translation adjustment	—	—	(0.6)
Total other comprehensive income (loss)	1.1	(6.7)	(15.3)
Comprehensive loss attributable to partners’ capital	$(102.7)	$(335.3)	$(154.7)

See accompanying notes to consolidated financial statements.

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

	Accumulated Other Comprehensive Income (Loss)	Partners' Capital General Partner	Limited Partners	Total
	(In millions)			
Balance at December 31, 2014	$13.7	$30.6	$765.9	$810.2
Other comprehensive loss	(15.3)	—	—	(15.3)
Net income (loss)	—	14.0	(153.4)	(139.4)
Common units repurchased for phantom unit grants	—	—	(5.5)	(5.5)
Issuance of phantom units	—	—	1.9	1.9
Settlement of tax withholdings on equity-based incentive compensation	—	—	(1.5)	(1.5)
Reclassification of Liability Awards to equity	—	—	7.9	7.9
Amortization of phantom units	—	—	2.4	2.4
Proceeds from public offerings of common units, net	—	—	164.1	164.1
Contributions from Calumet GP, LLC	—	3.5	—	3.5
Distributions to partners	—	(20.6)	(203.8)	(224.4)
Balance at December 31, 2015	$(1.6)	$27.5	$578.0	$603.9
Other comprehensive loss	(6.7)	—	—	(6.7)
Net loss	—	(6.6)	(322.0)	(328.6)
Issuance of phantom units	—	—	4.1	4.1
Settlement of tax withholdings on equity-based incentive compensation	—	—	(2.4)	(2.4)
Amortization of phantom units	—	—	5.6	5.6
Contributions from Calumet GP, LLC	—	0.2	—	0.2
Distributions to partners	—	(5.3)	(52.1)	(57.4)
Balance at December 31, 2016	$(8.3)	$15.8	$211.2	$218.7
Other comprehensive income	1.1	—	—	1.1
Net loss	—	(2.1)	(101.7)	(103.8)
Settlement of tax withholdings on equity-based incentive compensation	—	—	(0.9)	(0.9)
Amortization of phantom units	—	—	4.7	4.7
Contributions from Calumet GP, LLC	—	0.1	—	0.1
Balance at December 31, 2017	$(7.2)	$13.8	$113.3	$119.9

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Operating activities			
Net loss	$(103.8)	$(328.6)	$(139.4)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Net loss from discontinued operations	72.5	31.8	54.0
Depreciation and amortization	154.8	152.0	122.6
Amortization of turnaround costs	24.3	33.2	29.0
Non-cash interest expense	10.2	9.6	6.6
Non-cash debt extinguishment costs	—	—	9.1
Unrealized (gain) loss on derivative instruments	(3.6)	(19.9)	39.5
Asset impairment	207.3	35.7	—
Equity-based compensation	11.6	5.6	9.8
Lower of cost or market inventory adjustment	(30.6)	(38.4)	67.0
Loss from unconsolidated affiliates	—	18.3	61.1
Loss on sale of unconsolidated affiliates	—	113.4	—
Gain on sale of business	(236.0)	—	—
Other non-cash activities	10.2	5.4	10.5
Changes in assets and liabilities:			
Accounts receivable	(158.9)	(38.9)	52.6
Inventories	(8.5)	41.5	25.0
Prepaid expenses and other current assets	(0.8)	(4.2)	0.6
Derivative activity	(0.5)	(19.0)	(7.0)
Turnaround costs	(14.5)	(8.7)	(19.3)
Other assets	(0.5)	(0.6)	—
Accounts payable	70.6	18.4	(77.3)
Accrued interest payable	0.9	21.4	(6.5)
Accrued salaries, wages and benefits	18.0	(17.8)	10.7
Other taxes payable	0.9	3.6	1.8
Other liabilities	(24.2)	(16.6)	74.5
Pension and postretirement benefit obligations	(2.7)	(2.0)	(2.3)
Net cash provided by (used in) discontinued operating activities	(23.2)	8.9	53.8
Net cash provided by (used in) operating activities	(26.5)	4.1	376.4
Investing activities			
Additions to property, plant and equipment	(70.0)	(139.2)	(332.1)
Investment in unconsolidated affiliates	—	(45.7)	(50.2)
Proceeds from sale of unconsolidated affiliates	—	29.0	—
Proceeds from sale of property, plant and equipment	0.3	1.7	0.1
Proceeds from sale of business, net	484.5	—	—
Net cash provided by (used in) discontinued investing activities	38.6	—	(6.8)
Net cash provided by (used in) investing activities	453.4	(154.2)	(389.0)
Financing activities			
Proceeds from borrowings — revolving credit facility	901.2	1,187.1	1,390.0
Repayments of borrowings — revolving credit facility	(911.2)	(1,287.9)	(1,429.8)
Proceeds from borrowings — senior notes	—	393.1	322.6

Repayments of borrowings — senior notes	—	—	(275.0)
Proceeds from borrowings — related party note	—	—	75.0
Repayments of borrowings — related party note	—	(75.0)	—
Payments on capital lease obligations	(2.5)	(8.5)	(8.0)
Proceeds from inventory financing	100.1	—	—
Proceeds from (payments on) other financing obligations	(2.3)	8.5	(2.5)
Proceeds from public offerings of common units, net	—	—	164.1
Debt issuance costs	(2.2)	(11.4)	(5.6)
Contributions from Calumet GP, LLC	0.1	0.2	3.5
Distributions to partners	—	(57.4)	(224.6)
Net cash provided by financing activities	83.2	148.7	9.7
Net increase (decrease) in cash, cash equivalents and restricted cash	510.1	(1.4)	(2.9)
Cash, cash equivalents and restricted cash at beginning of year	4.2	5.6	8.5
Cash, cash equivalents and restricted cash at end of year	$514.3	$4.2	$5.6
Cash and cash equivalents	$164.3	$4.2	$5.6
Restricted cash	$350.0	$—	$—
Supplemental disclosure of cash flow information			
Interest paid, net of capitalized interest	$163.7	$130.2	$120.6
Income taxes paid	$0.4	$1.2	$1.1
Supplemental disclosure of non-cash investing and financing activities			
Non-cash consideration received for the sale of Anchor	$25.4	$—	$—
Non-cash property, plant and equipment additions	$9.1	$14.0	$56.5
Non-cash capital lease	$—	$2.3	$4.4

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of the Business
Calumet Specialty Products Partners, L.P. (the "Company") is a publicly-traded Delaware limited partnership listed on the NASDAQ Global Select Market ("NASDAQ") under the ticker symbol "CLMT." The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of December 31, 2017, the Company had 76,788,801 limited partner common units and 1,567,118 general partner equivalent units outstanding. The general partner owns 2% of the Company and all of the incentive distribution rights (as defined in the Company's partnership agreement), while the remaining 98% is owned by limited partners.
The Company is engaged in the production and marketing of crude oil-based specialty products including lubricating oils, white mineral oils, solvents, petrolatums, waxes, and fuel and fuel related products including gasoline, diesel, jet fuel, asphalt and heavy fuel oils. The Company is based in Indianapolis, Indiana and owns specialty and fuel products facilities. The Company owns and leases additional facilities, primarily related to production and marketing of specialty and fuel products, throughout the United States ("U.S."). Subsequent to the sale of Anchor Drilling Fluids USA, LLC ("Anchor") on November 21, 2017, the Company manages its business in two reportable segments: specialty products and fuel products.
Prior to November 21, 2017, the Company owned and operated Anchor, which provided oilfield services and products in the United States. On November 21, 2017, the Company completed the sale of Anchor. As a result, effective in its fourth quarter of 2017, the Company classified its results of operations for all periods presented to reflect Anchor as a discontinued operation and classified the assets and liabilities of Anchor as discontinued operations. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services. See Note 3 for further discussion.
2. Summary of Significant Accounting Policies
Consolidation
The consolidated financial statements reflect the accounts of the Company and its wholly-owned subsidiaries. All intercompany profits, transactions and balances have been eliminated. Investments in significant noncontrolled entities are accounted for either by using the equity method or cost method of accounting.
Reclassifications
Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the current year presentation.
Use of Estimates
The Company's consolidated financial statements are prepared in conformity with U.S. generally accepted accounting principles ("U.S. GAAP") which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.
Cash, Cash Equivalents and Restricted Cash
Cash, cash equivalents and restricted cash include all highly liquid investments with a maturity of three months or less at the time of purchase.
The sale of the Superior, Wisconsin refinery ("Superior Refinery") resulted in restricted cash and was based upon the value of collateral under the Company's debt agreements. Under the indentures governing the Company's senior notes, proceeds from Asset Sales (as defined in the indentures) can only be used for, among other things, to repay, redeem or repurchase debt; to make certain acquisitions or investments; and to make capital expenditures.
Accounts Receivable
The Company performs periodic credit evaluations of customers' financial condition and generally does not require collateral. Accounts receivable are carried at their face amounts. The Company maintains an allowance for doubtful accounts for estimated losses in the collection of accounts receivable. The Company makes estimates regarding the future ability of its customers to make required payments based on historical experience, the age of the accounts

receivable balances, credit quality of its customers, current economic conditions, expected future trends and other factors that may affect customers' ability to pay. Individual accounts are written off against the allowance for doubtful accounts after all reasonable collection efforts have been exhausted.

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

The activity in the allowance for doubtful accounts was as follows (in millions):

	December 31,		
	2017	2016	2015
Beginning balance	$0.9	$0.9	$1.4
Provision	6.1	0.3	—
Write-offs, net	—	(0.3)	(0.5)
Ending balance	$7.0	$0.9	$0.9

Inventories

The cost of inventory is recorded using the last-in, first-out ("LIFO") method. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market value. The replacement cost of these inventories, based on current market values, would have been $4.6 million lower and $15.7 million lower as of December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, the Company had $1.4 million and $1.3 million, respectively, of inventory consigned to others.

On March 31, 2017 and June 19, 2017, the Company sold inventory comprised of crude oil and refined products to Macquarie Energy North America Trading Inc. ("Macquarie") under Supply and Offtake Agreements as described in Note 8 — "Inventory Financing Agreements" related to the Great Falls and Shreveport refineries, respectively. The crude oil remains in the legal title of Macquarie and is stored in the Company's refinery storage tanks governed by storage agreements. Legal title to the crude oil passes to the Company at the storage tank outlet. After processing, Macquarie takes title to the refined products stored in the Company's storage tanks until sold to third parties. While title to certain inventories will reside with Macquarie, the Supply and Offtake Agreements are accounted for by the Company similar to a product financing arrangement; therefore, the inventories sold to Macquarie will continue to be included in the Company's consolidated balance sheets until processed and sold to a third party. The Company is obligated to repurchase the inventory in certain scenarios. The agreements are accounted for similar to a product financing arrangement.

Inventories consist of the following (in millions):

	December 31, 2017			December 31, 2016		
	Titled Inventory	Supply & Offtake Agreements (1)	Total	Titled Inventory	Supply & Offtake Agreements (1)	Total
Raw materials	$42.0	$ 17.6	$59.6	$57.4	$ —	$57.4
Work in process	34.4	23.7	58.1	74.2	—	74.2
Finished goods	139.4	57.3	196.7	226.2	—	226.2
	$215.8	$ 98.6	$314.4	$357.8	$ —	$357.8

(1) Amounts represent LIFO value and do not necessarily represent the value at which the inventory was sold. Refer to Note 8 for further information.

Under the LIFO inventory method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. For each of the years ended December 31, 2017, 2016 and 2015, the Company recorded increases (exclusive of lower of cost or market ("LCM") adjustments) of $3.7 million, $28.5 million and $25.1 million, respectively, in cost of sales in the consolidated statements of operations due to the liquidation of inventory layers.

In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Such write downs are subject to reversal in subsequent periods, not to exceed LIFO cost, if prices recover. During the years ended December 31, 2017 and 2016, the Company recorded decreases in cost of sales in the consolidated statements of operations of $30.6 million and $38.4 million, respectively, due to the LCM valuation. During the year ended December 31, 2015, the Company recorded an increase in cost of sales in the consolidated statements of operations of $67.0 million due to the LCM valuation.

Derivatives

The Company is exposed to fluctuations in the price of numerous commodities, such as crude oil (its principal raw material) and natural gas, as well as the sales prices of gasoline, diesel and jet fuel. Given the historical volatility of commodity prices, these fluctuations can significantly impact sales, gross profit and net income. Therefore, the Company utilizes derivative instruments primarily to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas and the sale of fuel products. The Company employs various hedging strategies and does not hold or issue derivative instruments for trading purposes. For further information, please refer to Note 10.

On a regular basis, the Company enters into commodity contracts with counterparties for the purchase or sale of crude oil, blendstocks and various finished products. These contracts usually qualify for the normal purchase / normal sale exemption under ASC 815 and, as such, are not measured at fair value.

Property, Plant and Equipment

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

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

	December 31,	
	2017	2016
Land	$13.8	$19.6
Buildings and improvements (10 to 40 years)	36.9	69.0
Machinery and equipment (10 to 20 years)	1,622.8	2,055.3
Furniture and fixtures (5 to 10 years)	61.5	33.2
Assets under capital leases (4 to 26 years) [1]	18.2	51.3
Construction-in-progress	21.4	49.0
	1,774.6	2,277.4
Less accumulated depreciation	(615.4)	(645.0)
	$1,159.2	$1,632.4

[1] Assets under capital leases primarily relate to machinery and equipment.

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

During 2017, 2016 and 2015, the Company incurred $185.2 million, $166.8 million and $133.5 million, respectively, of interest expense of which $2.1 million, $5.1 million and $28.6 million, respectively, was capitalized as a component of property, plant and equipment.

The Company has not recorded an asset retirement obligation as of December 31, 2017 or 2016, because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

During the years ended December 31, 2017, 2016 and 2015, the Company recorded $130.0 million, $125.1 million and $93.2 million, respectively, of depreciation expense on its property, plant and equipment. Depreciation expense included $3.9 million, $3.6 million and $2.6 million for the years ended 2017, 2016 and 2015, respectively, related to the Company's capital lease assets.

The Company capitalizes the cost of computer software developed or obtained for internal use. Capitalized software is amortized using the straight-line method over five years. As of December 31, 2017 and 2016, the Company had $55.8 million and $17.6 million, respectively, of capitalized software costs. As of December 31, 2017 and 2016, the Company had $20.9 million and $17.2 million, respectively of accumulated depreciation related to the capitalized software costs. During the years ended December 31, 2017, 2016 and 2015, the Company recorded $3.3 million, $4.1 million and $4.2 million, respectively, of amortization expense on capitalized computer software. Capitalized software is included in furniture and fixtures.

Investment in Unconsolidated Affiliates

The Company accounts for its ownership in its Pacific New Investment Limited joint venture as an equity method investment in accordance with ASC 323, Investments — Equity Method and Joint Ventures and is recorded in investments in unconsolidated affiliates in the consolidated balance sheet. The equity method of accounting is applied when the investor has an ownership interest of less than 50% and/or has significant influence over the operating or financial decisions of the investee. Under the equity method, the Company’s proportionate share of net income (loss) is reflected as a single-line item in the consolidated statements of operations and as increases or decreases, as applicable, in the carrying value of the Company’s investment in the consolidated balance sheets. In addition, the proportionate share of net income (loss) is reflected as a non-cash activity in operating activities in the consolidated statements of cash flows. Contributions increase the carrying value of the investment and are reflected as an investing activity in the consolidated statements of cash flows.

The Company accounts for its ownership in Fluid Holding Corp. (“FHC”) as a cost method investment in accordance with ASC 323, Investments — Equity Method and Joint Ventures and is recorded in investments in unconsolidated affiliates in the consolidated balance sheet. The cost method of accounting is applied when the investor does not have the ability to exercise significant influence. Under the cost method, investments are carried at cost and are adjusted only for other-than-temporary declines in fair value, certain distributions and additional investments.

Equity method and cost method investments are assessed for other-than-temporary impairment whenever changes in the facts and circumstances indicate an other than temporary loss in value has occurred. During the year ended December 31, 2016, the Company recorded a $0.2 million impairment charge in loss from unconsolidated affiliates in the consolidated statements of operations. The Company recorded a $24.3 million impairment charge in loss from unconsolidated affiliates in the consolidated statements of operations in 2015. For further information on the Company’s investment in unconsolidated affiliates, refer to Note 5.

Goodwill

Goodwill represents the excess of purchase price over fair value of the net assets acquired in various acquisitions. See Note 6 for more information. The Company reviews goodwill for impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable in accordance with ASC 350, Intangibles — Goodwill and Other (Topic 350) and ASU 2017-04, Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment. Under ASC 350, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the impairment test is unnecessary.

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

If the Company’s qualitative assessment concludes that it is probable that an impairment exists or the Company skips the qualitative assessment then the Company needs to perform a quantitative assessment. In the first step of the quantitative assessment, the Company’s assets and liabilities, including existing goodwill and other intangible assets, are assigned to the identified reporting units to determine the carrying value of the reporting units. Under ASU 2017-04, goodwill impairment testing is done by comparing the fair value of the reporting unit to its carrying value. If the carrying amount exceeds the fair value, the Company would recognize an impairment charge for the amount that the reporting unit's carrying value exceeds the fair value, not to exceed the total amount of goodwill allocated to that reporting unit.

When performing the quantitative assessment, the fair value of the reporting units is determined using the income approach. The income approach focuses on the income-producing capability of the reporting unit, measuring the current value of the reporting unit by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation, and risks associated with the reporting unit. For more information, refer to Note 6.

Definite-Lived Intangible Assets

Definite-lived intangible assets consist of intangible assets associated with customer relationships, tradenames, trade secrets, patents and royalty agreements that were acquired in various acquisitions. The majority of these assets are being amortized using discounted estimated future cash flows over the term of the related agreements. Intangible assets associated with customer relationships are being amortized using the discounted estimated future cash flows method based upon assumed rates of annual customer attrition. For more information, refer to Note 6.

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Other Noncurrent Assets

Other noncurrent assets include turnaround costs. Turnaround costs represent capitalized costs associated with the Company's periodic major maintenance and repairs and were $13.4 million and $35.9 million as of December 31, 2017 and 2016, respectively. The Company capitalizes these costs and amortizes the costs on a straight-line basis over the lives of the turnaround assets which is generally two to five years. These amounts are net of accumulated amortization of $72.7 million and $101.9 million at December 31, 2017 and 2016, respectively.

Other Current Liabilities

Other current liabilities consisted of the following (in millions):

	December 31,	
	2017	2016
RINs Obligation	$59.1	$79.3
Other	14.6	20.3
Total	$73.7	$99.6

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

The Company uses the inventory model to account for RINs, measuring acquired RINs at weighted-average cost. The cost of RINs used each period is charged to cost of sales with cash inflows and outflows recorded in the operating cash flow section of the consolidated statements of cash flows. The liability is calculated by multiplying the RINs shortage (based on actual results) by the period end RINs spot price. The Company recognizes an asset at the end of each reporting period in which it has generated RINs in excess of its RINs Obligation. The asset is initially recorded at cost at the time the Company acquires them and are subsequently revalued at the lower of cost or market as of the last day of each accounting period and the resulting adjustments are reflected in costs of sales for the period in the consolidated statements of operations. The value of RINs in excess of the RINs Obligation, if any, would be reflected in other current assets on the consolidated balance sheets. RINs generated in excess of the Company's current RINs Obligation may be sold or held to offset future RINs Obligations. Any such sales of excess RINs are recorded in cost of sales in the consolidated statements of operations. The assets and liabilities associated with our RINs Obligation are considered recurring fair value measurements. See Note 7 for further information on the Company's RINs Obligation.

Impairment of Long-Lived Assets

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

During the fourth quarter of 2017, the Company identified impairment indicators that suggested the carrying values long-lived assets including property, plant and equipment at the Missouri and San Antonio reporting units within the specialty products and fuel products segments, respectively, may not be recoverable. The primary impairment indicators included recently completed projections of future cash flows and the associated impact on the long-range strategic plan forecasts, lower than expected cash flows attributed to these reporting units and poor local market conditions. Undiscounted cash flow tests performed for these reporting units indicated that the long-lived assets were not recoverable. The fair value of the reporting units was established using a discounted cash flow method which utilized Level 3 inputs in the fair value hierarchy. The principal parameters used to establish fair values included estimates of future margins on products produced and sold, future commodity prices, future capital expenditures and discount rates. As a result of the long-lived asset impairment assessment performed, the Company recorded impairment charges primarily on property, plant and equipment on its Missouri reporting unit of $59.2 million and on its San Antonio reporting unit of $147.0 million for the year ended December 31, 2017.

During 2016, the Company recorded write-downs related to idle fixed assets within the specialty products segments. Non-cash charges of $0.9 million were recorded in asset impairment on the consolidated statement of operations and consolidated statement of cash flows for the year ended December 31, 2016. No impairments of long-lived assets were recorded in 2015.

Revenue Recognition

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

Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same statement of operations line).

Concentrations of Credit Risk

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

Income Taxes

The Company, as a partnership, is generally not liable for federal and state income taxes on the earnings of Calumet Specialty Products Partners, L.P. and its wholly-owned subsidiaries. However, the Company conducts certain activities through wholly-owned subsidiaries that are corporations, which in certain circumstances are subject to federal, state and local income taxes. Additionally, the Company is subject to franchise taxes in certain states. Income taxes on the earnings of the Company, with the exception of the above mentioned taxes, are the responsibility of its partners, with earnings of the Company included in partners' earnings.

In the event that the Company's taxable income does not meet certain qualification requirements, the Company would be taxed as a corporation. Interest and penalties related to income taxes, if any, would be recorded in income tax expense. Generally, tax returns remain subject to examination by taxing authorities for three years. The Company had no unrecognized tax benefits as of December 31, 2017 and 2016.

The Company accounts for income taxes for its corporations under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in the Company's financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, the Company reassesses these probabilities and records any changes through the provision for income taxes.

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Excise and Sales Taxes

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

Earnings per Unit

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

Unit Based Compensation

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

Unit based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units ("Liability Awards"). Liability Awards are recorded in accrued salaries, wages and benefits based on the vested portion of the fair value of the awards on the balance sheet date. The fair value of Liability Awards is updated at each balance sheet date and changes in the fair value of the vested portions of the Liability Awards are recorded as increases or decreases to compensation expense. See Note 13 for more information on Liability Awards.

Shipping and Handling Costs

The Company complies with ASC 605-45, Revenue Recognition — Principal Agent Considerations. ASC 605-45 requires the classification of shipping and handling costs billed to customers in sales and the classification of shipping and handling costs incurred in cost of sales, or to be disclosed if classified elsewhere. The Company has reflected \$137.1 million, \$154.3 million and \$153.6 million, respectively, for the years ended December 31, 2017, 2016 and 2015, in transportation expense in the consolidated statements of operations, the majority of which is billed to customers.

Advertising Expenses

The Company expenses advertising costs as incurred which totaled \$6.6 million, \$9.9 million and \$14.2 million in 2017, 2016 and 2015, respectively. Advertising expenses are reported as selling expenses in the consolidated statements of operations.

Foreign Currency Translation and Transactions

Certain of the Company's subsidiaries use a local currency as their functional currency. Assets and liabilities of subsidiaries with a local currency as their functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income (loss), which is reflected in partners' capital in the Company's consolidated balance sheets.

Certain of the Company's subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than such entity's respective functional currency. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in other income (expense) in the consolidated statements of operations.

New Accounting Pronouncements

In August 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-12, Derivatives and Hedging (Topic 815) - Targeted Improvements to Accounting for Hedging Activities ("ASU 2017-12"). ASU 2017-12 which improves the financial reporting of hedging relationships to better align risk management activities in financial statements and make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. The standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted for any interim and annual financial statements that have not yet been issued. The Company is currently evaluating the adoption of ASU 2017-12 on the Company's consolidated financial statements.

In May 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-09, Compensation - Stock Compensation (Topic 718) - Scope of Modification Accounting ("ASU 2017-09"). ASU 2017-09 amends prior guidance by further defining when a change to the terms of a share-based award are required to be accounted for as a modification under the rules by providing specific criteria. ASU 2017-09 is effective for annual periods beginning after December 15, 2017. The adoption of ASU 2017-09 will not have an impact on the Company's consolidated financial statements.

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost ("ASU 2017-07"). The changes to the standard require employers to report the service cost component in the same line item as other compensation costs arising from services rendered by employees during the reporting period. The other components of net benefit costs will be presented in the statement of operations separately from the service cost and outside of a subtotal of operating income (loss). In addition, only the service cost component may be eligible for capitalization where applicable. ASU 2017-07 is effective for annual periods beginning after December 15, 2017. The adoption of ASU 2017-07 will not have an impact on the Company's consolidated financial statements.

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-04, Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment ("ASU 2017-04"), in which the guidance on testing for goodwill was updated by the elimination of Step 2 in the determination on whether goodwill should be considered impaired. The annual and/or interim assessments are still required to be completed. Further, the guidance eliminates the requirement to assess reporting units with zero or negative carrying values, however, the carrying values for all reporting units must be disclosed. ASU 2017-04 is effective for fiscal years (including interim periods) beginning after December 15, 2019, with early adoption permitted. The adopted ASU 2017-04 and applied it to its annual goodwill impairment assessment in 2017.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805) - Clarifying the Definition of a Business ("ASU 2017-01"). The guidance provides criteria for use in determining when to conclude a "set" (as defined in the original guidance) being acquired or disposed in a transaction is not a business. Where the criteria are not met, more stringent screening has been provided to define a set as a business without an output, as more narrowly defined within the guidance. ASU 2017-01 is effective for fiscal years (including interim periods) beginning after December 15, 2017, with early adoption permitted. The adoption of ASU 2017-01 will not have an impact on the Company's consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which supersedes the lease accounting requirements in Accounting Standards Codification ("ASC") Topic 840, Leases. ASU 2016-02 provides principles for the recognition, measurement, presentation and disclosure of leases for both lessees and lessors. The new standard requires lessees to apply a dual approach, classifying leases as either finance or operating leases based on the principle of whether or not the lease is effectively a financed purchase by the lessee. This classification will determine whether lease expense is recognized based on an effective interest method or on a straight-line basis over the term of the lease, respectively. A lessee is also required to record a right-of-use asset and a lease liability for all leases with a term of greater than twelve months regardless of classification. Leases with a term of twelve months or less will be accounted for similar to existing guidance for operating leases. In December 2017 and January 2018, the FASB released ASU 2017-13 and ASU 2018-01, respectively, which contain modifications to ASU 2016-02. The amendments in these standards are effective for fiscal years (including interim periods) beginning after December 15, 2018, with early adoption permitted and modified retrospective application required. The Company is currently evaluating the impact of these standards on its consolidated financial statements.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"). ASU 2016-01 requires that (i) equity investments in unconsolidated entities that are not accounted for under the equity method of accounting generally be measured at fair value with changes recognized in net income (loss) and (ii) when the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk be recognized separately in other comprehensive income (loss). Additionally, ASU 2016-01 changes the presentation and disclosure requirements for financial instruments. The amendments in this standard are generally effective for fiscal years (including interim periods) beginning after December 15, 2017, with early adoption not permitted. The adoption of ASU 2016-01 is not expected to have an impact on the Company's consolidated financial statements.

In May 2014, the FASB issued Accounting Standards Codification 606, Revenue from Contracts with Customers (Topic 606) ("ASC 606"), which supersedes the revenue recognition requirements in Accounting Standard Codification Topic 605, Revenue Recognition. The new accounting standard is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In order to apply this core principle, companies will apply the following five steps in determining the amount of revenues to recognize: (i) identify the contract; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management's judgment and an analysis of the contract's material terms and conditions.

The Company adopted the new standard on January 1, 2018 using a modified retrospective approach, which required it to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative adjustment to equity, if necessary. In accordance with this approach, the Company's consolidated revenues for periods prior to January 1, 2018 will not be revised.

The Company's implementation activities related to ASC 606 are complete and we will not have any material differences in the amount or timing of revenues as a result of the adoption of ASC 606. The Company's largest revenue streams consist of orders received from our customers for crude-oil based specialty products and fuel and fuel related products, generally based on market prices. These revenues are recognized at a point in time upon transfer of control of the product in accordance with contractual terms. In addition, the Company has identified some agreements with distributors within the specialty products segment that are subject to rebate and incentive programs that could contain elements of material rights and/or variable consideration. These elements did not result in a material change to how revenue is recognized for these agreements.

As a result of adopting the new standard, there will be changes to the Company's disclosures based on the additional requirements prescribed by ASC 606. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities.

Correction of Immaterial Errors

During the quarter ended September 30, 2016, the Company identified and corrected errors in the accounting for the LCM of inventory and income taxes that related to the year ended December 31, 2015. These errors primarily related to LCM adjustments at its branded and packaged products operating segment and an adjustment for a tax benefit associated with its decision to liquidate a wholly-owned C corporation as of December 31, 2015, and convert it to an entity which will not be subject to tax. The impact of correcting these items in the third quarter of 2016 increased cost of sales by $6.5 million, increased income tax benefit by $7.8 million and decreased net loss by $1.3 million. The Company concluded that the corrections to the financial statements were immaterial to its financial results for the years ended December 31, 2016 and 2015.

3. Discontinued Operations

On November 21, 2017, Calumet Operating, LLC, a Delaware limited liability company and a wholly-owned subsidiary of the Company, completed the sale to a subsidiary of Q'Max Solutions Inc. ("Q'Max") of all of the issued and outstanding membership interests in Anchor Drilling Fluids USA, LLC, ("Anchor"), for total consideration of approximately $89.6 million (subject to further post-closing adjustments) including a base price $50.0 million, $14.2 million to be paid at various times over the 24 month period following the closing of the transaction for net working capital and other items, and 10% equity ownership in FHC, the parent company of Q'Max (the "Anchor Transaction"). Effective in its fourth quarter of 2017, the Company classified its results of operations for all periods presented to reflect Anchor as a discontinued operation and classified the assets and liabilities of Anchor as discontinued operations. The Company recognized a net loss on sale of $62.6 million in net loss from discontinued operations in the consolidated statements of operations for the year ended December 31, 2017. Prior to being reported as discontinued operations, Anchor was included as its own reportable segment as oilfield services. As of December 31, 2017, the Company recorded a $15.1 million receivable in other accounts receivable in the consolidated balance sheet for the remaining payment of the base price and working capital and a $7.1 million receivable in other noncurrent assets, net in the consolidated balance sheet for the remaining payment of working capital.

The following table summarizes the results of discontinued operations for each of the periods presented (in millions):

	Year Ended December 31,		
	2017	2016	2015

Sales	$228.6	$125.1	$282.5
Cost of sales	(168.1)	(103.1)	(224.3)
Selling	(45.9)	(40.9)	(74.2)
General and administrative	(4.5)	(4.8)	(9.6)
Asset impairment	—	—	(33.8)
Loss on sale of business, net	(62.6)	—	—
Other	(21.0)	(16.0)	(23.2)
Net loss from discontinued operations before income taxes	$(73.5)	$(39.7)	$(82.6)
Income tax benefit [1]	(1.0)	(7.9)	(28.6)
Net loss from discontinued operations net of income taxes	$(72.5)	$(31.8)	$(54.0)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(1) Income tax benefit for 2016 included a $7.8 million tax refund related to federal and state income taxes.

The following table summarizes the major classes of assets and liabilities from discontinued operations:

	December 31, 2016
DISCONTINUED OPERATIONS ASSETS	
Current assets:	
Accounts receivable, net	$ 33.8
Inventories	28.4
Prepaid expenses and other current assets	0.4
Discontinued operations, current assets	62.6
Property, plant and equipment, net	45.6
Investment in unconsolidated affiliates	0.7
Other intangible assets, net	45.0
Discontinued operations, noncurrent assets	91.3
Discontinued operations, total assets	$ 153.9
DISCONTINUED OPERATIONS LIABILITIES	
Current liabilities:	
Accounts payable	$ 19.6
Accrued salaries, wages and benefits	0.4
Other taxes payable	0.4
Discontinued operations, current liabilities	$ 20.4

4. Divestitures

On November 8, 2017, Calumet Refining, LLC, a Delaware limited liability company (formerly known as Calumet Lubricants Co., Limited Partnership, an Indiana limited partnership) (“Calumet Refining”) and a wholly-owned subsidiary of the Company, completed the sale of all of the issued and outstanding membership interests in Calumet Superior, LLC, a Delaware limited liability company (“Superior”), which owns the Superior, Wisconsin refinery (“Superior Refinery”) and associated net working capital, the Superior Refinery’s wholesale marketing business and related assets, including certain owned or leased product terminals, and certain crude gathering assets and pipeline space in North Dakota to Husky Superior Refining Holding Corp., a Delaware corporation (“Husky”) (the “Superior Transaction”). Total consideration was $533.1 million which consisted of a base price of $435.0 million and $98.1 million for net working capital and reimbursement of certain capital spending, subject to further post-closing adjustments. The Superior Refinery is included in the Company’s fuel products segment. The Company recognized a net gain of $236.0 million in gain on sale of business in the consolidated statements of operations for the year ended December 31, 2017. The Company recorded a $41.0 million (subject to further post-closing adjustments which could increase the receivable to approximately$45.0 million according to the membership interest purchase agreement) receivable in other accounts receivable in the consolidated balance sheets for post-closing working capital adjustments.

The Company considered other qualitative and quantitative factors and concluded the Superior Transaction did not represent a strategic shift in the business. However, the Company considers Superior to be an individually significant component of its operations. The following table presents the net income before income taxes for Superior for the periods presented (in millions):

	Year Ended December 31,		
	2017	2016	2015

Sales	$669.1	$681.2	$856.8
Gross profit	$110.0	$68.5	$137.6
Net income before income taxes	$99.3	$54.5	$121.0

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5. Investment in Unconsolidated Affiliates

The following table summarizes the Company's investments in unconsolidated affiliates (in millions):

	Year Ended December 31, 2017			Year Ended December 31, 2016		
	Investment	Percent Ownership		Investment	Percent Ownership	
Pacific New Investment Limited	$9.6	23.8	%	$9.6	23.8	%
Fluid Holding Corp.	25.4	10	%	—	—	%
Total	$35.0			$9.6		

Dakota Prairie Refining, LLC

On June 27, 2016, the Company consummated the sale of its 50% equity interest in Dakota Prairie Refining, LLC ("Dakota Prairie") to joint venture partner WBI Energy, Inc. ("WBI"), a wholly owned subsidiary of MDU Resources Group, Inc. ("MDU"). Concurrent with the Company's sale of its equity interest in Dakota Prairie to WBI, Tesoro Refining & Marketing Company LLC ("Tesoro") acquired 100% of Dakota Prairie from WBI in a separate transaction that closed on June 27, 2016.

Under the terms of the definitive agreement with WBI, the Company received consideration of $28.5 million, which was offset by the Company's repayment of $36.0 million in borrowings under Dakota Prairie's revolving credit facility. In addition, the Company's $39.4 million letter of credit supporting the Dakota Prairie revolving credit facility was terminated. As part of the transaction, MDU and WBI released the Company from all liabilities arising out of or related to Dakota Prairie. In addition, Tesoro and Dakota Prairie released the Company from all liabilities arising out of the organization, management and operation of Dakota Prairie, subject to certain limited exceptions. Further, WBI agreed to indemnify the Company from all liabilities arising out of or related to Dakota Prairie, subject to certain limited exceptions. As a result of the sale of Dakota Prairie, the Company recorded a loss on sale of unconsolidated affiliate of $113.9 million during the year ended December 31, 2016.

During the year ended December 31, 2016, the Company purchased $5.3 million, of crude oil and other feedstocks at cost from Dakota Prairie. There were no accounts payable to Dakota Prairie as of December 31, 2016.

During the year ended December 31, 2016, the Company purchased $14.7 million of crude oil on behalf of Dakota Prairie and sold it to Dakota Prairie at cost, which resulted in an immaterial gains each year. There were no receivables due from Dakota Prairie as of December 31, 2016.

Pacific New Investment Limited and Shandong Hi-Speed Hainan Development Co., Ltd.

On August 5, 2015, the Company and The Heritage Group ("Heritage Group"), a related party, formed Pacific New Investment Limited ("PACNIL") for the purpose of investing in a joint venture with Shandong Hi-Speed Materials Group Corporation and China Construction Installation Engineering Co., Ltd. to construct, develop and operate a solvents refinery in mainland China. The joint venture is named Shandong Hi-Speed Hainan Development Co., Ltd. ("Hi-Speed"). The Company invested $4.8 million in June 2016 and $4.8 million in October 2016. As of December 31, 2016, the Company owned an equity interest of approximately 23.8% in PACNIL and through that ownership the Company owned an equity interest of approximately 6% in Hi-Speed. PACNIL formally notified Hi-Speed that it wishes to exit its investment in Hi-Speed. The Company and PACNIL believe they will fully recover their investment in Hi-Speed.

The Company accounts for its ownership in PACNIL under the equity method of accounting. As of December 31, 2017 and 2016, the Company had an investment of $9.6 million in PACNIL, primarily related to the purchase of equity in the Hi-Speed joint venture.

Fluid Holding Corp.

In connection with the Anchor Transaction, the Company received a 10% investment in FHC as part of the total consideration for Anchor. FHC provides oilfield services and products to customers globally. The Company accounts for its ownership in FHC under the cost method of accounting. As of December 31, 2017, the Company had an investment of $25.4 million in FHC, which was its estimated fair value using Level 3 inputs as of November 21, 2017. See Note 3 for further information on the Anchor Transaction.

Juniper GTL LLC

On June 9, 2014, the Company entered into a joint venture agreement with Clean Fuels North America, LLC, which is owned by SGC Energia and Great Northern Project Development, to develop, build and operate a gas-to-liquids ("GTL") plant in Lake Charles, Louisiana. The joint venture is named New Source Fuels, LLC, and it owns 100% of Juniper GTL LLC ("Juniper"). The Company invested $25.0 million in total in exchange for an equity interest of approximately 23% in the joint venture. During

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September 2015, the Company determined the fair value of its investment in Juniper was less than its carrying value of $24.3 million. As a result, the Company recorded a $24.3 million impairment charge in loss from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2015. Inputs used to estimate the fair value of Juniper were considered Level 3 of the fair value hierarchy. In June 2016, the Company sold its equity interest in New Source Fuels, LLC for an immaterial amount.

6. Goodwill and Other Intangible Assets

2017

The Company updated its financial projections in connection with its annual goodwill assessment and determined that its Dickinson reporting unit's fair value was below its carrying value. An impairment charge of $0.7 million for goodwill related to the specialty products segment was recorded in the consolidated statements of operations within asset impairment.

2016

In April 2016, the board of directors of the Company's general partner determined to suspend payment of the Company's quarterly cash distribution to unitholders. The suspension of the quarterly cash distribution caused a sustained decrease in the Company's common unit price. As a result, the Company determined that these events constituted a triggering event that required the Company to update its financial projections and its goodwill impairment assessment as of April 30, 2016. An impairment charge of $33.4 million for goodwill related to the fuel products segment was recorded in the consolidated statements of operations within asset impairment. The impairment charge was primarily driven by the reduced outlook on revenues and profitability as a result of falling crude oil prices and crack spreads.

In December 2016, the Missouri reporting unit experienced a significant reduction in orders from a customer of significance which is expected to have an adverse impact on the business. As a result, the Company determined that this event constituted a triggering event that required the Company to update its financial projections and its goodwill impairment assessment in December 2016. An impairment charge of $1.4 million for goodwill related to the specialty products segment was recorded in the consolidated statements of operations within asset impairment.

To derive the fair value of the reporting units, as required in step one of the impairment test, the Company used the income approach, specifically the discounted cash flow method, to determine the fair value of each reporting unit and the associated amount of the impairment charge. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation, and risks associated with the reporting unit.

Inputs used to estimate the fair value of the Company's reporting units are considered Level 3 inputs of the fair value hierarchy and include the following:

- The Company's financial projections for its reporting units are based on its analysis of various supply and demand factors which include, among other things, industry-wide capacity, its planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in the Company's planning and capital investment reviews and include recent historical prices and published forward prices.
- The discount rate used to measure the present value of the projected future cash flows is based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible.

For Level 3 measurements, significant increases or decreases in long-term growth rates or discount rates in isolation or in combination could result in a significantly lower or higher fair value measurement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Changes in goodwill balances for the periods indicated below are as follows (in millions):

	Specialty Products	Fuel Products	Total
Net balance as of December 31, 2015	$ 173.5	$ 38.5	$ 212.0
Impairment [1]	(1.4)	(33.4)	(34.8)
Net balance as of December 31, 2016	$ 172.1	$ 5.1	$ 177.2
Impairment [1]	(0.7)	—	(0.7)
Divestiture [2]	—	(5.1)	(5.1)
Net balance as of December 31, 2017	$ 171.4	$ —	$ 171.4

(1) Total accumulated goodwill impairment as of December 31, 2017 and 2016, is $35.5 million and $34.8 million, respectively.
(2) Divestiture relates to sale of the Superior Refinery. See Note 4 for additional information.

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

	Weighted Average Life (Years)	December 31, 2017		December 31, 2016	
		Gross Amount	Accumulated Amortization	Gross Amount	Accumulated Amortization
Customer relationships	22	$ 181.3	$ (107.6)	$ 186.7	$ (97.2)
Tradenames	11	26.8	(13.8)	26.8	(9.9)
Trade secrets	13	52.7	(35.1)	52.7	(29.6)
Patents	12	1.6	(1.6)	1.6	(1.5)
Royalty agreements	19	6.2	(2.6)	6.2	(2.3)
	19	$ 268.6	$ (160.7)	$ 274.0	$ (140.5)

Tradenames, trade secrets, patents and royalty agreements are being amortized to properly match expenses with the undiscounted estimated future cash flows over the terms of the related agreements or the period expected to be benefited. The costs of agreements with terms allowing for the potential extension of such agreements are being amortized based on the initial term only. Customer relationships are being amortized to properly match expenses with the undiscounted estimated future cash flows based upon assumed rates of annual customer attrition. For the years ended December 31, 2017, 2016 and 2015, the Company recorded amortization expense of intangible assets of $24.6 million, $26.9 million and $29.4 million, respectively.

As of December 31, 2017, the Company estimates that amortization of intangible assets for the next five years will be as follows (in millions):

Year	Amortization Amount
2018	$ 19.9
2019	$ 16.8
2020	$ 14.0
2021	$ 11.5
2022	$ 9.4

7. Commitments and Contingencies

Operating Leases

The Company has various operating leases primarily for the use of land, storage tanks, railcars, equipment, precious metals and office facilities that extend through July 2055. Renewal options are available on certain of these leases in which the Company is the lessee. Rent expense for the years ended December 31, 2017, 2016 and 2015 was $53.2 million, $56.6 million and $57.6 million, respectively.

As of December 31, 2017, the Company had estimated minimum commitments for the payment of rentals under leases which, at inception, had a noncancelable term of more than one year, as follows (in millions):

Year	Operating Leases
2018	$ 31.4
2019	21.7
2020	16.7
2021	9.5
2022	7.3
Thereafter	10.8
Total	$ 97.4

Crude Oil Supply, Other Feedstocks and Finished Products

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

Certain other feedstocks are purchased under long-term supply contracts. The Company also purchases finished products from Houston Refining. The Company is required to purchase all of the naphthenic lubricating oils produced at Houston Refining's refinery in Houston, Texas, up to 3,100 bpd, and has a right of first refusal to purchase any additional naphthenic lubricating oils (above the 3,100 bpd) produced at the refinery. In addition, Houston Refining is required to toll-process a minimum of approximately 600 bpd of white mineral oil for the Company at Houston Refining's Houston, Texas refinery. The annual purchase commitment under these agreements is approximately $114.0 million.

As of December 31, 2017, the estimated minimum purchase commitments under the Company's crude oil, other feedstock supply and finished product agreements were as follows (in millions):

Year	Commitment
2018	$ 297.5
2019	126.7
2020	21.1
2021	21.0
2022	21.0
Thereafter	84.2
Total	$ 571.5

The Company has a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of three months. Based upon this minimum supply quantity, the Company expects to purchase approximately $11.4 million of feedstock for the LVT unit for the term of the contract expiring March 31, 2018, based on pricing estimates as of December 31, 2017. This amount is not included in the table above.

Contingencies

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

Environmental

The Company conducts crude oil and specialty hydrocarbon refining, blending and terminal operations, and such 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 the Company’s operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company may release materials into the environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, requiring the application of specific health and safety criteria addressing worker protection and imposing substantial liabilities for pollution resulting from its operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of

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investigatory, remedial or corrective action obligations or the 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 Company activities. 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 released or disposed. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments, some of which legal requirements are discussed below, could significantly increase the Company's operational or compliance expenditures.

Remediation of subsurface contamination is in process at certain of the Company's refinery sites and is being overseen by the appropriate state agencies. Based on current investigative and remedial activities, the Company believes that the soil and groundwater contamination at these refineries can be controlled or remediated without having a material adverse effect on the Company's financial condition. However, such costs are often unpredictable and, therefore, there can be no assurance that the future costs will not become material.

San Antonio Refinery

In connection with the acquisition of the San Antonio refinery, the Company 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 the Company's acquisition of the facility. The Company does not expect this pre-existing contamination at the San Antonio refinery to have a material adverse effect on its 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"), the Company 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. The Company believes 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 the Company a notice challenging the Company's position that Holly is obligated to indemnify the Company's 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 expenditures totaled approximately $18.7 million as of December 31, 2017, of which $14.6 million was capitalized into the cost of the Company's recently completed refinery expansion project and $2.4 million was expensed. The Company continues to believe that Holly is responsible to indemnify the Company for these remediation expenses disputed by Holly, and on September 22, 2015, the Company initiated a lawsuit against Holly and the sellers of the Great Falls refinery under the asset purchase agreement. On November 24, 2015, Holly and the sellers of the Great Falls refinery under the asset purchase agreement 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. The first phase of the arbitration is scheduled for July 2018. In the event the Company is unsuccessful in the legal dispute with Holly, the Company will be responsible for the remediation expenses. The Company expects that it may incur costs to remediate other environmental conditions at the Great Falls refinery; however, the costs cannot be estimated at this time. The Company believes at this time that these other costs it may incur will not be material to its financial position or results of operations.

Shreveport, Cotton Valley and Princeton Refineries

On December 23, 2010, the Company entered into a settlement agreement with the Louisiana Department of Environmental Quality ("LDEQ") under LDEQ's "Small Refinery and Single Site Refinery Initiative," covering the Shreveport, Cotton Valley and Princeton 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, the Company agreed to complete beneficial environmental programs and implement emissions reduction projects at the Company's Shreveport, Cotton Valley and Princeton refineries on an agreed-upon schedule. During 2017 and 2016, the Company incurred of such capital expenditures approximately $0.7 million and $2.4 million, respectively. The Global Settlement is substantially complete and any remaining capital investment requirements will be incorporated into the Company's annual capital expenditures budget. The Company does not expect any additional capital expenditures included in the Global Settlement to have a material adverse effect on the Company's financial position or results of operations.

The Company is contractually indemnified by Shell Oil Company ("Shell"), as successor to Pennzoil-Quaker State Company, and Atlas Processing Company, under an asset purchase agreement between the Company and Shell, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company's acquisition of the facility. The Company believes the contractual indemnity is unlimited in amount and duration, but requires the Company to contribute $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities. The Company has recorded the $1.0 million liability in the consolidated balance sheets.

Renewable Identification Numbers Obligation

The Company's RINs Obligation represents a liability for the purchase of RINs to satisfy the EPA requirement to blend biofuels into the fuel products it produces pursuant to the RFS. RINs are assigned to biofuels produced in the U.S. as required by the EPA. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, the Company is required to blend biofuels into the fuel products it produces at a rate that will meet the EPA's annual quota. To the extent the Company is unable to blend biofuels at that rate, it must purchase RINs in the open market to satisfy the annual requirement. The Company's RINs Obligation is based on the amount of RINs it must purchase net of amounts internally generated or purchased and the price of those RINs as of the balance sheet date.

In February 2017 and in May 2017, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full-year 2016, as provided for under the federal Clean Air Act, as amended ("CAA"). In granting those exemptions, the EPA determined that for the full-year 2016, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

In October 2016, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full-year 2015, as provided for under the CAA. In granting those exemptions, the EPA determined that for the full-year 2015, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

In June 2016, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full-year 2014, as provided for under the CAA. In granting those exemptions, the EPA determined that for the full-year 2014, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

As of December 31, 2017 and 2016, the Company had a RINs Obligation of $59.1 million and $79.3 million, respectively.

Occupational Health and Safety

The Company is subject to various laws and regulations relating to occupational health and safety, including the U.S. Occupational Safety and Health Act and comparable state laws. These laws and regulations strictly govern the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in the Company's operations and that this information be provided to employees, contractors, state and local government authorities and customers. The Company maintains safety and training programs as part of its ongoing efforts to promote compliance with applicable laws and regulations. The Company conducts periodic audits of Process Safety Management ("PSM") systems at each of its locations subject to the PSM standard. The Company's compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures. Changes in occupational safety and health laws and regulations or a finding of non-compliance with current laws and regulations could result in additional capital expenditures or operating expenses, as well as civil penalties and, in the event of a serious injury or fatality,

criminal charges.
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 the Company as a result of the Cotton Valley inspection, which included a proposed penalty amount of $0.2 million. The Company has contested the Cotton Valley Citation and the parties have reached a tentative settlement with OSHA on the matter, which the Company does not believe will have a material adverse effect on its financial position or results of operations.
Labor Matters
The Company has approximately 500 employees covered by various collective bargaining agreements, or approximately 31% of its total workforce of approximately 1,600 employees. These agreements have expiration dates of October 31, 2020, January 31,

2019, March 31, 2019 and April 30, 2019. Therefore, the Company has none of its employees who are covered by a collective bargaining agreement which will expire in less than one year and does not expect any work stoppages.

Legal Proceedings

The Company is subject to claims and litigation arising in the normal course of its business. The Company has recorded accruals with respect to certain of these matters, where appropriate, that are reflected in the consolidated financial statements but are not individually considered material. For other matters, the Company has not recorded accruals because it has not yet determined that a loss is probable or because the amount of loss cannot be reasonably estimated. While the ultimate outcome of claims and litigation currently pending cannot be determined, the Company currently does not expect that these proceedings and claims, individually or in the aggregate (including matters for which the Company has recorded accruals), will have a material adverse effect on its financial position, results of operations or cash flows. The outcome of any litigation is inherently uncertain, however, and if decided adversely to the Company, or if the Company determines that settlement of particular litigation is appropriate, the Company may be subject to liability that could have a material adverse effect on its financial position, results of operations or cash flows.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued primarily to vendors. As of December 31, 2017 and 2016, the Company had outstanding standby letters of credit of \$67.3 million and \$82.1 million, respectively, under its senior secured revolving credit facility (the "revolving credit facility"). Refer to Note 9 for additional information regarding the Company's revolving credit facility. At December 31, 2017 and 2016, the maximum amount of letters of credit the Company could issue under its revolving credit facility was subject to borrowing base limitations, with a maximum letter of credit sublimit equal to \$600.0 million, which amount may be increased to 90% of revolver commitments in effect (\$900.0 million at December 31, 2017 and December 31, 2016) with the consent of the Agent (as defined in the revolving credit agreement).

As of December 31, 2017 and 2016, the Company had availability to issue letters of credit of approximately \$252.0 million and approximately \$360.8 million, respectively, under its revolving credit facility.

8. Inventory Financing Agreements

On March 31, 2017, the Company entered into several agreements with Macquarie to support the operations of the Great Falls refinery (the "Great Falls Supply and Offtake Agreements"). The Great Falls Supply and Offtake Agreements expire on October 31, 2019. On July 27, 2017, the Company amended the Great Falls Supply and Offtake Agreements to provide Macquarie the option to terminate the Great Falls Supply and Offtake Agreements with nine months' notice any time prior to June 2019.

On June 19, 2017, the Company entered into several agreements with Macquarie to support the operations of the Shreveport refinery (the "Shreveport Supply and Offtake Agreements", and together with the Great Falls Supply and Offtake Agreements, the "Supply and Offtake Agreements"). The Shreveport Supply and Offtake Agreements expire on June 2020; however, Macquarie has the option to terminate the Shreveport Supply and Offtake Agreements with nine months' notice any time prior to June 2019.

At the commencement of the Great Falls Supply and Offtake Agreements, the Company sold to Macquarie inventory comprised of 652,000 barrels of crude oil and refined products valued at \$32.2 million.

At the commencement of the Shreveport Supply and Offtake Agreements, the Company sold to Macquarie inventory comprised of 987,000 barrels of crude oil and refined products valued at \$54.8 million.

In addition, the Company incurred approximately \$3.1 million of costs related to the Supply and Offtake Agreements. These capitalized costs are recorded in obligations under inventory financing agreements in the Company's consolidated balance sheets and amortized to interest expense over the term of the agreement.

During the terms of the Supply and Offtake Agreements, the Company may purchase crude oil from Macquarie or one of its affiliates. Per the Supply and Offtake Agreements, Macquarie will provide up to 30,000 barrels per day of crude oil to the Great Falls refinery and 60,000 barrels per day of crude oil to the Shreveport refinery. The Company agreed to purchase the crude oil on a just-in-time basis to support the production operations at the Great Falls and Shreveport refineries. Additionally, the Company agreed to sell, and Macquarie agreed to buy, at market prices, refined products produced at the Great Falls and Shreveport refineries. For Shreveport, finished products consisting of finished fuel products (other than jet fuel), lubricants and waxes, Macquarie may (but is not required to) sell such products to the sales intermediation party ("SIP"), and the SIP may (but is not required to) sell such products to Shreveport, as applicable, for sale in turn to third parties. For jet fuel and certain intermediate products, Macquarie may (but is not required to) sell such products to Shreveport for sale thereby to third parties. The Company will then repurchase the refined products from Macquarie or the SIP prior to selling the refined products to third parties.

The Supply and Offtake Agreements are subject to minimum and maximum inventory levels. The agreements also provide for the lease to Macquarie of crude oil and certain refined product storage tanks located at the Great Falls and Shreveport refineries and certain offsite locations. Following expiration or termination of the agreements, Macquarie has the option to require the Company to purchase the crude oil and refined product inventories then owned by Macquarie and located at the leased storage tanks at then current market prices. In addition, barrels owned by the Company are pledged as collateral to support the Deferred Payment Arrangement (defined below) obligations under these agreements.

While title to certain inventories will reside with Macquarie, the Supply and Offtake Agreements are accounted for by the Company similar to a product financing arrangement; therefore, the inventories sold to Macquarie will continue to be included in the Company's consolidated balance sheets until processed and sold to a third party. Each reporting period, the Company will record liabilities in an amount equal to the amount the Company expects to pay to repurchase the inventory held by Macquarie based on market prices at the termination date included in obligations under inventory financing agreements in the consolidated balance sheets. The Company has determined that the redemption feature on the initially recognized liabilities related to the Supply and Offtake Agreements is an embedded derivative indexed to commodity prices. As such, the Company has accounted for these embedded derivatives at fair value with changes in the fair value, if any, recorded in gain (loss) on derivative instruments in the Company's consolidated statements of operations. For more information on the valuation of the associated derivatives, see Note 10 - "Derivatives" and Note 11 - "Fair Value Measurements." The embedded derivatives will be recorded in obligations under inventory financing agreements on the consolidated balance sheets. The cash flow impact of the embedded derivatives will be classified as a change in derivative activity in the financing activities section in the consolidated statements of cash flows.

For the year ended December 31, 2017, the Company incurred $6.8 million of financing costs related to the Supply and Offtake Agreements, which are included in interest expense in the Company's consolidated statements of operations.

The Company has provided collateral of $4.0 million related to the initial purchase of the Great Falls and Shreveport inventory to cover credit risk for future crude oil deliveries and potential liquidation risk if Macquarie exercises its rights and sells the inventory to third parties. The collateral was recorded as a reduction to the obligations under inventory financing agreements pursuant to a master netting agreement.

The Supply and Offtake Agreements also include a deferred payment arrangement ("Deferred Payment Arrangement") whereby the Company can defer payments on just-in-time crude oil purchases from Macquarie owed under the agreements up to the value of the collateral provided (90% of the collateral inventory). The deferred amounts under the deferred payment arrangement will bear interest at a rate equal to LIBOR plus 3.25% per annum for both Shreveport and Great Falls. Amounts outstanding under the Deferred Payment Arrangement are included in obligations under inventory financing agreements in the Company's consolidated balance sheets. Changes in the amount outstanding under the Deferred Payment Arrangement are included within cash flows from financing activities on the consolidated statements of cash flows. As of the year ended December 31, 2017, the capacity of the Deferred Payment Arrangement was $17.8 million and the Company had $11.3 million deferred payments outstanding.

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9. Long-Term Debt

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

	December 31, 2017	December 31, 2016
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments quarterly, borrowings due July 2019, weighted average interest rates of 8.4% and 4.8% at December 31, 2017 and 2016, respectively	$ 0.2	$ 10.2
Borrowings under 2021 Secured Notes, interest at a fixed rate of 11.5%, interest payments semiannually, borrowings due January 2021, effective interest rates of 12.3% and 12.2% for the year ended December 31, 2017 and 2016, respectively	400.0	400.0
Borrowings under 2021 Notes, interest at a fixed rate of 6.5%, interest payments semiannually, borrowings due April 2021, effective interest rate of 6.8% for each year ended December 31, 2017 and 2016	900.0	900.0
Borrowings under 2022 Notes, interest at a fixed rate of 7.625%, interest payments semiannually, borrowings due January 2022, effective interest rate of 8.0% for each year ended December 31, 2017 and 2016 [1]	352.1	352.5
Borrowings under 2023 Notes, interest at a fixed rate of 7.75%, interest payments semiannually, borrowings due April 2023, effective interest rate of 8.0% for each year ended December 31, 2017 and 2016	325.0	325.0
Other	6.6	8.0
Capital lease obligations, at various interest rates, interest and principal payments monthly through November 2034	44.0	46.5
Less unamortized debt issuance costs [2]	(25.9)	(33.2)
Less unamortized discounts	(9.7)	(11.8)
Total long-term debt	1,992.3	1,997.2
Less current portion of long-term debt [3]	354.1	3.5
	$ 1,638.2	$ 1,993.7

(1) The balance includes a fair value interest rate hedge adjustment, which increased the debt balance by $2.1 million and $2.5 million as of December 31, 2017 and 2016, respectively.

(2) Deferred debt issuance costs are being amortized by the effective interest rate method over the lives of the related debt instruments. These amounts are net of accumulated amortization of $21.8 million and $14.5 million at December 31, 2017 and 2016, respectively.

(3) The sale of the Superior Refinery resulted in $350.0 million of restricted cash and was based upon the value of collateral under the Company’s debt agreements. Under the indentures governing the Company’s senior notes, proceeds from Asset Sales (as defined in the indentures) can only be used for, among other things, to repay, redeem or repurchase debt; to make certain acquisitions or investments; and to make capital expenditures. These proceeds need to be used within one year of the Asset Sales (as defined in the indentures) and as such were recorded as current.

Senior Notes

11.50% Senior Secured Notes (the “2021 Secured Notes”)

On April 20, 2016, the Company issued and sold $400.0 million in aggregate principal amount of 11.50% Senior Secured Notes due January 15, 2021, in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended (the “Securities Act”), to eligible purchasers at a discounted price of 98.273 percent of par. Subject to certain exceptions, the 2021 Secured Notes are secured by a lien on all of the fixed assets that secure the Company’s obligations under its secured hedge agreements, including certain present and future real property, fixtures and equipment; all U.S. registered patents and patent license rights, trademarks and trademark license rights, copyrights and copyright license rights and trade secrets; chattel paper, documents and instruments; certain cash deposits in the property, plant and equipment proceeds account; certain books and records; and all accessions and proceeds of any of the foregoing. The Company received net proceeds of approximately $382.5 million net of discount, initial purchasers' fees and estimated expenses, which it used to repay borrowings outstanding under its revolving credit facility and for general partnership purposes, including planned capital expenditures at its facilities and working capital. Interest on the 2021 Secured Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2016.

7.75% Senior Notes (the “2023 Notes”)

On March 27, 2015, the Company issued and sold $325.0 million in aggregate principal amount of 7.75% Senior Notes due April 15, 2023 in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 99.257 percent of par. The Company received net proceeds of approximately $317.0 million net of discount, initial purchasers’ fees and expenses, which the Company used to fund the redemption of $178.8 million in aggregate principal amount of outstanding 9.625% senior notes due 2020 on April 28, 2015, to repay borrowings outstanding under its revolving credit facility and for general partnership purposes, including planned capital expenditures at the Company’s facilities and working capital. Interest on the 2023 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2015.

On March 27, 2015, in connection with the issuance and sale of the 2023 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2023 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2023 Notes can offer to exchange the 2023 Notes for registered notes having substantially the same terms as the 2023 Notes and evidencing the same indebtedness as the 2023 Notes. On December 11, 2015, the Company filed an exchange offer registration statement for the 2023 Notes with the SEC, which was declared effective on January 28, 2016. The exchange offer was completed on March 7, 2016, thereby fulfilling all of the requirements of the 2023 Notes registration rights agreement.

6.50% Senior Notes (the “2021 Notes”)

On March 31, 2014, the Company issued and sold $900.0 million in aggregate principal amount of 6.50% Senior Notes due April 15, 2021 in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at par. The Company received net proceeds of approximately $884.0 million, net of initial purchasers’ fees and expenses, which the Company used to fund the purchase price of ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. (subsequently converted to ADF Holdings, LLC and Anchor Drilling Fluids USA, LLC), the redemption of $500.0 million in aggregate principal amount outstanding of 9.375% Senior Notes due 2019 and for general partnership purposes, including planned capital expenditures at the Company’s facilities. Interest on the 2021 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2014.

On March 31, 2014, in connection with the issuance and sale of the 2021 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2021 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2021 Notes can offer to exchange the 2021 Notes for registered notes having substantially the same terms as the 2021 Notes and evidencing the same indebtedness as the 2021 Notes. On March 24, 2015, the Company filed an exchange offer registration statement for the 2021 Notes with the SEC, which was declared effective on April 3, 2015. The exchange offer was completed on April 30, 2015, thereby fulfilling all of the requirements of the 2021 Notes registration rights agreement.

7.625% Senior Notes (the “2022 Notes”)

On November 26, 2013, the Company issued and sold $350.0 million in aggregate principal amount of 7.625% Senior Notes due January 15, 2022, in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 98.494 percent of par. The Company received net proceeds of approximately $337.4 million, net of discount, initial purchasers’ fees and expenses, which the Company used for general partnership purposes, to fund previously announced organic growth projects, the purchase price of the Bel-Ray acquisition and the redemption of $100.0 million in aggregate principal amount outstanding of 9.375% Senior Notes due 2019. Interest on the 2022 Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2014.

On November 26, 2013, in connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2022 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2022 Notes can offer to exchange the 2022 Notes for registered notes having substantially the same terms as the 2022 Notes and evidencing the same indebtedness as the 2022 Notes. On November 27, 2013, the Company filed an exchange offer registration statement for the 2022 Notes with the SEC, which was declared effective on December 10, 2013. The exchange offer was completed on January 13, 2014, thereby fulfilling all of the requirements of the 2022 Notes registration rights agreement.

2021 Secured Notes, 2021 Notes, 2022 Notes and 2023 Notes

In accordance with SEC Rule 3-10 of Regulation S-X, condensed consolidated financial statements of non-guarantors are not required. The Company has no assets or operations independent of its subsidiaries. Obligations under its 2021, 2022 and 2023 Notes are fully and unconditionally and jointly and severally guaranteed on a senior unsecured basis by the Company’s current 100%-owned operating subsidiaries and certain of the Company’s future operating subsidiaries, with the exception of the Company’s “minor” subsidiaries (as defined by Rule 3-10 of Regulation S-X), including Calumet Finance Corp. (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2021 Secured, 2021, 2022 and 2023 Notes). There are no significant restrictions on the ability of the Company or subsidiary guarantors for the Company to obtain funds from its subsidiary guarantors by dividend or loan. None of the subsidiary guarantors' assets represent restricted assets pursuant to SEC Rule 4-08(e)(3) of Regulation S-X.

The 2021 Secured, 2021, 2022 and 2023 Notes are subject to certain automatic customary releases, including the sale, disposition, or transfer of capital stock or substantially all of the assets of a subsidiary guarantor, designation of a subsidiary guarantor as unrestricted in accordance with the applicable indenture, exercise of legal defeasance option or covenant defeasance option, liquidation or dissolution of the subsidiary guarantor and a subsidiary guarantor ceases to both guarantee other Company debt and to be an obligor under the revolving credit facility. The Company's operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes.

The indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes contain covenants that, among other things, restrict the Company's ability and the ability of certain of the Company's subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company's common units or redeem or repurchase its subordinated debt or, in the case of the 2021 Secured Notes, its unsecured notes; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (vii) consolidate, merge or transfer all or substantially all of the Company's assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2021 Secured, 2021, 2022 and 2023 Notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's") or S&P Global Ratings ("S&P") and no Default or Event of Default, each as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes, has occurred and is continuing, many of these covenants will be suspended. As of December 31, 2017, the Company's Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes) was 1.7. As of December 31, 2017, the Company was in compliance with all covenants under the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes.

Second Amended and Restated Senior Secured Revolving Credit Facility

The Company has a $900.0 million senior secured revolving credit facility, subject to borrowing base limitations, which includes a $500.0 million incremental uncommitted expansion feature. Refer to Note 21 for additional information regarding the Company's revolving credit facility. The revolving credit facility is the Company's primary source of liquidity for cash needs in excess of cash generated from operations. The revolving credit facility matures in July 2019 and, as of December 31, 2017, bore interest at a rate equal to either the prime rate plus a basis points margin or the London Interbank Offered Rate ("LIBOR") plus a basis points margin, at the Company's option. As of December 31, 2017, the margin was 50 basis points for prime rate loans and 150 basis points for LIBOR rate loans; however, the margin can fluctuate quarterly based on the Company's average availability for additional borrowings under the revolving credit facility in the preceding fiscal quarter as follows:

Quarterly Average Availability Percentage	Margin on Base Rate Revolving Loans	Margin on LIBOR Revolving Loans
≥ 66%	0.50%	1.50%
≥ 33% and < 66%	0.75%	1.75%
< 33%	1.00%	2.00%

In addition to paying interest quarterly on outstanding borrowings under the revolving credit facility, the Company is required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to 0.250% or 0.375% per annum depending on the average daily available unused borrowing capacity for the preceding month. The Company also pays a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

The borrowing capacity at December 31, 2017, under the revolving credit facility was approximately $319.0 million. As of December 31, 2017, the Company had $0.2 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $67.3 million, leaving approximately $252.0 million available for additional borrowings based on specified availability limitations. Lenders under the revolving credit facility have a first priority lien on the Company's accounts receivable, inventory and substantially all of its cash (collectively, the "Credit Agreement Collateral").

On April 20, 2016, the Company and certain of its operating subsidiaries as borrowers (collectively, the "Borrowers") entered into a Second Amendment to Second Amended and Restated Credit Agreement (the "Second Amendment"), by and among the Borrowers, the Agent (as defined below) and the lenders party thereto (including Bank of America, N.A.), amending the Company's revolving credit facility. The Second Amendment, among other things, amended the revolving credit facility to permit (a) the issuance of the 2021 Secured Notes pursuant to the indenture governing the 2021 Secured Notes and (b) such 2021 Secured Notes to be secured by a lien on the Fixed Asset Collateral (as defined in the Intercreditor Agreement), subject to the terms of the Intercreditor Agreement.

On March 31, 2017, the Company amended its revolving credit facility to allow for the entry into the Supply and Offtake Agreements at the Great Falls refinery. The amendment resulted in the release of certain Eligible Inventory (as defined in the revolving credit agreement) from the revolving credit facility as that inventory is now collateral under the Supply and Offtake Agreements. For additional discussion of the Supply and Offtake Agreements, refer to Note 8.

The revolving credit facility contains various covenants that limit, among other things, the Company's ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates and enter into a merger, consolidation or sale of assets. Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company's availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $45.0 million (which amount is subject to increase in proportion to revolving commitment increases), then the Company will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0 until availability under the revolving credit facility exceeds the greater of the foregoing amounts for 30 consecutive days. See Note 21 for details of the third amended and restated credit agreement.

As of December 31, 2017, the Company was in compliance with all covenants under the revolving credit facility.

Master Derivative Contracts

The Company's payment obligations under all of the Company's master derivatives contracts for commodity hedging generally are secured by a first priority lien on the Company's real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). The Company had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 2017. The Company's master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on the Company's operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements.

Collateral Trust Agreement

In connection with the private placement of the 2021 Secured Notes, on April 20, 2016, the Company entered into an amended and restated collateral trust agreement (the "Collateral Trust Agreement") which governs how the holders of the 2021 Secured Notes and secured hedging counterparties share collateral pledged as security for the payment obligations owed by it to the holders of the 2021 Secured Notes and secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $150.0 million the extent to which forward purchase contracts for physical commodities are covered by, and secured under, the Collateral Trust Agreement and the Parity Lien Security Documents (as defined in the Collateral Trust Agreement). There is no such limit on financially settled derivative instruments used for commodity hedging. Subject to certain conditions set forth in the Collateral Trust Agreement, the Company has the ability to add secured hedging counterparties from time to time.

Intercreditor Agreement

The 2021 Secured Notes are not secured by the collateral securing the Company's revolving credit facility. In connection with the offering of the 2021 Secured Notes, the Collateral Trustee entered into a Second Amended and Restated Intercreditor Agreement (the "Intercreditor Agreement") among the Collateral Trustee, as fixed asset collateral trustee, Bank of America, N.A., as agent for the lenders under the Company's revolving credit facility (in such capacity, the “Agent”), the Company and the other grantors named therein, providing for certain access and administrative agreements with respect to the Credit Agreement Collateral and the Fixed Asset Collateral (as defined in the Intercreditor Agreement).

Related Party Note Payable

On December 30, 2015, the Company entered into an agreement with The Heritage Group, an affiliate of the Company’s general partner, in which The Heritage Group made a $27.0 million uncommitted prepayment for the purchase of certain finished products and entered into a $48.0 million unsecured note payable with the Company as the borrower. Imputed interest on the prepayment totaled $1.5 million. The note bore interest of 6.0%, with interest payments due on March 31, 2016, June 30, 2016, and July 31, 2016. Principal payments of $15.0 million each were due on May 31, 2016 and June 30, 2016, with the remaining principal amount due before July 31, 2016. The unsecured note payable and the uncommitted prepayment were fully repaid in 2016. The proceeds were used for general partnership purposes.

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Capital Leases

Assets recorded under capital lease obligations are included in property, plant and equipment and total $18.2 million and $51.3 million as of December 31, 2017 and 2016, respectively. As of December 31, 2017 and 2016, the Company had recorded $11.4 million and $7.5 million, respectively, in accumulated depreciation for capital lease assets.

On July 7, 2014, the Company entered into a capital lease agreement with TexStar Midstream Logistics, L.P. (“TexStar”) under which TexStar constructed, owns and operates a 30,000 bpd crude oil pipeline system supplying significant volumes of Eagle Ford crude oil to the Company’s San Antonio refinery for a term of 20 years. Thereafter, the agreement will continue on a month-to-month basis unless terminated by either party. Under the terms of the agreement, TexStar installed and operates the Karnes North Pipeline System (“KNPS”), a pipeline that transports crude oil from Karnes City, Texas, to the San Antonio refinery’s Elmendorf, Texas, terminal, a key supply hub for the San Antonio refinery. The Company expects to receive deliveries of at least 12,000 bpd of crude oil through the KNPS-Elmendorf terminal supply route. The pipeline became fully operational on November 1, 2014. The total gross obligation under this capital lease agreement as of December 31, 2017 and 2016 was $39.4 million. Total depreciation expense for this lease during each of the years ended December 31, 2017 and 2016, was $2.0 million.

As of December 31, 2017, the Company had estimated minimum commitments for the payment of total rentals under capital leases relating to continuing and discontinued operations as follows (in millions):

Year	Capital Leases
2018	$ 9.0
2019	7.4
2020	6.9
2021	6.9
2022	6.9
Thereafter	82.1
Total minimum lease payments	119.2
Less amount representing interest	75.2
Capital lease obligations	44.0
Less obligations due within one year	2.7
Long-term capital lease obligations	$ 41.3

Maturities of Long-Term Debt

As of December 31, 2017, principal payments on debt obligations and future minimum rentals on capital lease obligations are as follows (in millions):

Year	Maturity
2018	$354.1
2019	2.9
2020	2.4
2021	953.3
2022	351.2
Thereafter	361.9
Total	$2,025.8

10. Derivatives

The Company is exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in the Company’s fuel products segment), natural gas and precious metals. The Company uses various strategies to reduce its exposure to commodity price risk. The strategies to reduce the Company’s risk utilize both physical forward contracts and financially settled derivative instruments, such as swaps, collars, options and futures, to attempt to reduce the

Company's exposure with respect to:

- crude oil purchases and sales;
- fuel product sales and purchases;
- natural gas purchases;
- precious metals purchases; and

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- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI"), Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent ("Brent").

The Company manages its exposure to commodity markets, credit, volumetric and liquidity risks to manage its costs and volatility of cash flows as conditions warrant or opportunities become available. These risks may be managed in a variety of ways that may include the use of derivative instruments. Derivative instruments may be used for the purpose of mitigating risks associated with an asset, liability and anticipated future transactions and the changes in fair value of the Company's derivative instruments will affect its earnings and cash flows; however, such changes should be offset by price or rate changes related to the underlying commodity or financial transaction that is part of the risk management strategy. The Company does not speculate with derivative instruments or other contractual arrangements that are not associated with its business objectives. Speculation is defined as increasing the Company's natural position above the maximum position of its physical assets or trading in commodities, currencies or other risk bearing assets that are not associated with the Company's business activities and objectives. The Company's positions are monitored routinely by a risk management committee to ensure compliance with its stated risk management policy and documented risk management strategies. All strategies are reviewed on an ongoing basis by the Company's risk management committee, which will add, remove or revise strategies in anticipation of changes in market conditions and/or its risk profiles. Such changes in strategies are to position the Company in relation to its risk exposures in an attempt to capture market opportunities as they arise.

The Company is obligated to repurchase crude oil and refined products from Macquarie at the termination of the Supply and Offtake Agreements in certain scenarios. The Company has determined that the redemption feature on the initially recognized liability related to the Supply and Offtake Agreements is an embedded derivative indexed to commodity prices. As such, the Company has accounted for this embedded derivative at fair value with changes in the fair value, if any, recorded in gain (loss) on derivative instruments in the Company's consolidated statement of operations.

The Company recognizes all derivative instruments at their fair values (see Note 11) as either current assets or current liabilities in the consolidated balance sheets. Fair value includes any premiums paid or received and unrealized gains and losses. Fair value does not include any amounts receivable from or payable to counterparties, or collateral provided to counterparties. Derivative asset and liability amounts with the same counterparty are netted against each other for financial reporting purposes. The Company's financial results are subject to the possibility that changes in a derivative's fair value could result in significant ineffectiveness and potentially no longer qualify portions or all of its derivative instruments for hedge accounting.

The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets in the Company's consolidated balance sheets (in millions):

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Derivative instruments not designated as hedges:						
Specialty products segment:						
Natural gas swaps	$—	$ —	$ —	$0.1	$ (0.1)	$ —

Fuel products segment:						
Crude oil swaps	0.3	(0.3)	—	10.3	(7.4)	2.9
Crude oil basis swaps	—	—	—	—	(2.1)	(2.1)
Crude oil percentage basis swaps	—	—	—	0.1	(0.1)	—
Total derivative instruments	$0.3	$ (0.3)	$ —	$10.5	$ (9.7)	$ 0.8

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The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative liabilities in the Company's consolidated balance sheets (in millions):

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Derivative instruments not designated as hedges:						
Specialty products segment:						
Natural gas swaps	$—	$ —	$ —	$(1.2)	$ 0.1	$ (1.1)
Fuel products segment:						
Inventory financing obligation	(4.4)	—	(4.4)	—	—	—
Crude oil swaps	—	0.3	0.3	(8.2)	7.4	(0.8)
Crude oil basis swaps	—	—	—	(7.1)	2.1	(5.0)
Crude oil percentage basis swaps	—	—	—	(0.6)	0.1	(0.5)
Gasoline swaps	(0.2)	—	(0.2)	—	—	—
Gasoline crack spread swaps	(1.8)	—	(1.8)	(3.5)	—	(3.5)
Diesel swaps	(0.2)	—	(0.2)	—	—	—
Diesel crack spread swaps	(4.1)	—	(4.1)	(1.4)	—	(1.4)
2/1/1 crack spread swaps	—	—	—	(2.5)	—	(2.5)
Total derivative instruments	$(10.7)	$ 0.3	$ (10.4)	$(24.5)	$ 9.7	$ (14.8)

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of December 31, 2017, the Company had no counterparty relationship in which the derivatives held were net assets. As of December 31, 2016, the Company had one counterparty in which the derivatives held were net assets. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least A3 and BBB+ by Moody's and S&P, respectively. In the event of default, the Company would potentially be subject to losses on derivative instruments with mark-to-market gains. The Company requires collateral from its counterparties when the fair value of the derivatives exceeds agreed-upon thresholds in its master derivative contracts with these counterparties. No such collateral was held by the Company as of December 31, 2017 or 2016. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in prepaid expenses and other current assets on the Company's consolidated balance sheets and is not netted against derivative assets or liabilities. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability. As of December 31, 2017 and 2016, the Company had provided its counterparties with no collateral.

Certain of the Company's outstanding derivative instruments are subject to credit support agreements with the applicable counterparties which contain provisions setting certain credit thresholds above which the Company may be required to post agreed-upon collateral, such as cash or letters of credit, with the counterparty to the extent that the Company's mark-to-market net liability, if any, on all outstanding derivatives exceeds the credit threshold amount per such credit support agreement. The majority of the credit support agreements covering the Company’s outstanding derivative instruments also contain a general provision stating that if the Company experiences a material adverse change in its business, in the reasonable discretion of the counterparty, the Company’s credit threshold could be lowered by such counterparty. The Company does not expect that it will experience a material adverse change in its business.

The cash flow impact of the Company’s derivative activities is classified primarily as a change in derivative activity in the operating activities section in the consolidated statements of cash flows.

Derivative Instruments Designated as Cash Flow Hedges

Prior to 2017, the Company accounted for certain derivatives hedging purchases of crude oil and sales of gasoline and diesel as cash flow hedges. The derivative instruments designated as cash flow hedges that are hedging sales and purchases were recorded to sales and cost of sales, respectively, in the consolidated statements of operations upon recording the related hedged transaction

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in sales or cost of sales. During 2016, the Company reclassified a net gain of $6.4 million from other accumulated other comprehensive loss to net loss. There was no such activity in 2017.

Derivative Instruments Not Designated as Hedges

For derivative instruments not designated as hedges, the change in fair value of the asset or liability for the period is recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations. Upon the settlement of a derivative not designated as a hedge, the gain or loss at settlement is recorded to realized gain (loss) on derivative instruments in the consolidated statements of operations. The Company has entered into crude oil basis swaps that do not qualify as cash flow hedges for accounting purposes as they were not entered into simultaneously with a corresponding NYMEX WTI derivative contract. Additionally, the Company has entered into natural gas collars, natural gas swaps and certain other crude oil swaps that do not qualify as cash flow hedges for accounting purposes. However, these instruments provide economic hedges of the Company's crude oil and natural gas purchases and gasoline and diesel sales.

The Company recorded the following gains (losses) in its consolidated statements of operations related to its derivative instruments not designated as hedges (in millions):

	Amount of Gain (Loss) Recognized in Realized Loss on Derivative Instruments		Amount of Gain (Loss) Recognized in Unrealized Gain on Derivative Instruments	
	Year Ended December 31,		Year Ended December 31,	
Type of Derivative	2017	2016	2017	2016
Specialty products segment:				
Natural gas swaps	$ (3.6)	$ (11.3)	$ 1.0	$ 14.7
Fuel products segment:				
Inventory financing obligation	—	—	(4.4)	—
Crude oil swaps	(1.9)	5.3	(1.7)	7.3
Crude oil basis swaps	3.2	(4.1)	7.1	(5.9)
Crude oil percentage basis swaps	2.3	(4.3)	0.5	5.4
Crude oil options	—	(2.6)	—	0.3
Crude oil futures	—	(2.0)	—	—
Gasoline swaps	(0.6)	—	(0.2)	—
Gasoline crack spread swaps	(6.2)	(2.5)	3.0	(0.5)
Diesel swaps	(0.5)	—	(0.2)	—
Diesel crack spread swaps	(5.0)	(0.4)	(1.5)	(2.7)
2/1/1 crack spread swaps	(0.9)	(0.8)	—	—
Natural gas swaps	—	(1.3)	—	1.3
Total	$ (13.2)	$ (24.0)	$ 3.6	$ 19.9

Derivative Positions — Specialty Products Segment

Natural Gas Swap Contracts

At December 31, 2016, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2017	1,350,000	$ 3.88
Second Quarter 2017	1,320,000	$ 3.87

Third Quarter 2017	1,320,000	$ 3.87
Fourth Quarter 2017	960,000	$ 3.72
Total	4,950,000	
Average price		$ 3.85

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Derivative Positions — Fuel Products Segment
Crude Oil Swap Contracts
At December 31, 2017, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2018	28,000	311	$ 48.25
Total	28,000		
Average price			$ 48.25

At December 31, 2016, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2017	320,049	3,556	$ 48.87
Second Quarter 2017	323,605	3,556	$ 48.87
Third Quarter 2017	327,161	3,556	$ 48.87
Fourth Quarter 2017	327,161	3,556	$ 48.87
Total	1,297,976		
Average price			$ 48.87

At December 31, 2016, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	130,320	1,448	$ 41.56
Second Quarter 2017	131,768	1,448	$ 41.56
Third Quarter 2017	133,216	1,448	$ 41.56
Fourth Quarter 2017	133,216	1,448	$ 41.56
Total	528,520		
Average price			$ 41.56

Crude Oil Basis Swap Contracts
The Company entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between WCS and NYMEX WTI. At December 31, 2016, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2017	630,000	7,000	$ (13.22)
Second Quarter 2017	637,000	7,000	$ (13.22)
Third Quarter 2017	644,000	7,000	$ (13.22)
Fourth Quarter 2017	644,000	7,000	$ (13.22)

Total	2,555,000	
Average differential		$ (13.22)

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Crude Oil Percentage Basis Swap Contracts
The Company entered into derivative instruments to secure a percentage differential of WCS crude oil to NYMEX WTI. At December 31, 2016, the Company had the following derivatives related to crude oil percentage basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)
First Quarter 2017	270,000	3,000	72.3 %
Second Quarter 2017	273,000	3,000	72.3 %
Third Quarter 2017	276,000	3,000	72.3 %
Fourth Quarter 2017	276,000	3,000	72.3 %
Total	1,095,000		
Average percentage			72.3 %

Gasoline Crack Spread Swap Contracts
At December 31, 2017, the Company had the following derivatives related to gasoline crack spread sales in its fuel products segment, none of which are designated as hedges:

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2018	826,000	9,178	$ 12.27
Total	826,000		
Average price			$ 12.27

At December 31, 2016, the Company had the following derivatives related to gasoline crack spread sales in its fuel products segment, none of which are designated as hedges:

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 10.21
Total	590,000		
Average price			$ 10.21

Gasoline Swap Contracts
At December 31, 2017, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as hedges:

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2018	14,000	156	$ 61.35
Totals	14,000		
Average price			$ 61.35

Diesel Crack Spread Swap Contracts

At December 31, 2017, the Company had the following derivatives related to diesel crack spread sales in its fuel products segment, none of which are designated as hedges:

Diesel Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2018	826,000	9,178	$ 17.58
Total	826,000		
Average price			$ 17.58

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At December 31, 2016, the Company had the following derivatives related to diesel crack spread sales in its fuel products segment, none of which are designated as hedges:

Diesel Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 13.67
Total	590,000		
Average price			$ 13.67

Diesel Swap Contracts
At December 31, 2017, the Company had the following derivatives related to diesel sales in its fuel products segment, none of which are designated as hedges:

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2018	14,000	156	$ 66.35
Totals	14,000		
Average price			$ 66.35

2/1/1 Crack Spread Swap Contracts
At December 31, 2016, the Company had the following derivatives related to 2/1/1 crack spread sales in its fuel products segment, none of which are designated as hedges:

2/1/1 Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 11.91
Total	590,000		
Average price			$ 11.91

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

- Level 1 — inputs include observable unadjusted quoted prices in active markets for identical assets or liabilities
- Level 2 — inputs include other than quoted prices in active markets that are either directly or indirectly observable
- Level 3 — inputs include unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions

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

Derivative instruments are reported in the accompanying consolidated financial statements at fair value. The Company's derivative instruments consist of over-the-counter ("OTC") contracts, which are not traded on a public exchange. Substantially all of the Company's derivative instruments are with counterparties that have long-term credit ratings of at least A3 and BBB+ by Moody's and S&P, respectively.

To estimate the fair values of the Company's commodity derivative instruments, the Company uses the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. Various analytical tests are performed to validate the counterparty data. The fair values of the Company's derivative instruments are adjusted for nonperformance risk and creditworthiness of the hedging entities through the Company's credit valuation adjustment ("CVA"). The CVA is calculated at the counterparty level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. The Company uses the counterparty's marginal default rate and the Company's survival rate when the Company is in a net asset position at the payment date and uses the Company's marginal default rate and the counterparty's survival rate when the Company is in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2017, the Company's net liabilities changed by an immaterial amount. As a result of applying the CVA at December 31, 2016, the Company's net assets were increased by less than $0.1 million and net liabilities were reduced by approximately $0.5 million.

Observable inputs utilized to estimate the fair values of the Company's derivative instruments were based primarily on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, the Company has categorized these derivative instruments as Level 3. Significant increases (decreases) in any of those unobservable inputs in isolation would result in a significantly lower (higher) fair value measurement. The Company believes it has obtained the most accurate information available for the types of derivative instruments it holds. See Note 10 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value in the accompanying consolidated financial statements. At December 31, 2017, the Company's investments associated with its Pension Plan (as such term is hereinafter defined) primarily consisted of mutual funds. The mutual funds are valued at the net asset value ("NAV") of shares in each fund held by the Pension Plan at quarter end as provided by the respective investment sponsors or investment advisers. Plan investments can be redeemed within a short time frame (10 or so business days), if requested. See Note 14 for further information on pension assets.

Liability Awards

Unit based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units ("Liability Awards"). The Liability Awards are categorized as Level 1 because the fair value of the Liability Awards is based on the Company's quoted closing unit price as of each balance sheet date.

Renewable Identification Numbers Obligation

The Company's RINs Obligation is categorized as Level 2 and is measured at fair value using the market approach based on quoted prices from an independent pricing service. See Note 7 for further information on the Company's RINs Obligation.

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Hierarchy of Recurring Fair Value Measurements

The Company’s recurring assets and liabilities measured at fair value were as follows (in millions):

	December 31, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$—	$—	$—	$—	$2.9	$2.9
Crude oil basis swaps	—	—	—	—	—	—	(2.1)	(2.1)
Total derivative assets	—	—	—	—	—	—	0.8	0.8
Pension Plan investments	0.2	—	—	0.2	0.3	—	—	0.3
Total recurring assets at fair value	$0.2	$—	$—	$0.2	$0.3	$—	$0.8	$1.1
Liabilities:								
Derivative liabilities:								
Inventory financing obligation	$—	$—	$(4.4)	$(4.4)	$—	$—	$—	$—
Crude oil swaps	—	—	0.3	0.3	—	—	(0.8)	(0.8)
Crude oil basis swaps	—	—	—	—	—	—	(5.0)	(5.0)
Crude oil percentage basis swaps	—	—	—	—	—	—	(0.5)	(0.5)
Gasoline crack spread swaps	—	—	(1.8)	(1.8)	—	—	(3.5)	(3.5)
Gasoline swaps	—	—	(0.2)	(0.2)	—	—	—	—
2/1/1 crack spread swaps	—	—	—	—	—	—	(2.5)	(2.5)
Diesel swaps	—	—	(0.2)	(0.2)	—	—	—	—
Diesel crack spread swaps	—	—	(4.1)	(4.1)	—	—	(1.4)	(1.4)
Natural gas swaps	—	—	—	—	—	—	(1.1)	(1.1)
Total derivative liabilities	—	—	(10.4)	(10.4)	—	—	(14.8)	(14.8)
RINs Obligation	—	(59.1)	—	(59.1)	—	(79.3)	—	(79.3)
Liability Awards	(5.6)	—	—	(5.6)	—	—	—	—
Total recurring liabilities at fair value	$(5.6)	$(59.1)	$(10.4)	$(75.1)	$—	$(79.3)	$(14.8)	$(94.1)

The table below sets forth a summary of net changes in fair value of the Company’s Level 3 financial assets and liabilities (in millions):

	For the Year Ended December 31,	
	2017	2016
Fair value at January 1,	$(14.0)	$(33.9)
Realized loss on derivative instruments	13.2	24.0
Unrealized gain on derivative instruments	3.6	19.9
Settlements	(13.2)	(24.0)
Fair value at December 31,	$(10.4)	$(14.0)
Total gain included in net loss attributable to changes in unrealized gain relating to financial assets and liabilities held as of December 31,	$3.6	$19.9

All settlements from derivative instruments not designated as hedges are recorded in gain (loss) on derivative instruments in the consolidated statements of operations. See Note 10 for further information on derivative instruments.

Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of impairment.

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

generally be classified within Level 3, in the event that the Company were required to measure and record such assets at fair value within its consolidated financial statements. See Note 6 for further information on goodwill impairment.
The Company periodically evaluates the carrying value of long-lived assets to be held and used, including definite-lived intangible assets and property plant and equipment, when events or circumstances warrant such a review. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved and these assets would generally be classified within Level 3, in the event that the Company was required to measure and record such assets at fair value within its consolidated financial statements. See Note 2 for further information on long-lived asset impairment.
The Company received an equity interest in FHC in connection with the Anchor Transaction. The Company recorded the FHC investment at its estimated fair value as of November 21, 2017 using Level 3 inputs. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation and risks associated with the company.

Estimated Fair Value of Financial Instruments

Cash, cash equivalents and restricted cash

The carrying value of cash, cash equivalents and restricted cash is each considered to be representative of its fair value.

Debt

The estimated fair value of long-term debt at December 31, 2017 and 2016, consists primarily of senior notes. The estimated aggregate fair value of the Company's senior notes defined as Level 1 was based upon quoted market prices in an active market. The estimated aggregate fair value of the Company's senior secured notes classified as Level 2 was based upon directly observable inputs. The carrying value of borrowings, if any, under the Company's revolving credit facility, capital lease obligations, related party note payable and other obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. See Note 9 for further information on long-term debt.
The Company's carrying and estimated fair value of the Company's financial instruments, carried at adjusted historical cost, were as follows (in millions):

		December 31, 2017		December 31, 2016	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$1,576.5	$ 1,556.4	$1,334.1	$ 1,552.2
Senior notes	2	$456.4	$ 387.6	$458.8	$ 384.5
Revolving credit facility	3	$0.2	$ 0.2	$6.0	$ 6.0
Capital lease and other obligations	3	$50.6	$ 50.6	$54.5	$ 54.5

12. Partners' Capital

Units Outstanding

Of the 76,788,801 common units outstanding at December 31, 2017, 60,422,882 common units were held by the public, with the remaining 16,365,919 common units held by the Company's affiliates (including members of the Company's general partner and their families).
Significant information regarding rights of the limited partners includes the following:

- Rights to receive distributions of available cash within 45 days after the end of each quarter, to the extent the Company has sufficient cash from operations after the establishment of cash reserves.
- Limited partners have limited voting rights on matters affecting the Company's business. The general partner may consider only the interests and factors that it desires and has no duty or obligation to give any consideration of any interests of the Company's limited partners. Limited partners have no right to elect the board of directors of the

Company’s general partner.

- The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. Any holder, other than the general partner or the general partner’s affiliates, that owns 20% or more of any class of units outstanding cannot vote on any matter.
- The Company may issue an unlimited number of limited partner interests without the approval of the limited partners.

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- Limited partners may be required to sell their units to the general partner if at any time the general partner owns more than 80% of the issued and outstanding common units.

Distributions and Incentive Distribution Rights

The Company’s general partner is entitled to incentive distributions if the amount it distributes to unitholders with respect to any quarter exceeds specified target levels shown below:

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

The Company’s ability to make distributions is limited by its debt instruments. The revolving credit facility generally permits the Company to make cash distributions to unitholders as long as immediately after giving effect to such a cash distribution the Company has availability under the revolving credit facility at least the greater of (i) 15% of the Borrowing Base (as defined in the credit agreement) then in effect and (ii) $70.0 million (which amount is subject to increase in proportion to revolving commitment increases). Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company’s availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the credit agreement) then in effect and (b) $45.0 million (which amount is subject to increase in proportion to revolving commitment increases), the Company will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the credit agreement) of at least 1.0 to 1.0 until availability under the revolving credit facility exceeds the greater of the foregoing amounts for 30 consecutive days. The indenture governing the 2021 Secured Notes, which is the most restrictive indenture, provides that if the Company’s Fixed Charge Coverage Ratio (as defined in the indenture) for the most recently ended four full fiscal quarters is not less than 2.25 to 1.0, the Company will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in the Company’s partnership agreement) with respect to its preceding fiscal quarter, subject to certain customary adjustments described in the indenture. If the Company’s Fixed Charge Coverage Ratio for the most recently ended four full fiscal quarters is less than 2.25 to 1.0 but greater than 1.50 to 1.0, the Company will be able to pay distributions to its unitholders up to an amount equal to a $50.0 million basket. If the Company’s Fixed Charge Coverage Ratio is not greater than 1.50 to 1.0, the Company will be able to pay distributions to its unitholders in an amount less than Incremental Funds (as defined in the indenture) not previously expended for such distributions. The indenture related to the 2021 Secured Notes is outlined above as it remains the most restrictive of all senior notes indentures with respect to unitholder distributions.

The Company’s distribution policy is as defined in its partnership agreement. In April 2016, the board of directors of the Company’s general partner determined to suspend payment of the Company’s quarterly cash distribution to unitholders. The board of directors of the Company’s general partner will continue to evaluate the Company’s ability to reinstate the quarterly cash distribution. The Company made no distributions to its partners for the year ended December 31, 2017. For the years ended December 31, 2016 and 2015, the Company made distributions of $57.4 million and $224.6 million, respectively, to its partners. For the years ended December 31, 2017 and 2016, the general partner was allocated no incentive distribution rights. For the year ended 2015, the general partner was allocated $16.8 million in incentive distribution rights.

13. Unit-Based Compensation

The Company’s general partner originally adopted a Long-Term Incentive Plan on January 24, 2006, which was amended and restated effective December 10, 2015 (“LTIP”), for its employees, consultants and directors and its affiliates who perform services for the Company. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights (“DERs”). Subject to adjustment for certain events, an aggregate of 3,883,960 common units may be delivered pursuant to awards under the LTIP. Units withheld to satisfy the Company’s general partner’s tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the Company’s general partner’s board of directors.

Liability Awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units. Phantom unit Liability Awards are recorded in accrued salaries, wages and benefits in the consolidated balance sheets based on the vested portion of the fair value of the awards on the balance sheet date. The fair value of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to compensation expense within general and administrative expense in the consolidated statements of operations. As a result of the amendment and

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restatement of the LTIP on December 10, 2015, all Liability Awards at that point were modified to value the awards based upon the closing unit price on that date. This modification did not affect the remaining service period.

Phantom Units

Non-employee directors of the Company's general partner have been granted phantom units under the terms of the LTIP as part of their director compensation package related to fiscal years 2016 and 2015. These phantom units have a four year service period with one-quarter of the phantom units vesting annually on each December 31 of the vesting period. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest, the recipients have DERs on these phantom units from the date of grant.

For the years ended December 31, 2017, 2016 and 2015 named executive officers were awarded phantom units under the terms of the LTIP, as part of certain employment agreements and arrangements and as part of the Company's achievement of specified levels of financial performance in fiscal years 2017 and 2015. These phantom units are subject to time-vesting requirements whereby either 25% of the units vest during the fiscal year, and the remainder will vest ratably over the next three years on each December 31 or 100% of the phantom units vest in three years. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest, the recipients have DERs on these phantom units from the date of grant.

The Company uses the market price of its common units on the grant date to calculate the fair value and related compensation cost of the phantom units. The Company amortizes this compensation cost to partners' capital and general and administrative expense in the consolidated statements of operations using the straight-line method over the service period, as it expects these units to fully vest.

Performance Units

In 2017, the Company granted certain named executive officers and other executives performance units with market performance conditions. The award is eligible to vest during the period commencing January 1, 2017 and ending December 31, 2020. A portion of the performance units are equity-classified awards, in which the fair value was determined on the grant date by application of the Monte Carlo simulation model. In addition, a portion of the performance units are liability-classified awards and the fair value was determined by the market price of the Company's common units on the grant date to calculate. The Company amortizes this compensation over the service period only if the performance condition is considered probable of occurring.

A summary of the Company's non-vested phantom units and performance units as of December 31, 2017, and the changes during the years ended December 31, 2017, 2016 and 2015, are presented below:

	Number of Phantom Units	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2015	502,120	$ 26.48
Granted	343,533	21.70
Vested	(321,741)	23.54
Forfeited	(103,188)	23.94
Nonvested at December 31, 2015	420,724	$ 24.27
Granted	1,880,094	4.57
Vested	(1,455,131)	6.35
Forfeited	(90,854)	14.82
Nonvested at December 31, 2016	754,833	$ 9.58
Granted	2,753,507	4.10
Vested	(925,199)	7.30
Forfeited	(47,363)	9.73
Nonvested at December 31, 2017	2,535,778	$ 3.11

For the years ended December 31, 2017, 2016 and 2015, compensation expense of $11.6 million, $5.6 million and $7.5 million, respectively, was recognized in the consolidated statements of operations related to vested phantom unit grants, including $7.0 million and $5.0 million, attributable to Liability Awards for the years ended December 31, 2017 and 2015. There was no compensation expense attributable to Liability Awards for the year ended December 31, 2016. As of December 31, 2017 and 2016, there was a total of $7.9 million and $7.2 million, respectively, of unrecognized compensation costs related to non-vested phantom unit grants, including $3.3 million, attributable to Liability Awards for the year ended December 31, 2017. These costs are expected

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to be recognized over a weighted-average period of approximately 2 years. The total fair value of phantom units vested during the years ended December 31, 2017, 2016 and 2015, was $7.2 million, $5.8 million and $7.0 million, respectively.

14. Employee Benefit Plans

Defined Contribution Plan

The Company has a domestic defined contribution plan administered by its general partner for (i) all full-time employees that are eligible to participate in the plan (“401(k) Plan”). Participants in the 401(k) Plan are allowed to contribute 1% to 70% of their pre-tax earnings to the plan, subject to government imposed limitations. The Company matches 100% of each 1% of eligible compensation contributed by the participant up to 4% and 50% of each additional 1% of eligible compensation contributed up to 6%, for a maximum contribution by the Company of 5% of eligible compensation contributed per participant. The plan also includes a profit-sharing component for eligible employees. Contributions under the profit-sharing component are determined by the board of directors of the Company’s general partner and are discretionary. The funding policy is consistent with funding requirements of applicable laws and regulations.

The Company recorded the following 401(k) Plan matching contribution expense in the consolidated statement of operations (in millions):

	Year Ended December 31,		
	2017	2016	2015
401(k) Plan matching contribution expense	$5.7	$6.0	$5.0

Defined Benefit Pension Plan

The Company has domestic noncontributory defined benefit plans for those salaried employees as well as those employees represented by either the United Steelworkers (“USW”) or the International Union of Operating Engineers (“IUOE”); who (i) were formerly employees of Penreco and became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 (“Penreco Pension Plan”) or (ii) were formerly employees of Montana Refining Company, Inc. and who became employees of the Company as a result of the acquisition of the Great Falls refinery on October 1, 2012 (the “Great Falls Pension Plan” and together with the Penreco Pension Plan, the “Pension Plan”). The Company sold the Superior Refinery in 2017 and Husky assumed the retirement plan covering the Superior employees. Therefore, during 2017, the pension benefit obligation was reduced and certain applicable retirement plan assets were distributed to Husky related to the plan liabilities assumed by Husky. As a result of the completion of the sale of Superior Refinery, the Company was required to remeasure certain pension plan obligations, which resulted in immaterial impact to the consolidated statement of operations.

During 2017, the Company made contributions of $2.3 million to its Pension Plan and expects to make less than $0.1 million in 2018 to its Pension Plan.

Under the Penreco Pension Plan, benefits are based primarily on years of service for USW and IUOE represented employees and the employee’s final 60 months’ average compensation for salaried employees. In 2009, the Company amended the Penreco Pension Plan, which curtailed Penreco employees from accumulating additional benefits subsequent to December 31, 2009.

Under the Great Falls Pension Plan, benefits are based primarily on years of service and the employees’ 36 months’ highest average compensation for salaried employees. Effective October 1, 2012, the date of the acquisition of the Great Falls refinery, the Company amended the Montana Pension Plan, which curtailed only the Montana salaried employees from accumulating additional benefits subsequent to October 31, 2012. Effective August 31, 2015, the Company again amended the Great Falls Pension Plan, which curtailed the collective bargaining employees from accumulating additional benefits subsequent to December 31, 2015. As a result, the Company recorded $0.9 million curtailment gain for the year ended December 31, 2015. The Company recorded no curtailment gain for the years

ended December 31, 2017 and December 31, 2016.
Defined Benefit Other Plans
The Company also has domestic contributory defined benefit post-retirement medical plans and contributory life insurance plans for (i) those salaried employees, as well as those employees represented by either the International Brotherhood of Teamsters ("IBT") or USW, who were formerly employees of Penreco and who became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 ("Penreco Other Plan"). The funding policy is consistent with funding requirements of applicable laws and regulations.
Effective 2009, the Company amended the Penreco Other Plan, which curtailed employees from accumulating additional benefits subsequent to February 28, 2009. The long-term accrued benefit obligation recognized in the consolidated balance sheets for the Penreco Other Plan was $0.2 million as of December 31, 2017 and 2016. In addition, there was no other post-retirement benefit income related to this plan for years ended December 31, 2017 and 2016.

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All information presented below has been adjusted for these curtailments for the Pension Plan. The change in the benefit obligations, change in the plan assets, funded status and amounts recognized in the consolidated balance sheets were as follows (in millions):

	Year Ended December 31, 2017	2016
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$60.9	$60.3
Service cost	0.1	0.1
Interest cost	2.3	2.5
Plan settlements	—	(0.6)
Benefit payments	(2.5)	(2.5)
Actuarial loss	4.2	1.1
Reduction due to sale of the Superior Refinery	(26.6)	—
Administrative expense	(0.1)	—
Benefit obligation at end of year	$38.3	$60.9
Change in plan assets:		
Fair value of plan assets at beginning of year	$49.8	$47.5
Plan settlements	—	(0.6)
Benefit payments	(2.5)	(2.5)
Actual return on assets	7.4	3.8
Employer contribution	2.3	1.6
Administrative expense	$(0.1)	$—
Distribution to acquirer of the Superior Refinery	(21.5)	—
Fair value of plan assets at end of year	$35.4	$49.8
Funded status — benefit obligation in excess of plan assets	$(2.9)	$(11.1)
Reconciliation of amounts recognized in the consolidated balance sheets:		
Accrued benefit obligation, long-term	$(2.9)	$(11.1)
Unrecognized net actuarial loss	6.0	7.1
Accumulated other comprehensive loss	6.0	7.1
Net amount recognized at end of year	$3.1	$(4.0)

The accumulated benefit obligation for the Pension Plan was $38.3 million and $60.9 million as of December 31, 2017 and 2016, respectively. Selected information for the Company’s Pension Plan with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31, 2017	2016
Accumulated benefit obligation	$ 38.3	$ 60.9
Fair value of plan assets	$ 35.4	$ 49.8

Selected information for the Company’s Pension Plan with projected benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31, 2017	2016
Projected benefit obligation	$ 38.3	$ 60.9

Fair value of plan assets	$ 35.4	$ 49.8

The components of net periodic benefit cost (income) were as follows (in millions):

	Pension Plan Year Ended December 31,		
	2017	2016	2015
Service cost	$0.1	$0.1	$0.5
Interest cost	2.3	2.5	2.6
Expected return on assets	(2.9)	(3.2)	(3.3)
Amortization of net loss	0.2	0.1	0.8
Settlement loss recognized	0.7	—	—
Curtailment gain recognized	—	—	(0.9)
Net periodic benefit cost (income)	$0.4	$(0.5)	$(0.3)

The components of changes recognized in other comprehensive (income) loss for the Pension Plan were as follows (in millions):

	Pension Plan Year Ended December 31,		
	2017	2016	2015
Changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:			
Net (gain) loss	$(0.2)	$0.4	$(4.3)
Amounts recognized as a component of net periodic benefit cost:			
Amortization or settlement recognition of net loss	(0.9)	(0.1)	(0.8)
Total recognized in other comprehensive (income) loss	$(1.1)	$0.3	$(5.1)

The portion relating to the Pension Plan classified in accumulated other comprehensive loss includes losses of $6.0 million and $7.1 million as of December 31, 2017 and 2016, respectively. In 2018, the estimated amount that will be amortized from accumulated other comprehensive loss includes a net loss of $0.1 million for the Pension Plan.

For the Pension Plan, the Company uses a corridor approach to amortize actuarial gains and losses. Under this approach, net actuarial gains or losses in excess of ten percent of the larger of the projected benefit obligation or the fair value of plan assets are amortized on a straight-line basis. The period of amortization is the average remaining service of active participants who are expected to receive benefits under the plans.

All pension plans have a December 31 measurement date. The significant weighted average assumptions used to determine the benefit obligations for the years ended December 31, 2017 and 2016, were as follows:

	Benefit Obligations Assumptions	
	2017	2016
Discount rate for Penreco Pension Plan	3.56%	4.08%
Discount rate for Superior Pension Plan	N/A	4.06%
Discount rate for Great Falls Pension Plan	3.54%	4.04%

The significant weighted average assumptions used to determine the net periodic benefit cost (income) for the years ended December 31, 2017, 2016 and 2015 were as follows:

	Net Periodic Benefit (Income) Cost Assumptions		
	2017	2016	2015

Discount rate for Penreco Pension Plan	4.08%	4.30%	3.92%
Discount rate for Superior Pension Plan	4.06%	4.27%	3.86%
Discount rate for Great Falls Pension Plan	4.04%	4.21%	4.13%
Expected return on plan assets for Penreco Pension Plan (1)	6.35%	6.75%	6.75%
Expected return on plan assets Superior Pension Plan (1)	6.35%	6.75%	6.75%
Expected return on plan assets for Great Falls Pension Plan (1)	6.35%	6.75%	6.75%
Rate of compensation increase for Great Falls Pension Plan	N/A	N/A	3.00%

(1) The Company considered the historical returns, the future expectation for returns for each asset class and fair value of the plan assets, as well as the target asset allocation of the Pension Plan portfolio which was developed in accordance with the Company's Statement of Investment Policy, to develop the expected long-term rate of return on plan assets.

Investment Policy

The Defined Benefit Plan Investment Committee (the "Investment Committee") is responsible for the overall management of the Pension Plan assets, and its responsibilities encompass establishing the investment strategies and policies, monitoring the management of plan assets, reviewing the asset allocation mix on a regular basis, monitoring the performance of the Pension Plan assets to determine whether the investments objectives are met and guidelines followed and taking the appropriate action if objectives are not followed. The Company uses different investment managers with various asset management objectives to eliminate any significant concentration of risk. The Investment Committee believes there are no significant concentrations of risks associated with the investment assets. The Company's investment manager will assist in the continual assessment of assets and the potential reallocation of certain investments and will evaluate the selection of investment managers for the Pension Plan assets based on such factors as organizational stability, depth of resources, experience, investment strategy and process, performance expectations and fees.

Long-term strategic investment objectives utilize a diversified mix of equity and fixed income securities to preserve the funded status of the trusts, and balance risk and return in relationship to the respective liabilities. The primary investment strategy currently employed is a dynamic de-risking strategy that periodically rebalances among various investment categories depending on the current funded position and maximizes the effectiveness of the Pension Plan asset allocation strategy. This program is designed to actively move from return-seeking investments (such as equities) toward liability-hedging investments (such as fixed income) as funding levels improve.

Effective June 2013, all of the Pension Plan assets were invested in a Master Trust. Trust assets in the Pension Plan are invested subject to the policy restriction that the average quality of the fixed income portfolio must be rated at least investment grade by both Moody's and S&P. These assets are invested in accordance with prudent expert standards as mandated by the Employee Retirement Income Security Act ("ERISA"). The Pension Plan's target asset allocation is currently comprised of the following:

Asset Class	Range of Asset Allocation	Target Allocation
Domestic equities	15–25%	20%
Foreign equities	15–25%	20%
Fixed income	55–65%	60%

Investment Fund Strategies

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

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

The Company’s Pension Plan asset allocations, as of December 31, 2017 and 2016, by asset category, are as follows:

	2017	2016
Cash and cash equivalents	1 %	1 %
Domestic equities	12 %	17 %
Foreign equities	12 %	17 %
Fixed income	75 %	65 %
	100 %	100 %

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At December 31, 2017, the Company's investments associated with its Pension Plan primarily consisted of (i) cash and cash equivalents and (ii) mutual funds. Mutual funds are valued based on the NAV per share (or its equivalent) as a practical expedient to estimate fair value due to the absence of readily available market prices. NAV's are provided by the respective investment sponsors or investment advisers and are subsequently reviewed and approved by management. In the event management concludes a reported NAV does not reflect fair value or is not determined as of the financial reporting measurement date, the Company will consider whether and when deemed necessary to make an adjustment at the balance sheet date. In determining whether an adjustment to the external valuation is required, the Company will review material factors that could affect the valuation, such as changes to the composition or performance of the underlying investments or comparable investments, overall market conditions, expected sale prices for private investments which are probable of being sold in the short-term and other economic factors that may possibly have a favorable or unfavorable effect on the reported external valuation. See Note 11 for the definition of Level 1.

The Company's Pension Plan assets measured at fair value, were as follows (in millions):

	Fair Value of Pension Assets at December 31,			
	2017		2016	
	Level 1	Total	Level 1	Total
Cash and cash equivalents	$0.2	$0.2	$0.3	$0.3
Total plan assets subject to leveling	$0.2	0.2	$0.3	0.3
Plan assets measured at net asset value				
Domestic equities		4.3		8.6
Foreign equities		4.4		8.7
Fixed income		26.5		32.2
Total plan assets measured at net asset value		35.2		49.5
Total plan assets		$35.4		$49.8

The following benefit payments for the Pension Plan, which reflect expected future service, as appropriate, are expected to be paid in the years indicated as of December 31, 2017 (in millions):

	Pension Benefits
2018	$ 1.6
2019	1.7
2020	1.8
2021	1.9
2022	1.9
2023 to 2027	10.7
Total	$ 19.6

15. Accumulated Other Comprehensive Income (Loss)

The table below sets forth a summary of changes in accumulated other comprehensive income (loss) by component for the years ended December 31, 2017 and 2016 (in millions):

	Derivatives	Defined Benefit Pension And Retiree	Foreign Currency Translation Adjustment	Total

		Health Benefit Plans		
Accumulated other comprehensive income (loss) at December 31, 2015	$ 6.4	$ (6.8)	$ (1.2)	$(1.6)
Other comprehensive loss before reclassifications	—	(0.4)	—	(0.4)
Amounts reclassified from accumulated other comprehensive income (loss)	(6.4)	0.1	—	(6.3)
Net current period other comprehensive loss	(6.4)	(0.3)	—	(6.7)
Accumulated other comprehensive loss at December 31, 2016	$ —	$ (7.1)	$ (1.2)	$(8.3)
Other comprehensive income before reclassifications	—	0.2	—	0.2
Amounts reclassified from accumulated other comprehensive loss	—	0.9	—	0.9
Net current period other comprehensive income	—	1.1	—	1.1
Accumulated other comprehensive loss at December 31, 2017	$ —	$ (6.0)	$ (1.2)	$(7.2)

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The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive loss in the Company's consolidated statements of operations for the years ended December 31, 2017 and 2016 (in millions):

Components of Accumulated Other Comprehensive Loss	2017	2016	Location of Gain (Loss)
Derivative gains (losses) reflected in gross profit			
	$ —	$ 59.7	Sales
	—	(53.3)	Cost of sales
	$ —	$ 6.4	Total
Amortization of defined benefit pension benefit plans:			
Amortization or settlement recognition of net loss	$ (0.9)	$ (0.1)	[1]
	$ (0.9)	$ (0.1)	Total

(1) This accumulated other comprehensive loss component is included in the computation of net periodic pension cost. See Note 14 for additional information.

16. Income Taxes

The Company, as a partnership, is generally not liable for federal and state income taxes on the earnings of Calumet Specialty Products Partners, L.P. and its wholly-owned subsidiaries. However, the Company conducts certain activities through immaterial, wholly-owned subsidiaries that are corporations, which in certain circumstances are subject to federal, state and local income taxes. Additionally, the Company is subject to franchise taxes in certain states. Income taxes on the earnings of the Company, with the exception of the above mentioned taxes, are the responsibility of its partners, with earnings of the Company included in partners' earnings.

On December 22, 2017, the President of the United States signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act") that makes significant changes to the U.S. Internal Revenue Code. Among other changes, the Tax Act includes a new deduction on certain pass-through income, a repeal of the partnership technical termination rule, and new limitations on certain deductions and credits, including interest expense deductions. Since the operations of a partnership are not subject to federal income tax, and most provisions of the Tax Act are effective for tax years beginning after December 31, 2017, the legislation has no material impact to the Company for 2017. The Company is in the process of analyzing the Tax Act and its possible effect going forward, as it will impact allocations to unitholders.

For the year ended December 31, 2017, an income tax benefit of $0.1 million, as compared to an income tax expense of $0.2 million for the years ended December 31, 2016 and 2015.

As a result of the Company's analysis, management has determined that the Company does not have any uncertain tax positions.

17. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit (in millions, except unit and per unit data):

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

	Year Ended December 31,		
	2017	2016	2015
Numerator for basic and diluted earnings per limited partner unit:			
Net loss from continuing operations	$(31.3)	$(296.8)	$(85.4)
Less:			
General partner's interest in net loss from continuing operations	(0.6)	(6.0)	(1.7)
General partner's incentive distribution rights	—	—	16.8
Net loss from continuing operations available to limited partners	$(30.7)	$(290.8)	$(100.5)
Net loss from discontinued operations available to limited partners	(71.0)	(31.2)	(52.9)
Net loss available to limited partners	$(101.7)	$(322.0)	$(153.4)
Denominator for basic and diluted earnings per limited partner unit:			
Weighted average limited partner units outstanding [(1)]	77,598,950	77,043,935	74,896,096
Limited partners' interest basic and diluted net loss per unit:			
From continuing operations	$(0.40)	$(3.77)	$(1.34)
From discontinued operations	(0.91)	(0.41)	(0.71)
Limited partners' interest	$(1.31)	$(4.18)	$(2.05)

(1) Total diluted weighted average limited partner units outstanding excludes 0.2 million, 0.5 million and 0.4 million potentially dilutive phantom units which would be antidilutive for the years ended December 31, 2017, 2016 and 2015, respectively.

18. Transactions with Related Parties

During the years ended December 31, 2017, 2016 and 2015, the Company had product sales to related parties, excluding the transactions discussed below, of $37.9 million, $13.1 million and $12.0 million, respectively. Trade accounts and other receivables from related parties at December 31, 2017 and 2016 were $0.3 million and $1.1 million, respectively. The Company also had purchases from related parties, excluding transactions discussed below, during the years ended December 31, 2017, 2016 and 2015 of $7.1 million, $6.4 million and $5.0 million, respectively. Accounts payable to related parties, excluding accounts payable related to the transactions discussed below, at December 31, 2017 and 2016, were $3.1 million and $1.5 million, respectively.

The general partner employs all of the Company's employees and the Company reimburses the general partner for certain of its expenses.

The Company had a general services master services agreement with a third party construction company related to the Great Falls refinery expansion project in which various construction related services were performed during 2016 and 2015. This third party was related to refinery management. For the years ended December 31, 2016 and 2015, the Company had capital expenditures of $10.4 million and $43.0 million, respectively, for construction related services. The Company had no capital expenditures and no accounts payable for 2017. Accounts payable under this contract at December 31, 2016 were $2.5 million.

During 2015, the Company entered into an agreement for logistic administration/support, general administrative management and fiscal administration services with Monument Chemical, Inc. ("Monument Chemical"). Monument Chemical is owned by a limited partner and a member of the board of the Company's general partner is a member of Monument Chemical's management. Under this agreement, Monument Chemical rents storage tanks in Belgium on the Company's behalf and organizes delivery of products to the Company's customers. A commission is paid to Monument Chemical based on the sales value invoiced to the Company's customers. For the years ended December 31, 2017 and

2016, the Company paid total commissions and general administrative fees of $1.2 million and $1.3 million, respectively. Accounts payable under this contract at December 31, 2017 and 2016 were immaterial.
During the years ended December 31, 2016 and 2015, the Company entered into various transactions with Dakota Prairie. See Note 5 for further information on Dakota Prairie transactions.
During 2016, the Company entered into a joint venture agreement with The Heritage Group. See Note 5 for further information on the joint venture with The Heritage Group.

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On December 30, 2015, the Company entered into an agreement with The Heritage Group in which The Heritage Group made an uncommitted prepayment for the purchase of certain finished products and entered into an unsecured note payable with the Company as the borrower. See Note 9 for further information on this agreement.

19. Segments and Related Information

a. Segment Reporting

The Company manages its business in two operating segments, which are grouped on the basis of similar product, market and operating factors into the following reportable segments:

- Specialty Products. The specialty products segment produces a variety of lubricating oils, solvents, waxes, synthetic lubricants and other products which are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. Specialty products also include synthetic lubricants used in manufacturing, mining and automotive applications.
- Fuel Products. The fuel products segment produces primarily gasoline, diesel, jet fuel and asphalt which are primarily sold to customers located in the PADD 2 and PADD 4 areas within the U.S.

Prior to the sale of Anchor, as disclosed in Note 3, the Company reported an oilfield services segment, which was solely comprised of Anchor. As a result of Anchor's classification as a discontinued operation, the Company has removed the oilfield services segment.

The accounting policies of the reporting segments are the same as those described in the summary of significant accounting policies as disclosed in Note 2, except that the disaggregated financial results for the reporting segments have been prepared using a management approach, which is consistent with the basis and manner in which management internally disaggregates financial information for the purposes of assisting internal operating decisions. The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. The Company evaluates performance based upon Adjusted EBITDA (a non-GAAP financial measure). The Company defines Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense (including debt issuance and extinguishment costs); (b) income taxes; (c) depreciation and amortization; (d) impairment; (e) unrealized losses from mark to market accounting for hedging activities; (f) realized gains under derivative instruments excluded from the determination of net income (loss); (g) non-cash equity-based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (h) debt refinancing fees, premiums and penalties, (i) any net loss realized in connection with an asset sale that was deducted in computing net income (loss) and (j) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

The Company manages its assets on a total company basis, not by segment. Therefore, management does not review any asset information by segment and, accordingly, the Company does not report asset information by segment.

Reportable segment information is as follows (in millions):

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

Year Ended December 31, 2017	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,300.4	$2,463.4	$3,763.8	$ —	$ 3,763.8
Intersegment sales	0.2	54.8	55.0	(55.0)	—
Total sales	$1,300.6	$2,518.2	$3,818.8	$ (55.0)	$ 3,763.8
Adjusted EBITDA	$186.5	$127.8	$314.3	$ —	$ 314.3
Reconciling items to net loss:					
Depreciation and amortization	70.5	108.6	179.1	—	179.1
Impairment charges	60.3	147.0	207.3	—	207.3
Gain on sale of business	—	(236.0)	(236.0)	—	(236.0)
Unrealized gain on derivatives					(3.6)
Interest expense					183.1
Non-cash equity-based compensation and other items					15.8
Income tax benefit					(0.1)
Net loss from continuing operations					$ (31.3)

Year Ended December 31, 2016	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,252.3	$2,222.0	$3,474.3	$ —	$ 3,474.3
Intersegment sales	2.5	34.5	37.0	(37.0)	—
Total sales	$1,254.8	$2,256.5	$3,511.3	$ (37.0)	$ 3,474.3
Loss from unconsolidated affiliates	$(0.3)	$(18.0)	$(18.3)	$ —	$ (18.3)
Adjusted EBITDA	$188.9	$(10.1)	$178.8	$ —	$ 178.8
Reconciling items to net loss:					
Depreciation and amortization	74.7	110.5	185.2	—	185.2
Realized gain (loss) on derivatives, not reflected in net loss or settled in a prior period	1.9	(8.3)	(6.4)	—	(6.4)
Impairment charges	1.9	34.0	35.9	—	35.9
Loss on sale of unconsolidated affiliate	—	113.9	113.9	—	113.9
Unrealized gain on derivatives					(19.9)
Interest expense					161.7
Non-cash equity-based compensation and other items					5.0
Income tax expense					0.2
Net loss from continuing operations					$ (296.8)

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

Year Ended December 31, 2015	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,367.8	$2,562.5	$3,930.3	$ —	$ 3,930.3
Intersegment sales	2.9	39.1	42.0	(42.0)	—
Total sales	$1,370.7	$2,601.6	$3,972.3	$ (42.0)	$ 3,930.3
Loss from unconsolidated affiliates	$—	$(61.1)	$(61.1)	$ —	$ (61.1)
Adjusted EBITDA	$201.7	$81.9	$283.6	$ —	$ 283.6
Reconciling items to net loss:					
Depreciation and amortization	69.2	82.4	151.6	—	151.6
Realized loss on derivatives, not reflected in net loss or settled in a prior period	(3.0)	(7.0)	(10.0)	—	(10.0)
Impairment charges	—	24.3	24.3	—	24.3
Unrealized loss on derivatives					39.5
Interest expense					104.9
Debt extinguishment costs					46.6
Non-cash equity-based compensation and other items					11.9
Income tax expense					0.2
Net loss from continuing operations					$ (85.4)

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three years ended December 31, 2017, 2016 and 2015. Substantially all of the Company's long-lived assets are domestically located.

c. Product Information

The Company offers specialty products primarily in categories consisting of lubricating oils, solvents, waxes, packaged and synthetic specialty products and other. Fuel products categories primarily consist of gasoline, diesel, jet fuel, asphalt, heavy fuel oils and other. The following table sets forth the major product category sales for each segment (dollars in millions):

	Year Ended December 31, 2017		2016		2015	
Specialty products:						
Lubricating oils	$584.2	15.5 %	$538.7	15.5 %	$575.6	14.6 %
Solvents	274.4	7.3 %	237.7	6.8 %	302.0	7.7 %
Waxes	117.2	3.1 %	128.7	3.7 %	136.9	3.5 %
Packaged and synthetic specialty products	260.7	6.9 %	244.7	7.0 %	261.5	6.7 %
Other	63.9	1.7 %	102.5	3.0 %	91.8	2.3 %
Total	1,300.4	34.5 %	1,252.3	36.0 %	1,367.8	34.8 %
Fuel products:						
Gasoline	948.5	25.2 %	844.3	24.3 %	1,047.1	26.6 %
Diesel	877.9	23.4 %	808.4	23.3 %	894.8	22.8 %
Jet fuel	135.0	3.6 %	117.5	3.4 %	149.6	3.8 %
Asphalt, heavy fuel oils and other	502.0	13.3 %	451.8	13.0 %	471.0	12.0 %
Total	2,463.4	65.5 %	2,222.0	64.0 %	2,562.5	65.2 %
Consolidated sales	$3,763.8	100.0%	$3,474.3	100.0%	$3,930.3	100.0%

d. Major Customers

During the years ended December 31, 2017, 2016 and 2015, the Company had no customer that represented 10% or greater of consolidated sales.

e. Major Suppliers

During the years ended December 31, 2017, 2016 and 2015, the Company had two suppliers that supplied approximately 65.7%, 64.5% and 52.2%, respectively, of its crude oil supply.

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

20. Quarterly Financial Data (Unaudited)

The table below sets forth selected quarterly financial data for each of the last two fiscal years (in millions, except unit and per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
2017					
Sales	$ 886.5	$ 967.0	$ 1,026.5	$ 883.8	$ 3,763.8
Gross profit	129.5	143.7	127.7	97.3	498.2
Net income (loss) from continuing operations	1.5	12.0	(26.1)	(18.7)	(31.3)
Net income (loss) from discontinued operations	(7.7)	(2.4)	2.5	(64.9)	(72.5)
Net income (loss)	(6.2)	9.6	(23.6)	(83.6)	(103.8)
Net income (loss) available to limited partners	(6.1)	9.2	(23.1)	(81.9)	(101.7)
Limited partners' interest basic and diluted net income (loss) per unit:					
From continuing operations	$ 0.02	$ 0.15	$ (0.33)	$ (0.24)	$ (0.40)
From discontinued operations	(0.10)	(0.03)	0.03	(0.82)	(0.91)
Limited partners' interest	$ (0.08)	$ 0.12	$ (0.30)	$ (1.06)	$ (1.31)
Basic weighted average limited partner units outstanding	77,412,634	77,554,815	77,632,784	77,784,534	
Diluted weighted average limited partner units outstanding	78,259,909	77,714,112	77,931,605	77,784,534	

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
2016					
Sales	$ 680.6	$ 951.6	$ 932.3	$ 909.8	$ 3,474.3
Gross profit	80.3	130.5	103.0	72.5	386.3
Net loss from continuing operations	(56.9)	(135.3)	(33.1)	(71.5)	(296.8)
Net loss from discontinued operations	(10.8)	(12.6)	(0.3)	(8.1)	(31.8)
Net loss	(67.7)	(147.9)	(33.4)	(79.6)	(328.6)
Net loss available to limited partners	(66.3)	(145.0)	(32.7)	(78.0)	(322.0)
Limited partners' interest basic and diluted net loss per unit:					
From continuing operations	$ (0.73)	$ (1.73)	$ (0.42)	$ (0.91)	$ (3.77)
From discontinued operations	(0.14)	(0.16)	—	(0.10)	(0.41)
Limited partners' interest	$ (0.87)	$ (1.89)	$ (0.42)	$ (1.01)	$ (4.18)
Basic and diluted weighted average limited partner units outstanding	76,449,841	76,761,504	77,331,347	77,351,593	

[1] The sum of the four quarters may not equal the total year due to rounding.

21. Subsequent Events

Revolving Credit Facility

On February 23, 2018, the Borrowers entered into a Third Amended and Restated Credit Agreement (the "Third Amendment") with Bank of America, N.A., as a lender and Agent for the lenders, and certain other lenders (with Bank of America, N.A., the "Lenders"). The Third Amendment provides a $600.0 million senior secured revolving credit facility limited by a borrowing base calculation and has an aggregate letter of credit sublimit of $300.0 million, which may be increased with Agent consent to up to 90% of the revolver commitments. The revolving credit facility includes

a $25.0 million senior secured first loaned in and last to be repaid out ("FILO") revolving credit facility.
The Third Amendment authorizes incremental uncommitted expansion features in an aggregate of up to $500.0 million pursuant to an increase in the revolver commitments. The Third Amendment also authorizes incremental uncommitted foreign subsidiary credit facilities of up to $50.0 million. The aggregate amount of such incremental revolving loans and foreign subsidiary incremental facilities cannot exceed $500.0 million.

Lenders under the Third Amendment have a first priority lien on, among other things, the Company’s accounts receivable and inventory and substantially all of its cash. The Third Amendment matures on February 18, 2023. The Company may be required to make mandatory prepayments under certain conditions.

2021 Secured Notes

On March 8, 2018, the Company issued a press release announcing that it has called for redemption of all of the 2021 Secured Notes. The redemption date for the Notes is April 9, 2018, and holders will receive a redemption price of 100.0% of the principal amount of the 2021 Secured Notes, plus accrued and unpaid interest thereon up to, but not including, the Redemption Date, plus a Make Whole Premium (as defined in the Indenture, dated April 20, 2016, governing the 2021 Secured Notes).

Form 12b-25

On March 19, 2018, the Company filed a Form 12b-25 with the Securities and Exchange Commission on the basis that the Company had determined that it was unable to file this Annual Report on Form 10-K for the year ended December 31, 2017 by March 16, 2018, the due date for such filing, without unreasonable effort or expense.

Renewable Identification Numbers

In March 2018, the EPA granted the Company’s fuel products refineries a “small refinery exemption” under the RFS for the full-year 2017, as provided for under the CAA. This exemption included the Superior Refinery for which the Company retained the RINs Obligation for 2017 up to the closing date of the sale of the refinery to Husky. In granting those exemptions, the EPA determined that for the full-year 2017, compliance with the RFS would represent a “disproportionate economic hardship” for these refineries.

Acquisition

On March 23, 2018, the Company and Heritage Group, a related party, acquired Biosynthetic Technologies, LLC (“Biosynthetic Technologies”), a startup company which developed an intellectual property portfolio for the manufacture of renewable-based and biodegradable esters for $7.0 million. The purchase price was split 50/50 between the Company and Heritage Group. The Company intends to develop and commercialize the renewable esters and is designing a commercial scale test at its existing esters manufacturing plant in Missouri.

Fair Value

The fair value of the Company’s senior notes has decreased by approximately $34.0 million subsequent to December 31, 2017.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure
None.
Item 9A. Controls and Procedures
Evaluation of Disclosure Controls and Procedures
As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), as amended, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective as of December 31, 2017 at the reasonable assurance level due to the material weaknesses described below. Notwithstanding these material weaknesses, management concluded that the consolidated financial statements included in this Annual Report present fairly, in all material respects, the financial position of the Company at December 31, 2017 in conformity with GAAP and our external auditors have issued an unqualified opinion on our consolidated financial statements as of and for the year ended December 31, 2017.
Management’s Report on Internal Control Over Financial Reporting
The management of Calumet Specialty Products Partners, L.P. (the “Company”) is responsible for establishing and maintaining adequate internal control over financial reporting. The Company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company’s assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.
Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2017, based on criteria for effective internal control over financial reporting described in “Internal Control - Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (“COSO”). During the quarter ended September 30, 2017, we identified two material weaknesses in internal control over financial reporting, which continue to exist as of December 31, 2017. The ERP system implementation resulted in business and operational interruptions and have resulted in a pervasive material weakness in the financial statement close process as of December 31, 2017. The material weaknesses are as follows:
•The ineffective design and implementation of effective controls with respect to the implementation of our enterprise resource planning (“ERP”) system consistent with our financial reporting requirements. Specifically, management did not exercise sufficient corporate governance and oversight, design effective controls over the ERP implementation to ensure appropriate data conversion and data integrity, or provide sufficient end user training to our employees to ensure that our employees could effectively operate the system and carry out their responsibilities.

•The ineffective design and maintenance of information technology (“IT”) general controls for the ERP system that are relevant to the preparation of our financial statements. Specifically, we did not (i) maintain adequate user access controls to ensure appropriate segregation of duties and to adequately restrict access to financial applications and data; and (ii) maintain program change management controls to ensure that IT program and data changes affecting financial IT applications and underlying accounting records were tested, approved and implemented appropriately.
•The untimely and insufficient operation of controls in the financial statement close process, specifically lack of timely account reconciliation, analysis and review related to all financial statement accounts.

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These material weaknesses resulted in not having adequate automated and manual controls designed and in place and not achieving the intended operating effectiveness of those controls impacting all financial statement accounts and disclosures.

Based on our assessment, we have concluded that internal control over financial reporting was not effective as of December 31, 2017.

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

Planned Remediation Efforts to Address Material Weaknesses

In order to remediate these material weaknesses and further strengthen the overall controls surrounding information systems, we are taking the following steps to improve the overall processes and controls:

- Corporate Governance and Oversight - We hired a new Chief Accounting Officer in September 2017 who has significant SAP and ERP implementation experience to help enhance the capabilities of existing management to oversee the ongoing work being completed to help stabilize the ERP system and oversee the key enhancements needed to enable us to realize the value of the system. We are seeking to augment this capability by hiring an experienced ERP change management person to drive the changes that will be required to realize the value from the system. We have further re-organized the IT organization to better equip the team to manage the changes that will be required to enhance the ERP system.
- Data Integrity and Data Conversion - We continue to perform validations on data included in the new ERP system.
- End User Training - To reinforce the importance of our control environment across the company, we are developing and providing additional training to employees to enhance their understanding of the new ERP system so that they can effectively operate the system.
- User Access IT General Controls - We are addressing segregation of duties conflicts in addition to developing controls so that appropriate system access rights are granted to system users and controls related to routine reviews of user system access. In addition, we have implemented a new delegation of authority policy.
- Program Change IT General Controls - We are developing a more robust process for the initiation, testing and approval of change activities.
- Financial Statement Close Process - We are reviewing, analyzing, and properly documenting our processes related to internal controls over financial reporting. We are designing and implementing effective review and approval controls. We are also designing and implementing effective review and approval controls over account reconciliations, journal entries, and management estimates across our remaining internal control processes. These controls will address the accuracy and completeness of the data used in the performance of the respective control.

The Company started the remediation process outlined above prior to September 30, 2017. When fully implemented and operational, we believe the measures described above will remediate the control deficiencies that have led to the material weaknesses we have identified and strengthen our internal controls over financial reporting. We are committed to continuing to improve our internal control processes and we will continue to review our financial reporting controls and procedures. As we continue to evaluate and work to improve our internal controls over financial reporting, we may determine to take additional measures to address control deficiencies or modify certain activities of the remediation measures described above.

Changes in Internal Control over Financial Reporting

On September 1, 2017, we implemented an ERP system on a company-wide basis, which is expected to improve the efficiency of certain financial and related transaction processes. The implementation resulted in business and operational interruptions and the three material weaknesses identified above. As discussed above, we believe we have developed an appropriate plan to remediate and have begun our remediation efforts related to the material weaknesses. With the exception of the foregoing remediation actions and the changes described in the previous section, there have been no changes in our internal control over financial reporting during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of Calumet GP, LLC
General Partner and the Partners of Calumet Specialty Products Partners, L.P.

Opinion on Internal Control over Financial Reporting

We have audited Calumet Specialty Products Partners, L.P.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, because of the effect of the material weaknesses described below on the achievement of the objectives of the control criteria, Calumet Specialty Products Partners, L.P. (the Company) has not maintained effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.
A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment. Management has identified material weaknesses related to (i) the ineffective design and implementation of effective controls with respect to the implementation of the organization's enterprise resource planning ("ERP") system (ii) the ineffective design and maintenance of information technology general controls for the ERP system that are relevant to the preparation of financial statements and (iii) the untimely and insufficient operation of controls in the financial statement close process, specifically lack of timely account reconciliation, analysis and review related to all financial statement accounts.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's consolidated balance sheets as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive loss, partners' capital and cash flows for each of the three years in the period ended December 31, 2017, and the related notes. These material weaknesses were considered in determining the nature, timing and extent of audit tests applied in our audit of the 2017 consolidated financial statements, and this report does not affect our report dated April 2, 2018, which expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP
Indianapolis, Indiana
April 2, 2018

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Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers of Our General Partner and Corporate Governance

Management of Calumet Specialty Products Partners, L.P. and Director Independence

Our general partner, Calumet GP, LLC, manages our operations and activities. Unitholders are limited partners and are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. Our general partner owes a fiduciary duty to our unitholders, as limited by the various provisions of our partnership agreement modifying and restricting the fiduciary duties that might otherwise be owed by our general partner to our unitholders.

The directors of our general partner oversee our operations. The owners of our general partner have appointed seven members to our general partner's board of directors. The directors of our general partner are generally elected by a majority vote of the owners of our general partner on an annual basis. However, as long as our executive vice chairman of our general partner, F. William Grube, and trusts, established for the benefit of his family members or Permitted Transferees (as defined in our partnership agreement), continue to own at least 30% of the membership interests in our general partner, Mr. Grube (or in certain specified instances, his designee or transferee) has the right to serve as a director of our general partner. The directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified.

Pursuant to Section 4360 of the NASDAQ Stock Market, LLC Marketplace Rules ("NASDAQ Rules"), a listed limited partnership like us is not required to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/governance committee. However, three of our general partner's seven directors are "independent" as that term is defined in the NASDAQ Rules and Rule 10A-3 of the Exchange Act. In determining the independence of each director, our general partner has adopted standards that incorporate the NASDAQ Rules and Exchange Act standards. Our general partner's independent directors as determined in accordance with those standards are: James S. Carter, Robert E. Funk and Stephen P. Mawer.

The officers of our general partner manage the day-to-day affairs of our business. Officers serve at the discretion of the board of directors.

Directors and Executive Officers

The following table shows information regarding the directors and executive officers of Calumet GP, LLC as of April 2, 2018:

Name	Age	Position with Calumet GP, LLC
Fred M. Fehsenfeld, Jr.	67	Chairman of the Board
F. William Grube	70	Executive Vice Chairman
Timothy Go	51	Chief Executive Officer
D. West Griffin	57	Executive Vice President — Chief Financial Officer
Bruce A. Fleming	61	Executive Vice President — Strategy & Growth
Christopher H. Bohnert	51	Chief Accounting Officer
William A. Anderson	49	Executive Vice President — Sales
James S. Carter	69	Director
Robert E. Funk	72	Director
Stephen P. Mawer	53	Director
Daniel J. Sajkowski	58	Director
Amy M. Schumacher	47	Director

Each director's biographical information set forth below includes the particular experience and qualifications that led the board of directors to conclude that the director is qualified to serve in such capacity.

Fred M. Fehsenfeld, Jr. has served as the chairman of the board of our general partner since September 2005. Mr. Fehsenfeld also served as the vice chairman of the board of our Predecessor from 1990 until our initial public offering. Mr. Fehsenfeld has worked for The Heritage Group in various capacities since 1977 and has served as its managing trustee since 1980. Mr. Fehsenfeld received his B.S. in mechanical engineering from Duke University and his M.S. in management from the Massachusetts Institute of Technology Sloan School.

As co-founder of our Predecessor, Mr. Fehsenfeld has an extensive knowledge base regarding the Company's operations and has participated in all major strategic decision making for the Company and our Predecessor since their inception. In his role as managing trustee of The Heritage Group, Mr. Fehsenfeld serves in lead executive roles, including the role of chairman and chief executive officer, for a multitude of different companies within The Heritage Group, providing a breadth of experience in leadership and management across a wide variety of industries, including energy. Since 2008, Mr. Fehsenfeld has served as chairman of the board of directors of Heritage-Crystal Clean, Inc., a publicly-traded environmental services company which is owned in part by The Heritage Group. Mr. Fehsenfeld is the father of Amy M. Schumacher, member of the board of directors of our general partner.

F. William Grube has served as the executive vice chairman of the board of our general partner since April 2015. From January 2011 through April 2015, Mr. Grube served as chief executive officer and vice chairman of the board of our general partner. From September 2005 through December 2010, Mr. Grube served as chief executive officer, president and director of our general partner. Mr. Grube has also served as president and chief executive officer of our Predecessor from 1990 until our initial public offering. From 1973 to 1989, Mr. Grube served as executive vice president of Rock Island Refining Corporation. Mr. Grube received his B.S. in chemical engineering from Rose-Hulman Institute of Technology and his M.B.A. from Harvard University.

As co-founder of our Predecessor and through his role as prior chief executive officer, Mr. Grube possesses unique experience relative to the management of the Company on a day-to-day basis over a significant time period and across all functional areas of the Company. Mr. Grube has significant technical expertise in refining developed over the course of his career, with both the Company and our Predecessor, as well as another refining company which specialized in the production of fuel products.

Timothy Go has served as chief executive officer of our general partner since January 2016. Prior to joining the Company, Mr. Go served as vice president — operations of Flint Hills Resources, LP, a wholly owned subsidiary of Koch Industries, Inc., since July 2013. From 2011 through 2013, Mr. Go served as vice president — operations excellence of Flint Hills Resources, LP. From August 2008 through 2011, Mr. Go served as managing director — operations excellence of Koch Industries, Inc. Mr. Go received a B.S. in chemical engineering from the University of Texas at Austin.

D. West Griffin has served as executive vice president and chief financial officer of our general partner since January 2017. Prior to joining the Company, Mr. Griffin was a founder and served as the chief financial officer of Energy XXI (Bermuda) Limited (also known as Energy XXI Ltd.) from 2005 to 2014. In 2004, Mr. Griffin served as chief financial officer of Alon USA. From 1999 through 2002, Mr. Griffin served as chief financial officer of InterGen North America. Mr. Griffin received his B.E. and his M.B.A from Dartmouth College.

Bruce A. Fleming has served as executive vice president — strategy & growth of our general partner since March 2016. Prior to joining the Company, Mr. Fleming served as the vice president of mergers & acquisitions at Tesoro Corporation and as an officer of Tesoro Companies Inc. since 2004. From 1997 through 2004, Mr. Fleming served as managing director of Hong Kong-based Orient Refining Ltd., and from 1981 through 1996 he held senior operations, business development and planning roles with Amoco Oil and Amoco Corporation where he was most recently vice president of China business development. Mr. Fleming earned a Ph.D. in chemical engineering from Princeton University and a B.S. in chemical engineering from the University of Delaware. He is a member of the Board of M&A Standards.

Christopher H. Bohnert has served as the chief accounting officer of our general partner since September 2017. Prior to joining the Company, Mr. Bohnert, served as chief accounting officer of Titan International, Inc. since 2015. From 2014 to 2015, Mr. Bohnert served as chief financial officer and vice president, finance at Silgan Plastics, a plastic packaging manufacturer and, from 2005-2012, he served as chief financial officer of AB Mauri North America, a bakery ingredient manufacturer. Mr. Bohnert received his B.S. in economics and accounting from the University of Missouri (Columbia) and a Master’s in accountancy from the University of South Carolina.

William A. Anderson has served as executive vice president — sales of our general partner since October 2014. From October 2012 through October 2014, Mr. Anderson served as vice president — marketing and new products. From September 2005 through September 2012, Mr. Anderson served as vice president — sales of our general partner. Mr. Anderson served as vice president — sales and marketing of our Predecessor from 2000 until our initial public offering and served in various other capacities from 1993 to 2000. Mr. Anderson received his B.A. in communications from DePauw University.

James S. Carter has served as a member of the board of directors of our general partner since January 2006. Mr. Carter worked in various capacities at ExxonMobil including vice president of U.S. marketing and sales of fuels and specialty products, manager of U.S. refining and marketing planning and analysis, manager of U.S. distribution activities, analysis manager of ExxonMobil International, and advisor to ExxonMobil headquarters for European refining and marketing until his retirement in 2003. Mr. Carter is a member of the Association of Audit Committee Members, Inc. Mr. Carter received his B.S. in mechanical engineering from Clemson University and his M.B.A. in finance and accounting from Tulane University.

Mr. Carter brings extensive marketing and managerial experience with one of the largest integrated energy companies in the world. He possesses a broad background in petroleum products marketing, with specific experience in the marketing of fuel products.

Robert E. Funk has served as a member of the board of directors of our general partner since January 2006. Mr. Funk previously served as vice president — corporate planning and economics of CITGO Petroleum Corporation, a refiner and marketer of transportation fuels, lubricants, petrochemicals, refined waxes, asphalt and other industrial products, from 1997 until his retirement in December 2004. Mr. Funk previously served CITGO or its predecessor, Cities Services Company, as general manager — facilities planning from 1988 to 1997, general manager — lubricants operations from 1983 to 1988 and manager — refinery east, Lake Charles refinery from 1982 to 1983. Mr. Funk received his B.S. in chemical engineering from the University of Kansas.

Mr. Funk has extensive refining industry experience including planning, operations and managerial roles for a large multinational refining company. His broad background of experience provides helpful insight to the Company in its implementation of strategic initiatives and its refinery operations in general.

Stephen P. Mawer has served as a board member of our general partner since March 2016. He retired as president of Koch Supply & Trading in 2014 following a 27-year career in commodities trading, risk management and refining operations. While at Koch, Mr. Mawer led global commodities trading and served as a senior member of the Koch Industries management team. Mr. Mawer holds Bachelor’s and Master’s degrees in chemical engineering from the University of Cambridge, England. Currently, he serves as a member of the Board of Directors at Zenith Energy Management, a midstream company.

Mr. Mawer brings extensive knowledge of petroleum markets, refining economics, supply/marketing optimization and risk management

Daniel J. Sajkowski has served as a member of the board of directors of our general partner since September 2014. Mr. Sajkowski has served as executive vice president, growth and new ventures of The Heritage Group since 2013. Prior to joining The Heritage Group, Mr. Sajkowski was the senior director — downstream technology at Sapphire Energy from 2010 until 2013. From 2004 to 2010, Mr. Sajkowski served as business unit leader at BP’s Whiting, Indiana refinery. During his career with BP/Amoco, Mr. Sajkowski also held positions as the manager of integrated supply and trading from 2002 until 2004 and vice president of refining technology from 2000 until 2002. Mr. Sajkowski earned his B.S. and M.S. degrees in chemical engineering from the University of Michigan and a Ph.D. in chemical engineering from Stanford University. He also completed the General Manager Program at Harvard University.

Mr. Sajkowski has extensive refining industry experience including planning, operations and managerial roles for a large multinational refining company. His broad background of experience provides helpful insight to the Company in its implementation of strategic initiatives and its refinery operations in general.

Amy M. Schumacher has served as a member of the board of directors of our general partner since September 2014. Ms. Schumacher has served as the president of Monument Chemicals, Inc. and Haltermann Solutions since 2010. In addition, in July 2016, Ms. Schumacher assumed the role of president of The Heritage Group. Prior to joining Monument Chemicals, Inc. and Haltermann Solutions, Ms. Schumacher worked in various capacities for The Heritage Group leading a variety of growth projects from 2003 until 2010. From 1998 to 2003, Ms. Schumacher was a consultant with Accenture. Ms. Schumacher received her B.S. in civil engineering from Purdue University and her M.S. in management from the Massachusetts Institute of Technology Sloan School. Ms. Schumacher currently serves as a trustee for The Heritage Group and sits on a number of private subsidiary boards. Ms. Schumacher is the daughter of Fred M. Fehsenfeld, Jr., the chairman of the board of our general partner.

Ms. Schumacher has extensive managerial experience including planning and strategy. She possesses a broad background within the chemicals industry, with specific experience in strategic growth projects.

Board of Directors Committees

Conflicts Committee

Two members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be owners, officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by NASDAQ and the Exchange Act to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. The two independent board members who serve on the conflicts committee are Messrs. James S. Carter and Robert E. Funk. Mr. Funk serves as the chairman of the conflicts committee.

Compensation Committee

The board of directors of our general partner also has a compensation committee which, among other responsibilities, has overall responsibility for evaluating and either approving or recommending to the board of directors the director, chief executive officer and senior executive compensation plans, policies and programs of the Company. NASDAQ does not require a limited partnership like us to have a compensation committee comprised entirely of independent directors. Accordingly, Messrs. Fred M. Fehsenfeld, Jr., Stephen P. Mawer and Amy M. Schumacher serve as members of our compensation committee. Mr. Mawer serves as the chairman of the compensation committee.

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The board of directors has adopted a written charter for the compensation committee which defines the scope of the committee's authority. The committee may form and delegate some or all of its authority to subcommittees comprised of committee members when it deems appropriate. The committee is responsible for reviewing and recommending to the board of directors for its approval the annual salary and other compensation components for the chief executive officer. The committee reviews and makes recommendations to the board of directors for its approval of any of the Company's equity compensation-based plans, including the Long-Term Incentive Plan, or any cash bonus or incentive compensation plans or programs. Also, the committee reviews and approves all annual salary and other compensation arrangements and components for the senior executives of the Company. Further, the compensation committee periodically reviews and makes a recommendation to the board of directors for changes in the compensation of all directors. The committee has the authority to retain or terminate any compensation consultant that assists it in the evaluation of director and senior executive compensation and to obtain independent advice and assistance from internal and external legal, accounting and other advisors.

See Item 11 "Executive and Director Compensation — Compensation Discussion and Analysis — Peer Group and Compensation Targets" for additional discussion regarding the results of this executive compensation review.

Audit Committee

The board of directors of our general partner has an audit committee comprised of three directors, Messrs. James S. Carter, Robert E. Funk and Stephen P. Mawer, each of whom the board of directors of our general partner has determined meets the independence and experience standards established by NASDAQ and the SEC. In addition, the board of directors of our general partner has determined that Mr. Carter is an "audit committee financial expert" as defined by the SEC. Mr. Carter serves as the chairman of the audit committee.

The board of directors has adopted a written charter for the audit committee. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approves all auditing services and related fees and the terms thereof and pre-approves any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee.

Risk Committee

The board of directors of our general partner has established a risk committee which, among other responsibilities, oversees the Company's risk assessment practices. Messrs. Robert E. Funk, Stephen P. Mawer and Daniel J. Sajkowski serve as members of our risk committee. Mr. Sajkowski serves as the chairman of the risk committee. The board of directors has adopted a written charter for the risk committee which defines the scope of the committee's authority.

Strategy and Growth Committee

The board of directors of our general partner has established a strategy and growth committee which, among other responsibilities, oversees our (i) long-term strategy, (ii) risks and opportunities relating to such strategy, (iii) strategic decisions regarding investments, mergers, acquisitions and divestitures, (iv) capitalization, (v) ownership structure and (vi) distribution policy. Messrs. Fred M. Fehsenfeld, Jr., F. William Grube, Robert E. Funk and Stephen P. Mawer serve as members of the strategy and growth committee. The board of directors has adopted a written charter for the strategy and growth committee which defines the scope of the committee's authority.

Talent and Leadership Development Committee

The board of directors of our general partner has established a talent and leadership development committee which, among other responsibilities, monitors our strategic, long-term, and sustainable approach to talent and development issues relating to people. Ms. Amy M. Schumacher serves as the chairwoman and sole member of the talent and leadership development committee. The board of directors has adopted a written charter for the talent and leadership development committee which defines the scope of the committee's authority.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all directors, officers, employees and contractors.

Available on our website at www.calumetspecialty.com are copies of our board of directors committee charters and Code of Business Conduct and Ethics, all of which also will be provided to unitholders without charge upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana, 46214.

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires Calumet's directors and certain executive officers, as well as beneficial owners of ten percent or more of Calumet's common units, to report their holdings and transactions in Calumet's securities. Based on information furnished to Calumet and contained in reports filed pursuant to Section 16(a), as well as written representations that no other reports were required for 2017, Calumet's directors and executive officers filed all reports required by Section 16(a) with the exception of (i) one late filing related to the vesting of phantom units into common units on December 20, 2017, for Timothy Go and (ii) one late filing related to the vesting of phantom units into common units delivered on December 20, 2017, for Christopher H. Bohnert.

Item 11. Executive and Director Compensation

Compensation Discussion and Analysis

Overview

For purposes of this Compensation Discussion and Analysis and the compensation tables that follow, the names and positions of our named executive officers for the 2017 fiscal year were:

- Timothy Go — Chief Executive Officer
- F. William Grube — Executive Vice Chairman of the Board
- D. West Griffin — Executive Vice President — Chief Financial Officer
- R. Patrick Murray, II — former Vice President — Special Projects
- Bruce A. Fleming — Executive Vice President — Strategy & Growth
- William A. Anderson — Executive Vice President — Sales

Mr. Griffin was appointed executive vice president and chief financial officer effective January 5, 2017. Mr. Murray served as executive vice president and chief financial officer through January 5, 2017. Mr. Murray transitioned into a new role of vice president, chief accounting officer and assistant secretary beginning on January 5, 2017 and transitioned again to a new role of vice president - specialty projects in April 2017. Mr. Murray's employment with the Company ended on November 1, 2017. Due to certain SEC disclosure requirements, Mr. Murray is included herein.

The compensation committee of the board of directors of our general partner oversees our compensation programs. Our general partner maintains compensation and benefits programs designed to allow us to attract, motivate and retain the best possible employees to manage us, including executive compensation programs designed to reward the achievement of both short-term and long-term goals necessary to promote growth and generate positive unitholder returns. Our general partner's executive compensation programs are based on a pay-for-performance philosophy, including measurement of our performance against specified financial targets including Adjusted EBITDA and net indebtedness (as defined below). Our executive compensation programs include both long-term and short-term compensation elements which, together with base salary and employee benefits, constitute a total compensation package intended to be competitive with similar companies.

Under their collective authority, the compensation committee and the board of directors maintain the right to develop and modify compensation programs and policies as they deem appropriate. Factors they may consider in making decisions to materially increase or decrease compensation include our overall financial performance, our growth over time, our changes in complexity as well as individual executive job scope, complexity and performance, and changes in competitive compensation practices in our defined labor markets. In determining any forms of compensation other than the base salary for the senior executives, or in the case of the chief executive officer, the recommendation to the board of directors of the forms of compensation for the chief executive officer, the compensation committee considers our financial performance and relative unitholder return, the value of similar incentive awards to senior executives at comparable companies and the awards given to senior executives in past years.

Financial Performance Metric Used in Compensation Programs

Our primary business objectives are to generate cash flows and reduce debt levels. As a result, our Adjusted EBITDA is the primary measurement of performance taken into account in setting policies and making compensation decisions, as we believe this represents the most comprehensive measurement of our ability to generate cash flows. Both short-term and long-term forms of executive compensation are specifically structured on our achievement relative to annual Adjusted EBITDA and ratio of net debt to Adjusted EBITDA goals and, as such, determination of related awards, as well as their grant or payment, occurs subsequent to the end of each fiscal year upon final determination of Adjusted EBITDA and net indebtedness (defined below). We believe that including these financial objectives as the primary performance measurements to determine compensation awards for all of our executive officers recognizes the integrated and collaborative effort required by the full executive team to maximize performance. Adjusted EBITDA is a non-GAAP measure that we define, consistent with the terms of our revolving credit agreement and senior notes indentures. The most directly comparable GAAP performance measure for Adjusted EBITDA is Net income

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(loss). Please refer to Part II, Item 6 "Selected Financial Data — Non-GAAP Financial Measures" for our definition of Adjusted EBITDA.

"Net Indebtedness" is defined as any indebtedness of the Company, whether or not contingent, (i) in respect of borrowed money; (ii) evidenced by bonds, notes, debentures or similar instruments; (iii) in respect of all outstanding letters of credit issued for the account of Company that support obligations that constitute indebtedness (provided that the amount of such included letters of credit shall not exceed the amount of the indebtedness being supported) and, without duplication, the unreimbursed amount of all drafts drawn under letters of credit issued for the account of the Company; (iv) in respect of bankers' acceptances; (v) representing capital lease obligations; (vi) representing the balance deferred and unpaid of the purchase price of any property, except any such balance that constitutes an accrued expense or trade payable; or (vii) representing any obligations under swap contracts; if and to the extent any of the preceding items (other than letters of credit and obligations under swap contracts) would appear as a liability on the Company's balance sheet prepared in accordance with GAAP, less any cash and cash equivalents on Company's balance sheet prepared in accordance with GAAP. In addition, indebtedness includes all indebtedness of other persons secured by a lien on any of the Company's assets (whether or not such indebtedness is assumed by the Company) and, to the extent not otherwise included, the Company's guarantee of any other person's or entity's indebtedness. For the avoidance of doubt, indebtedness excludes any obligation arising from any agreement providing for indemnities, purchase price adjustments, holdbacks, contingency payment obligations based on the performance of the acquired or disposed assets or similar obligations (other than guarantees of indebtedness) incurred by the Company in connection with its acquisition or disposition of assets.

Peer Comparisons and Outside Consultants

To evaluate all areas of executive compensation, from time to time the compensation committee seeks the additional input of outside compensation consultants and available comparative information to validate that the compensation programs established for our executives are consistent with the philosophy of compensating our executives at ranges that approximate within 10% of the 25th percentile of market for companies of similar size to us. The compensation committee most recently retained Buck Consultants, LLC ("Buck Consultants") in 2016 as an independent consultant to review our general partner's executive compensation programs and the Buck Consultants review indicated that aggregate target total direct compensation of our key executives, which includes all the major elements of our executive compensation program, including base salary, short-term incentives and long-term compensation, was within the 25th percentile of market by approximately 25%. The compensation committee did not engage any outside consultants with respect to the 2017 year compensation decisions.

Review of Named Executive Officer Performance

The compensation committee reviews, on an annual basis, each compensation element for a named executive officer. In each case, the compensation committee takes into account the scope of responsibilities and experience and balances these against competitive salary levels. The compensation committee has the opportunity to meet with the named executive officers at various times during the year, which allows the compensation committee to form its own assessment of each individual's performance.

Objectives of Compensation Programs

Our executive compensation programs are designed with the following primary objectives:

- reward strong individual performance that drives our positive financial results;
- make incentive compensation a significant portion of an executive's total compensation, designed to balance short-term and long-term performance;
- align the interests of our executives with those of our unitholders; and
- attract, develop and retain executives with a compensation structure that is competitive with other publicly-traded partnerships of similar size.

Elements of Executive Compensation

The compensation committee believes the total compensation and benefits program for our named executive officers should consist of the following:

- base salary;

- annual incentive plan which includes short-term cash awards and also includes an optional deferred compensation element;
- long-term incentive compensation, including unit-based awards;
- retirement, health and welfare benefits; and
- perquisites.

These elements are designed to constitute an integrated executive compensation structure meant to incentivize a high level of individual executive officer performance in line with our financial and operating goals.

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Base Salary

Design. Salaries provide executives with a base level of semi-monthly income as consideration for fulfillment of certain roles and responsibilities. The salary program assists us in achieving our objective of attracting and retaining the services of quality individuals who are essential for the growth and profitability of Calumet. Generally, changes in the base salary levels for our named executive officers are determined on an annual basis by the compensation committee of the board of directors and are effective at the beginning of the following fiscal year.

Results. The 2017 and 2016 base salaries for Messrs. Go, Grube, Griffin, Murray, Fleming and Anderson are as follows:

	2017 Base Salary	2016 Base Salary
Timothy Go	$500,000	$500,000
F. William Grube	$454,363	$454,363
D. West Griffin	$400,000	-
R. Patrick Murray, II	$353,067	$353,067
Bruce F. Fleming	$385,000	$350,000
William A. Anderson	$325,130	$325,130

Compensation Changes for 2018. With respect to our named executive officers, the compensation committee approved increased salaries for certain executives as part of its annual salary review process. Effective January 1, 2018, the base salaries were increased for Messrs. Griffin, Fleming and Anderson to $412,008, $398,475 and $333,259, respectively.

Short-Term Cash Bonus Awards

Design. Under the Annual Bonus Program Cash Incentive Compensation Plan (the “Cash Incentive Plan”), short-term cash bonus awards are designed to aid us in retaining and motivating executives to assist us in meeting our financial performance objectives on an annual basis. Short-term cash awards are granted to named executive officers (other than Mr. Grube) and certain other management employees based on our achievement of performance targets on the ratio of Net Indebtedness to Adjusted EBITDA. Mr. Grube received an award based on Adjusted EBITDA performance targets. We chose performance metrics that were applicable to all named executive officers. We believe each of these goals establishes a direct link between executive compensation and our financial performance.

The compensation committee establishes minimum, target and stretch incentive opportunities for each executive officer and other key employees expressed as a percentage of base salary. The amount that is paid out is based on our achievement of a minimum, target or stretch level of Adjusted EBITDA or ratio of Net Indebtedness to Adjusted EBITDA during the fiscal year, as applicable. The compensation committee may determine whether the applicable performance period will be a full calendar year or a specific portion of a calendar year, depending upon our incentive goals for the short-term cash awards for that year. At the recommendation of the compensation committee, the board of directors approves Adjusted EBITDA and ratio of Net Indebtedness to Adjusted EBITDA targets for each performance period based on budgets prepared by management. When making the annual determination of the minimum goal, target goal and stretch goal levels of Adjusted EBITDA and ratio of Net Indebtedness to Adjusted EBITDA, the compensation committee and the board of directors consider the specific circumstances facing us during the relevant year. Generally, the compensation committee seeks to set the minimum goal, target goal and stretch goal levels such that the relative challenge of achieving each level is consistent from year to year. The expectation that management will achieve the minimum goal level is high, while meaningful additional effort would be required to achieve the target goal and considerable additional effort would be required to achieve the stretch goal.

Generally, no awards are paid under the Cash Incentive Plan unless we achieve at least the minimum Adjusted EBITDA or ratio of Net Indebtedness to Adjusted EBITDA goal, as applicable. If the minimum, target or stretch level Adjusted EBITDA or ratio of Net Indebtedness to Adjusted EBITDA goal is achieved, participants in the plan will receive their minimum, target or stretch cash award opportunity, respectively. If our Adjusted EBITDA or ratio of Net Indebtedness to Adjusted EBITDA is between specified goal levels, participants are eligible to receive a prorated

percentage of their cash award opportunity based on where the actual Adjusted EBITDA or ratio of Net Indebtedness to Adjusted EBITDA amount falls between the levels.
For Messrs. Go, Griffin, Fleming and Anderson, earned awards will be paid fifty percent in cash and fifty percent in fully vested phantom unit awards granted pursuant to the Long-Term Incentive Plan. All phantom units granted will be granted with distribution equivalent rights.
2017 Target Goal and Results. For fiscal year 2017, the minimum ratio of Net Indebtedness to Adjusted EBITDA goal was 11.4, the target goal was 6.7 and the stretch goal was 5.0 for Messrs. Go, Griffin, Fleming and Anderson. For fiscal year 2017, the minimum Adjusted EBITDA goal was $175.0 million, the target goal was $300.0 million and the stretch goal was $400.0 for Mr. Grube. For the reasons described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations —

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2017 Update," we met at least our target goal with 2017 ratio of Net Indebtedness to Adjusted EBITDA of 6.4 and Adjusted EBITDA of $317.2 million as defined in the Cash Incentive Plan.

The following table summarizes the levels of cash award opportunity for each eligible named executive officer and the actual percentage earned by them for 2017:

	Cash Incentive Bonus Award Opportunity as a Percentage of Base Salary		
	Minimum	Target	Stretch
Timothy Go, D. West Griffin, Bruce A. Fleming and William A. Anderson (1)	50%	150%	250%
F. William Grube (2)	25%	50%	100%

(1) Company performance goals are based on the ratio of Net Indebtedness to Adjusted EBITDA.

(2) Company performance goals are based on Adjusted EBITDA.

The compensation committee may also subject a portion of the award to individual performance goals. With respect to Messrs. Go, Griffin and Fleming, 70% of the 2017 award will be based upon the company performance goal noted above, and 30% on individual performance goals. With respect to Mr. Anderson, 25% will be based on the company performance goal noted above and 75% will be based upon individual performance goals.

Mr. Murray was not eligible for an award under the Cash Incentive Plan during 2017.

For 2017, the ratio of Net Indebtedness to Adjusted EBITDA and Adjusted EBITDA were set at the budgeted amount, a level that the board of directors believed reflected the reasonable expectations management had for our financial performance during the fiscal year and likely to be achieved given actual Adjusted EBITDA achieved for the 2016 fiscal year. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — 2017 Update," for a discussion of the factors that impacted our results. Prior to 2017, compensation targets were based on Distributable Cash Flow. Upon the recommendation of the compensation committee, the board of directors changed the primary measurement of performance for compensation purposes to Adjusted EBITDA. We believe this represents the most comprehensive measurement of our financial performance of our assets.

The following tables reflect our historical minimum, target and stretch goals:

	Ratio of Net Indebtedness to Adjusted EBITDA				Adjusted EBITDA (Dollars in millions)			
Fiscal Year	Actual	Min. Goal	Target Goal	Stretch Goal	Actual	Min. Goal	Target Goal	Stretch Goal
2017	6.4	11.4	6.7	5.0	$317.2	$175.0	$300.0	$400.0

Distributable Cash Flow (Dollars in millions) (1)				
Fiscal Year	Actual	Minimum Goal	Target Goal	Stretch Goal
2016 (2)	$(75.6)	$220.6	$261.4	$302.3
2015 (2)	$224.5	$151.1	$203.1	$255.1

(1) Prior to 2017, compensation targets were based on Distributable Cash Flow.

(2) For 2016, actual results exclude a favorable $51.4 million LCM inventory adjustment, include an $18.5 million loss from unconsolidated affiliates and exclude bonus expense for calculation purposes.

For 2015, actual results exclude an unfavorable $81.8 million LCM inventory adjustment, include a $37.5 million loss from unconsolidated affiliates and exclude bonus expense for calculation purposes.

Individual Performance and Personal Objectives. The Compensation Committee evaluates the individual performance of, and performance objectives for, our named executive officers. Individual performance and objectives are specific to each officer position and are set at the beginning of the fiscal year.

Criteria used to measure an individual's performance may include assessment of objective criteria (e.g., execution of projects within budget parameters, improving profitability, or timely completing an acquisition or divestiture) as well as qualitative factors such as the executive's ability to lead, ability to communicate, and successful adherence to our stated values (i.e., commitment to safety, commitment to integrity, respect, commitment to excellence, innovation, entrepreneurship and collaboration). There are no specific weights assigned to these various elements of performance.

Compensation Changes for 2018. Upon the recommendation of the compensation committee, the board of directors has approved new ratio of Net Indebtedness to Adjusted EBITDA and Adjusted EBITDA targets for the 2018 fiscal year based on budgets prepared by management. We do not disclose our confidential 2018 targets, which, if disclosed, would put us at a competitive disadvantage. However, we believe that management will achieve the 2018 minimum goal level, while meaningful additional effort would be required to achieve the target goal and considerable additional effort would be required to achieve the stretch goal. There is no guarantee that our named executive officers will receive an award related to the 2018 year. The 2018 targets and actual results will be fully discussed within our compensation disclosures for the 2018 year.
For further description of this compensation program, please see "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Cash Incentive Plan."
Executive Deferred Compensation Plan
Design. The compensation committee allows for the participation of the executive officers in the Calumet Specialty Products Partners, L.P. Executive Deferred Compensation Plan (the "Deferred Compensation Plan") to encourage the officers to save for retirement and to assist us in retaining our officers. The Deferred Compensation Plan is intended to promote retention by giving employees an opportunity to save in a tax-efficient manner. The terms governing the retirement benefit under this plan for the executive officers are the same as those available for other eligible employees in the U.S. Pursuant to the Deferred Compensation Plan, a select group of management, including the named executive officers, and all of the non-employee directors are eligible to participate by making an annual irrevocable election to defer, in the case of management, all or a portion of their annual cash incentive award under the Cash Incentive Plan, and, in the case of non-management directors, all or none of their annual cash retainer. The deferred amounts are credited to participants' accounts in the form of phantom units, with each such phantom unit representing a notional unit that entitles the holder to receive either an actual common unit or the cash value of a common unit (determined by using the fair market value of a common unit at the time a determination is needed). The phantom units credited to each participant's account also receive distribution equivalent rights ("DERs"), which are credited to the participant's account in the form of additional phantom units. In our sole discretion, we may make matching contributions of phantom units or purely discretionary contributions of phantom units, in amounts and at times as the compensation committee recommends and the board of directors approves.
Results. We did not make any discretionary matching contributions of phantom units to the accounts of those participants in the Deferred Compensation Plan during 2017.
Long-Term Unit-Based Awards
Design. Long-term unit-based awards may consist of any type of award allowed pursuant to our Long-Term Incentive Plan, including phantom units, restricted units, unit options, substitution awards and DERs. These awards are granted to employees, consultants and directors of our general partner under the provisions of our Long-Term Incentive Plan, as amended, originally adopted on January 24, 2006, and administered by the compensation committee. These awards aid Calumet in retaining and motivating executives to assist us in meeting our financial performance objectives.
In fiscal year 2017, the annual unit award opportunity to named executive officers consisted of the contingent right to receive phantom units. Under the Long-Term Incentive Plan, phantom units are granted only upon our achievement of specified levels of Distributable Cash Flow. When granted, phantom units are subject to further time-based vesting criteria specified in the grant. Upon satisfaction of the time-based vesting criteria specified in the grant, phantom units convert into common units (or cash equivalent). Accordingly, these awards established a direct link between executive compensation and our financial performance. This component of executive compensation, when coupled with an extended ratable vesting period as compared to cash awards, further aligns the interests of executives with our unitholders in the longer-term and reinforces unit ownership levels among executives.
Phantom unit awards were granted to Mr. Grube in 2017 based on achievement with respect to the Adjusted EBITDA minimum, target or stretch goals discussed above in "Short-Term Cash Awards."
Performance unit awards were granted to Messrs. Go, Griffin, Fleming and Anderson in 2017 based on achievement with respect to the applicable performance goals from January 1, 2017 through December 31, 2020. Performance units earned are based on the following: (1) 25% will vest upon the commencement of equity distributions to unitholders;

(2) 25% will vest on the date that our weighted average common unit price is $8.00; and (3) 50% will vest on the date that our weighted average common unit price is $16.00. The weighted average will be measured using the weighted average closing sales price of our common units during any 120-day period. Our performance unit award payout is determined in accordance with the following table.

Messrs. Go, Griffin, Fleming and Anderson also received strategic units in 2017 based on the passage of time and the achievement with respect to the applicable performance goal. Strategic units earned are based on the following: (1) 40% will vest on January 1, 2018; (2) 20% will vest on the date that our weighted average common unit price is $7.00; (3) 20% will vest on the date that our weighted average common unit price is $10.00; and (4) 20% will vest on the date that our weighted average common unit price is $18.00.

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The weighted average will be measured using the weighted average closing sales price of our common units during any 120-day period. Our performance unit award payout is determined in accordance with the following table.

Any vested performance units or strategic units will be delivered to the respective named executive officer within 30 days of the first to occur of (a) the second anniversary of any termination of employment or service with the Company or (b) a change in control.

Results. The following tables reflect the number of phantom units that could be awarded to Messrs. Go, Griffin, Fleming and Anderson depending on whether we achieved the applicable performance goal achievement in 2017:

	Performance Units (1)			Strategic Units (1)				
	Distributions	$8 Unit Price Target	$16 Unit Price Target	Vest on 1/1/2018	$7 Unit Price Target	$10 Unit Price Target	$18 Unit Price Target	Actual
Timothy Go	125,000	125,000	250,000	200,000	100,000	100,000	100,000	225,000
D. West Griffin (2)	62,500	62,500	125,000	100,000	50,000	50,000	50,000	112,500
Bruce A. Fleming	31,250	31,250	62,500	50,000	25,000	25,000	25,000	56,250
William A. Anderson	21,875	21,875	43,750	35,000	17,500	17,500	17,500	39,375

(1) These phantom units will also receive DERs, if any, which would be paid in the form of cash.

(2) Mr. Griffin agreed to purchase $500,000 worth of common units on the open market in exchange for vesting of his equity awards in accordance with his offer letter of employment. Mr. Griffin has purchased common units with an acquisition cost of $250,000, leaving $250,000 worth of purchases left to be executed. The amounts disclosed in the table assume Mr. Griffin purchases the remaining $250,000 worth of common units as we believe this is probable of occurring.

The following table reflect the number of phantom units that would be awarded to Mr. Grube depending on whether we achieved the Adjusted EBITDA minimum, target or stretch goals discussed above in “Short-Term Cash Awards”.

Phantom units earned in 2017, which will be awarded in the first quarter of 2018:

	2017 Phantom Unit Award Opportunity			Phantom Units Earned (1)
	Minimum	Target	Stretch	
F. William Grube	5,400	10,800	16,200	10,800

(1) Phantom units granted pursuant to our annual awards are subject to a time-vesting requirement, whereby 100% of the units vest in three years. These phantom units will also receive DERs, if any, which would be paid in the form of cash.

Mr. Murray was not eligible for an award under the Long-Term Incentive Plan.

For further description of this compensation program, please see “Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Long-Term Incentive Plan.”

Health and Welfare Benefits

We offer a variety of health and welfare benefits to all eligible employees of our general partner. These benefits are consistent with the types of benefits provided by our peer group and provided so as to ensure that we are able to maintain a competitive position in terms of attracting and retaining executive officers and other employees. In addition, the health and welfare programs are intended to protect employees against catastrophic loss and encourage a healthy lifestyle. The named executive officers generally are eligible for the same benefit programs on the same basis as the rest of our employees. Our health and welfare programs include medical, pharmacy, dental, life and accidental death and dismemberment insurance coverages. In addition, all employees working over 30 hours per week are eligible for long-term disability coverage. Long-term disability coverage benefits specific to the named executive officers provide for a compensation allowance, which is grossed up for the payment of taxes, to allow them to purchase long-term disability coverage on an after-tax basis at no net cost to them. As structured, these long-term disability benefits will pay 60% of monthly earnings, as defined by the policy, up to a maximum of $15,000 per month during a period of continuing disability up to normal retirement age, as defined by the policy. Executive officers and other key employees are also eligible to obtain annual executive physical examinations which are paid for by us. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

Retirement Benefits

We provide the Calumet GP, LLC Retirement Savings Plan (the "401(k) Plan") to assist our eligible officers and employees in providing for their retirement. Named executive officers participate in the same retirement savings plan as other eligible employees subject to ERISA limits. We match 100% of each 1% of eligible compensation contribution by the participant up to 4% and 50% of each additional 1% of eligible compensation contribution up to 6%, for a maximum contribution by us of 5% of eligible compensation contributions per participant. These contributions are provided as a reward for prior contributions and future efforts toward our success and growth.

Perquisites

We provide executive officers with perquisites and other personal benefits that we believe are reasonable and consistent with our overall compensation programs and philosophy. These benefits are provided in order to enable us to attract and retain these executives. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

All named executive officers are provided with all, or certain of, the following benefits as a supplement to their other compensation:

- Executive Physical Program: Generally on an annual basis, we pay for a complete and professional personal physical exam for each named executive officer appropriate for his age to improve his health and productivity.
- Club Memberships: We pay club membership fees for certain named executive officers. Although such club memberships may be used for personal purposes in addition to business entertainment purposes, each named executive officer having such a membership is responsible for the reimbursement to us or direct payment for any incremental costs above the base membership fees associated with his personal use of such membership.
- Spousal and Family Travel: On an occasional basis, we pay expenses related to travel of the spouses or certain family members of our named executive officers in order to accompany the named executive officer to business-related events.
- Long-Term Disability Insurance: We provide compensation to allow each named executive officer to purchase long-term disability insurance on an after-tax basis at no net cost to him.
- Use of Company Aircraft: On an occasional basis, our named executive officers may be eligible to use a leased aircraft for personal use and the incremental cost to us is treated as and reflected in the tables below as compensation to the applicable officer for purposes of these disclosures. The items that we use to determine the incremental cost to us of these flights include the variable costs for personal use of aircraft that were charged to us by the vendor that operates the leased aircraft for contracted hourly costs, fuel charges, and taxes.
- Commuting and Living Expenses: In order for us to attract top executive talent, we must not be limited to those individuals residing in the Indianapolis metropolitan area and in some cases must be willing to offer payment or reimbursement for an agreed upon amount of relocation, commuting, temporary housing and other related costs.

The compensation committee periodically reviews the perquisite program to determine if adjustments are appropriate and noted the addition of payment of legal expenses was appropriate.

Other Compensation Related Matters

Clawback Policy

The Long-Term Incentive Plan was last amended and restated on December 10, 2015. This amendment included a new provision that addresses the potential need to recover awards granted under that plan. To the extent that applicable laws or listing standards would require it, or otherwise as determined appropriate by us, all awards granted under the Long-Term Incentive Plan shall be subject to clawback, forfeiture, repurchase or recoupment, as appropriate.

Tax Implications of Executive Compensation

Because we are not an entity taxable as a corporation, many of the tax issues associated with executive compensation that face publicly-traded corporations do not directly affect us. Internal Revenue Code Section 409A ("Section 409A") provides that amounts deferred under nonqualified deferred compensation plans are includible in a participant's income when vested, unless certain requirements are met. If these requirements are not met, participants are also subject to an additional income tax and interest. All of our awards under our Long-Term Incentive Plan, severance arrangements and other nonqualified deferred compensation plans presently meet these requirements. As a result, employees will be taxed when the deferred compensation is actually paid to them. We will be entitled to a tax deduction at that time.

Executive Ownership of Units

While we have not adopted any security ownership requirements or policies for our executives, our executive compensation programs foster the enhancement of executives' equity ownership through long-term unit-based awards under the Long-Term

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Incentive Plan. Further, in 2006 several executives purchased a significant number of our common units as participants in a directed unit program in conjunction with our initial public offering. For a listing of security ownership by our named executive officers, refer to Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

The board of directors of our general partner has adopted the Insider Trading Policy of Calumet GP, LLC and Calumet Specialty Products Partners, L.P. (the "Insider Trading Policy"), which provides guidelines to employees, officers and directors with respect to transactions in our securities. Pursuant to Calumet's Insider Trading Policy, all executive officers and directors must confer with our chief financial officer before effecting any put or call options for our securities. Further, the Insider Trading Policy states that we strongly discourage all such transactions by officers, directors and all other employees and consultants. The Insider Trading Policy is available on our website at www.calumetspecialty.com or a copy will be provided at no cost to unitholders upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana, 46214.

Employment Agreements

Our general partner has entered into employment agreements with Timothy Go, chief executive officer and F. William Grube, executive vice chairman to ensure they will perform their roles for an extended period of time given their position and value to us. For a discussion of the material terms of the employment agreements, please refer to "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Employment Agreements."

Under these employment agreements, the named executive officers are entitled to receive severance compensation if their employment is terminated under certain conditions, such as termination by the named executive officer for "good reason" or by us without "cause," each as defined in the agreements and further described in "Potential Payments Upon Termination or Change in Control."

The employment agreements with the named executive officers and the related severance provisions are designed to meet the following objectives:

- Change in Control: In certain scenarios, the potential for merger or being acquired may be in the best interests of our unitholders. We provide the potential for severance compensation to the named executive officers in the event of a change in control transaction to promote their ability to act in the best interests of our unitholders even though their employment could be terminated as a result of the transaction.
- Termination without Cause: We believe severance compensation in such a scenario is appropriate because the named executive officers are bound by confidentiality, nonsolicitation and noncompetition provisions covering one year after termination and because we and the named executive officer have mutually agreed to a severance package that is in place prior to any termination event. This provides us with more flexibility to make a change in this executive position if such a change is in our and our unitholders' best interests.

The salary multiple of the change of control benefits, use of the single or double trigger change of control benefits and the amount of the severance payout were determined through negotiations with each named executive officer at the time that we entered into the employment agreements. Relative to the overall value to us, the compensation committee believes these potential benefits are reasonable.

Our general partner terminated Mr. Murray's employment agreement and entered into a severance agreement with Mr. Murray upon his departure in November 2017 that provides for certain severance benefits. The terms and conditions of the severance agreement are described further below.

Report of the Compensation Committee for the Year Ended December 31, 2017

The compensation committee of our general partner has reviewed and discussed our Compensation Discussion and Analysis with management. Based upon such review, the related discussion with management and such other matters deemed relevant and appropriate by the compensation committee, the compensation committee has recommended to the board of directors that our Compensation Discussion and Analysis be included in the Company's Annual Report on Form 10-K.

Members of the Compensation Committee:

Stephen P. Mawer, Chairman
Fred M. Fehsenfeld, Jr.
Amy M. Schumacher

Summary Compensation Table

The following table sets forth certain compensation information of our named executive officers for the years ended December 31, 2017, 2016 and 2015:

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Summary Compensation Table for 2017

Name and Principal Position	Year	Salary	Bonus (5)	Unit Awards (6)	Non-Equity Incentive Plan Compensation (7)	All Other Compensation (8)	Total
Timothy Go (1)	2017	$500,000	$—	$4,836,561	$ 437,500	$ 14,713	$5,788,774
Chief Executive Officer	2016	$500,000	$250,000	$625,000	$ —	$ 95,815	$1,470,815
F. William Grube Executive Vice Chairman	2017	$454,363	$—	$57,780	$ 227,182	$ 14,136	$753,461
	2016	$454,363	$—	$19,881	$ —	$ 20,200	$494,444
	2015	$454,363	$—	$574,253	$ 641,351	$ 70,323	$1,740,290
D. West Griffin (2) Executive Vice President - Chief Financial Officer	2017	$394,110	$—	$2,218,750	$ 300,000	$ 258,681	$3,171,541
R. Patrick Murray, II (3)	2017	$322,739	$—	$—	$ —	$ 419,749	$742,488
Former Vice President - Special	2016	$353,067	$—	$25,268	$ —	$ 20,987	$399,322
Projects and Former Executive Vice President - Chief Financial Officer and Secretary	2015	$339,488	$—	$423,072	$ 431,280	$ 47,865	$1,241,705
Bruce A. Fleming (4)	2017	$385,000	$—	$1,315,500	$ 356,125	$ 24,405	$2,081,030
Executive Vice President - Strategy & Growth	2016	$280,021	$—	$749,947	$ —	$ 54,600	$1,084,568
William A. Anderson Executive Vice President - Sales	2017	$325,130	$—	$896,563	$ 225,000	$ 14,518	$1,461,211
	2016	$325,130	$—	$—	$ —	$ 21,416	$346,546
	2015	$312,626	$—	$338,400	$ 441,284	$ 60,633	$1,152,943

(1) Mr. Go's employment with us commenced September 2015. He was appointed chief executive officer effective January 1, 2016, and was not a named executive officer prior to 2016.

(2) Mr. Griffin was appointed executive vice president, chief financial officer effective January 5, 2017.

(3) Mr. Murray's employment was terminated in November 2017.

(4) Mr. Fleming's employment with us commenced March 21, 2016.

(5) Mr. Go received a signing bonus of $250,000 per his employment agreement.

(6) The amounts include the aggregate grant date fair value of (i) 143,990 phantom unit awards granted to Mr. Go during the 2017 fiscal year relating to a correction that was needed in the number of phantom units granted to Mr. Go in 2015 and 2016 (described further below), (ii) 2016 unit awards for Mr. Fleming relate to a matching phantom unit award granted to Mr. Fleming equal to his common unit purchases in 2016, pursuant to an agreement we entered into with Mr. Fleming upon his entry into our employment to match certain purchases of our common units that he made during 2016, (iii) performance units and strategic units to reward Messrs. Go, Griffin, Fleming and Anderson the number of which is determined based on certain market and company performance and (iv) phantom units to reward Mr. Grube for services provided during the fiscal year and the number of which is determined based on our level of Adjusted EBITDA during the fiscal year. The amounts reflect the aggregate grant date fair value computed in accordance with FASB ASC Topic 718. See Note 13 to our consolidated financial statements for the fiscal year ending December 31, 2017 for a discussion of the assumptions used to determine the FASB ASC Topic 718 value of the awards.

(7) Represents amounts earned under our Cash Incentive Plan and not deferred into the Deferred Compensation Plan. Please read "Compensation Discussion and Analysis — Elements of Executive Compensation — Short-Term Cash Awards" for further details.

(8)

The following table provides the aggregate "All Other Compensation" information for each of the named executive officers, except that it excludes perquisites or other personal benefits received by Messrs. Go, Grube, Murray, Fleming and Anderson in 2017, as such amounts for these named executive officers were less than $10,000 in aggregate:

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	Timothy Go	F. William Grube	D. West Griffin	R. Patrick Murray, II	Bruce A. Fleming	William A. Anderson
401(k) Plan Matching Contributions	$13,250	$13,250	$13,250	$9,294	$13,250	$13,250
Relocation Expenses (1)	—	—	78,627	—	10,090	—
Commuting and Living Expenses (2)	—	—	163,723	—	—	—
Long-Term Disability Insurance	—	—	1,716	—	—	—
Term Life Insurance	1,463	886	1,365	1,381	1,065	1,268
Post-Employment Payments (3)	—	—	—	409,074	—	—
Total	$14,713	$14,136	$258,681	$419,749	$24,405	$14,518

(1) Includes a tax gross up of $28,627 for Mr. Griffin.

(2) As part of Mr. Griffin's offer letter of employment, we provided him $25,000 quarterly for living and commuting expenses. Includes a tax gross up of $63,723.

(3) As part of Mr. Murray' resignation, we entered into a severance and general release agreement with him. The agreement provided for a severance payment of $353,067. Additionally, Mr. Murray was provided free and clean title to his company automobile, reimbursed for fourteen months of COBRA insurance coverage and paid unused vacation.

Grants of Plan-Based Awards

The following table sets forth grants of plan-based awards to our named executive officers for the year ended December 31, 2017:

Grants of Plan-Based Awards Table for the Year Ended December 31, 2017

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Minimum ($)	Target ($)	Maximum ($)	Estimated Possible Payouts Under Equity Incentive Plan Awards (2) Minimum (#)	Target (#)	Maximum (#)	All Other Unit Awards: Number of Units (3) (#)	Grant Date Fair Value of Unit Awards ($)
Timothy Go		$250,000	$750,000	$1,250,000					
	2/23/2017				—	500,000	—		$1,162,500
	5/4/2017							143,990	$561,561
	8/3/2017				—	300,000	—		$1,605,000
	8/3/2017							200,000	$1,070,000
F. William Grube		$113,591	$227,182	$454,363					
	8/3/2017				5,400	10,800	16,200		$57,780
D. West Griffin		$200,000	$450,000	$1,000,000					
	2/23/2017				—	250,000	—	—	$581,250
	8/3/2017				—	150,000	—		$802,500
	8/3/2017							100,000	$535,000
Bruce A. Fleming		$192,500	$577,500	$962,500					
	2/23/2017				—	125,000	—		$290,625
	8/3/2017				—	75,000	—		$401,250
	8/3/2017							50,000	$267,500
William A. Anderson		$162,565	$487,695	$812,825					
	2/23/2017				—	87,500	—		$203,438
	8/3/2017				—	52,500	—		$280,875
	8/3/2017							35,000	$187,250

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(1) Estimated possible payouts under non-equity incentive plan awards represent the ranges of potential cash incentive awards granted under our Cash Incentive Plan related to fiscal year 2017 for each named executive officer, although we did not pay these awards for the 2017 year. For a description of this plan and available awards please read "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Cash Incentive Plan."

(2) Estimated possible payouts under equity incentive plan awards for Mr. Grube represent the ranges of potential unit based awards that could have been earned under the 2017 Phantom Unit Program as part of the Long-Term Incentive Plan. Estimated possible payouts under equity incentive plan awards for Messrs. Go, Griffin, Fleming and Anderson represent grants of performance and strategic units in which a portion vests upon the reinstatement of the distribution to unitholders and portions vest if the 120-day moving average closing price of our common units reaches $7 per unit, $8 per unit, $10 per unit, $16 per unit and $18 per unit during the period of January 1, 2017 through December 31, 2020.

(3) All other unit awards represent (i) 143,990 phantom unit awards granted to Mr. Go during the 2017 fiscal year relating to a correction that was needed in the number of phantom units granted to Mr. Go in 2016 (described further below) and (ii) grants of strategic units in which a portion vests on January 1, 2018.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

Description of Cash Incentive Plan

Annual ratio of Net Indebtedness to Adjusted EBITDA and Adjusted EBITDA goals are recommended by the compensation committee to the board of directors and are based upon our annual forecast of financial performance for the upcoming fiscal year, and such goals are reviewed and approved by the board of directors. Three increasing goals of the ratio of Net Indebtedness to Adjusted EBITDA (applicable to the named executive officers other than Mr. Grube) and Adjusted EBITDA (applicable to Mr. Grube) are established to calculate awards under the Cash Incentive Plan: minimum, target and stretch. Under the Cash Incentive Plan, if our actual performance meets at least the minimum ratio of Net Indebtedness to Adjusted EBITDA or Adjusted EBITDA goal for the fiscal year, as applicable, executives and certain other management employees may receive incentive awards ranging from 20% to 50% of base salary, depending on the employee's position with the general partner. If financial performance exceeds the minimum ratio of Net Indebtedness to Adjusted EBITDA or Adjusted EBITDA goal, as applicable, the cash incentive award paid as a percentage of base salary may be larger, ultimately reaching an upper range of 60% to 250% of base salary, if the stretch goal is reached. Cash incentive awards are prorated if actual performance falls between the defined minimum and stretch goals. If the ratio of Net Indebtedness to Adjusted EBITDA or Adjusted EBITDA, as applicable, falls below the minimum goal, no cash incentive awards are paid under the Cash Incentive Plan. The compensation committee can recommend to the full board of directors, however, that cash awards be given notwithstanding the fact that we failed to achieve at least the minimum ratio of Net Indebtedness to Adjusted EBITDA or Adjusted EBITDA goal. Awards earned, if any, under this plan are generally paid in the first quarter of the following fiscal year after finalizing the calculation of our performance relative to the ratio of Net Indebtedness to Adjusted EBITDA or Adjusted EBITDA targets. The following table summarizes the levels of awards available to participants in the Cash Incentive Plan:

	Cash Incentive Award Calculated as a Percentage of Base Salary		
Incentive Level (1)	Minimum	Target	Stretch
1	50%	150%	250%
2	25%	50%	100%
3	50%	100%	200%
4	50%	100%	150%
5	20%	40%	80%
6	20%	40%	60%

(1) Messrs. Go, Griffin, Fleming and Anderson participate in the Cash Incentive Plan at Incentive Level 1. Mr. Grube participates in the Cash Incentive Plan at Incentive Level 2.

Participants in the Cash Incentive Plan are eligible to defer all or a portion of their award, if any, under the Cash Incentive Plan into the Deferred Compensation Plan, which was adopted by the board of directors on December 18, 2008 and effective as of January 1, 2009. See “Compensation Discussion and Analysis — Elements of Executive Compensation — Executive Deferred Compensation Plan” for additional discussion of this plan.

Description of Long-Term Incentive Plan

Following is a summary of the Long-Term Incentive Plan and the material terms related to phantom units that we may grant pursuant to the Long-Term Incentive Plan:

General. The Long-Term Incentive Plan provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of DERs. Subject to adjustment for certain events, an aggregate of 3,883,960 common units may be delivered pursuant to awards under the Long-Term Incentive Plan. Units withheld to satisfy our general partner's tax withholding obligations are available for delivery pursuant to other awards. Our general partner's board of directors, in its discretion, may terminate the Long-Term Incentive Plan at any time with respect to the common units for which a grant has not theretofore been made. The Long-Term Incentive Plan will automatically terminate on the earlier of the 10th anniversary of the date it was approved by the board of directors of our general partner or when common units are no longer available for delivery pursuant to awards under the Long-Term Incentive Plan. Our general partner's board of directors has the right to alter or amend the Long-Term Incentive Plan or any part of it from time to time and the compensation committee may amend any award; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant. Subject to unitholder approval, if required by the rules of the principal national securities exchange upon which the common units are traded, the board of directors of our general partner may increase the number of common units that may be delivered with respect to awards under the Long-Term Incentive Plan.

Phantom Units. During 2017, we granted phantom units pursuant to the Long-Term Incentive Plan. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equal to the fair market value of a common unit. The compensation committee may make grants of phantom units under the Long-Term Incentive Plan to eligible individuals containing such terms, consistent with the Long-Term Incentive Plan, as the compensation committee may determine, including the period over which phantom units granted will vest. The compensation committee may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the phantom units will vest automatically upon a change of control (as defined in the Long-Term Incentive Plan) of us or our general partner, subject to any contrary provisions in the award agreement. If a grantee's employment, consulting or membership on the board of directors terminates for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the grant agreement or the compensation committee provides otherwise. Common units to be delivered with respect to these awards may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units with respect to these awards, the total number of common units outstanding will increase. Any outstanding restricted unit or phantom unit awards fully vest upon the occurrence of certain events including, but not limited to, change of control, death, disability and normal retirement.

DERs are rights that entitle the grantee to receive, with respect to a phantom unit, cash equal to the cash distributions made by us on a common unit. The compensation committee, in its discretion, may grant tandem DERs with phantom units on such terms as it deems appropriate.

Participants do not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our general partner will receive remuneration for the units delivered with respect to these awards.

2017 Phantom Unit Program. Mr. Go also received an additional grant of phantom units during 2017 that were unrelated to our 2017 annual equity program. In 2016 and 2015, we granted Mr. Go phantom units that were intended to be equal to the value of a certain percentage of his salary on the date of grant. In April 2017, we discovered an error in the methodology previously used to convert cash to equity awards in 2016, therefore we granted him additional phantom units in order to correct the difference in the number of phantom units he should have received on the original grant dates in 2016 and 2015. The additional 143,990 phantom units granted to Mr. Go in 2017 were granted with the same terms and conditions as the original 2016 and 2015 grants, which resulted in a portion of the awards (40,529 phantom units) being vested on the date of grant. See "Compensation Discussion and Analysis — Elements of Executive Compensation — Long-Term Unit-Based Awards" for additional discussion of this plan.

Description of Employment Agreements

Employment Agreement with Timothy Go, Chief Executive Officer: Our general partner has an employment agreement with Mr. Go dated as of September 14, 2015 (“Go Effective Date”). The initial term of his employment agreement is three years and will expire on September 14, 2018, but the agreement provides for automatic extensions of an additional twelve months beginning on the third anniversary of the Go Effective Date, and on every anniversary of the Go Effective Date thereafter, unless either party notifies the other of non-extension at least 180 days prior to any such anniversary date.

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The agreement provides for an initial annual base salary of $500,000, subject to various adjustments by the board of directors of our general partner that have been made following the Go Effective Date, as well as a signing bonus, the right to participate in the Long-Term Incentive Plan, other bonus plans, our retirement, health and welfare benefit plans, and the use of an automobile. Mr. Go's employment agreement may be terminated at any time by either party with proper notice. The potential severance benefits provided within the employment agreement are described in greater detail in the "Potential Payments Upon Termination or Change in Control" section below. For the term of his employment agreement and for the one-year period following the termination of employment, Mr. Go is prohibited from engaging in competition (as defined in his employment agreement) with us and soliciting our customers and employees.

Amended and Restated Employment Agreement with F. William Grube, Executive Vice Chairman. Our general partner has an amended and restated employment agreement with Mr. Grube dated as of December 31, 2015 (the "Grube Effective Date"). The initial term of the amended agreement is five years and will expire on December 31, 2020 (the "Employment Period"), but the agreement provides for automatic extensions of an additional twelve months added to the Employment Period beginning on the third anniversary of the Grube Effective Date, and on every anniversary of the Grube Effective Date thereafter, unless either party notifies the other of non-extension at least ninety days prior to any such anniversary date.

The agreement provides for an initial annual base salary of approximately $454,363, subject to various adjustments by the board of directors of our general partner that have been made following the Grube Effective Date, as well as the right to participate in the Long-Term Incentive Plan, other bonus plans, our retirement, health and welfare benefit plans, and the use of an automobile. Mr. Grube's employment agreement may be terminated at any time by either party with proper notice. The potential severance benefits provided within the employment agreement are described in greater detail in the "Potential Payments Upon Termination or Change in Control" section below. For the term of the employment agreement and for the one-year period following the termination of employment, Mr. Grube is prohibited from engaging in competition (as defined in the employment agreement) with us and soliciting our customers and employees.

Severance and General Release Agreement with R. Patrick Murray, II. In connection with the termination of Mr. Murray's employment on November 1, 2017, we entered into a severance and general release agreement with Mr. Murray, pursuant to which Mr. Murray is entitled to a severance payment of $353,057. The severance agreement further provided for accelerated vesting for any unvested phantom units, free and clean title to his company automobile, reimbursed for fourteen months of COBRA insurance coverage and paid unused vacation.

We do not maintain employment agreements with Messrs. Griffin, Fleming or Anderson.

Salary in Proportion to Total Compensation

The following table sets forth the percentage of each named executive officer's total compensation that we paid in the form of salary for 2017.

Salary Percentage for 2017

Name	Percentage of Total Compensation
Timothy Go	9%
F. William Grube	60%
D. West Griffin	12%
R. Patrick Murray, II	43%
Bruce A. Fleming	19%
William A. Anderson	22%

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Outstanding Equity Awards at Fiscal Year-End

Our named executive officers had the following outstanding equity awards at December 31, 2017.

Outstanding Equity Awards at December 31, 2017

	Unit Awards			
Name	Number of Units That Have Not Vested (#) (1)	Market Value of Units That Have Not Vested ($) (2)	Equity Incentive Plan Awards: Number of Unearned Units That Have Not Vested (#) (1)	Equity Incentive Plan Awards: Market Value of Units that Have Not Vested ($) (2)
Timothy Go	286,486	$ 2,205,942	575,000	$4,427,500
F. William Grube	16,200	$ 124,740	—	$—
D. West Griffin (3)	100,000	$ 770,000	287,500	$2,213,750
Bruce A. Fleming	121,519	$ 935,696	143,750	$1,106,875
William A. Anderson	38,600	$ 297,220	100,625	$774,813

(1) These units are scheduled to vest in amounts and on the dates shown in the following table:

Vesting Date	Timothy Go	F. William Grube	D. West Griffin	Bruce A. Fleming	William A. Anderson
January 1, 2018	200,000	—	100,000	50,000	35,000
December 31, 2018	47,423	5,400	—	35,760	3,600
December 31, 2019	39,063	—	—	35,759	—
March 7, 2021	—	10,800	—	—	—
Reinstatement of Distributions	125,000	—	62,500	31,250	21,875
$10 Price Target	100,000	—	50,000	25,000	17,500
$16 Price Target	250,000	—	125,000	62,500	43,750
$18 Price Target	100,000	—	50,000	25,000	17,500
	861,486	16,200	387,500	265,269	139,225

(2) Market value of phantom units reported in these columns is calculated by multiplying the closing market price of $7.70 of our common units at December 29, 2017 (the last trading day of the fiscal year), by the number of units outstanding.

(3) Mr. Griffin agreed to purchase $500,000 worth of common units on the open market in exchange for vesting of his equity awards in accordance with his offer letter of employment. Mr. Griffin has purchased common units with an acquisition cost of $250,000, leaving $250,000 worth of purchases left to be executed. The amounts disclosed in the table assume Mr. Griffin purchases the remaining $250,000 worth of common units as we believe this is probable of occurring.

Options Exercises and Stock Vested

Our named executive officers exercised no options and had a total of 604,633 phantom units related to the Deferred Compensation Plan and the Long-Term Incentive Plan vest during the year ended December 31, 2017. The vested units related to the Deferred Compensation Plan will remain in the Deferred Compensation Plan until the earlier of the date specified by each participant and the participant’s termination of employment, as further described under

"Nonqualified Deferred Compensation" below.

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Unit Awards Vested During Year Ended December 31, 2017

Name	Unit Awards Number of Units Vested	Value Realized on Vesting (1)
Timothy Go	333,478	$ 2,678,902
F. William Grube	8,100	$ 62,370
D. West Griffin (2)	112,500	$ 996,250
R. Patrick Murray, II	13,770	$ 110,231
Bruce A. Fleming	92,010	$ 773,477
William A. Anderson	44,775	$ 390,268

(1) Market value of phantom units reported in this column is calculated by multiplying the closing market price of our common units on the vesting date by the number of units vesting on such date.

(2) Mr. Griffin agreed to purchase $500,000 worth of common units on the open market in exchange for vesting of his equity awards in accordance with his offer letter of employment. Mr. Griffin has purchased common units with an acquisition cost of $250,000, leaving $250,000 worth of purchases left to be executed. The amounts disclosed in the table assume Mr. Griffin purchases the remaining $250,000 worth of common units as we believe this is probable of occurring.

Nonqualified Deferred Compensation

The Deferred Compensation Plan became effective as of January 1, 2009. The Deferred Compensation Plan is an unfunded arrangement intended to be exempt from the participation, vesting, funding and fiduciary requirements set forth in Title I of the Employee Retirement Income Security Act of 1974, as amended, and to comply with Section 409A of the Code. Our obligations under the Deferred Compensation Plan will be general unsecured obligations to pay deferred compensation in the future to eligible participants in accordance with the terms of the Deferred Compensation Plan from our general assets. The compensation committee of our general partner's board of directors acts as the plan administrator.

Executive Contributions in Nonqualified Deferred Compensation Table for 2017

Name	Executive Contributions in 2017 (1)	Company Contributions in 2017 (2)	Aggregate Earnings in 2017 (3)	Aggregate Withdrawals/ Distributions in 2017 (4)	Aggregate Balance at End of 2017 (5)
F. William Grube	$ —	$ —	$ —	$ —	$ 278,655
R. Patrick Murray, II	$ —	$ —	$ —	$ (286,082)	$ —

(1) No executive contributions were made with respect to the 2017 year. Executive contributions in 2017 would have represented phantom units granted to certain of our named executive officers based on their individual elections to defer all or a portion of their cash incentive award under the Cash Incentive Plan related to the 2017 fiscal year into the Deferred Compensation Plan.

(2) No company contributions were made with respect to the 2017 year. Our contributions in 2017 would have represented discretionary matching contributions made in the form of phantom units granted to our named executive officers based on their individual elections to defer all or a portion of their cash award under the Cash Incentive Plan related to the 2017 fiscal year into the Deferred Compensation Plan.

(3) Aggregate earnings in 2017 would have represented additional phantom units earned through DERs in the applicable named executive officer's Deferred Compensation Plan account on phantom units granted under the executive contribution and the discretionary matching contribution in fiscal years 2015, 2014, 2012, 2011, 2010 and 2009. These amounts, which would have represented the fair value of the phantom units earned on the

corresponding dates of our distributions to our unitholders in fiscal year 2017, and would have been included as compensation in 2017 under "Unit Awards" in the Summary Compensation Table.

(4) Represents phantom units distributed in accordance with Mr. Murray's termination. The amount reported in this column represents the fair market value of the common units on the distribution date.

(5) While the aggregate balance of each participant's Deferred Compensation Plan account at the end of the fiscal year is comprised of the phantom units related to the executive and discretionary matching contributions as well as the phantom

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units attributable to aggregate earnings accumulated during the 2017 year, the dollar amount of each participant's account as of December 31, 2017, was determined by multiplying all phantom units deemed to be included in the participant's account by the closing price of our common units on December 29, 2017 (the last trading day of the fiscal year), which was $7.70. The phantom units associated with each executive's account as of December 31, 2017, were as follows: Mr. Grube, 36,189. Subject to the Mr. Grube's continued employment with us, these phantom units will become vested over a four year period (except for phantom units associated with executive contributions, which are fully vested at the time of cash incentive deferral), but such vesting applies to the number of phantom units credited to the participant's account, and not the value of the account at any given time. The value of the executive's accounts will fluctuate due to the fact that the value of their phantom units will track the value of our common units. Also, please keep in mind that the executive's accounts are not currently fully vested; subject to the forfeiture provisions described below, these amounts do not reflect the payout amount that an executive would receive if he voluntarily left our service prior to vesting. The amounts in this column also include amounts that were previously reported as compensation in the Summary Compensation Table during previous years as follows: (a) for 2009, Mr. Grube, $113,348 (b) for 2010, Mr. Grube, $115,373 and (c) for 2011, Mr. Grube, $160,800.

The named executive officers, as well as other officers and key employees, participate in the Deferred Compensation Plan by making an annual irrevocable election to defer all or a portion of their annual cash incentive award for the year. The deferred amounts will be credited to the participants' accounts in the form of phantom units, and will receive DERs to be credited in the form of additional phantom units to the participants' account. We have the discretion to make matching contributions of phantom units or purely discretionary contributions of phantom units, in amounts and at times as the compensation committee determines appropriate. For the 2017 year, there were no matching contributions of deferred amounts related to the 2017 fiscal year. Participants will at all times be 100% vested in amounts they have deferred; however, amounts we have contributed may be subject to a vesting schedule, as determined appropriate by the compensation committee. The participants' accounts are adjusted at least quarterly to determine the fair market value of our phantom units, as well as any DERs that may have been credited in that time period. Distributions from the Deferred Compensation Plan are payable on the earlier of the date specified by each participant and the participant's termination of employment. Death, disability, normal retirement or our change of control (as such terms are defined within the Long-Term Incentive Plan) require automatic distribution of the Deferred Compensation Plan benefits, and will also accelerate at that time the vesting of any portion of a participant's account that has not already become vested. Benefits will be distributed to participants in the form of our common units, cash or a combination of common units and cash at the election of the compensation committee. In the event that accounts are paid in common units, such units will be distributed pursuant to the Long-Term Incentive Plan. Unvested portions of a participant's account will be forfeited in the event that a distribution was due to a participant's voluntary resignation or a termination for cause. To ensure compliance with Section 409A of the Code, distributions to participants that are considered "key employees" (as defined in Code Section 409A of the Code) may be delayed for a period of six months following such key employees' termination of employment with us.

Potential Payments Upon Termination or Change in Control

We provide certain of our named executive officers with certain severance and change in control benefits in order to provide them with assurances against certain types of terminations without cause or resulting from change in control transactions where the terminations were not based upon cause. This type of protection is intended to provide the executive with a basis for keeping focus and functioning in the unitholders' interests at all times. In addition to the potential acceleration of our equity-based awards upon certain events, our employment agreements with Messrs. Go, and Grube contain severance and change in control provisions.

In the event that severance payments are triggered under the applicable employment agreement, Messrs. Go and Grube will be eligible to receive payments as soon as administratively possible, though if Code Section 409A would subject them to additional taxes upon receipt of the payments, we will delay the payment of these amounts for a period of six months and provide for interest to accrue on such delayed amounts at the maximum nonusurious rate from the date of the originally scheduled payment date. Messrs. Go and Grube are also eligible to receive an additional sum from us in the event that any termination payments we provide to them is considered "parachute" payments pursuant to

Section 280G of the Internal Revenue Code of 1986, as amended (the “Code”); a parachute payment could occur in connection with a change in control or a termination of employment that was also in connection with a change in control, but such a payment would not occur in the event of a termination of Messrs. Go’s and Grube’s employment that is not in connection with a change in control. This additional payment, if necessary, would equal the amount necessary to place them in the same after-tax position they would have been in absent the additional excise taxes imposed by Section 280G of the Code. Lastly, severance potentially payable to the executives under their employment agreements is partially provided in consideration for the executive’s agreement not to compete with us or solicit our employees for a period of one year following a termination of employment.

The employment agreements in place as of December 31, 2017, contain the following definitions for each of the possible “triggering events” that could result in a termination payment to the below referenced named executive officers:

- Cause. Mr. Go may be terminated for cause if: (i) Mr. Go is indicted for a felony (or a plea of nolo contendere thereto); (ii) Mr. Go’s conduct in connection with his employment duties or responsibilities is fraudulent, unlawful, or grossly negligent; (iii) Mr. Go exhibits willful misconduct; (iv) Mr. Go is materially insubordinate or fails to follow the lawful instructions or directions from the board of directors or its designee, if such failure is not cured; if curable, by Mr. Go after he has been given ten (10) days written notice of such failure; (v) any material breach of the employment agreement by Mr. Go occurs, including but not limited to, a breach of the restrictive covenants set forth in Section 10 of the agreement, if such breach is not cured, if curable, by Mr. Go after he has been given ten (10) days written notice of such breach; (vi) any acts of dishonesty are committed by Mr. Go, resulting or intending to result in personal gain or enrichment at the expense of the Company, its subsidiaries or affiliates; or (vii) Mr. Go fails to comply with a material policy of the Company, its subsidiaries or affiliates, if such failure is not cured, if curable, by Mr. Go after he has been given ten (10) days written notice of such failure.

Mr. Grube may be terminated for cause due to: (i) Mr. Grube's willful and continuing failure (excluding as a result of his mental or physical incapacity) to perform his duties and responsibilities with us; (ii) Mr. Grube's having committed any act of material dishonesty against us or any of our affiliates (including theft, misappropriation, embezzlement, forgery, fraud, or willful and intentional falsification of records or misrepresentations); (iii) Mr. Grube's willful and continuing material breach of the employment agreement; (iv) Mr. Grube's having been convicted of, or having entered a plea of nolo contendre to any felony; or (v) Mr. Grube's having been the subject of any final and non-appealable order, judicial or administrative, obtained or issued by the SEC, for any securities violation involving fraud, including, for example, any such order consented to by Mr. Grube in which findings of facts or any legal conclusions establishing liability are neither admitted nor denied.

- Change in Control. Messrs. Go's and Grube's agreements state that a change in control may occur upon any of the following events:

any "person" or "group," within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, as amended, other than the Company or its Affiliates, or Fred M. Fehsenfeld Jr. or F. William Grube or their respective immediate families or Affiliates, becomes the beneficial owner, by way or merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the voting power of the outstanding equity interests of the Company;

a person or entity other than the Company or an Affiliate of the Company becomes the general partner of the Company; or

the sale or other disposition, including by liquidation or dissolution, of all or substantially all of the assets of the Company in one or more transactions to any person other than an Affiliate of the Company.

- Good Reason. Mr. Go has the right to terminate employment under his employment agreement, upon the occurrence of any of the following circumstances, without his prior consent: (i) material diminution in his total compensation opportunity in effect on the Go Effective Date; (ii) material breach by us of any of our covenants or obligations under his agreement; (iii) material reduction in his authority, duties or responsibilities or reporting relationship; (iv) the involuntary relocation of the geographic location of his principal place of employment by more than 100 miles from the location of his principal place of employment as of the Go Effective Date; and (v) following a Change in Control (as defined in the agreement), our failure to obtain an agreement from any successor to us to assume and agree to perform this agreement in the same manner and to the same extent that we would be required to perform if no succession had taken place, except where such assumption occurs by operation of law; provided however, that notwithstanding the foregoing provisions or any other provisions of his agreement to the contrary, any assertion by him of a termination for Good Reason (as defined in his agreement) shall not be effective unless all of the following conditions are satisfied: (i) the conditions described above giving rise to his termination of employment must have arisen without his consent; (ii) he must provide written notice to the board of directors of the existence of such condition(s) within 30 days of the initial existence of such condition(s); (iii) the condition(s) specified in such notice must remain uncorrected for 30 days following the board of directors' receipt of such written notice; and (iv) the date of his termination of employment must occur within 90 days after the initial existence of the condition(s) specified in such notice.

Good reason under Mr. Grube's employment agreement includes: (i) any material breach by us of the employment agreement; (ii) any requirement by us that Mr. Grube relocate outside of the metropolitan Indianapolis, Indiana area;

(iii) failure of any successor to assume the employment agreement not later than the date as of which it acquires substantially all of the equity, assets or business of us; (iv) any material reduction in Mr. Grube’s title, authority, responsibilities, or duties (including a change that causes him to cease being a member of the board of directors or reporting directly and solely to the board of directors); or (v) the assignment of Mr. Grube any duties materially inconsistent with his duties as our executive vice chairman.

- Totally Disabled. Under Mr. Go’s employment agreement, we have the right to terminate his employment if he is unable to perform, with or without reasonable accommodation, the essential functions of his position as a result of a physical or mental injury or illness for a period of (i) 90 consecutive days or (ii) 180 days in any one year period.

Mr. Grube's employment agreement states that if he is unable to perform his duties under his employment agreement by reason of mental or physical incapacity for 90 consecutive calendar days during the Employment Period we have the right to terminate his employment; provided that we will not have the right to terminate his employment for disability if (i) in the written opinion of a qualified physician reasonably acceptable to us is delivered to us within 30 days of our delivery to Mr. Grube of a notice of termination (as defined in the employment agreement), it is reasonably likely that Mr. Grube will be able to resume his duties on a regular basis within 90 days of the notice of termination and (ii) Mr. Grube does resume such duties within such time.

Change of Control Pursuant to Long-Term Incentive Plan

Upon a Change of Control, all outstanding awards granted pursuant to the Long-Term Incentive Plan shall automatically vest and be payable at their maximum target level or become exercisable in full, as the case may be, or any restricted periods connected to the award shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. We provided these "single-trigger" change of control benefits because we believed such benefits were important retention tools for us, as providing for accelerated vesting of awards under the Long-Term Incentive Plan upon a Change of Control enables employees, including the named executive officers, to realize value from these awards in the event that we go through a change of control transaction. In addition, we believed that it was important to provide the named executive officers with a sense of stability, both in the middle of transactions that may create uncertainty regarding their future employment and post-termination as they seek future employment. Whether or not a change of control results in a termination of our officers' employment with us or a successor entity, we wanted to provide our officers with certain guarantees regarding the importance of equity incentive compensation awards they were granted prior to that change of control. Further, we believe that change of control protection allows management to focus their attention and energy on the business transaction at hand without any distractions regarding the effects of a change of control. Also, we believe that such protection maximizes unitholder value by encouraging the named executive officers to review objectively any proposed transaction in determining whether such proposed transaction is in the best interest of our unitholders, whether or not the executive will continue to be employed.

For purposes of the Long-Term Incentive Plan, a Change of Control shall be deemed to have occurred upon one or more of the following events: (i) any person or group, other than a person or group who is our affiliate, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of fifty percent (50%) or more of the voting power of our outstanding equity interests; (ii) a person or group, other than our general partner or one of our general partner's affiliates, becomes our general partner; or (iii) the sale or other disposition, including by liquidation or dissolution, of all or substantially all of our assets or the assets of our general partner in one or more transactions to any person or group other than an a person or group who is our affiliate. However, in the event that an award is subject to Code Section 409A, a Change of Control shall have the same meaning as such term in the regulations or other guidance issued with respect to Code Section 409A for that particular award.

Under the Long-Term Incentive Plan, awards that were outstanding as of December 31, 2017, will also accelerate upon a termination due to death, disability or a normal retirement upon or after reaching the age of 66. The board of directors has the final authority to determine if a disability is permanent or of a long-term duration resulting in termination from us. A "disability" per the terms of the Long-Term Incentive Plan grant means (i) a participant's inability to engage in any substantial gainful activity by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, or (ii) the participant is, by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, receiving income replacement benefits for a period of not less than 3 months under one of our accident and health plans. We have determined that providing acceleration of the Long-Term Incentive Plan awards upon a death or disability is appropriate because the termination of a participant's employment with us due to such an occurrence is often an unexpected event, and it is our belief that providing an immediate value to the participant or his family, as appropriate, in such a situation is a competitive retention tool. We also believe that providing for acceleration upon a normal retirement is appropriate due to the fact that the definition of a normal retirement requires an executive to remain employed with us until late in his career, and the acceleration of their equity awards upon such an event provides the executives with a reassurance that they will receive value for their awards at the end of their career. We have determined that it is in the unitholders' best interest to provide such retention tools with respect to our equity compensation awards due to the fact that we strive to retain a high level of executive talent while competing in a very aggressive industry.

Change of Control with Respect to Deferred Compensation Plan Participants

The Deferred Compensation Plan provides the executives with the opportunity to defer all or a portion of their eligible compensation each year. At the time of their deferral election, the executive may choose a day in the future in which a payout from the plan will occur with regard to their vested account balance, or, if earlier, the payout of vested accounts will occur upon the executive's termination from service for any reason. Despite the executive's payout election date, however, the Deferred Compensation Plan accounts will also receive accelerated vesting and a pay out in the event of the executive's termination from service due to death, disability or normal retirement, or upon the occurrence of a Change of Control.

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A “disability” under the Deferred Compensation Plan means (i) a participant’s inability to engage in any substantial gainful activity by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, or (ii) the participant is, by reason of a physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of 12 months, receiving income replacement benefits for a period of not less than 3 months under one of our accident and health plans. A “normal retirement” means a participant’s termination of employment on or after the date that he or she reaches the age of 66.

There are various connections between the Deferred Compensation Plan and the Long-Term Incentive Plan. A “Change of Control” for the Deferred Compensation Plan shall have the same definition as that term within the Long-Term Incentive Plan noted above. Our compensation committee also has the discretion to pay Deferred Compensation Plan accounts in either cash or our common units. In the event that a Deferred Compensation Plan account is settled in our common units, those units will be issued pursuant to the Long-Term Incentive Plan. For purposes of this disclosure we have assumed that the compensation committee would determine to settle the Deferred Compensation Plan accounts solely in our common units, meaning that the amounts below would reflect the fair market value of common units that could be issued pursuant to the Long-Term Incentive Plan in connection with a termination of employment or a Change of Control. Please note that the compensation committee’s decision regarding such a settlement could not be determined with any certainty until such an event actually occurred.

The table below reflects the amount of compensation payable to our named executive officers in the event of a termination of employment or a change in control of the Company on December 31, 2017. For purposes of calculating the potential payments, we have made certain assumptions that we have determined to be reasonable and relevant to our unitholders.

Name	Benefits	Termination by Us Without Cause, or Good Reason Termination by Executive	Termination by Us for Cause, or Without Good Reason Termination by Executive	Termination by Us Without Cause, or Good Reason Termination, in Connection with a Change in Control	Termination Due to Death or Disability	Change in Control
Timothy Go	Base Salary (1)	$ 750,000	$ —	$ 1,500,000	$ —	$ —
	Compensation Incentive Awards (2)	656,250	—	1,312,500	437,500	—
	Long-Term Incentive Plan (3)	5,567,974	2,097,657	4,911,724	4,692,974	3,201,099
	Post-Employment Health Care (5)	37,055	—	55,583	—	—
	Outplacement Assistance (6)	50,000	—	50,000	—	—
	Total	$ 7,061,279	$ 2,097,657	$ 7,829,807	$ 5,130,474	$ 3,201,099
F. William Grube	Base Salary (1)	$ 1,363,089	$ —	$ 1,363,089	$ —	$ —
	Compensation Incentive Awards (2)	227,182	—	227,182	227,182	—
	Long-Term Incentive Plan (3)	187,110	62,370	187,110	187,110	187,110
	Deferred Compensation Plan (4)	278,655	278,655	278,655	278,655	278,655
	Total	$ 2,056,036	$ 341,025	$ 2,056,036	$ 692,947	$ 465,765
D. West Griffin	Long-Term Incentive Plan (3)	$ 866,250	$ 866,250	$ 866,250	$ 866,250	$ 866,250

	Total	$ 866,250	$ 866,250	$ 866,250	$ 866,250	$ 866,250
Bruce A. Fleming	Long-Term Incentive Plan (3)	$ 1,259,173	$ 708,477	$ 1,259,173	$ 1,259,173	$ 1,259,173
	Total	$ 1,259,173	$ 708,477	$ 1,259,173	$ 1,259,173	$ 1,259,173
William A. Anderson	Long-Term Incentive Plan (3)	$ 372,488	$ 344,768	$ 372,488	$ 372,488	$ 372,488
	Total	$ 372,488	$ 344,768	$ 372,488	$ 372,488	$ 372,488

(1) As per his employment agreement, Mr. Go will receive 3 times his base salary if a qualifying termination occurs within twenty-four months following a Change in Control ("Change in Control Period") or 1.5 times his base salary if the qualifying termination occurs at any time other than the Change in Control Period and Mr. Grube will receive 3 times his base salary.

(2) As per their employment agreements, for termination due to death or disability, Messrs. Go and Grube will be entitled to receive a pro rata portion of any incentive compensation awards for the bonus year in which the termination occurs. For termination for good reason by the executive or by us without cause, Mr. Go will be entitled to 3 times his cash incentive bonus if a qualifying termination occurs with the Change in Control Period or 1.5 times his cash incentive bonus if the termination occurs at any time other than the Change in Control Period and Mr. Grube will be entitled to receive a

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pro rata portion of any compensation incentive awards for the bonus year in which the termination occurs. For termination without good reason by executive or by us with cause, Messrs. Go and Grube will not be entitled to any pro rata portion of incentive compensation awards.

(3) All amounts assume that the executives received full vesting of equity awards due to the applicable qualifying termination or Change in Control event, and the value of all phantom units pursuant to equity awards under the Long-Term Incentive Plan were valued at our December 29, 2017 (the last trading day of the fiscal year), closing common unit price of $7.70. As required pursuant to Section 409A of the Code, in the event that any of the executives are also “key employees” as defined in Section 409A of the Code at the time a settlement would become due, we would delay the settlement of such an executive’s equity awards until the first day of the seventh month following the applicable event requiring settlement of equity awards under the Long-Term Incentive Plan.

(4) Amounts assume that the executives received full vesting of the accounts due to the applicable qualifying termination or Change in Control event or in the event of termination for cause, just the vested balance, and the value of all phantom units held in the Deferred Compensation Plan accounts was valued at our December 29, 2017 (the last trading day of the fiscal year), closing common unit price of $7.70. As required pursuant to Section 409A of the Code, in the event that any of the executives are also “key employees” as defined in Section 409A of the Code at the time a settlement would become due, we would delay the settlement of such an executive’s account until the first day of the seventh month following the applicable event requiring settlement of the Deferred Compensation Plan account.

(5) Per the employment agreement of Mr. Go, in connection with certain qualifying terminations, if the executive timely and properly elects continuation coverage under the Company’s group health plans pursuant to the Consolidated Omnibus Reconciliation act of 1985 (“COBRA”) then: (i) the Company shall reimburse the executive for the difference between the monthly amount the executive pays to effect and continue such coverage for himself and spouse and eligible dependents, if any, and the monthly employee contribution amount that active similarly situated employees of the Company pay for the same or similar coverage under such group health plans; and (ii) on and after the date the executive is no longer eligible to receive COBRA continuation coverage, if the executive has not become eligible to receive coverage under a group health plan sponsored by another employer, then the Company shall pay a lump sum cash payment equal to the product of (x) the monthly reimbursement amount and (y) (A) if such termination does not occur within the Change of Control Period, 18 and (B) if such termination occurs within the Change in Control Period, 24.

(6) Per the employment agreement for Mr. Go, in connection with certain qualifying terminations, for the 12-month period beginning on his termination date, or until the executive begins other full-time employment with a new employer, whichever occurs first, the executive shall be entitled to receive outplacement services that are directly related to the termination of the executive’s employment and are provided by a nationally prominent executive outplacement services firm, provided however, that the total amount of the expenses paid by Company shall not exceed $50,000. A maximum payment is assumed to be made.

In connection with the termination of Mr. Murray’s employment on November 1, 2017, we entered into a severance and general release agreement with Mr. Murray, pursuant to which Mr. Murray is entitled to a severance payment of $353,057. The severance agreement further provided for accelerated vesting for any unvested phantom units, free and clean title to his company automobile, reimbursed for fourteen months of COBRA insurance coverage and paid unused vacation.

Compensation of Directors

Officers or employees of our general partner who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each director who is not an officer or employee of our general partner receives an annual fee as well as compensation for attending meetings of the board of directors and board committee meetings. For 2017, we determined to pay all director compensation in arrears for the 2017 year, therefore there is no compensation reportable in the Director Compensation Table below for 2017. However, our non-employee directors were entitled to fees and equity awards for 2017 that consisted of the following:

- an annual fee of $70,000;

- an annual award of restricted or phantom units with a market value of approximately $100,000;
- an audit committee and strategy and growth committee chair annual fee of $10,000;
- a non-chair audit committee member annual fee of $6,000;
- a non-chair strategy and growth committee annual fee of $5,000;
- a conflicts committee and compensation committee chair annual fee of $8,000;
- a non-chair conflicts committee and compensation committee annual fee of $4,000;
- all other committee chair annual fee of $5,000s; and
- all other committee member annual fee of $2,500.

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With respect to the 2017 year, the Board determined that all cash fees earned in the 2017 year would be paid in the form of phantom unit awards granted pursuant to our Long-Term Incentive Plan in the first quarter of 2018. To determine the number of phantom units to be granted in lieu of such cash fees, the cash value of all fees earned during each quarter of 2017 were divided by the closing price of our common units on the last business day of each applicable quarter. In previous years the directors could elect to receive phantom units under our Deferred Compensation Plan in lieu of receiving cash fees. If the directors elected phantom units rather than cash, they would have received one matching phantom unit for each three phantom units deferred into the Deferred Compensation Plan. As the directors did not defer fees from 2017 into the Deferred Compensation Plan, the Board determined to credit each director with one additional phantom unit for each three phantom units earned during each quarter in 2017 (the "Matching Units"). Following the end of the 2017 year, all phantom units deemed to be earned during 2017, including the Matching Units, were granted to the directors with a three year vesting schedule.

In addition, we reimburse each non-employee director for his or her out-of-pocket expenses incurred in connection with attending meetings of the board of directors or board committees. Under certain circumstances, we will also indemnify each director for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth certain compensation information of our non-employee directors for the year ended December 31, 2017:

Director Compensation Table for 2017

Name	Fees Earned or Paid in Cash [(1)]	Unit Awards [(2)]	Total
Fred M. Fehsenfeld, Jr.	$18,750	$ 6,252	$25,002
James S. Carter	$21,000	$ 7,000	$28,000
Robert E. Funk	$20,125	$ 8,708	$28,833
Stephen P. Mawer	$20,250	$ —	$20,250
George C. Morris III [(3)]	$20,000	$ 6,668	$26,668
Daniel J. Sajkowski	$18,750	$ 6,252	$25,002
Amy M. Schumacher	$18,750	$ 6,252	$25,002

(1) Includes fees related to fiscal year 2016 earned in 2017. As noted above, the cash fees earned by each non-employee director in 2017 were paid in the form of phantom unit awards that were granted on March 7, 2018. Because the grant date of those phantom units occurred in 2018, the awards will be reflected within the Director Compensation table for 2018.

(2) The amounts in this column are calculated based on the aggregate grant date fair value of matching phantom unit awards granted to those non-employee directors who deferred all of the 2016 fees they earned in 2017 pursuant to the Deferred Compensation. No phantom units were granted for 2017 until March 7, 2018. Due to the timing of the 2017 grants, the phantom units granted with respect to the 2017 year are not reflected within the table above, but will instead be included within the Director Compensation table for the 2018 year as applicable.

(3) Mr. Morris resigned from the board of directors on March 28, 2017.

Annual Phantom Unit Awards and Matching Units

As noted above, the 2017 annual grants and the Matching Units were not granted to the directors until after the end of the 2017 year. The number of phantom units granted in March 2018 with respect to the 2017 annual grant and the 2017 Marching Units are disclosed in the table below.

Annual Director Phantom Unit Awards

	Grant Date	Number of Units Granted (#) [(1)]	Number of Matching Units Granted (#) [(2)]	Aggregate Grant Date Fair

				Value
Fred M. Fehsenfeld, Jr.	March 7, 2018	24,722	4,677	$ 240,280
James S. Carter	March 7, 2018	26,404	5,236	$ 257,088
Robert E. Funk	March 7, 2018	27,340	5,548	$ 266,448
Stephen P. Mawer	March 7, 2018	26,872	5,392	$ 261,768
Daniel J. Sajkowski	March 7, 2018	24,722	4,677	$ 240,280
Amy M. Schumacher	March 7, 2018			