HOLLY ENERGY PARTNERS LP
Form 10-K
February 22, 2017

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

FORM 10-K

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

For the fiscal year ended December 31, 2016
OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to _____________
Commission File Number 1-32225

HOLLY ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	20-0833098
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2828 N. Harwood, Suite 1300 Dallas, Texas	75201-1507
(Address of principal executive offices)	(Zip Code)

(214) 871-3555
Registrant’s telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:
Common Limited Partner Units

Securities registered pursuant to 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 ý 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 ý
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 ý 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. ý

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 ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $1.3 billion on June 30, 2016, the last day of the registrant's most recently completed second fiscal quarter, based on the last sales price as quoted on the New York Stock Exchange on such date.

The number of the registrant’s outstanding common limited partners units at February 17, 2017 was 62,780,503.

DOCUMENTS INCORPORATED BY REFERENCE: None

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PART I

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains certain “forward-looking statements” within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Form 10-K, including, but not limited to, those under “Business”, “Risk Factors” and “Properties” in Items 1, 1A and 2 and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7, are forward-looking statements. Forward looking statements use words such as “anticipate,” “project,” “expect,” “plan,” “goal,” “forecast,” “intend,” “should,” “would,” “could,” “may,” and similar expressions and statements regarding our plans and objectives for future operations. These statements are based on our beliefs and assumptions and those of our general partner using currently available information and expectations as of the date hereof, are not guarantees of future performance and involve certain risks and uncertainties. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give assurance that our expectations will prove to be correct. All statements concerning our expectations for future results of operations are based on forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- risks and uncertainties with respect to the actual quantities of petroleum products and crude oil shipped on our pipelines and/or terminalled, stored or throughput in our terminals;
- the economic viability of HollyFrontier Corporation, Alon USA, Inc. and our other customers;
- the demand for refined petroleum products in markets we serve;
- our ability to purchase and integrate future acquired operations;
- our ability to complete previously announced or contemplated acquisitions;
- the availability and cost of additional debt and equity financing;
- the possibility of reductions in production or shutdowns at refineries utilizing our pipeline and terminal facilities;
- the effects of current and future government regulations and policies;
- our operational efficiency in carrying out routine operations and capital construction projects;
- the possibility of terrorist attacks and the consequences of any such attacks;
- general economic conditions; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our Securities and Exchange Commission filings.

Cautionary statements identifying important factors that could cause actual results to differ materially from our expectations are set forth in this Form 10-K, including, without limitation, the forward-looking statements that are referred to above. When considering forward-looking statements, you should keep in mind the known material risk factors and other cautionary statements set forth in this Form 10-K under “Risk Factors” in Item 1A. All forward-looking statements included in this Form 10-K and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INDEX TO DEFINED TERMS AND NAMES

The following terms and names that appear in this form 10-K are defined on the following pages:

Items 1 and 2. Business and Properties

OVERVIEW

Holly Energy Partners, L.P. (“HEP”) is a Delaware limited partnership engaged principally in the business of operating a system of petroleum product and crude pipelines, storage tanks, distribution terminals, loading rack facilities and refinery processing units in West Texas, New Mexico, Utah, Nevada, Oklahoma, Wyoming, Kansas, Arizona, Idaho and Washington. We were formed in Delaware in 2004 and maintain our principal corporate offices at 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. Our telephone number is 214-871-3555 and our internet website address is www.hollyenergy.com. The information contained on our website does not constitute part of this Annual Report on Form 10-K. A copy of this Annual Report on Form 10-K will be provided without charge upon written request to the Vice President, Investor Relations at the above address. A direct link to our filings at the U.S. Securities and Exchange Commission (“SEC”) website is available on our website on the Investors page. Also available on our website are copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics, all of which will be provided without charge upon written request to the Vice President, Investor Relations at the above address. In this document, the words “we,” “our,” “ours” and “us” refer to HEP and its consolidated subsidiaries or to HEP or an individual subsidiary and not to any other person. “HFC” refers to HollyFrontier Corporation and its subsidiaries, other than HEP and its subsidiaries and other than Holly Logistic Services, L.L.C. (“HLS”), a subsidiary of HollyFrontier Corporation that is the general partner of the general partner of HEP and manages HEP.

We own and operate petroleum product and crude pipelines, terminal, tankage and loading rack facilities, and refinery processing units that support the refining and marketing operations of HFC in the Mid-Continent, Southwest and Northwest regions of the United States and Alon USA, Inc.’s (“Alon”) refinery in Big Spring, Texas. HFC owns a 37% interest in us, including the 2% general partner interest and a 35% limited partnership interest. Our assets are categorized into a Pipelines and Terminals segment and a Refinery Processing Unit segment. Segment disclosures are discussed in Note 14 to our consolidated financial statements in Part II, Item 8.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling and storing refined products and other hydrocarbons, providing other services at our storage tanks and terminals and charging a tolling fee per barrel or thousand standard cubic feet of feedstock throughput in our refinery processing units. We do not take ownership of products that we transport, terminal, store or process, and therefore, we are not directly exposed to changes in commodity prices.

We have a long-term strategic relationship with HFC. Our growth plan is to continue to pursue purchases of logistic and other assets at HFC's existing refining locations in New Mexico, Utah, Oklahoma, Kansas and Wyoming. We also expect to work with HFC on logistic asset acquisitions in conjunction with HFC’s refinery acquisition strategies. Furthermore, we will continue to pursue third-party logistic asset acquisitions that are accretive to our unitholders and increase the diversity of our revenues.

PIPELINES AND TERMINALS

Pipelines

Our refined product pipelines transport light refined products from HFC’s Navajo refinery in New Mexico and Alon’s Big Spring refinery in Texas to their customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Utah, and Oklahoma and from various refineries in Utah, Wyoming, and Montana (including HFC's Woods Cross refinery in Utah) to Las Vegas, Nevada and Cedar City, Utah. The refined products transported in these pipelines include conventional gasolines, federal, state and local specification reformulated gasoline, low-octane gasoline for oxygenate blending, distillates that include high- and low-sulfur diesel and jet fuel and liquefied petroleum gases ("LPGs") (such as propane, butane and isobutane).

Our intermediate product pipelines consist principally of three parallel pipelines that connect the Navajo refinery, Lovington and Artesia facilities. These pipelines primarily transport intermediate feedstocks and crude oil for HFC’s refining operations in New Mexico. We also own pipelines that transport intermediate product and gas between HFC's Tulsa East and West refinery facilities.

Our crude pipelines consist of crude oil trunk, gathering and connection pipelines located in West Texas, New Mexico, Kansas and Oklahoma that deliver crude oil to HFC's Navajo and El Dorado refineries and crude oil pipelines that support HFC’s Woods Cross refinery.

Our pipelines are regularly inspected, are well maintained and, we believe, are in good repair. Generally, other than as may be provided in certain pipelines and terminal agreements, substantially all of our pipelines are unrestricted as to the direction in which product flows and the types of crude and refined products that we can transport on them. The Federal Energy Regulatory Commission

("FERC") regulates the transportation tariffs for interstate shipments on our refined product pipelines and state regulatory agencies regulate the transportation tariffs for intrastate shipments on our pipelines.

HFC shipped an aggregate of 62% of the petroleum products transported on our refined product pipelines and 95% of the throughput volumes transported on our intermediate pipelines in 2016. HFC is the only shipper on our crude pipelines.

The following table details the average aggregate daily number of barrels of petroleum products transported on our pipelines in each of the periods set forth below for HFC and for third parties.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Volumes transported for barrels per day ("bpd"):					
HFC	542,762	558,027	457,014	397,359	405,718
Third parties	75,909	73,555	64,055	63,337	63,152
Total	618,671	631,582	521,069	460,696	468,870
Total barrels in thousands (“mbbls”)	226,434	230,527	190,190	168,154	171,606

Our pipeline assets are managed by geographic region; significant pipeline assets are grouped accordingly and described below.

Mid-Continent Region

Tulsa, Oklahoma Interconnect Pipelines
Five pipelines, totaling seven miles, move intermediate product and gas between HFC’s Tulsa East and West refinery facilities.

El Dorado Crude Delivery Pipeline
This 2-mile pipeline supplies HFC's El Dorado Refinery facility with crude oil from HEP's El Dorado crude tankage. HFC is the only shipper on this line.

Osage Pipe Line Company LLC
This 135-mile pipeline supplies HFC's El Dorado Refinery with crude oil from Cushing, Oklahoma and also has a connection to the Jayhawk pipeline that services the CHS refinery in McPherson, Kansas. HEP has a 50% interest in this entity and is the operator of the pipeline.

Cheyenne Pipeline LLC
This 87-mile crude oil pipeline runs from Fort Laramie, Wyoming to Cheyenne, Wyoming. HEP owns a 50% interest in this entity; the pipeline is operated by an affiliate of Plains All American Pipeline, L.P. ("Plains").

Southwest Region

Artesia, New Mexico to El Paso, Texas
These 371 miles of pipeline are comprised of four main segments which are regulated by the FERC. The segments primarily ship refined product produced at the Navajo refinery to HFC's El Paso terminal: (1) 156 miles of 6-inch pipeline from HFC's Navajo refinery to HFC's El Paso terminal, (2) 82 miles of 12-inch pipeline from HFC's Navajo refinery to our Orla tank farm, (3) 126 miles from our Orla tank farm to outside El Paso and (4) 7 miles from outside El Paso to HFC's El Paso terminal. There are two shippers on the latter two segments, HFC and Alon, and HFC is the only shipper on the first two segments.

Refined products destined to HFC's El Paso terminal are delivered to common carrier pipelines for transportation to Arizona, northern New Mexico and northern Mexico and to the terminal's truck rack for local delivery by tanker truck.

Artesia, New Mexico to Moriarty, New Mexico

The Artesia to Moriarty refined product pipeline consists of a 60 mile segment that extends from HFC's Navajo refinery Artesia facility to White Lakes Junction, New Mexico, and another 155 mile segment that extends from White Lakes Junction to our Moriarty terminal, where it also connects to our Moriarty to Bloomfield pipeline. HEP owns the segment from Artesia to White Lakes Junction and leases the segment from White Lakes Junction to Moriarty from Mid-America Pipeline Company, LLC ("Mid-America") under a long-term lease agreement which expires in 2027. The current monthly lease payment is $530,000 (subject to adjustments for changes in Producer Price Index ("PPI")) to the owner/operator, Mid-America. HFC is the only shipper on this pipeline.

Moriarty, New Mexico to Bloomfield, New Mexico
This 191-mile pipeline is leased from Mid-America and ships refined product from Moriarty to Western Refining's terminal in Bloomfield and our Bloomfield terminal, which is currently idled. This pipeline is operated by Mid-America (or its designee), and HFC is the only shipper on this pipeline.

Big Spring, Texas to Abilene and Wichita Falls, Texas
These two pipelines carry refined product produced at Alon's Big Spring refinery to the Abilene and Wichita Falls terminals and span 100 miles from Big Spring to Abilene and 227 miles from Big Spring to Wichita Falls. Alon is the only shipper on these pipelines.

Wichita Falls, Texas to Duncan, Oklahoma
This 47-mile, common carrier pipeline is regulated by the FERC and transports refined product from the Wichita Falls terminal to Alon's Duncan terminal. Alon is the only shipper on this pipeline.

Midland, Texas to Orla, Texas
This 135-mile pipeline is used for the shipment of refined product from Midland to our tank farm at Orla (refined product produced at Alon's Big Spring refinery). Alon is the only shipper on this pipeline.

Intermediate pipelines between Lovington, New Mexico and Artesia, New Mexico
Two of the three 65-mile pipelines are used for the shipment of intermediate feedstocks, crude oil and LPGs from HFC's Navajo refinery Lovington facility to its Artesia facility. The third pipeline is used to supply both HFC's Navajo refinery Artesia and Lovington facilities with crude oil from the Barnsdall and Beeson gathering systems. This third pipeline can also connect to the Roadrunner pipeline (described below). HFC is the primary shipper on these pipelines.

Roadrunner pipeline
The 69-mile Roadrunner crude oil pipeline connects the Navajo refinery Lovington facility to a terminal on the Centurion Pipeline in Slaughter, Texas that extends to Cushing, Oklahoma. This pipeline is currently used to deliver crude oil from Lovington to Slaughter, but has been reversed in prior years for the shipment of crude oil from Cushing, Oklahoma to the Navajo refinery Lovington facility.

New Mexico and Texas crude oil pipelines
The 802-mile network of crude oil gathering and trunk pipelines deliver crude oil to HFC’s Navajo refinery from New Mexico and Texas. The crude oil trunk pipelines consist of nine pipeline segments that deliver crude oil to the Navajo refinery Lovington facility and fourteen pipeline segments that deliver crude oil to the Navajo refinery Artesia facility. The crude oil gathering pipelines connect crude leases and crude gathering hubs to the crude oil trunk pipeline system.

New Mexico crude expansion pipelines
HEP constructed three pipelines to expand on the existing network of New Mexico crude oil pipelines discussed above. They include (1) the 46-mile Beeson pipeline which delivers crude oil from the crude oil gathering system to the Navajo refinery Lovington facility and the Roadrunner Pipeline (2) the 61-mile Whites City crude pipeline which delivers crude oil from HEP's Whites City Road crude truck off-loading station to Artesia Station and (3) the 13-mile Bisti connector pipeline which delivers crude oil from HEP's Beeson Crude Station to the Plains All-American Bisti Pipeline.

Northwest Region

Utah refined product pipelines

The Utah refined product pipelines consist of four pipeline segments: (1) a 2-mile segment from Woods Cross, UT to Pioneer Pipe Line Company's terminal is used for product shipments to and through the Pioneer terminal (2) another 2-mile segment is used to ship refined product from HFC's Woods Cross refinery to the UNEV pipeline origin pump station (3) a 4-mile segment from HFC's Woods Cross refinery to Chevron Pipeline’s Salt Lake City products pipeline is used for product shipments from HFC’s Woods Cross refinery to Tesoro Logistics LP's Northwest Pipeline origin station (4) in 2016, HEP completed construction of the fourth 1- mile segment which will be used to move refined product from Chevron's Salt Lake City refining facility into the UNEV pipeline origin pump station. HFC is the only shipper on the three former segments and Chevron is the only shipper on the fourth, common carrier segment.

UNEV refined product pipeline
The 427-mile UNEV products pipeline is used for the shipment of refined products from Woods Cross, Utah to terminals in Las Vegas, Nevada and Cedar City, Utah. HFC and Sinclair Transportation Company (“Sinclair”) are the primary shippers on this

pipeline. This pipeline is owned by UNEV Pipeline, LLC ("UNEV"). HEP owns a 75% interest in UNEV and HEP is the operator of this pipeline.

SLC Pipeline LLC
This 95-mile crude oil pipeline ("SLC Pipeline") is used to transport crude into the Salt Lake City, Utah area from the Utah terminus of the Frontier Pipeline (described below) as well as crude flowing from Wyoming and Utah via the Plains Rocky Mountain pipeline. HEP owns a 25% interest in this entity; the pipeline is operated by an affiliate of Plains.

Frontier Aspen LLC
This 289-mile crude oil pipeline ("Frontier Pipeline") spans from Casper, Wyoming to Frontier Station, Utah through a connection to the SLC Pipeline. HEP owns a 50% interest in this entity; the pipeline is operated by an affiliate of Plains.

The following table sets forth certain operating data for each of our refined product, intermediate and crude pipelines, most of which are described above. We calculate the capacity of our pipelines based on the throughput capacity for barrels of refined product, intermediate or crude that may be transported in the existing configuration; in some cases, this includes the use of drag reducing agents.

Origin and Destination	Diameter (inches)	Length (miles)	Capacity (bpd)	
Refined Product Pipelines:				
Artesia, NM to El Paso, TX	6	156	19,000	
Artesia, NM to Orla, TX to El Paso, TX	8/12/8	215	70,000	(1)
Artesia, NM to Moriarty, NM(2)	12/8	215	27,000	(3)
Moriarty, NM to Bloomfield, NM(2)	8	191	14,400	(3)
Big Spring, TX to Abilene, TX	6/8	100	20,000	
Big Spring, TX to Wichita Falls, TX	6/8	227	23,000	
Wichita Falls, TX to Duncan, OK	6	47	21,000	
Midland, TX to Orla, TX	8/10	135	25,000	
Artesia, NM to Roswell, NM	4	35	5,300	(7)
Mountain Home, ID	4	13	6,000	
Woods Cross, UT	10/12/8	8	70,000	
Woods Cross, UT to Las Vegas, NV	12	427	62,000	
Salt Lake City, UT to UNEV Pipeline, UT	10	1	60,000	
Tulsa, OK(4)				
Intermediate Product Pipelines:				
Lovington, NM to Artesia, NM	8	65	48,000	
Lovington, NM to Artesia, NM	10	65	72,000	
Lovington, NM to Artesia, NM	16	65	98,400	
Tulsa, OK(5)	8/10/12	7		(5)
Evans Junction to Artesia, NM	8	12	107	(6)
Crude Pipelines:				
Artesia Region Gathering	Various	497	70,000	
West Texas Gathering	Various	305	35,000	
Roadrunner Pipeline	16	69	62,400	
Beeson Pipeline	8/10	46	95,000	
El Dorado Crude Delivery Pipeline	16	4	165,000	
Bisti Connection Pipeline	12	13	82,000	
Whites City Pipeline	8	8	40,000	

(1) Includes 15,000 bpd capacity on the Orla to El Paso segment of this pipeline, leased to Alon under capacity lease agreements.
(2) The White Lakes Junction to Moriarty segment of our Artesia to Moriarty pipeline and the Moriarty to Bloomfield pipeline is leased from Mid-America under a long-term lease agreement.
(3) Capacity for this pipeline is reflected in the information for the Artesia to Moriarty pipeline.
(4) Tulsa gasoline and diesel fuel connections to Magellan’s pipeline are less than one mile.

(5) The capacities of the three gas pipelines are 10 million standard cubic feet per day ("MMSCFD"), 22 MMSCFD and 10 MMSCFD, and the two liquid pipelines are 45,000 bpd and 60,000 bpd.
(6) The capacity is in MMSCFD per day.
(7) Pipeline is currently idled.

Terminals, Loading Racks and Refinery Tankage

Our refined product terminals receive products from pipelines connected to HFC's refineries and Alon's Big Spring refinery. We then distribute them to HFC and third parties, who in turn deliver them to end-users and retail outlets. Our terminals are generally complementary to our pipeline assets and serve HFC's and Alon's marketing activities and other customers. Terminals play a key role in moving product to the end-user market by providing the following services:

- distribution;
- blending to achieve specified grades of gasoline and diesel, including the blending of butane, ethanol and biodiesel;
- other ancillary services that include the injection of additives and filtering of jet fuel; and
- storage and inventory management.

Typically, our refined product terminal facilities consist of multiple storage tanks and are equipped with automated truck loading equipment that operates 24 hours a day. This automated system provides for control of security, allocations, and credit and carrier certification by remote input of data by our customers. In addition, nearly all of our terminals are equipped with truck loading racks capable of providing automated blending to individual customer specifications.

Our refined product terminals derive most of their revenues from terminalling fees paid by customers. We charge a fee for transferring refined products from the terminal to trucks or to pipelines connected to the terminal. In addition to terminalling fees, we generate revenues by charging our customers fees for storage, blending, injecting additives, and filtering jet fuel. HFC currently accounts for the substantial majority of our refined product terminal revenues.

Our crude terminal receives crude from the Osage pipeline and derives most of its revenues from throughput charges.

The table below sets forth the total average throughput for our refined product and crude terminals in each of the periods presented:

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Refined products and crude terminalled for (bpd):					
HFC	413,487	391,292	261,888	255,108	271,549
Third parties	72,342	78,403	69,100	63,791	53,456
Total	485,829	469,695	330,988	318,899	325,005
Total (mbbls)	177,813	171,439	120,811	116,398	118,952

Our refinery tankage consists of on-site tankage at HFC's refineries. Our refinery tankage derives its revenues from fixed fees or throughput charges in providing HFC's refining facilities with approximately 10,377,000 barrels of storage.

Our terminals, loading racks and refinery tankage are managed by geographic region; significant assets are grouped accordingly and described below.

Mid-Continent Region

Cheyenne, Wyoming facility truck racks

The Cheyenne loading rack facilities consist of light refined product, heavy product and LPG truck racks. These racks load refined product and propane onto tanker trucks for delivery to markets in surrounding areas. Additionally, these facilities include four crude oil Lease Automatic Custody Transfer ("LACT") units that unload crude oil from tanker trucks.

El Dorado, Kansas crude tankage

On March 6, 2015, we acquired an existing crude tank farm from an unrelated party. The crude tank farm is adjacent to HFC's El Dorado Refinery and is used, primarily, to store and supply crude oil for this refinery facility. HFC is the main customer of this crude tank farm.

El Dorado, Kansas facility truck racks
The El Dorado loading rack facilities consist of a light refined products truck rack and a propane truck rack. These racks load refined products and propane onto tanker trucks for delivery to markets in surrounding areas.

Tankage at HFC refinery facilities
At HFC's Cheyenne, El Dorado, and Tulsa refinery facilities, HEP owns refined product, intermediate and crude tankage that support these refineries in production and distribution. HFC is the only customer utilizing these tanks.

Tulsa, Oklahoma facilities truck and rail racks
The Tulsa truck and rail loading rack facilities consist of loading racks located at HFC’s Tulsa refinery West and East facilities. Loading racks at the Tulsa refinery West facility consist of rail and truck racks that load refined products and lube oil produced at the refinery onto rail cars and tanker trucks. Loading racks at the Tulsa refinery East facility consist of truck and rail racks at which we load refined products and off load crude. The truck racks also load asphalt and LPG.

Tulsa, Oklahoma tanks
On March 31, 2016, we acquired crude oil tanks from an unrelated party. The crude tank farm is adjacent to HFC's Tulsa Refinery and is used, primarily, to store and supply crude oil for this refinery facility. HFC is the main customer of this crude tank farm.

Southwest Region

Abilene, Texas terminal
This terminal receives refined products from Alon's Big Spring refinery, which accounted for all of its volumes in 2016. Refined products received at this terminal are sold locally via a truck rack or pumped over a 2-mile pipeline to Dyess Air Force Base. Alon is the only customer at this terminal.

Artesia, New Mexico facility truck rack
The truck rack at HFC's Navajo refinery Artesia facility loads light refined product produced at the Navajo refinery onto tanker trucks for delivery to markets in the surrounding area. HFC is the only customer of this truck rack.

Artesia, New Mexico railyard
HEP constructed 8,300 track feet of rail storage on land situated near the railway station of Artesia, New Mexico. HEP leases this land from BNSF Railway Company and subleases the land to HFC. HEP leases the track to HFC and HEP is receiving reimbursement from HFC for the construction costs over the 25 year term of the lease.

Lovington, New Mexico facility asphalt truck rack
The asphalt loading rack facility at HFC's Navajo refinery Lovington facility loads asphalt produced at the Navajo refinery into tanker trucks. HFC is the only customer of this truck rack.

Moriarty, New Mexico terminal
We receive light refined product at this terminal from the Navajo refinery Artesia facility through our pipelines. Refined product received at this terminal is sold locally, via the truck rack. HFC is the only customer at this terminal and there are no competing terminals in Moriarty, New Mexico.

Orla, Texas tank farm
The Orla tank farm receives refined product from Alon's Big Spring refinery. Refined product received at the tank farm is delivered into our Orla to El Paso pipeline segment (described above). Alon is the only customer at this tank farm.

Tankage at HFC refinery facilities

At HFC's Artesia and Lovington refinery facilities, HEP owns crude tankage that supports the refineries in their production of petroleum products. HFC is the only customer utilizing these tanks.

Tucson, Arizona terminal

We own 100% of the improvements and lease the underlying ground at this terminal. Refined product received at the Tucson terminal originate from HFC's Navajo refinery Artesia facility and is transported, on our pipelines, to HFC's El Paso terminal where it connects to Kinder Morgan Energy Partners, L.P.'s East system pipeline that delivers into the Tucson terminal. Refined product received at this terminal is sold locally, via the truck rack. Competition in this market includes terminals owned by Kinder Morgan.

Wichita Falls, Texas terminal
This terminal receives refined product from Alon's Big Spring refinery, which accounted for all of its volumes in 2016. Refined product received at this terminal is sold via a truck rack or shipped via pipeline connections to Alon’s terminal in Duncan, Oklahoma and also to NuStar Energy L.P.’s Southlake Pipeline. Alon is the only customer at this terminal.

Northwest Region

Mountain Home, Idaho terminal
We receive jet fuel from third parties at this terminal that is transported on Tesoro Logistics LP's Salt Lake City to Boise, Idaho pipeline. We then transport the jet fuel from the Mountain Home terminal through our 13-mile pipeline to the United States Air Force base outside of Mountain Home. Our pipeline associated with this terminal is the only pipeline that supplies jet fuel to the air base. We are paid a single fee, from the Defense Energy Support Center, for injecting, storing, testing and transporting jet fuel at this terminal.

Spokane, Washington Terminal
This terminal is connected to the Woods Cross refinery via a Tesoro Logistics common carrier pipeline. The Spokane terminal is also supplied by rail and truck. Refined product received at this terminal is sold locally, via the truck rack. We have several major customers at this terminal. Other terminals in the Spokane area include terminals owned by ExxonMobil and ConocoPhillips.

Tankage at HFC refinery facilities
At HFC's Woods Cross refinery facility, HEP owns crude tankage that supports the refinery in its production of petroleum products. HFC is the only customer utilizing these tanks.

UNEV terminals
UNEV owns two terminals, located in Cedar City, Utah and Las Vegas, Nevada, that receive product primarily from HFC and Sinclair through the UNEV Pipeline, originating in Woods Cross, Utah. Refined product received at these terminals is sold locally.

Woods Cross, Utah facility truck rack
The truck rack at the Woods Cross facility loads light refined product produced at HFC's Woods Cross refinery onto tanker trucks for delivery to markets in the surrounding area. HFC is the only customer of this truck rack.

The following table outlines the locations of our terminals and their storage capacities, number of tanks, supply source, and mode of delivery:

Terminal Location	Storage Capacity (barrels)	Number of Tanks	Supply Source	Mode of Delivery
Moriarty, NM	211,000	9	Pipeline	Truck
Bloomfield, NM [1]	203,000	7	Pipeline	Truck
Tucson, AZ[2]	186,000	9	Pipeline	Truck
Mountain Home, ID[3]	122,000	4	Pipeline	Pipeline
Spokane, WA	384,000	28	Pipeline/Rail	Truck
Abilene, TX	157,000	6	Pipeline	Truck/Pipeline
Wichita Falls, TX	220,000	11	Pipeline	Truck/Pipeline
Las Vegas, NV	378,000	12	Pipeline/Truck	Truck
Cedar City, UT	235,000	7	Pipeline/Rail/Truck	Truck
Orla tank farm	129,000	5	Pipeline	Pipeline
El Dorado, KS crude tankage	1,150,000	11	Pipeline	Pipeline
Artesia facility railyard	N/A	N/A	Rail	Rail
Artesia facility truck rack	N/A	N/A	Refinery	Truck
Lovington facility asphalt truck rack	N/A	N/A	Refinery	Truck
Woods Cross facility truck rack	N/A	N/A	Refinery	Truck/Pipeline
Tulsa West facility truck and rail rack	N/A	N/A	Refinery	Truck/Rail/Pipeline
Tulsa East facility truck and rail racks	N/A	N/A	Refinery	Truck/Rail/Pipeline
Cheyenne facility truck racks	N/A	N/A	Refinery	Truck
El Dorado facility truck racks	N/A	N/A	Refinery	Truck
Total	3,375,000			

(1) Inactive
(2) The underlying ground at the Tucson terminal is leased.
(3) Handles only jet fuel.

The following table outlines the locations of our refinery tankage, storage capacity, tankage type and number of tanks:

Refinery Location	Storage Capacity (barrels)	Tankage Type	Number of Tanks
Artesia , NM	180,000	Crude oil	2
Lovington, NM	309,000	Crude oil	2
Woods Cross, UT	190,000	Crude oil	3
Tulsa, OK	3,855,000	Crude oil and refined product	60
Cheyenne, WY	1,966,000	Crude oil and refined product	56
El Dorado, KS	3,877,000	Refined and intermediate product	85
Total	10,377,000		

CONTROL OPERATIONS OF PIPELINES AND TERMINALS

All of our pipelines are operated via geosynchronous satellite, microwave and radio systems from our central control room located in Artesia, New Mexico. We also monitor activity at our terminals from this control room. The control center operates with state-of-the-art Supervisory Control and Data Acquisition, or SCADA, systems. Our control center is equipped with computer systems designed to continuously monitor operational data, including refined product and crude oil throughput, flow rates, and pressures. In addition, the control center monitors alarms and throughput balances. The control center operates remote pumps, motors, engines, and valves associated with the delivery of refined products and crude oil. The computer systems are designed to enhance leak-detection capabilities, sound automatic alarms if operational conditions outside of pre-established parameters occur, and provide for remote-controlled shutdown of pump stations on the pipelines. Pump stations and meter-measurement points on the pipelines are linked by satellite or telephone communication systems for remote monitoring and control, which reduces our requirement for full-time on-site personnel at most of these locations.

REFINERY PROCESSING UNITS

Our refinery processing units are integrated in HFC's El Dorado, Kansas refinery and HFC's Woods Cross, Utah refinery and are used to support their daily operations, which chemically transform crude oil into various petroleum products, including gasoline, diesel, LPGs, and asphalt.

HFC is committed to supply these units with a minimum feedstock throughput for each calender quarter. HEP has committed that these units yield a certain level of petroleum product. The initial terms for the refinery processing units at HFC's El Dorado and Woods Cross refineries extend through 2030 and 2031, respectively.

The El Dorado units were first operational in the third and fourth quarters of 2015 and the Woods Cross units were first operational in the second quarter of 2016. These units will be operating on a daily basis until they are taken down for large-scale maintenance, which can be every two to four years and could last from two to four weeks. During this maintenance period (turnaround), the minimum feedstock throughput is adjusted so that HFC is not penalized for HEP's maintenance requirements.

HEP's revenue is primarily generated from the minimum throughput commitment, and HEP charges a tolling fee per barrel or thousand standard cubic feet of feedstock throughput. The tolling fee is meant to provide HEP with revenue that surpasses the amount of its expected operating costs, which include natural gas and maintenance. On any calendar month where the cost of natural gas exceeds what is included in the tolling fee, HEP will charge HFC for recovery of this additional cost. Additionally, if operating costs are more than expected after the first calendar year of operation, the tolling fee will be permanently adjusted, one time, to recover these costs. The same type of one-time adjustment will be made upon completion of the first turnaround for each unit.

Our refinery processing units are managed by refinery; significant assets are grouped accordingly and described below.

El Dorado Refinery

Naphtha Fractionation Unit - El Dorado, Kansas refinery facility
The feedstock used by the naphtha fractionation unit is desulfurized naphtha, which is produced by the refinery earlier in the refining process. Desulfurized naphtha is a key component in gasoline, and this unit is used to reduce the level of benzene precursors. This allows the resulting product to be processed further to produce gasoline that meets regulatory requirements. The unit's feedstock capacity is 50,000 bpd of desulfurized naphtha.

Hydrogen Generation Unit - El Dorado, Kansas refinery facility
The hydrogen unit primarily uses natural gas as a feedstock to produce hydrogen gas that is used in HFC's operation of its El Dorado, Kansas refinery. This feedstock is supplied from purchased natural gas. The hydrogen unit's natural gas feedstock capacity is 6,100 thousand standard cubic feet per day.

Woods Cross Refinery

Crude Unit - Woods Cross, Utah refinery facility
The crude unit is comprised of several components, primarily an atmospheric distillation tower, a desalter and heat exchangers, together referred to as the crude unit. The crude unit uses black wax and other crudes as feedstock and is the first step in the refining process to separate crude into refined products. This process is accomplished by heating the crude until it is distilled into various intermediate streams. These intermediate streams are further refined downstream of the crude unit. The initial rejection of major contaminants is also performed by the crude unit. Its feedstock capacity is 15,000 bpd of crude oil.

Fluid Catalytic Cracking Unit - Woods Cross, Utah refinery facility
The fluid catalytic cracking unit ("FCC") is used to convert the high-boiling, high-molecular weight hydrocarbon fractions of crude oil to more valuable products like gasoline, diesel and LPGs. This conversion is performed by the cracking of petroleum hydrocarbons achieved from extremely high temperatures and fluidized catalyst. The FCC's capacity is 8,000 bpd of atmospheric tower bottoms from the crude unit, discussed above, and gas oil.

Polymerization Unit - Woods Cross, Utah refinery facility
The polymerization unit uses the LPGs, propylene and butylene, from the FCC unit and polymerizes them into high octane gasoline blendstock using heat and catalysts. This gasoline blendstock is combined with other blendstocks in the refinery to make finished gasoline. The polymerization unit's feedstock capacity is 2,500 bpd.

ACQUISITIONS

Osage
On February 22, 2016, HFC obtained a 50% membership interest in Osage Pipe Line Company, LLC (“Osage”) in a non-monetary exchange for a 20-year terminalling services agreement, whereby, a subsidiary of Magellan Midstream Partners (“Magellan”) will provide terminalling services for all HFC products originating in Artesia, New Mexico that require terminalling in or through El Paso, Texas. Osage is the owner of the Osage pipeline, a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to HFC’s El Dorado Refinery in Kansas and also has a connection to the Jayhawk pipeline that services the CHS refinery in McPherson, Kansas. The Osage pipeline is the primary pipeline that supplies HFC's El Dorado Refinery with crude oil.

Concurrent with this transaction, we entered into a non-monetary exchange with HFC, whereby we received HFC’s interest in Osage in exchange for our El Paso terminal. Under this exchange, we have also agreed to build two connections on our south products pipeline system that will permit HFC access to Magellan’s El Paso terminal. Effective upon the closing of this exchange, we are the named operator of the Osage pipeline and transitioned into that role on September 1, 2016.

Tulsa Tanks
On March 31, 2016, we acquired crude oil tanks located at HFC’s Tulsa refinery from an affiliate of Plains for $39.5 million. In 2009, HFC sold these tanks to Plains and leased them back, and due to HFC’s continuing interest in the tanks, HFC accounted for the transaction as a financing arrangement. Accordingly, the tanks remained on HFC’s balance sheet and were depreciated for accounting purposes.

Cheyenne Pipeline
On June 3, 2016, we acquired a 50% interest in Cheyenne Pipeline LLC, owner of the Cheyenne pipeline, in exchange for a contribution of $42.6 million in cash to Cheyenne Pipeline LLC. Cheyenne Pipeline LLC will continue to be operated by Plains, which owns the remaining 50% interest. The 87-mile crude oil pipeline runs from Fort Laramie to Cheyenne, Wyoming and has an 80,000 bpd capacity.

Woods Cross Operating
Effective October 1, 2016, we acquired all the membership interests of Woods Cross Operating LLC (“Woods Cross Operating”), a wholly owned subsidiary of HFC, which owns the newly constructed atmospheric distillation tower, FCC, and polymerization unit located at HFC’s Woods Cross refinery, for cash consideration of $278 million. The consideration was funded with approximately $103 million in proceeds from a private placement of 3,420,000 common units representing limited partnership interests at a price of $30.18 per common unit with the balance funded with borrowings under our credit facility. In connection with this transaction, we entered into 15-year tolling agreements containing minimum quarterly throughput commitments from HFC that provide minimum annualized revenues of $56.7 million.

The acquisitions above and their basis of presentation are described further in Notes 1 and 2 in notes to consolidated financial statements of HEP and the descriptions in Notes 1 and 2 are incorporated herein by reference.

AGREEMENTS WITH HFC AND ALON

We serve HFC's refineries under long-term pipeline, terminal, tankage and refinery processing unit throughput agreements expiring from 2019 to 2036. Under these agreements, HFC agrees to transport, store, and process throughput volumes of refined products, crude oil and feedstocks on our pipelines, terminal, tankage, loading rack facilities and refinery processing units that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual rate adjustments on July 1st each year based on the PPI or the FERC index. As of December 31, 2016, these agreements with HFC require minimum annualized payments to us of $321.0 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us the amount of any shortfall in cash by the last day of the month following the end of the quarter. Under certain of the agreements, a shortfall payment may be applied as a credit in the following four quarters after minimum obligations are met.

We have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that also is subject to annual tariff rate adjustments. We also have a capacity lease agreement under which we lease Alon space on our Orla to El Paso pipeline for the shipment of refined product. The terms under this lease agreement expire beginning in 2018 through 2022. As of December 31, 2016, these agreements with Alon require minimum annualized payments to us of $32.6 million.

A significant reduction in revenues under these agreements could have a material adverse effect on our results of operations.

Furthermore, if new laws or regulations that affect terminals or pipelines are enacted that require us to make substantial and unanticipated capital expenditures at the pipelines or terminals, we will have the right after we have made efforts to mitigate their effects to negotiate a monthly surcharge on HFC for the use of the terminals or to file for an increased tariff rate for use of the pipelines to cover HFC's pro rata portion of the cost of complying with these laws or regulations including a reasonable rate of return. In such instances, we will negotiate in good faith with HFC to agree on the level of the monthly surcharge or increased tariff rate.

For additional information regarding our significant customers, see Note 9 to the Consolidated Financial Statements included in Item 8 of Part II of this Form 10-K.

Omnibus Agreement

Under certain provisions of an omnibus agreement we have with HFC (the "Omnibus Agreement"), we pay HFC an annual administrative fee ($2.5 million in 2016) for the provision by HFC or its affiliates of various general and administrative services to us. This fee includes expenses incurred by HFC to perform centralized corporate functions, such as executive management, legal, accounting, treasury, information technology and other corporate services, including the administration of employee benefit plans. This fee does not include the salaries of personnel employed by HFC who perform services for us on behalf of HLS or the cost of their employee benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct expenses they incur on our behalf. In addition, we also pay for our own direct general and administrative costs, including costs relating to operating as a separate publicly held entity, such as costs for preparation of partners' K-1 tax information, SEC filings, investor relations, directors' compensation, directors' and officers' insurance and registrar and transfer agent fees.

Under HLS's secondment agreement with HFC (the "Secondment Agreement"), certain employees of HFC are seconded to HLS, our ultimate general partner, to provide operational and maintenance services for certain of our processing, refining, pipeline and tankage assets at the El Dorado and Cheyenne refineries, and HLS reimburses HFC for its prorated portion of the wages, benefits, and other costs of these employees for our benefit.

CAPITAL REQUIREMENTS

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of, and are expected to continue to consist of, maintenance capital expenditures and expansion capital expenditures. "Maintenance capital expenditures" represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity of existing assets. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations. "Expansion capital expenditures" represent capital expenditures to expand the operating capacity of existing or new assets, whether through construction or acquisition. Expansion capital expenditures include expenditures to acquire assets, to grow our business and to expand existing facilities, such as projects that increase throughput capacity on our pipelines and in our terminals. Repair and maintenance expenses associated with existing assets that are minor in nature and do not extend the useful life of existing assets are charged to operating expenses as incurred.

Each year the board of directors of HLS, our ultimate general partner, approves our annual capital budget, which specifies capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, additional projects may be approved. The funds allocated for a particular capital project may be expended over a period in excess of a year, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year's capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. The 2017 capital budget is comprised of $9 million for maintenance capital expenditures and $30 million for expansion capital expenditures. We expect the majority of the expansion capital budget to be invested in refined product pipeline expansions, crude system enhancements, new storage tanks, and enhanced blending capabilities at our racks. In addition to our capital budget, we may spend funds periodically to perform capital upgrades or additions to our assets where a customer reimburses us for such costs. The upgrades or additions would generally benefit the customer over the remaining life of the related service agreements.

We expect that our currently planned sustaining and maintenance capital expenditures, as well as expenditures for acquisitions and capital development projects, will be funded with cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our senior secured revolving credit facility (the “Credit Agreement”), or a combination thereof. With volatility and uncertainty at times in the credit and equity markets, there may be limits on our ability to issue new debt or equity financing. Additionally, due to pricing movements in the debt and equity markets, we may not be able to issue new debt and equity securities at acceptable pricing. Without additional capital beyond amounts available under the Credit Agreement, our ability to obtain funds for some of these capital projects may be limited.

Under the terms of the transaction to acquire HFC's 75% interest in UNEV, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation and amortization above $30 million beginning July 1, 2016, and ending in June 2032, subject to certain limitations. However, to the extent earnings thresholds are not achieved, no redemption payments are required. No redemption payments have been required to date.

SAFETY AND MAINTENANCE

Many of our pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the Department of Transportation. PHMSA has promulgated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance could result in increased costs.

In addition, many states have adopted regulations, similar to existing PHMSA regulations, for certain intrastate pipelines. For example, Texas has developed regulatory programs that largely parallel the federal regulatory scheme and impose additional requirements for certain pipelines.

We perform preventive and normal maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We also conduct routine and required inspections of our pipelines and other assets as required by regulations. We inject corrosion inhibitors into our mainlines to help control internal corrosion. External coatings and impressed current cathodic protection systems are used to protect against external corrosion. We regularly monitor, test and record the effectiveness of these corrosion-inhibiting systems. We monitor the structural integrity of covered segments of our pipeline systems through a program of periodic internal inspections using both “dent pigs” and electronic “smart pigs”, as well as hydrostatic testing that conforms to federal standards. We follow these inspections with a review of the data, and we make repairs as necessary to ensure the integrity of the pipeline. We have initiated a risk-based approach to prioritizing the pipeline segments for future smart pig runs or other approved integrity testing methods. We believe this approach will allow the pipelines that have the greatest risk potential to receive the highest priority in being scheduled for inspections or pressure tests for integrity. We believe our inspection process substantially complies with all applicable regulatory requirements. Nonetheless, the adoption of new or amended regulations or the reinterpretation of existing laws and regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could possibly have a substantial effect on us and similarly situated midstream operators.

Maintenance facilities containing equipment for pipe repairs, spare parts, and trained response personnel are located along the pipelines. Employees participate in simulated spill deployment exercises on a regular basis. Also they participate in actual spill response boom deployment exercises in planned spill scenarios in accordance with Oil Pollution Act of 1990 requirements. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal and state laws, the regulations prescribed by PHMSA, standards prescribed by the American Petroleum Institute and accepted industry practice.

At our terminals, tanks designed for gasoline storage are equipped with internal or external floating roofs that minimize emissions and prevent potentially flammable vapor accumulation between fluid levels and the roof of the tank. Our terminal facilities have facility response plans, spill prevention and control plans, and other plans and programs to respond to emergencies.

Many of our terminal loading racks are protected with water deluge systems activated by either heat sensors or an emergency switch. Several of our terminals are also protected by foam systems that are activated in case of fire. All of our terminals are subject to participation in a comprehensive environmental management program to assure compliance with applicable air, solid waste, and wastewater regulations.

COMPETITION

As a result of our physical integration with HFC's refineries, our contractual relationship with HFC under the Omnibus Agreement and the HFC pipelines and terminals, tankage and throughput agreements, we believe that we will not face significant competition for barrels of refined products transported from HFC's refineries, particularly during the terms of our long-term transportation agreements with HFC expiring in 2019 through 2036. Additionally, under our throughput agreement with Alon expiring in 2020, we believe that we will not face significant competition for those barrels of refined products we transport from Alon's Big Spring refinery.

However, we do face competition from other pipelines that may be able to supply the end-user markets of HFC or Alon with refined products on a more competitive basis. Additionally, if HFC's wholesale customers reduced their purchases of refined products due to the increased availability of cheaper product from other suppliers or for other reasons, the volumes transported through our pipelines could be reduced, which, subject to the minimum revenue commitments, could cause a decrease in cash and revenues generated from our operations.

The petroleum refining business is highly competitive. Among HFC's competitors are some of the world's largest integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems. HFC competes with independent refiners as well. Competition in particular geographic areas is affected primarily by the amounts of refined products produced by refineries located in such areas and by the availability of refined products and the cost of transportation to such areas from refineries located outside those areas.

In addition, we face competition from trucks that deliver product in a number of areas we serve. Although their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volumes in many areas we serve. The availability of truck transportation places some competitive constraints on us.

Our refined product terminals compete with other independent terminal operators as well as integrated oil companies based on terminal location, price, versatility and services provided. Our competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading arms. Historically, the significant majority of the throughput at our terminal facilities has come from HFC.

RATE REGULATION

Some of our existing pipelines are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for oil pipelines, a category that includes crude oil and petroleum product pipelines, be just and reasonable and not unduly discriminatory. The Interstate Commerce Act permits challenges to rates that are already on file and in effect by complaint. A successful challenge under a complaint may result in the complainant obtaining damages or reparations for up to two years prior to the date the complaint was filed. The Interstate Commerce Act also permits challenges to a proposed new or changed rate by a protest. A successful challenge under a protest may result in the protestant obtaining refunds or reparations from the date the proposed new or changed rate becomes effective. In either challenge process, the third party must be able to show it has a substantial economic interest in those rates to proceed. The FERC generally has not investigated interstate rates on its own initiative but will likely become a party to any proceedings when the rates receive either a complaint or a protest. However, the FERC is not prohibited from bringing an interstate rate under investigation without a third-party intervention.

While the FERC regulates the rates for interstate shipments on our refined product pipelines, the New Mexico Public Regulation Commission regulates the rates for intrastate shipments in New Mexico, the Texas Railroad Commission regulates the rates for intrastate shipments in Texas, the Oklahoma Corporation Commission regulates the rates for intrastate shipments in Oklahoma and the Idaho Public Utilities Commission regulates the rates for intrastate shipments in Idaho. State commissions have generally not been aggressive in regulating common carrier pipelines and generally have not investigated the rates or practices of petroleum pipelines in the absence of shipper complaints, and we do not believe the intrastate tariffs now in effect are likely to be challenged. However, a state regulatory commission could investigate our rates if such a challenge were filed.

ENVIRONMENTAL REGULATION AND REMEDIATION

Our operation of pipelines, terminals, and associated facilities in connection with the transportation and storage of refined products and crude oil is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment and natural resources. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position given that the operations of our competitors are similarly affected. We believe our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. In addition, many environmental laws contain citizen suit provisions, allowing environmental groups to bring suits to enforce compliance with environmental laws. Environmental groups frequently challenge pipeline infrastructure projects. Moreover, a major discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by employees, neighboring landowners and other third parties for personal injury and property damage.

Contamination resulting from spills of refined products and crude oil is not unusual within the petroleum pipeline industry. Historic spills along our existing pipelines and terminals as a result of past operations have resulted in contamination of the environment, including soils and groundwater. Site conditions, including soils and groundwater, are being evaluated at a few of our properties where operations may have resulted in releases of hydrocarbons and other wastes, none of which we believe will have a significant effect on our operations since the remediation of such releases would be covered under environmental indemnification agreements.

Under the Omnibus Agreement and certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain monetary and time limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC and occurring or existing prior to the date of such transfers.

We have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations.

There are environmental remediation projects that are currently in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities of HFC as the obligation for future remediation activities was retained by HFC. At December 31, 2016, we have an accrual of $7.1 million that relates to environmental clean-up projects for which we have assumed liability or for which the indemnity provided for by HFC has expired or will expire. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

We may experience future releases into the environment from our pipelines and terminals or discover historical releases that were previously unidentified or not assessed. Although we maintain an extensive inspection and audit program designed, as applicable, to prevent, detect and address these releases promptly, damages and liabilities incurred due to any future environmental releases from our assets have the potential to substantially affect our business.

EMPLOYEES

Neither we nor our general partner has employees. Direct support for our operations is provided by HLS, which utilizes 249 people employed by HFC dedicated to performing services for us. We reimburse HFC for direct expenses that HFC or its affiliates incurs on our behalf for these employees. HFC considers its employee relations to be good.

Under HLS's Secondment Agreement with HFC, certain employees of HFC are seconded to HLS to provide operational and maintenance services for certain of our pipelines and tankage assets at the El Dorado and Cheyenne refineries, and HLS reimburses HFC for its prorated portion of the wages, benefits, and other costs of these employees for our benefit.

Item 1A. Risk Factors

Investing in us involves a degree of risk, including the risks described below. Our operating results have been, and will continue to be, affected by a wide variety of risk factors, many of which are beyond our control, that could have adverse effects on profitability during any particular period. You should consider the following risk factors carefully together with all of the other information included in this Annual Report on Form 10-K, including the financial statements and related notes, when deciding to invest in us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially and adversely affect our business operations. If any of the following risks were to actually occur, our business, financial condition, results of operations or treatment of unitholders could be materially and adversely affected.

The headings provided in this Item 1A. are for convenience and reference purposes only and shall not affect or limit the extent or interpretation of the risk factors.

RISKS RELATED TO OUR BUSINESS

If we are unable to generate sufficient cash flow, our ability to pay quarterly distributions to our common unitholders at current levels or to increase our quarterly distributions in the future could be impaired materially.

Our ability to pay quarterly distributions depends primarily on cash flow (including cash flow from operations, financial reserves and credit facilities) and not solely on profitability, which is affected by non-cash items. As a result, we may pay cash distributions during periods of losses and may be unable to pay cash distributions during periods of income. Our ability to generate sufficient cash from operations is largely dependent on our ability to manage our business successfully which may also be affected by economic, financial, competitive, regulatory, and other factors that are beyond our control. Because the cash we generate from operations will fluctuate from quarter to quarter, quarterly distributions may also fluctuate from quarter to quarter.

We depend on HFC and particularly its Navajo and Woods Cross refineries for a substantial majority of our revenues; if those revenues were significantly reduced or if HFC's financial condition materially deteriorated, there would be a material adverse effect on our results of operations.

For the year ended December 31, 2016, HFC accounted for 78% of the revenues of our petroleum product and crude pipelines, 88% of the revenues of our terminals, tankage, and truck loading racks, and 100% of the revenue from our refinery processing units. We expect to continue to derive a majority of our revenues from HFC for the foreseeable future. If HFC satisfies only its minimum obligations under the long-term pipeline and terminal, tankage and throughput agreements that it has with us or is unable to meet its minimum annual payment commitment for any reason, including due to prolonged downtime or a shutdown at HFC's refineries, our revenues and cash flow would decline.

Any significant reduction in production at the Navajo refinery could reduce throughput in our pipelines and terminals, resulting in materially lower levels of revenues and cash flow for the duration of the shutdown. For the year ended December 31, 2016, production from the Navajo refinery accounted for 73% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 95% of the throughput volumes shipped on our New Mexico intermediate pipelines. Operations at any of HFC's refineries could be partially or completely shut down, temporarily or permanently, as the result of:

- competition from other refineries and pipelines that may be able to supply the refinery's end-user markets on a more cost-effective basis;
- operational problems such as catastrophic events at the refinery, labor difficulties, environmental proceedings or other litigation that cause a stoppage of all or a portion of the operations at the refinery;
- planned maintenance or capital projects;

- increasingly stringent environmental laws and regulations, such as the U.S. Environmental Protection Agency's gasoline and diesel sulfur control requirements that limit the concentration of sulfur in motor gasoline and diesel fuel for both on-road and non-road usage as well as various state and federal emission requirements that may affect the refinery itself and potential future climate change regulations;

- an inability to obtain crude oil for the refinery at competitive prices; or
- a general reduction in demand for refined products in the area due to:

a local or national recession or other adverse economic condition that results in lower spending by businesses and consumers on gasoline and diesel fuel;
higher gasoline prices due to higher crude oil costs, higher taxes or stricter environmental laws or regulations; or
a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy, whether as a result of technological advances by manufacturers, legislation either mandating or encouraging higher fuel economy or the use of alternative fuel or otherwise.

The effect on us of any shutdown would depend on the length of the shutdown and the extent of the refinery operations affected by the shutdown. We have no control over the factors that may lead to a shutdown or the measures HFC may take in response to a shutdown. HFC makes all decisions at each of its refineries concerning levels of production, regulatory compliance, refinery turnarounds (planned shutdowns of individual process units within the refinery to perform major maintenance activities), labor relations, environmental remediation, emission control and capital expenditures and is responsible for all related costs. HFC is under no contractual obligation to us to maintain operations at its refineries.

Furthermore, HFC's obligations under the long-term pipeline and terminal, tankage, tolling and throughput agreements with us would be temporarily suspended during the occurrence of a force majeure event that renders performance impossible with respect to an asset for at least 30 days. If such an event were to continue for a year, we or HFC could terminate the agreements. The occurrence of any of these events could reduce our revenues and cash flows.

We depend on Alon and particularly its Big Spring refinery for a portion of our revenues; if those revenues were significantly reduced, there could be a material adverse effect on our results of operations.

For the year ended December 31, 2016, Alon accounted for 8% of the combined revenues of our petroleum product and crude pipelines and of our terminals and truck loading racks, including revenues we received from Alon under a capacity lease agreement. If Alon satisfies only its minimum obligations under the long-term pipeline and terminal, tankage and throughput agreements that it has with us or is unable to meet its minimum annual payment commitment for any reason, including due to prolonged downtime or a shutdown at Alon’s refineries, our revenues and cash flow would decline.

A decline in production at Alon's Big Spring refinery could reduce materially the volume of refined products we transport and terminal for Alon and, as a result, our revenues could be materially adversely affected. The Big Spring refinery could partially or completely shut down its operations, temporarily or permanently, due to factors affecting its ability to produce refined products or for planned maintenance or capital projects. Such factors would include the factors discussed above under the discussion of risk with respect to the Navajo refinery.

The effect on us of any shutdown depends on the length of the shutdown and the extent of the refinery operations affected. We have no control over the factors that may lead to a shutdown or the measures Alon may take in response to a shutdown. Alon makes all decisions and is responsible for all costs at the Big Spring refinery concerning levels of production, regulatory compliance, refinery turnarounds, labor relations, environmental remediation, emission control and capital expenditures.

In addition, under our throughput agreement with Alon, if we are unable to transport or terminal refined products that Alon is prepared to ship, then Alon has the right to reduce its minimum volume commitment to us during the period of interruption. If a force majeure event occurs, we or Alon could terminate the Alon pipelines and terminals agreement after the expiration of certain time periods. The occurrence of any of these events could reduce our revenues and cash flows.

Due to our lack of asset and geographic diversification, adverse developments in our businesses could materially and adversely affect our financial condition, results of operations, or cash flows.

We rely exclusively on the revenues generated from our business. Due to our lack of asset and geographic diversification, especially our large concentration of pipeline assets serving the Navajo refinery, an adverse development in our business (including adverse developments due to catastrophic events or weather, decreased supply of crude oil and feedstocks and/or decreased demand for refined petroleum products), could have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets in more diverse locations.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

As of December 31, 2016, the principal amount of our total outstanding debt was $1,253 million. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Various limitations in our Credit Agreement and the indenture for our 6.0% senior notes due 2024 (the "6% Senior Notes") may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage could have important consequences. We require substantial cash flow to meet our payment obligations with respect to our indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to then-current economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our Credit Agreement to service our indebtedness. However, a significant downturn in our business or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We cannot guarantee that we would be able to refinance our existing indebtedness at maturity or otherwise or sell assets on terms that are commercially reasonable.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain beneficial transactions. The agreements governing our debt generally require us to comply with various affirmative and negative covenants including the maintenance of certain financial ratios and restrictions on incurring additional debt, entering into mergers, consolidations and sales of assets, making investments and granting liens. Additionally, our purchase and sale agreement with HFC with respect to the crude pipelines and tankage assets acquired in 2008 restrict us from selling the pipelines and terminals acquired from HFC and from prepaying borrowings and long-term debt to outstanding balances below $171 million prior to March 1, 2018, subject to certain limited exceptions. Our leverage may affect adversely our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisitions, construction or development activities, or to otherwise realize fully the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage also may make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

We may not be able to obtain funding on acceptable terms or at all because of volatility and uncertainty in the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

The domestic and global financial markets and economic conditions are disrupted and volatile from time to time due to a variety of factors, including low consumer confidence, high unemployment, geoeconomic and geopolitical issues, weak economic conditions and uncertainty in the financial services sector. In addition, the fixed-income markets have experienced periods of extreme volatility, which negatively impacted market liquidity conditions. As a result, the cost of raising money in the debt and equity capital markets has increased substantially at times while the availability of funds from these markets diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets may increase as many lenders and institutional investors increase interest rates, enact tighter lending standards, refuse to refinance existing debt on similar terms or at all and reduce, or in some cases cease, to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations.

Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to:

- meet our obligations as they come due;
- execute our growth strategy;
- complete future acquisitions or construction projects;
- take advantage of other business opportunities; or
- respond to competitive pressures.

Any of the above could have a material adverse effect on our revenues and results of operations.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities, if our assumptions concerning population growth are inaccurate, or if an agreement cannot be reached with HFC for the acquisition of assets on which we have a right of first offer.

Our strategy contemplates growth through the development and acquisition of crude, intermediate and refined products transportation and storage assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses, either from HFC or third parties, to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand-alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in our chosen businesses and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, or if the development or acquisition opportunities are on terms that do not allow us to obtain appropriate financing, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders. Additionally, our general partner, HEP Logistics Holdings, L.P. ("HEP Logistics"), is entitled to incentive distributions when the amount we distribute with respect to any quarter exceeds specified target levels. The amount of incentive distributions that we make to our general partner further limits the amount of capital available to us to finance future development and acquisitions.

In addition, we experience competition for the types of assets and businesses we have historically purchased or acquired. High competition, particularly for a limited pool of assets, may result in higher, less attractive asset prices, and therefore, we may lose to more competitive bidders. Such occurrences limit our ability to execute our growth strategy, which may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our growth strategy also depends upon:

- the accuracy of our assumptions about growth in the markets that we currently serve or have plans to serve in the Southwestern, Northwest and Mid-Continent regions of the United States;
- HFC's willingness and ability to capture a share of additional demand in its existing markets; and
- HFC's willingness and ability to identify and penetrate new markets in the Southwestern, Northwest and Mid-Continent regions of the United States.

If our assumptions about increased market demand prove incorrect, HFC may not have any incentive to increase refinery capacity and production or shift additional throughput to our pipelines, which would adversely affect our growth strategy.

Our Omnibus Agreement with HFC provides us with a right of first offer on certain of HFC’s existing or acquired logistics assets. The consummation and timing of any future acquisitions of these assets will depend upon, among other things, our ability to negotiate acceptable purchase agreements and commercial agreements with respect to the assets and our ability to obtain financing on acceptable terms. We can offer no assurance that we will be able to successfully consummate any future acquisitions pursuant to our right of first offer. In addition, certain of the assets covered by our right of first offer may require substantial capital expenditures in order to maintain compliance with applicable regulatory requirements or otherwise make them suitable for our commercial needs. For these or a variety of other reasons, we may decide not to exercise our right of first offer if and when any assets are offered for sale, and our decision will not be subject to unitholder approval. In addition, our right of first offer may be terminated upon a change of control of HFC.

We are exposed to the credit risks and certain other risks, of our key customers, vendors, and other counterparties.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers, vendors or other counterparties. We derive a significant portion of our revenues from contracts with key customers, including HFC and Alon under their respective pipelines and terminals, tankage, tolling and throughput agreements. To the extent that our customers may be unable to meet the specifications of their customers, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers.

Mergers among our existing customers could provide strong economic incentives for the combined entities to use systems other than ours, and we could experience difficulty in replacing lost volumes and revenues. Because a significant portion of our operating costs are fixed, a reduction in volumes would result not only in a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to unitholders.

If any of our key customers default on their obligations to us, our financial results could be adversely affected. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks. In addition, nonperformance by vendors who have committed to provide us with products or services could result in higher costs or interfere with our ability to successfully conduct our business.

Any substantial increase in the nonpayment and/or nonperformance by our customers or vendors could have a material adverse effect on our results of operations and cash flows.

In addition, in connection with the acquisition of certain of our assets, we have entered into agreements pursuant to which various counterparties, including HFC, have agreed to indemnify us, subject to certain limitations, for:

- certain pre-closing environmental liabilities discovered within specified time periods after the date of the applicable acquisition;
- certain matters arising from the pre-closing ownership and operation of assets; and
- ongoing remediation related to the assets.

Our business, results of operation, cash flows and our ability to make cash distributions to our unitholders could be adversely affected in the future if third parties fail to satisfy an indemnification obligation owed to us.

Competition from other pipelines that may be able to supply our shippers' customers with refined products at a lower price could cause us to reduce our rates or could reduce our revenues.

We and our shippers could face increased competition if other pipelines are able to supply our shippers' end-user markets competitively with refined products. For example, increased supplies of refined product delivered by Kinder Morgan's El Paso to Phoenix pipeline could result in additional downward pressure on wholesale-refined product prices and refined product margins in El Paso and related markets. Additionally, further increases in products from Gulf Coast refiners entering the El Paso and Arizona markets on this pipeline and a resulting increase in the demand for shipping product on the interconnecting common carrier pipelines could cause a decline in the demand for refined product from HFC and/or Alon. This could reduce our opportunity to earn revenues from HFC and Alon in excess of their minimum volume commitment obligations.

An additional factor that could affect some of HFC's and Alon's markets is excess pipeline capacity from the West Coast into our shippers' Arizona markets. Additional increases in shipments of refined products from the West Coast into our shippers' Arizona markets could result in additional downward pressure on refined product prices that, if sustained over the long term, could influence product shipments by HFC and Alon to these markets.

A material decrease in the supply, or a material increase in the price, of crude oil available to HFC's and Alon's refineries, and a corresponding decrease in demand for refined products in the markets served by our pipelines and terminals, could reduce our revenues materially.

The volume of refined products we transport in our refined product pipelines depends on the level of production of refined products from HFC's and Alon's refineries, which, in turn, depends on the availability of attractively-priced crude oil produced in the areas accessible to those refineries. In order to maintain or increase production levels at their refineries, our shippers must continually contract for new crude oil supplies. A material decrease in crude oil production from the fields that supply their refineries, as a result of depressed commodity prices, decreased demand, lack of drilling activity, natural production declines or otherwise, could result in a decline in the volume of crude oil our shippers refine, absent the availability of transported crude oil to offset such declines. Such an event would result in an overall decline in volumes of refined products transported through our pipelines and therefore a corresponding reduction in our cash flow. In addition, the future growth of our shippers' operations will depend in part upon whether our shippers can contract for additional supplies of crude oil at a greater rate than the rate of natural decline in their currently connected supplies.

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 and our shippers have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, geological considerations, governmental regulation and the availability and cost of capital, or over the level of drilling activity in the areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. Similarly, a material increase in the price of crude oil supplied to our shippers' refineries without an increase in the market value of the products produced by the refineries, either temporary or permanent, which causes a reduction in the production of refined products at the refineries, would cause a reduction in the volumes of refined products we transport, and our cash flow could be adversely affected.

Finally, our business depends in large part on the demand for the various petroleum products we gather, transport and store in the markets we serve. Reductions in that demand adversely affect our business. Market demand varies based upon the different end uses of the petroleum products we gather, transport and store. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, government regulation, technological advances in fuel economy and energy-generation devices, exploration and production activities, and actions by foreign nations, any of which could reduce the demand for the petroleum products in the areas we serve.

We may not be able to retain existing customers or acquire new customers.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain attractive revenues and cash flows depends on a number of factors outside our control, including competition from other pipelines and the demand for refined products in the markets that we serve. Our long-term pipeline and terminal, tankage and refinery processing unit throughput agreements with HFC and Alon expire beginning in 2019 through 2036.

Our operations are subject to evolving federal, state and local laws, regulations and permit/authorization requirements regarding environmental protection, health, operational safety and product quality. Potential liabilities arising from these laws, regulations and requirements could affect our operations and adversely affect our performance.

Our pipelines and terminal, tankage and loading rack operations are subject to increasingly strict environmental and safety laws and regulations.

Environmental laws and regulations have raised operating costs for the oil and refined products industry, and compliance with such laws and regulations may cause us, and the HFC and Alon refineries that we support, to incur potentially material capital expenditures associated with the construction, maintenance, and upgrading of equipment and facilities. Future environmental, health and safety requirements (or changed interpretations of existing requirements) may impose more stringent requirements on our assets and operations and require us to incur potentially material expenditures to ensure our continued compliance.

Our operations require numerous permits and authorizations under various laws and regulations, including environmental and worker health and safety laws and regulations. These authorizations and permits are subject to revocation, renewal or modification and can require operational changes that may involve significant costs to limit impacts or potential impacts on the environment and/or worker health and safety. A violation of these authorization or permit conditions or other legal or regulatory requirements could result in substantial fines, criminal sanctions, permit revocations and injunctions prohibiting our operations. In addition, major modifications of our operations could require modifications to our existing permits or expensive upgrades to our existing pollution control equipment that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may also be required to address conditions discovered in the future that require environmental response actions or remediation. The transportation and storage of refined products produces a risk that refined products and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, personal injury or property damages to private parties and significant business interruption. Further, we own or lease a number of properties that have been used to store or distribute refined products for many years. Many of these properties have also been operated by third parties whose handling, disposal, or release of hydrocarbons and other wastes were not under our control. Environmental laws can impose strict, joint and several liability for releases of hazardous substances into the environment, and we could find ourselves liable for past releases caused by third parties. If we were to incur a significant liability pursuant to environmental laws or regulations, it could have a material adverse effect on us.

Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and other gases) are in various phases of discussion or implementation. These include requirements that HFC's and Alon's refineries report emissions of greenhouse gases to the EPA, and proposed federal, state, and regional initiatives that require (or could require) us, HFC and Alon to reduce greenhouse gas emissions from our facilities. Requiring reductions in greenhouse gas emissions could cause us to incur substantial costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any greenhouse gas emissions programs, including the acquisition or maintenance of emission credits or allowances. These requirements may affect HFC's and Alon's refinery operations and have an indirect adverse effect on our business, financial condition and results of our operations.

Requiring a reduction in greenhouse gas emissions and the increased use of renewable fuels could also decrease demand for refined products, which could have an indirect, but material, adverse effect on our business, financial condition and results of operations. For example, in 2010, the EPA promulgated a rule establishing greenhouse gas emission standards for new-model passenger cars, light-duty trucks, and medium-duty passenger vehicles. Also in 2010, the EPA promulgated a rule establishing greenhouse gas emission thresholds for the permitting of certain stationary sources, which could require greenhouse emission controls for those sources. In addition, the EPA finalized new regulations in 2016 that limit methane emissions from certain new and modified oil and gas facilities. These requirements could result in increased compliance costs and could also have an indirect adverse effect on our business due to reduced demand for crude oil and refined products, and a direct adverse effect on our business from increased regulation of our facilities.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.
PHMSA regulations require pipeline operators to develop and implement integrity management programs for certain pipelines that, in the event of a pipeline leak or rupture could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require operators of covered pipelines to perform a variety of heightened assessment, analysis, prevention and repair activities. Routine assessments under the integrity management program may result in findings that require repairs or other actions.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA or states that result in more stringent or costly safety standards could possibly have a substantial effect on us and similarly situated midstream operators.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.
Among other things, the 2011 Amendments to the Pipeline Safety Act direct the Secretary of Transportation to study, and where appropriate based on the results and statutory factors, promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valves, leak detection, and other requirements. The 2011 Amendments also increased the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Amendments as well as any implementation of PHMSA regulations thereunder, reinterpretation of existing laws or regulations, or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect to the 2011 Amendments could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. Congress made additional changes to the Pipeline Safety Laws in 2016 that require PHMSA to issue additional regulations and perform studies that may or may not lead to additional requirements in the future. There are numerous, currently pending PHMSA rulemaking proceedings on a variety of pipeline safety topics. PHMSA’s rulemakings are intended to implement the 2011 and 2016 statutory changes, as well as additional policy priorities. For example, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline’s proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. Any such new and expanded requirements may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Increases in interest rates could adversely affect our business.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facility. From time to time we use interest rate derivatives to hedge interest obligations on specific debt. In addition, interest rates on future debt offerings could be higher, causing our financing costs to increase accordingly. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels.

We may be subject to information technology system failures, network disruptions and breaches in data security.

Information technology system failures, network disruptions (whether intentional by a third party or due to natural disaster), breaches of network or data security, or disruption or failure of the network system used to monitor and control pipeline operations could disrupt our operations by impeding our processing of transactions, our ability to protect customer or company information and our financial reporting. Our computer systems, including our back-up systems, could be damaged or interrupted by power outages, computer and telecommunications failures, computer viruses, internal or external security breaches, events such as fires, earthquakes, floods, tornadoes and hurricanes, and/or errors by our employees. Although we have taken steps to address these concerns by implementing sophisticated network security and internal control measures, a system failure or data security breach could have a material adverse effect on our financial condition and results of operations.

Our operations are subject to catastrophic losses, operational hazards and unforeseen interruptions for which we may not be adequately insured.

Our operations are subject to catastrophic losses, operational hazards and unforeseen interruptions such as natural disasters, adverse weather, tornadoes, earthquakes, accidents, fires, explosions, hazardous materials releases, cyber-attacks, mechanical failures and other events beyond our control. These events could result in an injury, loss of life, or property damage or destruction, as well as a curtailment or interruption in our operations. In addition, third-party damage, mechanical malfunctions, undetected leaks in pipelines, faulty measurement or other errors may result in significant costs or lost revenues.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates and exclusions from coverage may limit our ability to recover the amount of the full loss in all situations. As a result of market conditions, premiums and deductibles for certain of our insurance policies could increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

There can be no assurance that insurance will cover all or any damages and losses resulting from these types of hazards. We are not fully insured against all risks incident to our business and therefore, we self-insure certain risks. We are not insured against all environmental accidents that might occur, other than limited coverage for certain third party sudden and accidental claims. Our property insurance includes business interruption coverage for lost profit arising from physical damage to our facilities. If a significant accident or event occurs that is self-insured or not fully insured, our operations could be temporarily or permanently impaired, our liabilities and expenses could be significant and it could have a material adverse effect on our financial position. Because of our distribution policy, we do not have the same flexibility as other legal entities to accumulate cash to protect against underinsured or uninsured losses.

Any reduction in the capacity of, or the allocations to, our shippers on interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines and through our terminals.

HFC, Alon and the other users of our pipelines and terminals are dependent upon connections to third-party pipelines to receive and deliver crude oil and refined products. Any reduction of capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volumes of refined products over interconnecting pipelines, the allocations to existing shippers in these pipelines would be reduced, which could also reduce volumes transported in our pipelines or through our terminals.

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 products we distribute to meet certain quality specifications. In addition, we could be required to make substantial expenditures in the event of any changes in product quality specifications.

A significant portion of our operating responsibility on refined product pipelines is to ensure the quality and purity of the products loaded at our loading racks. If our quality control measures fail, off-specification product could be sent out to public gasoline stations. This type of incident could result in liability claims regarding damages caused by the off-specification fuel or could impact our ability to retain existing customers or to acquire new customers, any of which could have a material adverse impact on our results of operations and cash flows.

In addition, various federal, state and local agencies have the authority to prescribe specific product quality specifications of refined products. Changes in product quality specifications or blending requirements could reduce our throughput volume, require us to incur additional handling costs or require capital expenditures. For example, different product specifications for different markets impact the fungibility of the products in our system and could require the construction of additional storage. If we are unable to recover these costs through increased revenues, our cash flows and ability to pay cash distributions could be adversely affected. In addition, changes in the product quality of the products we receive on our petroleum products pipeline system could reduce or eliminate our ability to blend products.

Growing our business by constructing new pipelines and terminals, or expanding existing ones, subjects us to construction risks.

One of the ways we may grow our business is through the construction of new pipelines and terminals or the expansion of existing ones. The construction of a new pipeline or the expansion of an existing pipeline, by adding horsepower or pump stations or by adding a second pipeline along an existing pipeline, involves numerous regulatory, environmental, political, and legal uncertainties, most of which are beyond our control. For example, pipeline construction projects requiring federal approvals are generally subject to environmental review requirements under the National Environmental Policy Act, and must also comply with other natural resource review requirements imposed pursuant to the Endangered Species Act and the National Historic Preservation Act. These projects may not be completed on schedule (or at all) or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time and we will not receive any material increases in revenues until after completion of the project. Moreover, we may construct facilities to capture anticipated future growth in demand for refined products in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

Rate regulation, changes to rate-making rules, or a successful challenge to the rates we charge may reduce our revenues and the amount of cash we generate.

The FERC regulates the tariff rates for interstate movements and state regulatory authorities regulate the tariff rates for intrastate movements on our pipeline systems. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services.

The primary rate-making methodology of the FERC is price indexing. We use this methodology in all of our interstate markets. The indexing method allows a pipeline to increase its rates based on a percentage change in the PPI for finished goods. If the index falls, we will be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum allowable rate. If the FERC price indexing methodology permits a rate increase that is not large enough to fully reflect actual increases in our costs, we may need to file for a rate increase using an alternative method with a much higher burden of proof and without the guarantee of success. These FERC rate-making methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. On October 20, 2016, the FERC issued an Advance Notice of Proposed Rulemaking regarding Revisions to Indexing Policies and Page 700 of FERC Form No. 6, 157 FERC ¶ 61, 047 (2016) (“ANOPR”). If final rules are implemented as proposed in that ANOPR, such rules would create new tests for whether our pipelines providing service subject to FERC tariffs could increase rates in accordance with the FERC index in a given year and could restrict our ability to increase our rates as a result, in addition to increasing our annual reporting burdens and the associated costs. Any of the foregoing would adversely affect our revenues and cash flow.

If a party with an economic interest were to file either a protest of our proposal for increased rates or a complaint against our existing tariff rates, or the FERC were to initiate an investigation of our existing rates, then our rates could be subject to detailed review. If our proposed rate increases were found to be in excess of levels justified by our cost of service, the FERC could order us to reduce our rates, and to refund the amount by which the rate increases were determined to be excessive, plus interest. If our existing rates were found to be in excess of our cost of services, we could be ordered to refund the excess we collected for up to two years prior to the date of the filing of the complaint challenging the rates, and we could be ordered to reduce our rates prospectively. Also relevant to our rates and cost of service, on December 15, 2016, the FERC issued a Notice of Inquiry Regarding the Commission’s Policy for Recovery of Income Tax Costs, 157 FERC ¶ 61,210 (2016) (the “NOI”). The NOI sought comments on how the FERC should address any double recovery for partnership pipelines resulting from the FERC’s current income tax allowance and rate of return policies. If the NOI results in final regulations or policy changes that alter the FERC’s current approach to liquids pipeline ratemaking and the relevant components of our interstate pipeline transportation rates, those changes could require us to change our rate design and potentially lower our rates. In addition, a state commission also could investigate our intrastate rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our rates exceeded levels justified by our cost of service, the state commission could order us to reduce our rates. Any such reductions may result in lower revenues and cash flows if additional volumes and/or capacity are unavailable to offset such rate reductions.

HFC and Alon have agreed not to challenge, or to cause others to challenge or assist others in challenging, our tariff rates in effect during the terms of their respective pipelines and terminals agreements; however, other current or future shippers may still challenge our tariff rates.

Terrorist attacks (including cyber-attacks), and the threat of terrorist attacks or domestic vandalism, have resulted in increased costs to our business. Continued global hostilities or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks, on the energy transportation industry in general, and on us in particular, is unknown. Increased security measures taken by us as a precaution against possible terrorist attacks or vandalism have resulted in increased costs to our business. Uncertainty surrounding continued global hostilities or other sustained military campaigns, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror, may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products.

Changes in the insurance markets attributable to terrorist attacks could make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital including our ability to repay or refinance debt.

The U.S. government has issued public warnings that indicate that pipelines and other assets might be specific targets of terrorist organizations or “cyber security” events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets, our operations could be disrupted and/or customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation or litigation and or inaccurate information reported from our operations. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

Adverse changes in our and/or our general partner's credit ratings and risk profile may negatively affect us.

Our ability to access capital markets is important to our ability to operate our business. Regional and national economic conditions, increased scrutiny of the energy industry and regulatory changes, as well as changes in our economic performance, could result in credit agencies reexamining our credit rating.

We are in compliance with all covenants or other requirements set forth in our Credit Agreement. Further, we do not have any rating downgrade triggers that would automatically accelerate the maturity dates of any debt.

While credit ratings reflect the opinions of the credit agencies issuing such ratings and may not necessarily reflect actual performance, a downgrade in our credit rating could affect adversely our ability to borrow on, renew existing, or obtain access to new financing arrangements, could increase the cost of such financing arrangements, could reduce our level of capital expenditures and could impact our future earnings and cash flows.

The credit and business risk profiles of our general partner, and of HFC as the indirect owner of our general partner, may be factors in credit evaluations of us as a master limited partnership due to the significant influence of our general partner and its indirect owner over our business activities, including our cash distribution acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

We may be unsuccessful in integrating the operations of the assets we have acquired or may acquire with our operations, and in realizing all or any part of the anticipated benefits of any such acquisitions.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. Our capitalization and results of operations may change significantly as a result of completed or future acquisitions. Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets and the businesses associated with them, and new geographic areas and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Also, following an acquisition, we may discover previously unknown liabilities associated with the acquired business or assets for which we have no recourse under applicable indemnification provisions.

We own certain of our systems through joint ventures, and our control of such systems is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures.

Although our subsidiary is the operator of the UNEV pipeline and we own a majority interest in the joint venture that owns the UNEV pipeline, the joint venture agreement for the UNEV pipeline generally requires consent of our joint venture partner(s) for specified extraordinary transactions, such as reversing the flow of the pipeline or increasing the fees paid to our subsidiary pursuant to the operating agreement.

In addition, certain of our systems are operated by joint venture entities that we do not operate, or in which we do not have an ownership stake that permits us to control the business activities of the entity. We have limited ability to influence the business decisions of such joint venture entities.

Because we have partial ownership in the joint ventures, we may be unable to control the amount of cash we will receive from the operation and could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

If we are unable to complete capital projects at their expected costs or in a timely manner, if we incur increased maintenance or repair costs on assets, or if the market conditions assumed in our project economics deteriorate, our financial condition, results of operations, or cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving construction of new facilities (or improvements and increased maintenance or repair expenditures on our existing facilities) could adversely affect our ability to achieve forecasted operating results. Although we evaluate and monitor each capital spending project and try to anticipate difficulties that may arise, such delays or cost increases may arise as a result of numerous factors, such as:

- denial or delay in issuing requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of modular components and/or construction materials;
- severe adverse weather conditions, natural disasters, or other events (such as equipment malfunctions explosions, fires or spills) affecting our facilities, or those of 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 by, or disputes with, vendors, suppliers, contractors, or sub-contractors involved with a project.

If we are unable to complete capital projects at their expected costs or in a timely manner our financial condition, results of operations, or cash flows could be materially and adversely affected.

We do not own all of the land on which our pipeline systems and other assets are located, which could result in disruptions to our operations. Additionally, a change in the regulations related to a state’s use of eminent domain could inhibit our ability to secure rights-of-way for future pipeline construction projects. Finally, certain of our assets are located on tribal lands.

We do not own all of the land on which our pipeline systems and other assets are located, and we are, therefore, subject to the risk of increased costs or more burdensome terms to maintain necessary land use. We obtain the right to construct and operate pipelines and other assets on land owned by third parties and government agencies for specified periods. If we were to lose these rights through an inability to renew leases, right-of-way contracts or similar agreements, we may be required to relocate our pipelines or other assets and our business could be adversely affected. Additionally, it may become more expensive for us to obtain new rights-of-way or leases or to renew existing rights-of-way or leases. If the cost of obtaining or renewing such agreements increases, it may adversely affect our operations and the cash flows available for distribution to unitholders.

The adoption or amendment of laws and regulations that limit or eliminate a state’s ability to exercise eminent domain over private property in a state in which we operate could make it more difficult or costly for us to secure rights-of-way for future pipeline construction and other projects.

Certain of our pipelines are located on Native American tribal lands. Various federal agencies, along with each Native American tribe, promulgate and enforce regulations, including environmental standards, regarding operations on Native American tribal lands. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations (including various taxes, fees, and other requirements and conditions) and to grant approvals independent from federal, state and local statutes and regulations. These factors may increase our cost of doing business on Native American tribal lands.

Our business may suffer due to a change in the composition of our Board of Directors, if any of our key senior executives or other key employees who provide services to us discontinue employment, or if certain of our executive officers, who also allocate time to our general partner and its affiliates, do not have enough time to dedicate to our business. Furthermore, a shortage of skilled labor or disruptions in the labor force that provides services to us may make it difficult for us to maintain labor productivity.

Our future success depends to a large extent on the services of HLS's Board of Directors, key senior executives and key senior employees who provide services to us. Also, our business depends on the continuing ability to recruit, train and retain highly qualified employees in all areas of our operations, including accounting, business operations, finance and other key back-office and mid-office personnel. The competition for these employees is intense, and the loss of these executives or employees could harm our business. If any of these executives or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any executives. Furthermore, our operations require skilled and experienced laborers with proficiency in multiple tasks.

Our general partner shares officers and administrative personnel with HFC to operate both our business and HFC's business. These officers face conflicts regarding the allocation of their and other employees' time, which may affect adversely our results of operations, cash flows and financial condition.

A portion of HFC's employees that are seconded to us from time to time are represented by labor unions under collective bargaining agreements with various expiration dates. HFC may not be able to renegotiate the collective bargaining agreements when they expire on satisfactory terms or at all. A failure to do so may increase our costs. In addition, existing labor agreements may not prevent a future strike or work stoppage, and any work stoppage could negatively affect our results of operations and financial condition.

RISKS TO COMMON UNITHOLDERS

HFC and its affiliates may have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

Currently, HFC indirectly owns the 2% general partner interest and a 35% limited partner interest in us and owns and controls HLS, the general partner of our general partner, HEP Logistics. Conflicts of interest may arise between HFC and its affiliates, including our general partner, on the one hand, and us, on the other hand. As a result of these conflicts, the general partner may favor its own interests and the interests of its other affiliates over our interests. These conflicts include, among others, the following situations:

- HFC, as a shipper on our pipelines, has an economic incentive not to cause us to seek higher tariff rates or terminalling fees, even if such higher rates or terminalling fees would reflect rates that could be obtained in arm's-length, third-party transactions;
- neither our partnership agreement nor any other agreement requires HFC to pursue a business strategy that favors us or utilizes our assets, including whether to increase or decrease refinery production, whether to shut down or reconfigure a refinery, or what markets to pursue or grow. HFC's directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of HFC;
- our general partner is allowed to take into account the interests of parties other than us, such as HFC, in resolving conflicts of interest;
- our partnership agreement provides for modified or reduced fiduciary duties for our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines which costs incurred by HFC and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner may, in some circumstances, cause us to borrow funds to make cash distributions, even where the purpose or effect of the borrowing benefits our general partner or affiliates;
- our general partner determines the amount and timing of our asset purchases and sales, capital expenditures and borrowings, each of which can affect the amount of cash available to us; and
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including the pipelines and terminals agreement with HFC.

Cost reimbursements, which will be determined by our general partner, and fees due to our general partner and its affiliates for services provided, are substantial.

Under our Omnibus Agreement, we are obligated to pay HFC an administrative fee of currently $2.5 million per year for the provision by HFC or its affiliates of various general and administrative services for our benefit. In addition, we are required to reimburse HFC pursuant to the secondment arrangement for the wages, benefits, and other costs of HFC employees seconded to HLS to perform services at certain of our processing, refining, pipeline and tankage assets. We can neither provide assurance that HFC 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 HFC fails to provide us with adequate personnel, our operations could be adversely impacted.

The administrative fee and secondment allocations are subject to annual review and may increase if we make an acquisition that requires an increase in the level of general and administrative services that we receive from HFC or its affiliates. Our general partner will determine the amount of general and administrative expenses that will be allocated to us in accordance with the terms of our partnership agreement. In addition, our general partner and its affiliates are entitled to reimbursement for all other expenses they incur on our behalf, including the salaries of and the cost of employee benefits for employees of HLS who provide services to us.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf, plus the administrative fee. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. Our general partner and its affiliates also may provide us other services for which we are charged fees as determined by our general partner.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity to make acquisitions, fund expansion capital expenditures, or for other purposes.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, fund expansion capital expenditures or for other purposes. If we then issue additional equity at a significantly lower price, material dilution to our existing unitholders could result.

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

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 did not elect our general partner or the board of directors of HLS and have no right to do so on an annual or other continuing basis. The board of directors of HLS is chosen by the sole member of HLS. If unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. 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.

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. Unitholders will be unable to remove the general partner without its consent because the general partner and its affiliates own sufficient units to prevent its removal. 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 the general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of the general partner's general partner) cannot vote on any matter; however, no such person currently exists. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings, acquire information about our operations, and influence the manner or direction of management.

The 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 partners of our general partner from transferring their respective partnership interests in our general partner to a third party. The new partners of our general partner would then be in a position to replace the board of directors and officers of the general partner of our general partner with their own choices and to control the decisions made by the board of directors and officers.

We may issue additional limited partner units without unitholder approval, which would dilute an existing unitholder's ownership interests.

Under our partnership agreement, provided there is no significant decrease in our operating performance, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders, and HEP currently has a shelf registration on file with the SEC pursuant to which it may issue up to $2.0 billion in additional common units. On May 10, 2016, HEP established a continuous offering program under the shelf registration statement pursuant to which HEP may issue and sell common units from time to time, representing limited partner interests, up to an aggregate gross sales amount of $200 million. As of December 31, 2016, HEP has issued 703,455 units under this program for consideration of $23.5 million.

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will 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; and
- the market price of the common units may decline.

Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

In establishing cash reserves, our general partner may reduce the amount of cash available for distribution to unitholders.

Our partnership agreement requires us to distribute all available cash to our unitholders; however, it also 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 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 cash reserves will affect the amount of cash available to make the required payments to our debt holders or to pay the minimum quarterly distribution on our common units every quarter.

HFC and its affiliates may engage in limited competition with us.

HFC and its affiliates may engage in limited competition with us. Pursuant to the Omnibus Agreement, HFC and its affiliates agreed not to engage in the business of operating intermediate or refined product pipelines or terminals, crude oil pipelines or terminals, truck racks or crude oil gathering systems in the continental United States. The Omnibus Agreement, however, does not apply to:

- any business operated by HFC or any of its subsidiaries at the closing of our initial public offering;
- any business or asset that HFC or any of its subsidiaries acquires or constructs that has a fair market value or construction cost of less than $5 million; and
- any business or asset that HFC or any of its subsidiaries acquires or constructs that has a fair market value or construction cost of $5 million or more if we have been offered the opportunity to purchase the business or asset at fair market value, and we decline to do so.

In the event that HFC or its affiliates no longer control our partnership or there is a change of control of HFC, the non-competition provisions of the Omnibus Agreement will terminate.

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

If at any time our general partner and its affiliates own more than 80% of the common units (which it does not presently), our general partner will have the right (which it may assign to any of its affiliates or to us) but not the obligation 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, a holder of common units may be required to sell its units at a time or price that is undesirable to it and may not receive any return on its investment. A common unitholder may also incur a tax liability upon a sale of its units.

A unitholder may not have limited liability if a court finds that unitholder actions constitute control of our business or that we have not complied with state partnership law.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the “control” of our business. Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

In addition, Section 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Further, we conduct business in a number of states. In some of those states the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. The unitholders might be held liable for the partnership's obligations as if they were a general partner if a court or government agency determined that we were conducting business in the state but had not complied with the state's partnership statute.

HFC may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units. Additionally, HFC may pledge or hypothecate its common units or its interest in us.

HFC currently holds 22,380,030 of our common units, which is approximately 35% of our outstanding common units. The sale of these units in the public or private markets could have an adverse impact on the trading price of our common units. Additionally, we agreed to provide HFC registration rights with respect to our common units that it holds. HFC may pledge or hypothecate its common units, and such pledge or hypothecation may include terms and conditions that might result in an adverse impact on the trading price of our common units.

TAX RISKS TO COMMON UNITHOLDERS

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

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

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

At the entity level, were we to be subject to federal income tax, we would also be subject to the income tax provisions of many states. Moreover, states are evaluating ways to independently subject partnerships to entity-level taxation through the imposition of state income taxes, franchise taxes and other forms of taxation. For example, we are required to pay Texas margin tax on any income apportioned to Texas. Imposition of any additional such taxes on us or an increase in the existing tax rates would reduce the cash available for distributions to our unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present 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 and differing interpretations at any time. From time to time, members of Congress propose and consider similar substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no 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 federal income tax purposes.

We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

On January 24, 2017, the U.S. Treasury Department and the IRS published final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the “Final Regulations”) in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for federal income tax purposes.

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 have taken or may take on tax matters. 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 with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

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

Even if you do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. 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 and our cash available for distribution would not increase. Similarly, 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” being allocated to you as taxable income without any increase in our cash available for distribution. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to that income.

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

If a unitholder disposes of common units, it will recognize gain or loss equal to the difference between the amount realized and its 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 of the unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price the unitholder receives is less than its 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.

A substantial portion of the amount realized from the sale of a unitholder's common units, whether or not representing gain, may be taxed as ordinary income to the unitholder due to potential recapture items, including depreciation recapture. Thus, the unitholder may recognize both ordinary income and capital loss from the sale of such units if the amount realized on a sale of such units is less than the unitholder's 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 the unitholder sells his units, the unitholder may recognize ordinary income from our allocations of income and gain to the unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

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

An investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts ("IRAs"), Keogh Plans and other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be “unrelated business taxable income” and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and each non-U.S. person will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax adviser before investing in our common units.

We treat each purchaser of 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 have adopted 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 generally 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 units each month (the "Allocation Date") 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. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. 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 challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

A successful IRS challenge to these methods or allocations could adversely affect the amount 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.

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

We will be considered to have terminated our partnership for federal income tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders may receive two Schedules K-1) for one fiscal year and may result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in its taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short periods included in the year in which the termination occurs.

Unitholders likely will be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders likely will be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future. Unitholders likely will be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions, even if they do not live in these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Texas, New Mexico, Arizona, Utah, Idaho, Oklahoma, Washington, Kansas, Wyoming and Nevada. We may own property or conduct business in other states or foreign countries in the future. It is the unitholder's responsibility to file all federal, state, local and foreign tax returns.

Item 1B. Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 3. Legal Proceedings
We are a party to various legal and regulatory proceedings. While the outcome and impact on us cannot be predicted with certainty, based on advice of counsel, management believes that the resolution of these legal and regulatory proceedings through settlement or adverse judgment will not either individually or in the aggregate have a materially adverse effect on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures
Not applicable.

PART II

Item 5. Market for the Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Common Units
Our common limited partner units are traded on the New York Stock Exchange under the symbol "HEP." The following table sets forth the range of the daily high and low sales prices per common unit, cash distributions per common unit and the trading volume of common units for the periods indicated.

Years Ended December 31,	High	Low	Cash Distributions	Trading Volume
2016				
Fourth quarter	$34.87	$29.53	$ 0.6075	7,029,100
Third quarter	$36.98	$31.30	$ 0.5950	6,599,800
Second quarter	$36.99	$31.75	$ 0.5850	8,201,400
First quarter	$34.50	$21.44	$ 0.5750	11,258,800
2015				
Fourth quarter	$35.51	$26.75	$ 0.5650	9,219,400
Third quarter	$35.34	$26.25	$ 0.5550	7,924,000
Second quarter	$36.40	$30.00	$ 0.5450	6,532,300
First quarter	$35.10	$29.57	$ 0.5375	5,397,200

The cash distribution for the fourth quarter of 2016 was declared on January 26, 2017, and paid on February 14, 2017, to all unitholders of record on February 6, 2017.

As of February 13, 2017, we had approximately 20,135 common unitholders, including beneficial owners of common units held in street name.

We consider regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. See "Liquidity and Capital Resources" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of conditions and limitations prohibiting distributions under the Credit Agreement and indentures relating to our senior notes.

Within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is 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 laws, any of our debt instruments, or other agreements; or 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.

We make distributions in the following manner: 98% to our common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distributions for any prior quarters, thereafter.

Our general partner, HEP Logistics, is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels presented below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.25	98%	2%
First target distribution	Up to $0.275	98%	2%
Second target distribution	above $0.275 up to $0.3125	85%	15%
Third target distribution	above $0.3125 up to $0.375	75%	25%
Thereafter	Above $0.375	50%	50%

Common Unit Repurchases Made in the Quarter

The following table discloses purchases of our common units made by us or on our behalf for the periods shown below:

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plan or Program	Maximum Number of Units that May Yet be Purchased Under a Publicly Announced Plan or Program
October 2016	—	$ —	—	$ —
November 2016	75,831	$ 31.08	—	$ —
December 2016	11,599	$ 32.78	—	$ —
Total for October to December 2016	87,430		—	

The units reported represent (a) purchases of 74,360 common units in the open market for delivery to the recipients of our restricted unit, phantom unit and performance unit awards under our Long-Term Incentive Plan at the time of grant or settlement, as applicable; and (b) the delivery of 13,070 common units (which units were previously issued to certain officers and other employees pursuant to restricted unit awards at the time of grant) by such officers and employees to provide funds for the payment of payroll and income taxes due at vesting in the case of officers and employees who did not elect to satisfy such taxes by other means.

We have a Long-Term Incentive Plan for employees and non-employee directors who perform services for us. The units reported represent common units purchased in the open market for delivery to recipients of our restricted unit and performance unit awards under our Long-Term Incentive Plan at the time of grant or settlement, as applicable.

Item 6. Selected Financial Data

The following table shows selected financial information from the consolidated financial statements of HEP and from the combined financial statements of our Predecessor (defined below). We acquired assets from HFC, including El Dorado Operating on November 1, 2015, crude tanks at HFC's Tulsa refinery on March 31, 2016 and Woods Cross Operating on October 1, 2016. As we are a variable interest entity controlled by HFC, these acquisitions were accounted for as transfers between entities under common control. Accordingly, this financial data has been retrospectively adjusted to include the historical results of these acquisitions for all periods presented prior to the effective dates of each acquisition. We refer to these historical results as those of our "Predecessor." See Note 2 in notes to consolidated financial statements of HEP for further discussion of these acquisitions.

This table should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of HEP and related notes thereto included elsewhere in this Form 10-K.

	Years Ended December 31,				
	2016	2015 [1]	2014 [1]	2013 [1]	2012 [1]
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$402,043	$358,875	$332,545	$305,182	$292,560
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	123,986	105,556	106,185	100,131	89,654
Depreciation and amortization	70,428	63,306	62,529	65,783	57,821
General and administrative	12,532	12,556	10,824	11,749	7,594
	206,946	181,418	179,538	177,663	155,069
Operating income	195,097	177,457	153,007	127,519	137,491
Equity in earnings of equity method investments	14,213	4,803	2,987	2,826	3,364
Interest expense	(52,552)	(37,418)	(36,101)	(47,010)	(47,182)
Interest income	440	526	3	161	—
Loss on early extinguishment of debt	—	—	(7,677)	—	(2,979)
Gain on sale of assets and other	677	486	82	1,871	10
	(37,222)	(31,603)	(40,706)	(42,152)	(46,787)
Income before income taxes	157,875	145,854	112,301	85,367	90,704
State income tax expense	(285)	(228)	(235)	(333)	(371)
Net income	157,590	145,626	112,066	85,034	90,333
Allocation of net loss attributable to Predecessor	10,657	2,702	1,747	1,047	4,972
Allocation of net loss (income) attributable to noncontrolling interests	(10,006)	(11,120)	(8,288)	(6,632)	(1,153)
Net income attributable to the Partnership	158,241	137,208	105,525	79,449	94,152
General partner interest in net income, including incentive distributions[2]	(57,173)	(42,337)	(34,667)	(27,523)	(22,450)
Limited partners' interest in net income	$101,068	$94,871	$70,858	$51,926	$71,702
Limited partners' earnings per unit – basic and diluted[2]	$1.69	$1.60	$1.20	$0.88	$1.29
Distributions per limited partner unit	$2.3625	$2.2025	$2.0750	$1.9550	$1.8400
Other Financial Data:					
Cash flows from operating activities	$242,748	$230,746	$185,256	$182,393	$160,737
Cash flows from investing activities	$(143,030)	$(246,680)	$(198,423)	$(90,704)	$(51,219)
Cash flows from financing activities	$(111,074)	$28,117	$9,645	$(90,574)	$(110,650)

EBITDA[3]	$277,545	$237,180	$211,701	$192,054	$194,242
Distributable cash flow[4]	$218,810	$197,046	$172,718	$146,579	$153,125
Maintenance capital expenditures[5]	$9,658	$8,926	$4,616	$8,683	$5,649
Expansion capital expenditures	50,046	30,467	75,343	43,418	37,212
Acquisition capital expenditures	44,119	153,728	118,727	41,635	8,633
Total capital expenditures	$103,823	$193,121	$198,686	$93,736	$51,494
Balance Sheet Data (at period end):					
Net property, plant and equipment	$1,328,395	$1,293,060	$1,163,631	$1,018,854	$980,297
Total assets	$1,884,237	$1,777,646	$1,584,114	$1,442,573	$1,412,718
Long-term debt[6]	$1,243,912	$1,008,752	$866,986	$806,655	$863,520
Total liabilities	$1,412,446	$1,151,424	$989,324	$914,656	$940,152
Total equity[7]	$471,791	$626,222	$594,790	$527,917	$472,566

(1) Retrospectively adjusted as described in Note 2 of Consolidated Financial Statements.

(2) Net income attributable to HEP is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. HEP net income allocated to the general partner includes incentive distributions that are declared subsequent to quarter end. After the amount of incentive distributions and other priority allocations are allocated to the general partner, the remaining net income attributable to HEP is allocated to the partners based on their weighted average ownership percentage during the period.

(3) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income attributable to Holly Energy Partners plus (i) interest expense net of interest income and loss on early extinguishment of debt, (ii) state income tax and (iii) depreciation and amortization excluding amounts related to the Predecessor. EBITDA is not a calculation based upon generally accepted accounting principles ("GAAP"). However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income attributable to HEP or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants.

Set forth below is our calculation of EBITDA.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands)				
Net income attributable to the Partnership	$158,241	$137,208	$105,525	$79,449	$94,152
Add (subtract):					
Interest expense	49,306	35,490	34,280	44,041	40,141
Interest income	(440)	(526)	(3)	(161)	—
Amortization of discount and deferred debt issuance costs	3,246	1,928	1,821	2,120	1,946
Loss on early extinguishment of debt	—	—	7,677	—	2,979
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	—	—	849	5,095
State income tax expense	285	228	235	333	371
Depreciation and amortization	70,428	63,306	62,529	65,783	57,821
Predecessor depreciation and amortization	(3,521)	(454)	(363)	(360)	(8,263)
EBITDA	$277,545	$237,180	$211,701	$192,054	$194,242

(4) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts presented in our consolidated financial statements, with the general exception of maintenance capital expenditures. Distributable cash flow should not be considered in isolation or as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. It is also used by management for internal analysis and for our performance units. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating.

Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands)				
Net income attributable to the Partnership	$158,241	$137,208	$105,525	$79,449	$94,152
Add (subtract):					
Depreciation and amortization	70,428	63,306	62,529	65,783	57,821
Amortization of discount and deferred debt issuance costs	3,246	1,928	1,821	2,120	1,946
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	—	—	849	5,095
Loss on early extinguishment of debt	—	—	7,677	—	2,979
Increase (decrease) in deferred revenue related to minimum revenue commitments	(1,292)	(1,233)	(2,503)	3,686	462
Maintenance capital expenditures [5]	(9,658)	(8,926)	(4,616)	(8,683)	(5,649)
Crude revenue settlement	—	—	—	918	3,670
Increase (decrease) in environmental liability	(584)	1,107	1,596	619	211
Increase (decrease) in reimbursable deferred revenue	(2,733)	176	(2,274)	(1,642)	(815)
Other non-cash adjustments	4,683	3,934	3,326	3,840	1,516
Predecessor depreciation and amortization	$(3,521)	$(454)	$(363)	$(360)	$(8,263)
Distributable cash flow	$218,810	$197,046	$172,718	$146,579	$153,125

(5) Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations.

(6) Includes $553 million, $712 million, $571 million, $363 million and $421 million in Credit Agreement advances that were classified as long-term debt at December 31, 2016, 2015, 2014, 2013 and 2012, respectively.

(7) As a master limited partnership, we distribute our available cash, which historically has exceeded our net income attributable to HEP because depreciation and amortization expense represents a non-cash charge against income. The result is a decline in partners' equity since our regular quarterly distributions have exceeded our quarterly net income attributable to HEP. Additionally, if the assets contributed and acquired from HFC while we were a consolidated variable interest entity of HFC had been acquired from third parties, our acquisition cost in excess of HFC's basis in the transferred assets would have been recorded in our financial statements as increases to our properties and equipment and intangible assets at the time of acquisition instead of decreases to partners' equity.

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

This Item 7, including but not limited to the sections on "Liquidity and Capital Resources," contains forward-looking statements. See "Forward-Looking Statements" at the beginning of Part I and Item 1A. "Risk Factors." In this document, the words "we," "our," "ours" and "us" refer to HEP and its consolidated subsidiaries or to HEP or an individual subsidiary and not to any other person.

OVERVIEW

HEP is a Delaware limited partnership. We own and operate petroleum product and crude oil pipelines, terminal, tankage and loading rack facilities and refinery processing units that support the refining and marketing operations of HFC in the Mid-Continent, Southwest and Northwest regions of the United States and Alon's refinery in Big Spring, Texas. HEP, through its subsidiaries and joint ventures, owns and/or operates petroleum product and crude gathering pipelines, tankage and terminals in Texas, New Mexico, Arizona, Washington, Idaho, Oklahoma, Utah, Nevada, Wyoming and Kansas as well as refinery processing units in Utah and Kansas. HFC owned a 37% interest in us including the 2% general partnership interest, as of December 31, 2016.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling and storing refined products and other hydrocarbons, providing other services at our storage tanks and terminals and charging a tolling fee per barrel or thousand standard cubic feet of feedstock throughput in our refinery processing units. We do not take ownership of products that we transport, terminal or store, and therefore we are not directly exposed to changes in commodity prices.

We believe the long-term growth of global refined product demand and US crude production should support high utilization rates for the refineries we serve, which in turn will support volumes in our product pipelines, crude gathering system and terminals.

Acquisitions

On February 22, 2016, HFC obtained a 50% membership interest in Osage Pipe Line Company, LLC ("Osage") in a non-monetary exchange for a 20-year terminalling services agreement, whereby, a subsidiary of Magellan Midstream Partners ("Magellan") will provide terminalling services for all HFC products originating in Artesia, New Mexico that require terminalling in or through El Paso, Texas. Osage is the owner of the Osage pipeline, a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to HFC's El Dorado Refinery in Kansas and also has a connection to the Jayhawk pipeline that services the CHS refinery in McPherson, Kansas. The Osage pipeline is the primary pipeline that supplies HFC's El Dorado Refinery with crude oil.

Concurrent with this transaction, we entered into a non-monetary exchange with HFC, whereby we received HFC's interest in Osage in exchange for our El Paso terminal. Under this exchange, we also agreed to build two connections on our south products pipeline system that will permit HFC access to Magellan's El Paso terminal. Effective upon the closing of this exchange, we are the named operator of the Osage pipeline and transitioned into this role on September 1, 2016.

On March 31, 2016, we acquired crude oil tanks located at HFC's Tulsa refinery from an affiliate of Plains for $39.5 million. In 2009, HFC sold these tanks to Plains and leased them back, and due to HFC's continuing interest in the tanks, HFC accounted for the transaction as a financing arrangement. Accordingly, the tanks remained on HFC's balance sheet and were depreciated for accounting purposes.

On June 3, 2016, we acquired a 50% interest in Cheyenne Pipeline LLC, owner of the Cheyenne pipeline, in exchange for a contribution of $42.6 million in cash to Cheyenne Pipeline LLC. Cheyenne Pipeline LLC will continue to be operated by an affiliate of Plains, which owns the remaining 50% interest. The 87-mile crude oil pipeline runs from

Fort Laramie to Cheyenne, Wyoming and has an 80,000 barrel per day ("bpd") capacity.

On October 1, 2016, we acquired all the membership interests of Woods Cross Operating, a wholly owned subsidiary of HFC, which owns the newly constructed atmospheric distillation tower, fluid catalytic cracking unit, and polymerization unit located at HFC's Woods Cross refinery for cash consideration of $278 million. In connection with this transaction, we entered into 15-year tolling agreements containing minimum quarterly throughput commitments from HFC that provide minimum annualized revenues of $56.7 million.

We are a consolidated variable interest entity of HFC. Therefore, the acquisitions of the crude tanks at HFC's Tulsa refinery on March 31, 2016, and Woods Cross Operating on October 1, 2016, were accounted for as transfers between entities under common control. Accordingly, this financial data has been retrospectively adjusted to include the historical results of these acquisitions for all periods presented prior to the effective dates of each acquisition. We refer to these historical results as those of our "Predecessor." See Notes 1 and 2 in the notes to consolidated financial statements of HEP included in this annual report for further discussion of these acquisitions and basis of presentation.

Agreements with HFC and Alon

We serve HFC's refineries under long-term pipeline, terminal, tankage and refinery processing unit throughput agreements expiring from 2019 to 2036. Under these agreements, HFC agrees to transport, store, and process throughput volumes of refined product, crude oil and feedstocks on our pipelines, terminal, tankage, loading rack facilities and refinery processing units that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual rate adjustments on July 1st each year based on the PPI or the FERC index. As of December 31, 2016, these agreements with HFC require minimum annualized payments to us of $321.0 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us the amount of any shortfall in cash by the last day of the month following the end of the quarter. Under certain of the agreements, a shortfall payment may be applied as a credit in the following four quarters after minimum obligations are met.

We have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that is also subject to annual tariff rate adjustments. We also have a capacity lease agreement under which we lease Alon space on our Orla to El Paso pipeline for the shipment of refined product. The terms under this lease agreement expire beginning in 2018 through 2022. As of December 31, 2016, these agreements with Alon require minimum annualized payments to us of $32.6 million.

A significant reduction in revenues under these agreements could have a material adverse effect on our results of operations.

Under certain provisions of an omnibus agreement that we have with HFC (“Omnibus Agreement”), we pay HFC an annual administrative fee ($2.5 million in 2016), for the provision by HFC or its affiliates of various general and administrative services to us. This fee does not include the salaries of personnel employed by HFC who perform services for us on behalf of HLS or the cost of their employee benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct expenses they incur on our behalf.

Under HLS’s Secondment Agreement with HFC, certain employees of HFC are seconded to HLS to provide operational and maintenance services for certain of our processing, refining, pipeline and tankage assets at the El Dorado and Cheyenne refineries, and HLS reimburses HFC for its prorated portion of the wages, benefits, and other costs of these employees for our benefit.

We have a long-term strategic relationship with HFC. Our current growth plan is to continue to pursue purchases of logistic and other assets at HFC's existing refining locations in New Mexico, Utah, Oklahoma, Kansas and Wyoming. We also expect to work with HFC on logistic asset acquisitions in conjunction with HFC’s refinery acquisition strategies. Furthermore, we plan to continue to pursue third-party logistic asset acquisitions that are accretive to our unitholders and increase the diversity of our revenues.

RESULTS OF OPERATIONS

Income, Distributable Cash Flow and Volumes

The following tables present income, distributable cash flow and volume information for the years ended December 31, 2016, 2015 and 2014. These results have been adjusted to include the combined results of our Predecessor. See Notes 1 and 2 to the Consolidated Financial Statements of HEP for discussion of the basis of this presentation.

	Years Ended December 31,		Change from
	2016	2015	2015
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$83,102	$81,294	$1,808
Affiliates—intermediate pipelines	26,996	28,943	(1,947)
Affiliates—crude pipelines	70,341	67,088	3,253
	180,439	177,325	3,114
Third parties—refined product pipelines	52,195	51,022	1,173
	232,634	228,347	4,287
Terminals, tanks and loading racks:			
Affiliates	119,633	111,933	7,700
Third parties	16,732	15,632	1,100
	136,365	127,565	8,800
Affiliates—refinery processing units	33,044	2,963	30,081
Total revenues	402,043	358,875	43,168
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	123,986	105,556	18,430
Depreciation and amortization	70,428	63,306	7,122
General and administrative	12,532	12,556	(24)
	206,946	181,418	25,528
Operating income	195,097	177,457	17,640
Other income (expense):			
Equity in earnings of equity method investments	14,213	4,803	9,410
Interest expense, including amortization	(52,552)	(37,418)	(15,134)
Interest income	440	526	(86)
Gain on sale of assets and other	677	486	191
	(37,222)	(31,603)	(5,619)
Income before income taxes	157,875	145,854	12,021
State income tax expense	(285)	(228)	(57)
Net income	157,590	145,626	11,964
Add net loss applicable to predecessor	10,657	2,702	7,955
Allocation of net (income) loss attributable to noncontrolling interests	(10,006)	(11,120)	1,114
Net income attributable to Holly Energy Partners	158,241	137,208	21,033
General partner interest in net income, including incentive distributions [(1)]	(57,173)	(42,337)	(14,836)
Limited partners' interest in net income	$101,068	$94,871	$6,197
Limited partners' earnings per unit—basic and diluted [(1)]	$1.69	$1.60	$0.09

Weighted average limited partners' units outstanding	59,872	58,657	1,215
EBITDA [2]	$277,545	$237,180	$40,365
Distributable cash flow [3]	$218,810	$197,046	$21,764
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	128,140	124,061	4,079
Affiliates—intermediate pipelines	137,381	142,475	(5,094)
Affiliates—crude pipelines	277,241	291,491	(14,250)
	542,762	558,027	(15,265)
Third parties—refined product pipelines	75,909	73,555	2,354
	618,671	631,582	(12,911)
Terminals and loading racks:			
Affiliates	413,487	391,292	22,195
Third parties	72,342	78,403	(6,061)
	485,829	469,695	16,134
Affiliates—refinery processing units	51,778	6,774	45,004
Total for pipelines and terminal and refinery processing unit assets (bpd)	1,156,278	1,108,051	48,227

	Years Ended December 31, 2015	2014	Change from 2014
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$81,294	$77,852	$3,442
Affiliates—intermediate pipelines	28,943	29,813	(870)
Affiliates—crude pipelines	67,088	56,805	10,283
	177,325	164,470	12,855
Third parties—refined product pipelines	51,022	43,376	7,646
	228,347	207,846	20,501
Terminals, tanks and loading racks:			
Affiliates	111,933	110,726	1,207
Third parties	15,632	13,973	1,659
	127,565	124,699	2,866
Affiliates—refinery processing units	2,963	—	2,963
Total revenues	358,875	332,545	26,330
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	105,556	106,185	(629)
Depreciation and amortization	63,306	62,529	777
General and administrative	12,556	10,824	1,732
	181,418	179,538	1,880
Operating income	177,457	153,007	24,450
Other income (expense):			
Equity in earnings of equity method investments	4,803	2,987	1,816
Interest expense, including amortization	(37,418)	(36,101)	(1,317)
Interest income	526	3	523
Loss on early extinguishment of debt	—	(7,677)	7,677
Gain on sale of assets and other	486	82	404
	(31,603)	(40,706)	9,103
Income before income taxes	145,854	112,301	33,553
State income tax expense	(228)	(235)	7
Net income	145,626	112,066	33,560
Add net loss applicable to predecessor	2,702	1,747	955
Allocation of net income attributable to noncontrolling interests	(11,120)	(8,288)	(2,832)
Net income attributable to Holly Energy Partners	137,208	105,525	31,683
General partner interest in net income, including incentive distributions (1)	(42,337)	(34,667)	(7,670)
Limited partners' interest in net income	$94,871	$70,858	$24,013
Limited partners' earnings per unit—basic and diluted (1)	$1.60	$1.20	$0.40
Weighted average limited partners' units outstanding	58,657	58,657	—
EBITDA (2)	$237,180	$211,701	$25,479
Distributable cash flow (3)	$197,046	$172,718	$24,328

Volumes (bpd)

Pipelines:

Affiliates—refined product pipelines	124,061	119,156	4,905
Affiliates—intermediate pipelines	142,475	138,258	4,217
Affiliates—crude pipelines	291,491	199,600	91,891
	558,027	457,014	101,013
Third parties—refined product pipelines	73,555	64,055	9,500
	631,582	521,069	110,513
Terminals and loading racks:			
Affiliates	391,292	261,888	129,404
Third parties	78,403	69,100	9,303
	469,695	330,988	138,707
Affiliates—refinery processing units	6,774	—	6,774
Total for pipelines and terminal and refinery processing unit assets (bpd)	1,108,051	852,057	255,994

(1) Net income attributable to HEP is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. HEP net income allocated to the general partner includes incentive distributions that are declared subsequent to quarter end. After the amount of incentive distributions and other priority allocations are allocated to the general partner, the remaining net income attributable to HEP is allocated to the partners based on their weighted average ownership percentage during the period.

(2) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income attributable to HEP plus (i) interest expense and loss on early extinguishment of debt, net of interest income (ii) state income tax and (iii) depreciation and amortization excluding Predecessor. EBITDA is not a calculation based upon generally accepted accounting principles ("GAAP"). However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income attributable to Holly Energy Partners or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants. See our calculation of EBITDA under Item 6, "Selected Financial Data."

(3) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts presented in our consolidated financial statements, with the general exception of maintenance capital expenditures. Distributable cash flow should not be considered in isolation or as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. It is also used by management for internal analysis and for our performance units. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating. See our calculation of distributable cash flow under Item 6, "Selected Financial Data."

Results of Operations — Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

Summary

Net income attributable to HEP for the year ended December 31, 2016, was $158.2 million, a $21.0 million increase compared to the year ended December 31, 2015. The increase in earnings is primarily due to the newly constructed and acquired Woods Cross refinery processing units and recent acquisitions including interests in the Osage and Cheyenne pipelines, the Tulsa crude tanks acquired in the first quarter of 2016, and the El Dorado refinery process units dropped down in the fourth quarter of 2015 as well as increased earnings from our 75% interest in the UNEV products pipeline, offset by higher interest expense associated with our private placement of $400 million in aggregate principal amount of 6% senior unsecured notes due in 2024, which we issued in July and the proceeds of which were used to partially fund our Woods Cross processing units acquisition.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Revenues for the year ended December 31, 2016, include the recognition of $10.0 million of prior shortfalls billed to shippers in 2016 and 2015. As of December 31, 2016, deferred revenue on our consolidated balance sheet related to shortfalls billed was $5.6 million. Such deferred revenue will be recognized in earnings either as (a) payment for shipments in excess of guaranteed levels, if and to the extent the pipeline system will have the necessary capacity for shipments in excess of guaranteed levels, or (b) when shipping rights expire unused over the contractual make-up period.

Revenues

Revenues for the year ended December 31, 2016, were $402.0 million, a $43.2 million increase compared to the same period of 2015. The revenue increase was primarily due to the Woods Cross processing units acquired in the fourth quarter of 2016, the El Dorado processing units acquired in the fourth quarter of 2015, higher UNEV pipeline revenues, and revenues from the Tulsa crude tanks acquired in the first quarter of 2016.

Revenues from our refined product pipelines were $135.3 million, an increase of $3.0 million, primarily due to increased revenue from the UNEV pipeline of $4.0 million offset by PPI driven tariff rates decreases. Shipments averaged 204.0 mbpd compared to 197.6 mbpd for the year ended December 31, 2015, largely due to higher volumes on our UNEV pipeline.

Revenues from our intermediate pipelines were $27.0 million, a decrease of $1.9 million, on shipments averaging 137.4 mbpd compared to 142.5 mbpd for the year ended December 31, 2015. The decrease in revenue is mainly due to lower volumes from pipelines servicing HFC's Navajo refinery and a $0.7 million decrease in previously deferred revenue realized.
Revenues from our crude pipelines were $70.3 million, an increase of $3.3 million, on shipments averaging 277.2 mbpd compared to 291.5 mbpd for the year ended December 31, 2015. Revenues increased largely due to an increase in deferred revenue recognized and to a surcharge on our Beeson expansion. Volumes were lower due to lower throughput at HFC's Navajo refinery.
Revenues from terminal, tankage and loading rack fees were $136.4 million, an increase of $8.8 million compared to the year ended December 31, 2015. This increase is due principally to increased revenues from the El Dorado tanks and the newly acquired Tulsa crude tanks. Refined products and crude terminalled in our facilities increased to an average of 485.8 mbpd compared to 469.7 mbpd for the year ended December 31, 2015, largely due to the inclusion of volumes from our Tulsa crude tanks acquired in the first quarter of 2016 and our El Dorado crude tanks acquired late in the first quarter of 2015, offset by the transfer of the El Paso terminal to HFC in the first quarter of 2016.
Revenues from refinery processing units were $33.0 million, an increase of $30.1 million on throughputs averaging 51.8 mbpd compared to 6.8 mbpd for 2015. This increase in revenue is primarily due to the Woods Cross refinery processing units acquired in the fourth quarter of 2016 and an increase in revenue from the El Dorado refinery units acquired late in 2015.

Operations Expense

Operations (exclusive of depreciation and amortization) expense for the year ended December 31, 2016, increased by $18.4 million compared to the year ended December 31, 2015. The increase is mainly due to operating expenses from the newly constructed and acquired Woods Cross processing units and El Dorado refinery processing units.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2016, increased by $7.1 million compared to the year ended December 31, 2015. The increase is principally due to higher depreciation from our newly acquired Woods Cross refinery processing units.

General and Administrative

General and administrative costs for the year ended December 31, 2016, was in line with the year ended December 31, 2015.

Equity in Earnings of Equity Method Investments

See the summary chart below for a description of our equity in earnings of equity method investments:

	Years Ended December 31,	
Equity Method Investment	2016	2015
	(in thousands)	
SLC Pipeline LLC	$4,508	$3,306
Frontier Aspen LLC	4,130	1,497
Osage Pipe Line Company, LLC	3,250	—
Cheyenne Pipeline LLC	2,325	—
Total	$14,213	$4,803

SLC Pipeline LLC earnings for the year ended December 31, 2016, increased compared to the year ended December 31, 2015, due to higher pipeline throughput volumes. Frontier Aspen LLC earnings for year ended December 31, 2016, include a full year of operations compared to the year ended December 31, 2015, as we acquired our 50% interest on August 31, 2015.

Interest Expense

Interest expense for the year ended December 31, 2016, totaled $52.6 million, an increase of $15.1 million compared to the year ended December 31, 2015. The increase is primarily due to the issuance of new 6% Senior Notes in July 2016. Our aggregate effective interest rate was 4.7% and 4.0% for the years ended December 31, 2016 and 2015, respectively.

State Income Tax

We recorded state income tax expense of $285,000 and $228,000 for the years ended December 31, 2016 and 2015, respectively. All state income tax expense is solely attributable to the Texas margin tax.

Results of Operations—Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

Summary
Net income attributable to HEP for the year ended December 31, 2015, was $137.2 million, a $31.7 million increase compared to the year ended December 31, 2014. This increase in earnings is due principally to higher pipeline and terminal volumes and annual tariff increases, as well as a loss of $7.7 million recorded due to the early retirement of our 8.25% Senior Notes in March 2014.

Revenues for the year ended December 31, 2015, include the recognition of $10.3 million of prior shortfalls billed to shippers in 2015 and 2014. As of December 31, 2015, deferred revenue on our consolidated balance sheet related to shortfalls billed was $7.8 million. Such deferred revenue will be recognized in earnings either as (a) payment for shipments in excess of guaranteed levels, if and to the extent the pipeline system will have the necessary capacity to provide for shipments in excess of guaranteed levels, or (b) when shipping rights expire unused over the contractual make-up period.

Revenues
Total revenues for the year ended December 31, 2015, were $358.9 million, a $26.3 million increase compared to the year ended December 31, 2014. The revenue increase was mainly due to the effect of annual tariff increases, increased pipeline shipments due to increased volumes from the New Mexico gathering system and UNEV pipeline as well as revenues from the El Dorado crude tanks and refinery processing units acquired during 2015. Overall pipeline volumes were up 21% compared to the year ended December 31, 2014, largely due to increased volumes from the New Mexico gathering system expansion.

Revenues from our refined product pipelines were $132.3 million, an increase of $11.1 million compared to the year ended December 31, 2014, primarily due to increased volumes and annual tariff increases. Shipments averaged 197.6 mbpd compared to 183.2 mbpd for 2014, largely due to higher spot volumes on our UNEV pipeline and increased volumes from HFC's Navajo refinery as well as lower volumes in the second quarter of 2014 resulting from major maintenance at Alon's Big Spring Refinery.

Revenues from our intermediate pipelines were $28.9 million, a decrease of $0.9 million on shipments averaging 142.5 mbpd compared to 138.3 mbpd for the year ended December 31, 2014. The decrease in revenue is principally due to the effects of a $1.9 million decrease in deferred revenue realized offset by increased volumes and annual tariff increases.

Revenues from our crude pipelines were $67.1 million, an increase of $10.3 million on shipments averaging 291.5 mbpd compared to 199.6 mbpd for the year ended December 31, 2014. Revenues increased primarily due to the annual tariff increases and $5.8 million in increased revenue from the New Mexico gathering system expansion completed in 2014.

Revenues from terminal, tankage and loading rack fees were $127.6 million, an increase of $2.9 million compared to the year ended December 31, 2014. The increase in revenues is largely due to annual fee increases and increased volumes. Refined products terminalled in our facilities increased to an average of 469.7 mbpd compared to 331.0 mbpd for 2014, largely due to the El Dorado crude tanks acquired in 2015 and higher volumes at our UNEV and El Paso terminals as well as our Cheyenne and Tulsa loading racks.

Operations Expense
Operations expense for the year ended December 31, 2015, decreased by $0.6 million compared to the year ended December 31, 2014. This decrease is primarily due to lower employee costs of $5.4 million as a result of the secondment of employees in El Dorado and Cheyenne, recovery of environmental remediation costs from third parties

of $2.9 million and a decrease in reimbursable expense projects of $2.2 million offset by higher project maintenance costs of $6.6 million as well as additional operating expenses related to acquisitions during the year ended December 31, 2015 and 2016.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2015, increased by $0.8 million compared to the year ended December 31, 2014, due principally to depreciation on El Dorado refinery assets purchased and capital lease depreciation offset by lower asset abandonment charges for tankage permanently removed from service.

General and Administrative
General and administrative costs for the year ended December 31, 2015, increased by $1.7 million compared to the year ended December 31, 2014, primarily due to higher costs for professional services.

Equity in Earnings of Equity Method Investments
Our equity in earnings of the SLC Pipeline was was $3.3 million and $3.0 million for the years ended December 31, 2015 and 2014. Our equity in earnings of our 50% interest in Frontier Pipeline, purchased on August 31, 2015, was $1.5 million for the year ended December 31, 2015.

Interest Expense
Interest expense for the year ended December 31, 2015, totaled $37.4 million, an increase of $1.3 million compared to the year ended December 31, 2014 due to higher borrowings outstanding. Our aggregate effective interest rate was 4.0% and 4.3% for the years ended December 31, 2015 and 2014, respectively.

Loss on Early Extinguishment of Debt
We recognized a loss of $7.7 million upon the early extinguishment of our 8.25% Senior Notes for the year ended December 31, 2014. This loss related to the premium paid to noteholders upon their tender of an aggregate principal amount of $150.0 million and related financing costs that were previously deferred.

State Income Tax
We recorded state income tax expense of $228,000 and $235,000 for the years ended December 31, 2015 and 2014, respectively, which is solely attributable to the Texas margin tax.

LIQUIDITY AND CAPITAL RESOURCES

Overview
In March 2016, we amended our senior secured revolving credit facility (the “Credit Agreement”) expiring in November 2018, increasing the size of the Credit Agreement from $850 million to $1.2 billion. The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit.

During the year ended December 31, 2016, we received advances totaling $554.0 million and repaid $713.0 million, resulting in a net decrease of $159.0 million under the Credit Agreement and an outstanding balance of $553.0 million at December 31, 2016. We have no letters of credit outstanding under the Credit Agreement at December 31, 2016, and the available capacity under the Credit Agreement is $647 million at December 31, 2016.
If any particular lender under the Credit Agreement could not honor its commitment, we believe the unused capacity that would be available from the remaining lenders would be sufficient to meet our borrowing needs. Additionally, we review publicly available information on the lenders in order to monitor their financial stability and assess their ongoing ability to honor their commitments under the Credit Agreement. We do not expect to experience any difficulty in the lenders’ ability to honor their respective commitments, and if it were to become necessary, we believe there would be alternative lenders or options available.

On September 16, 2016, we entered into a common unit purchase agreement in which certain purchasers agreed to purchase in a private placement 3,420,000 common units representing limited partnership interests, at a price of $30.18 per common unit. The private placement closed on October 3, 2016, and we received proceeds of approximately $103 million, which were used to finance a portion of the Woods Cross acquisition discussed below. As a result of the private placement, HFC now owns a 37% interest in us (including the 2% general partner interest). To maintain the 2% general partner interest, HFC contributed $2.1 million in October 2016.

On July 19, 2016, we closed a private placement of $400 million in aggregate principal amount of 6% senior unsecured notes due in 2024. We used the net proceeds to repay indebtedness under our revolving Credit Agreement.

On May 10, 2016, we established a continuous offering program under which HEP may issue and sell common units from time to time, representing limited partner interests, up to an aggregate gross sales amount of $200 million. As of December 31, 2016, HEP has issued 703,455 units under this program, providing $23.5 million in gross proceeds. We incurred sales commissions of $0.5 million associated with the issuance of these units. In connection with this program and to maintain the 2% general partner interest, HFC made capital contributions totaling $0.5 million as of

December 31, 2016.

On January 4, 2017, we redeemed the $300 million aggregate principal amount of 6.5% senior notes due in 2020 at a redemption cost of $316.4 million, at which time we recognized a $12.2 million early extinguishment loss. We funded the redemption with borrowings under our Credit Agreement.

Under our registration statement filed with the SEC using a “shelf” registration process, we currently have the authority to raise up to $2.0 billion, less amounts issued under the $200 million continuous offering program, by offering securities, through one or more prospectus supplements that would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

We believe our current cash balances, future internally generated funds and funds available under the Credit Agreement will provide sufficient resources to meet our working capital liquidity needs for the foreseeable future.

In February, May, August and November 2016, we paid regular quarterly cash distributions of $0.5650, $0.5750, $0.5850 and $0.5950, on all units in an aggregate amount of $192.0 million, including $49.3 million of incentive distribution payments to our general partner.

Contemporaneously with our UNEV interest acquisition on July 12, 2012, HEP Logistics, our general partner, agreed to forego its right to incentive distributions of $1.25 million per quarter over twelve consecutive quarterly periods following the close of the transaction and up to an additional four quarters if HFC’s Woods Cross refinery expansion did not attain certain thresholds. HEP Logistics’ waiver of its right to incentive distributions of $1.25 million per quarter ended with the distribution paid in the third quarter of 2016.

Cash and cash equivalents decreased by $11.4 million during the year ended December 31, 2016. The cash flows provided by operating activities of $242.7 million were less than the cash flows used for financing and investing activities of $111.1 million and $143.0 million, respectively. Working capital decreased by $20.0 million to a deficiency of $7.8 million at December 31, 2016 from a surplus of $12.2 million at December 31, 2015.

Cash Flows—Operating Activities

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

Cash flows from operating activities increased by $12.0 million from $230.7 million for the year ended December 31, 2015, to $242.7 million for the year ended December 31, 2016. This increase is due principally to higher cash receipts for services performed and higher distributions received from equity investments partially offset by higher payments for interest and operating expenses in the year ended December 31, 2016, as compared to the prior year.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Under certain agreements, these shippers have the right to recapture these amounts if future volumes exceed minimum levels. We billed $10.0 million during the year ended December 31, 2015 and 2016, related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2016. Another $5.6 million is included as deferred revenue on our balance sheet at December 31, 2016, related to shortfalls billed during the year ended December 31, 2016.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

Cash flows from operating activities increased by $45.5 million from $185.3 million for the year ended December 31, 2014, to $230.7 million for the year ended December 31, 2015. This increase is due principally to $31.9 million of greater cash receipts for services performed in the year ended December 31, 2015, as compared to the prior year, as well as lower payments made for operating costs and interest expenses.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Under certain agreements, these shippers have the right to recapture these amounts if future volumes exceed minimum levels. We billed $10.3 million during the year ended December 31, 2014 and 2015, related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2015. Another $7.8 million is included as deferred revenue on our balance sheet at December 31, 2015, related to shortfalls billed during the year ended December 31, 2015.

Cash Flows—Investing Activities
Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

Cash flows used for investing activities decreased by $103.7 million from $246.7 million for the year ended December 31, 2015, to $143.0 million for the year ended December 31, 2016. During the years ended December 31, 2016 and 2015, we invested $59.7 million and $39.4 million in additions to properties and equipment, respectively. We acquired a 50% interest in Cheyenne Pipeline LLC for $42.6 million in June 2016, a 50% interest in Frontier Pipeline for $55.0 million in August 2015, and the El Dorado crude tank assets for $27.5 million in March 2015. We have retrospectively adjusted our historical financial results for all periods to include the Woods Cross refinery processing units and Tulsa tanks for the periods we were under common control of HFC. Therefore, cash flows from investing activities reflect outflows of $44.1 million for the Woods Cross refinery processing units and Tulsa tanks in 2016 and $98.6 million in 2015. The year ended December 31, 2015 also reflects outflows of $27.6 million related to our acquisition of the El Dorado refinery processing units. We received $3.0 million of distributions in excess of earnings of our equity method investments. We received $0.4 million in proceeds from the sale of assets during the year ended December 31, 2016.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014
Cash flows used for investing activities increased by $48.3 million from $198.4 million for the year ended December 31, 2014, to $246.7 million for the year ended December 31, 2015. During the years ended December 31, 2015 and 2014, we invested $39.3 million and $80.0 million in additions to properties and equipment, respectively. During the year ended December 31, 2015, we acquired a 50% interest in the Frontier Pipeline for $55.0 million and an existing crude tank farm adjacent to HFC's El Dorado refinery from a third-party for $27.5 million. The years ended December 31, 2015 and 2014, also reflect outflows of $27.6 million and $29.7 million, respectively, related to our acquisition of the El Dorado refinery processing units. We have retrospectively adjusted our historical financial results for all periods to include the Woods Cross refinery processing units and Tulsa tanks for the periods we were under common control of HFC. Therefore, cash flows from investing activities reflect outflows of $98.6 million and $89.0 million for the Woods Cross refinery processing units and Tulsa tanks in 2015 and 2014, respectively. The year ended December 31, 2014 also reflects outflows of $29.7 million related to our acquisition of the El Dorado refinery processing units. We received $1.3 million proceeds from the sale of assets during the year ended December 31, 2015.

Cash Flows—Financing Activities
Year Ended December 31, 2016 Compared with Year Ended December 31, 2015
Cash flows used for financing activities were $111.1 million for the year ended December 31, 2016, compared to cash flows provided by financing activities of $28.1 million for the year ended December 31, 2015, a decrease of $139.2 million. During the year ended December 31, 2016, we received $554.0 million and repaid $713.0 million in advances under the Credit Agreement. We also received net proceeds of $394.0 million from the issuance of our 6% Senior Notes and $125.9 million from issuance of common units. Additionally, we paid $192.0 million in regular quarterly cash distributions to our general and limited partners, $5.8 million to our noncontrolling interest and $3.5 million for the purchase of common units for recipients of our incentive grants. We have retrospectively adjusted our historical financial results for all periods to include the Woods Cross refinery processing units and Tulsa tanks for the periods we were under common control of HFC. Therefore, we recorded contributions from HFC for the Woods Cross Operating and Tulsa tank acquisitions of $51.3 million and recorded distributions to HFC for the acquisitions of $317.5 million. We paid $1.2 million to HFC related to the Osage acquisition. We also paid $4.0 million in deferred financing charges to amend the Credit Agreement. During the year ended December 31, 2015, we received $973.9 million and repaid $832.9 million in advances under the Credit Agreement. We also paid $169.1 million in regular quarterly cash distributions to our general and limited partners, paid $4.6 million to our noncontrolling interest and paid $3.6 million for the purchase of common units for recipients of our incentive grants. In addition, we received $27.6 million for the El Dorado Operating acquisition, $0.9 million for Tulsa tank expenditures from HFC, $99.9 million for the Woods Cross Operating acquisition, and recorded distributions to HFC for the El Dorado Operating acquisition of $62.0 million.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

Cash flows provided by financing activities were $28.1 million for the year ended December 31, 2015, compared to $9.6 million for the year ended December 31, 2014, an increase of $18.5 million. During the year ended December 31, 2015, we received $973.9 million and repaid $832.9 million in advances under the Credit Agreement. We also paid $169.1 million in regular quarterly cash distributions to our general and limited partners, paid $4.6 million to our noncontrolling interest and paid $3.6 million for the purchase of common units for recipients of our incentive grants. In addition, we received $27.6 million for the El Dorado Operating acquisition, $0.9 million for Tulsa tank expenditures from HFC, $99.9 million for the Woods Cross Operating acquisition, and recorded distributions to HFC for the El Dorado Operating acquisition of $62.0 million. During the year ended December 31, 2014, we received $642.3 million and repaid $434.3 million in advances under the Credit Agreement. We paid $156.2 million to redeem the 8.25% Senior Notes. We also paid $154.7 million in regular quarterly cash distributions to our general and limited partners, paid $4.0 million to our noncontrolling interest and paid $3.6 million for the purchase of common units for recipients of our incentive grants. In addition, we received $29.7 million for the El Dorado Operating acquisition, $2.9 million for Tulsa tank expenditures from HFC, $87.5 million for the Woods Cross Operating acquisition.

Capital Requirements

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of, and are expected to continue to consist of, maintenance capital expenditures and expansion capital expenditures. “Maintenance capital expenditures” represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity of existing assets. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations. “Expansion capital expenditures” represent capital expenditures to expand the operating capacity of existing or new assets, whether through construction or acquisition. Expansion capital expenditures include expenditures to acquire assets, to grow our business and to expand existing facilities, such as projects that increase throughput capacity on our pipelines and in our terminals. Repair and maintenance expenses associated with existing assets that are minor in nature and do not extend the useful life of existing assets are charged to operating expenses as incurred.

Each year the board of directors of HLS, our ultimate general partner, approves our annual capital budget, which specifies capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, additional projects may be approved. The funds allocated for a particular capital project may be expended over a period in excess of a year, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year’s capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. The 2017 capital budget is comprised of $9 million for maintenance capital expenditures and approximately $30 million for expansion capital expenditures. We expect the majority of the expansion capital budget to be invested in refined product pipeline expansions, crude system enhancements, new storage tanks, and enhanced blending capabilities at our racks. In addition to our capital budget, we may spend funds periodically to perform capital upgrades or additions to our assets where a customer reimburses us for such costs. The upgrades or additions would generally benefit the customer over the remaining life of the related service agreements. We expect that our currently planned sustaining and maintenance capital expenditures, as well as expenditures for acquisitions and capital development projects, will be funded with cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our Credit Agreement, or a combination thereof. With volatility and uncertainty at times in the credit and equity markets, there may be limits on our ability to issue new debt or equity financing. Additionally, due to pricing movements in the debt and equity markets, we may not be able to issue new debt and equity securities at acceptable pricing. Without additional capital beyond amounts available under the Credit Agreement, our ability to obtain funds for some of these capital projects may be limited.

Under the terms of the transaction to acquire HFC’s 75% interest in UNEV, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation, and amortization above $30 million beginning July 1, 2015, and ending in June 2032, subject to certain limitations. However, to the extent earnings thresholds are not achieved, no redemption payments are required. No redemption payments have been required to date.

Credit Agreement

In March 2016, we amended our Credit Agreement increasing the size of the Credit Agreement from $850 million to $1.2 billion. The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital as well as for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement involves recourse to HEP Logistics, our general partner, and is guaranteed by our material wholly-owned subsidiaries. Any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant. We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.750% to 1.75%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.750% to 2.75%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). The weighted-average interest rates on our Credit Agreement borrowings in effect at December 31, 2016 and 2015, were 2.978% and 2.655%, respectively. We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.30% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

The Credit Agreement imposes certain requirements on us with which we were in compliance as of December 31, 2016, including: a prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, make loans, acquire other companies, change the nature of our business, enter into a merger or consolidation, or sell assets; and covenants that require maintenance of a specified EBITDA to interest expense ratio, total debt to EBITDA ratio and senior debt to EBITDA ratio. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the debt and exercise other right