HOLLY ENERGY PARTNERS LP
Form 10-K
February 21, 2018

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, 2017
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. a smaller reporting company, or an emerging growth 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 ¨

Emerging growth company ¨

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

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $1.2 billion on June 30, 2017, 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 20, 2018 was 105,268,955.

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, Delek US Holdings, 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;
- the impact of recent changes in the tax laws and regulations that affect master limited partnerships; 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.

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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 Director, 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 Delek US Holdings, Inc.’s (“Delek”) refinery in Big Spring, Texas. At December 31, 2017, HFC owned approximately 59% of our outstanding common units as well as a non-economic general partner 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.

On October 31, 2017, we closed on a restructuring transaction with HEP Logistics Holdings, L.P. (“HEP Logistics”), a wholly-owned subsidiary of HFC and the general partner of HEP, pursuant to which the incentive distribution rights held by HEP Logistics were canceled, and HEP Logistics' 2% general partner interest in HEP was converted into a non-economic general partner interest in HEP. In consideration, we issued 37,250,000 of our common units to HEP Logistics. In addition, HEP Logistics agreed to waive $2.5 million of limited partner cash distributions for each of twelve consecutive quarters beginning with the first quarter the units issued as consideration were eligible to receive distributions.

PIPELINES AND TERMINALS

Pipelines

Our refined product pipelines transport light refined products from HFC’s Navajo refinery in New Mexico and Delek’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, Oklahoma, Utah and Wyoming that deliver crude oil to HFC's Navajo, El Dorado and Woods Cross refineries.

Our pipelines are regularly inspected. 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 and crude oil pipelines and state regulatory agencies regulate the transportation tariffs for intrastate shipments on our pipelines.

HFC shipped an aggregate of 63% of the petroleum products transported on our refined product pipelines, 97% of the throughput volumes transported on our intermediate pipelines, and 93% of the throughput on our crude pipelines in 2017.

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,				
	2017	2016	2015	2014	2013
Volumes transported for barrels per day ("bpd"):					
HFC	556,516	542,762	558,027	457,014	397,359
Third parties	99,847	75,909	73,555	64,055	63,337
Total	656,363	618,671	631,582	521,069	460,696
Total barrels in thousands (“mbbls”)	239,572	226,434	230,527	190,190	168,154

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 five main segments which are regulated by the FERC. The segments primarily ship refined product produced at the Navajo refinery to El Paso terminals: (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, (4) seven miles from outside El Paso to HFC's El Paso terminal and (5) six miles of 12-inch pipeline from outside El Paso to Magellan Midstream Partners' (“Magellan”) El Paso terminal. There are two shippers on the latter three segments, HFC and Delek, and HFC is the only shipper on the first two segments.

Refined products destined to HFC's El Paso terminal and Magellan'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 $535,000 (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 Delek'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. Delek 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 Delek's Duncan terminal. Delek 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 Delek's Big Spring refinery). Delek 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 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 Andeavor Logistics LP's Northwest Pipeline origin station (4) a 1- mile segment is 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 a common carrier pipeline used for the shipment of refined products from Woods Cross, Utah to terminals in Las Vegas, Nevada and Cedar City, Utah. 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
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 100% interest in this pipeline after purchasing the remaining 75% interest, effective October 31, 2017.

Frontier Aspen Pipeline
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 100% interest in this pipeline after purchasing the remaining 50% interest, effective October 31, 2017.

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	221	95,000	(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	61	50,000	
SLC Pipeline	16	95	105,000	
Frontier Pipeline	16	289	72,000	

(1) Includes 15,000 bpd capacity on the Orla to El Paso segment of this pipeline, leased to Delek 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 Delek'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 Delek’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,				
	2017	2016	2015	2014	2013
Refined products and crude terminalled for (bpd):					
HFC	428,001	413,487	391,292	261,888	255,108
Third parties	68,687	72,342	78,403	69,100	63,791
Total	496,688	485,829	469,695	330,988	318,899
Total (mbbls)	181,291	177,813	171,439	120,811	116,398

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 10,198,000 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 railyard
HEP constructed 23,500 track feet of rail storage on land situated near the railway station of Tulsa, Oklahoma. HEP leases a portion of this land from BNSF Railway Company and subleases this 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.

Southwest Region

Abilene, Texas terminal
This terminal receives refined products from Delek's Big Spring refinery, which accounted for all of its volumes in 2017. 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. Delek 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 Delek's Big Spring refinery. Refined product received at the tank farm is delivered into our Orla to El Paso pipeline segment (described above). Delek 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 a portion of 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. The lease on a portion of the underlying ground at this terminal expired in February 2018, and we are evaluating our options for this terminal.

Wichita Falls, Texas terminal

This terminal receives refined product from Delek's Big Spring refinery, which accounted for all of its volumes in 2017. Refined product received at this terminal is sold via a truck rack or shipped via pipeline connections to Delek’s terminal in Duncan, Oklahoma and also to NuStar Energy L.P.’s Southlake Pipeline. Delek 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 Andeavor 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 Andeavor Logistics LP's 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.

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 North Las Vegas, Nevada, that receive product 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
Frontier Anschutz Station	260,000	3	Pipeline	Pipeline
Frontier Arepi Station	100,000	3	Pipeline	Pipeline
SLC North Salt Lake Station	10,000	1	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
Tulsa facility railyard	N/A	N/A	Rail	Rail
Cheyenne facility truck racks	N/A	N/A	Refinery	Truck
El Dorado facility truck racks	N/A	N/A	Refinery	Truck
Total	3,745,000			

(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	3,727,000	Crude oil and refined product	61
Cheyenne, WY	1,915,000	Crude oil and refined product	54
El Dorado, KS	3,877,000	Refined and intermediate product	90
Total	10,198,000		

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 operate 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 turnaround costs are more than expected after the first turnaround for each unit, the tolling fee will be permanently adjusted, one time, to recover these costs.

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 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 agreed to build two connections on our south products pipeline system that will permit HFC access to Magellan’s El Paso terminal. These connections were in service in the fourth quarter of 2017. 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 is 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 $57 million as of the acquisition date.

SLC Pipeline and Frontier Aspen

On October 31, 2017, we acquired the remaining 75% interest in SLC Pipeline LLC ("SLC Pipeline") and the remaining 50% interest in Frontier Aspen LLC ("Frontier Aspen") from subsidiaries of Plains, for total consideration of $250 million. Prior to this acquisition, we held noncontrolling interests of 25% of SLC Pipeline and 50% of Frontier Aspen. As a result of the acquisitions, SLC Pipeline and Frontier Aspen are wholly-owned subsidiaries of HEP.

This acquisition was accounted for as a business combination achieved in stages with the consideration allocated to the acquisition date fair value of assets and liabilities acquired. The preexisting equity interests in SLC Pipeline and Frontier Aspen were remeasured at acquisition date fair value since we have a controlling interest. We recognized a gain on the remeasurement in the fourth quarter of 2017 of $36.3 million.

SLC Pipeline is the owner of a 95-mile crude pipeline that transports crude oil into the Salt Lake City area from the Utah terminal of the Frontier Pipeline and from Wahsatch Station. Frontier Aspen is the owner of a 289-mile crude pipeline from Casper, Wyoming to Frontier Station, Utah that supplies Canadian and Rocky Mountain crudes to Salt Lake City area refiners through a connection to the SLC Pipeline.

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 DELEK

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, 2017, these agreements with HFC require minimum annualized payments to us of $324 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 Delek expiring in 2020 under which Delek 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 Delek 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, 2017, these agreements with Delek require minimum annualized payments to us of $33 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 in notes to consolidated financial statements of HEP.

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 2017) 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, directors' compensation, 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, 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 2018 capital budget is comprised of $8 million for maintenance capital expenditures and $40 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.

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 and terminal 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. 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.

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 crude oil transported to or refined products transported from HFC's refineries, particularly during the terms of our long-term transportation agreements with HFC expiring between 2019 and 2036. Additionally, under our throughput agreement with Delek expiring in 2020, we believe that we will not face significant competition for those barrels of refined products we transport from Delek'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 Delek 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. These laws and regulations may require us to obtain permits for our operations or result in the imposition of strict requirements relating to air emissions, biodiversity, wastewater discharges, waste management, or the remediation of contamination. 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 operations, 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. 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. Some environmental laws impose liability without regard to fault or the legality of the original act on certain classes of persons that contributed to the releases of hazardous substances or petroleum hydrocarbon substances into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. 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 Delek with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Delek in 2005, under which Delek 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, 2017, we have an accrual of $6.5 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 269 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 the Secondment Agreement agreement with HFC, 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, 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, 2017, HFC accounted for 74% 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, 2017, production from the Navajo refinery accounted for 81% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 97% 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 Delek 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, 2017, Delek 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 Delek under a capacity lease agreement. If Delek 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 Delek’s refineries, our revenues and cash flow would decline.

A decline in production at Delek's Big Spring refinery could reduce materially the volume of refined products we transport and terminal for Delek 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 Delek may take in response to a shutdown. Delek 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 Delek, if we are unable to transport or terminal refined products that Delek is prepared to ship, then Delek has the right to reduce its minimum volume commitment to us during the period of interruption. If a force majeure event occurs, we or Delek could terminate the Delek 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, 2017, the principal amount of our total outstanding debt was $1,512 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. 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, credit ratings, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

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 Delek 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 Delek. This could reduce our opportunity to earn revenues from HFC and Delek in excess of their minimum volume commitment obligations.

An additional factor that could affect some of HFC's and Delek'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 Delek to these markets.

A material decrease in the supply, or a material increase in the price, of crude oil available to HFC's and Delek'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 Delek'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 Delek 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 Delek 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 new and/or 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. In May 2015, the EPA published a final rule that has the potential to greatly expand the definition of "waters of the United States" under the federal Clean Water Act ("CWA") and the jurisdiction of the Corps. The rule is currently subject to a number of legal challenges in federal court. The EPA and the Corps have proposed to repeal the May 2015 rule and have separately announced their intention to issue a revised rule defining the scope of the CWA's jurisdiction. The agencies have also issued a stay delaying implementation of the rule for two years. To the extent any final rule on the scope of the CWA expands jurisdictional waters, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. These and other authorizations and permits are subject to revocation, renewal, modification, or third party challenge, 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 Delek'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 Delek 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 or the payment of carbon taxes. These requirements may affect HFC's and Delek'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 and again in 2016, 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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. These requirements could, to the extent fully implemented, 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 certain 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. Effective April 27, 2017, to account for inflation, those maximum civil penalties were increased to $209,002 per violation per day, with a maximum of $2,090,022 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. PHMSA has delayed implementation of these regulations, but they are expected to become effective in 2018. 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, Delek 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 Delek 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 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. Following a recent decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Native American landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operations. 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 a 57% limited partner interest and a non-economic general partner interest in us 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. Beginning July 1, 2018, the administrative fee will be subject to an annual upward adjustment for changes in PPI. 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, 2017, HEP has issued 2.2 million units under this program for gross consideration of $77 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 59,630,030 of our common units, which is approximately 57% 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, and our current and former unitholders may be required to indemnify us for any taxes (including applicable penalties and interest) resulting from such audit adjustments that were paid on their behalf.

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

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

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

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

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

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

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

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

We 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.

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
2017				
Fourth quarter	$35.84	$31.56	$ 0.6500	9,662,789
Third quarter	$36.05	$30.11	$ 0.6450	16,750,589
Second quarter	$37.56	$30.36	$ 0.6325	8,644,252
First quarter	$38.09	$32.06	$ 0.6200	8,883,617
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

The cash distribution for the fourth quarter of 2017 was declared on January 26, 2018, and paid on February 14, 2018, to all unitholders of record on February 5, 2018.

As of February 13, 2018, we had approximately 19,650 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 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.

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	Maximum Number of Units that May Yet be Purchased

			Program	Under a Publicly Announced Plan or Program
October 2017	—	$ —	—	$ —
November 2017	—	$ —	—	$ —
December 2017	16,818	$ 33.90	—	$ —
Total for October to December 2017	16,818		—	

The units reported represent the delivery of 16,818 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 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 includes 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,				
	2017	2016	2015	2014	2013
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$454,362	$402,043	$358,875	$332,545	$305,182
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	137,605	123,986	105,556	106,185	100,131
Depreciation and amortization	79,278	70,428	63,306	62,529	65,783
General and administrative	14,323	12,532	12,556	10,824	11,749
	231,206	206,946	181,418	179,538	177,663
Operating income	223,156	195,097	177,457	153,007	127,519
Equity in earnings of equity method investments	12,510	14,213	4,803	2,987	2,826
Interest expense	(58,448)	(52,552)	(37,418)	(36,101)	(47,010)
Interest income	491	440	526	3	161
Loss on early extinguishments of debt	(12,225)	—	—	(7,677)	—
Remeasurement gain on preexisting equity interests	36,254	—	—	—	—
Gain on sale of assets and other	422	677	486	82	1,871
	(20,996)	(37,222)	(31,603)	(40,706)	(42,152)
Income before income taxes	202,160	157,875	145,854	112,301	85,367
State income tax expense	(249)	(285)	(228)	(235)	(333)
Net income	201,911	157,590	145,626	112,066	85,034
Allocation of net loss attributable to Predecessor	—	10,657	2,702	1,747	1,047
Allocation of net income attributable to noncontrolling interests	(6,871)	(10,006)	(11,120)	(8,288)	(6,632)
Net income attributable to the partners	195,040	158,241	137,208	105,525	79,449
General partner interest in net income, including incentive distributions(1)	(35,047)	(57,173)	(42,337)	(34,667)	(27,523)
Limited partners' interest in net income	$159,993	$101,068	$94,871	$70,858	$51,926
Limited partners' earnings per unit – basic and diluted(1)	$2.28	$1.69	$1.60	$1.20	$0.88
Distributions per limited partner unit	$2.5475	$2.3625	$2.2025	$2.0750	$1.9550
Other Financial Data:					
Cash flows from operating activities	$238,487	$243,548	$231,442	$185,256	$182,393
Cash flows from investing activities	$(286,273)	$(143,030)	$(246,680)	$(198,423)	$(90,704)
Cash flows from financing activities	$51,905	$(111,874)	$27,421	$9,645	$(90,574)
EBITDA(2)	$344,749	$277,545	$237,180	$211,701	$192,054
Distributable cash flow(3)	$242,955	$218,810	$197,046	$172,718	$146,579
Maintenance capital expenditures(4)	$7,748	$9,658	$8,926	$4,616	$8,683
Expansion capital expenditures	37,062	50,046	30,467	75,343	43,418
Acquisition capital expenditures	245,446	44,119	153,728	118,727	41,635
Total capital expenditures	$290,256	$103,823	$193,121	$198,686	$93,736
Balance Sheet Data (at period end):					
Net property, plant and equipment	$1,569,471	$1,328,395	$1,293,060	$1,163,631	$1,018,854
Total assets	$2,154,114	$1,884,237	$1,777,646	$1,584,114	$1,442,573
Long-term debt(5)	$1,507,308	$1,243,912	$1,008,752	$866,986	$806,655

Total liabilities	$1,669,049	$1,412,446	$1,151,424	$989,324	$914,656
Total equity(6)	$485,065	$471,791	$626,222	$594,790	$527,917

(1) Net income attributable to the partners 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 included incentive distributions that were 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 the partners is allocated to the partners based on their weighted average ownership percentage during the period. As a result of the IDR restructuring transaction, no IDR or general partner distributions were made after October 31, 2017. See "Business and Properties - Overview."

(2) 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,				
	2017	2016	2015	2014	2013
	(In thousands)				
Net income attributable to the partners	$195,040	$158,241	$137,208	$105,525	$79,449
Add (subtract):					
Interest expense	55,385	49,306	35,490	34,280	44,041
Interest income	(491)	(440)	(526)	(3)	(161)
Amortization of discount and deferred debt issuance costs	3,063	3,246	1,928	1,821	2,120
Loss on early extinguishment of debt	12,225	—	—	7,677	—
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	—	—	—	849
State income tax expense	249	285	228	235	333
Depreciation and amortization	79,278	70,428	63,306	62,529	65,783
Predecessor depreciation and amortization	—	(3,521)	(454)	(363)	(360)
EBITDA	$344,749	$277,545	$237,180	$211,701	$192,054

(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.

Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(In thousands)				
Net income attributable to the partners	$195,040	$158,241	$137,208	$105,525	$79,449
Add (subtract):					
Depreciation and amortization	79,278	70,428	63,306	62,529	65,783
Remeasurement gain on preexisting equity interests	(36,254)	—	—	—	—
Amortization of discount and deferred debt issuance costs	3,063	3,246	1,928	1,821	2,120
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	—	—	—	849
Loss on early extinguishment of debt	12,225	—	—	7,677	—
Increase (decrease) in deferred revenue related to minimum revenue commitments	(1,283)	(1,292)	(1,233)	(2,503)	3,686
Maintenance capital expenditures (4)	(7,748)	(9,658)	(8,926)	(4,616)	(8,683)
Crude revenue settlement	—	—	—	—	918
Increase (decrease) in environmental liability	(581)	(584)	1,107	1,596	619
Increase (decrease) in reimbursable deferred revenue	(3,679)	(2,733)	176	(2,274)	(1,642)
Other non-cash adjustments	2,894	4,683	3,934	3,326	3,840
Predecessor depreciation and amortization	—	(3,521)	(454)	(363)	(360)
Distributable cash flow	$242,955	$218,810	$197,046	$172,718	$146,579

(4) 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.

(5) Includes $1,012 million, $553 million, $712 million, $571 million and $363 million in Credit Agreement advances that were classified as long-term debt at December 31, 2017, 2016, 2015, 2014 and 2013, respectively.

(6) 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 Delek's refinery in Big Spring, Texas. HEP, through its subsidiaries and joint ventures, owns and/or operates petroleum product and crude 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 59% of our outstanding common units and the non-economic general partner interest as of December 31, 2017.

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 $57 million as of the acquisition date.

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.

On October 31, 2017, we acquired the remaining 75% interest in SLC Pipeline and the remaining 50% interest in Frontier Aspen from subsidiaries of Plains, for total consideration of $250 million. Prior to this acquisition, we held noncontrolling interests of 25% of SLC Pipeline and 50% of Frontier Aspen. As a result of the acquisitions, SLC Pipeline and Frontier Aspen are wholly-owned subsidiaries of HEP.

This acquisition was accounted for as a business combination achieved in stages with the consideration allocated to the acquisition date fair value of assets and liabilities acquired. The preexisting equity interests in SLC Pipeline and Frontier Aspen were remeasured at acquisition date fair value since we will have a controlling interest, and we recognized a gain on the remeasurement in the fourth quarter of 2017 of $36.3 million.

SLC Pipeline is the owner of a 95-mile crude pipeline that transports crude oil into the Salt Lake City area from the Utah terminal of the Frontier Pipeline and from Wahsatch Station. Frontier Aspen is the owner of a 289-mile crude pipeline from Casper, Wyoming to Frontier Station, Utah that supplies Canadian and Rocky Mountain crudes to Salt Lake City area refiners through a connection to the SLC Pipeline.

Agreements with HFC and Delek

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, 2017, these agreements with HFC require minimum annualized payments to us of $324 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 Delek expiring in 2020 under which Delek 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 Delek 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, 2017, these agreements with Delek require minimum annualized payments to us of $33 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 2017), 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, 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, 2017, 2016 and 2015. 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, 2017	2016	Change from 2016
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$80,030	$83,102	$(3,072)
Affiliates—intermediate pipelines	28,732	26,996	1,736
Affiliates—crude pipelines	65,960	70,341	(4,381)
	174,722	180,439	(5,717)
Third parties—refined product pipelines	52,379	52,195	184
Third parties—crude pipelines	7,939	—	7,939
	235,040	232,634	2,406
Terminals, tanks and loading racks:			
Affiliates	125,510	119,633	5,877
Third parties	16,908	16,732	176
	142,418	136,365	6,053
Affiliates—refinery processing units	76,904	33,044	43,860
Total revenues	454,362	402,043	52,319
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	137,605	123,986	13,619
Depreciation and amortization	79,278	70,428	8,850
General and administrative	14,323	12,532	1,791
	231,206	206,946	24,260
Operating income	223,156	195,097	28,059
Other income (expense):			
Equity in earnings of equity method investments	12,510	14,213	(1,703)
Interest expense, including amortization	(58,448)	(52,552)	(5,896)
Interest income	491	440	51
Loss on early extinguishment of debt	(12,225)	—	(12,225)
Remeasurement gain on preexisting equity interests	36,254	—	36,254
Gain on sale of assets and other	422	677	(255)
	(20,996)	(37,222)	16,226
Income before income taxes	202,160	157,875	44,285
State income tax expense	(249)	(285)	36
Net income	201,911	157,590	44,321
Allocation of net loss attributable to Predecessor	—	10,657	(10,657)
Allocation of net income attributable to noncontrolling interests	(6,871)	(10,006)	3,135
Net income attributable to the partners	195,040	158,241	36,799
General partner interest in net income attributable to the partners [(1)]	(35,047)	(57,173)	22,126
Limited partners' interest in net income	$159,993	$101,068	$58,925
Limited partners' earnings per unit—basic and diluted [(1)]	$2.28	$1.69	$0.59
Weighted average limited partners' units outstanding	70,291	59,872	10,419
EBITDA [(2)]	$344,749	$277,545	$67,204
Distributable cash flow [(3)]	$242,955	$218,810	$24,145

Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	133,822	128,140	5,682
Affiliates—intermediate pipelines	141,601	137,381	4,220
Affiliates—crude pipelines	281,093	277,241	3,852
	556,516	542,762	13,754
Third parties—refined product pipelines	78,013	75,909	2,104
Third parties—crude pipelines	21,834	—	21,834
	656,363	618,671	37,692
Terminals and loading racks:			
Affiliates	428,001	413,487	14,514
Third parties	68,687	72,342	(3,655)
	496,688	485,829	10,859
Affiliates—refinery processing units	63,572	51,778	11,794
Total for pipelines and terminal and refinery processing unit assets (bpd)	1,216,623	1,156,278	60,345

	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
Allocation of net loss attributable to Predecessor	10,657	2,702	7,955
Allocation of net income attributable to noncontrolling interests	(10,006)	(11,120)	1,114
Net income attributable to the partners	158,241	137,208	21,033
General partner interest in net income attributable to the partners [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

(1) Net income attributable to the partners 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 included incentive distributions that were 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 the partners is allocated to the partners based on their weighted average ownership percentage during the period. As a result of the IDR restructuring transaction, no IDR or general partner distributions were made after October 31, 2017. See "Business and Properties - Overview."

(2) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income attributable to the partners 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, 2017 Compared with Year Ended December 31, 2016

Summary

Net income attributable to the partners for the year ended December 31, 2017, was $195.0 million, a $36.8 million increase compared to the year ended December 31, 2016. The increase in earnings is primarily due to (a) the Woods Cross processing units acquired in the fourth quarter of 2016, (b) the gain recognized on the acquisition of SLC Pipeline and Frontier Aspen for the remeasurement of preexisting equity interests, offset by (c) a charge of $12.2 million related to the early redemption of our previously outstanding $300 million, 6.5% Senior Notes (the "6.5% Senior Notes"), due in 2020 and (d) higher interest expense of $5.9 million.

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, 2017, include the recognition of $9.7 million of prior shortfalls billed to shippers in 2017 and 2016. As of December 31, 2017, deferred revenue on our consolidated balance sheet related to shortfalls billed was $4.0 million.

Revenues

Revenues for the year ended December 31, 2017, were $454.4 million, a $52.3 million increase compared to the same period of 2016. The increase is primarily due to the $43.5 million of revenue recorded for the Woods Cross processing units acquired in the fourth quarter of 2016 as well as revenues from the SLC and Frontier Aspen pipelines acquired in the fourth quarter of 2017.

Revenues from our refined product pipelines were $132.4 million, a decrease of $2.9 million, on shipments averaging 211.8 mbpd compared to 204.0 mbpd for the year ended December 31, 2016. The decrease in revenue is primarily due to lower volumes on product pipelines due to the turnaround at HFC's Navajo refinery in the first quarter of 2017 as well as a decrease of $2.3 million in previously deferred revenue realized. The increase in volumes is primarily due to higher volumes on relatively short pipelines with lower tariff rates.

Revenues from our intermediate pipelines were $28.7 million, an increase of $1.7 million, on shipments averaging 141.6 mbpd compared to 137.4 mbpd for the year ended December 31, 2016. The increase in revenue is mainly due to higher volumes from

pipelines servicing HFC's Navajo refinery after its turnaround in the first quarter of 2017 as well as an increase of $1.5 million in previously deferred revenue realized.
Revenues from our crude pipelines were $73.9 million, an increase of $3.6 million, on shipments averaging 302.9 mbpd compared to 277.2 mbpd for the year ended December 31, 2016. Revenues and volumes increased mainly due to revenues from the fourth quarter of 2017 acquisition of the remaining interests in SLC Pipeline and Frontier Aspen offset by lower throughput due to HFC's Navajo refinery turnaround in the first quarter of 2017.
Revenues from terminal, tankage and loading rack fees were $142.4 million, an increase of $6.1 million compared to the year ended December 31, 2016. Refined products and crude terminalled in our facilities increased to an average of 496.7 mbpd compared to 485.8 mbpd for the year ended December 31, 2016. The volume and revenue increases are mainly due to our Tulsa crude tanks acquired on the last day of the first quarter of 2016, higher throughput on the UNEV terminals, and higher reimbursable revenue related to tank inspections and repairs, offset by the transfer of the El Paso terminal to HollyFrontier in the first quarter of 2016.
Revenues from refinery processing units were $76.9 million, an increase of $43.9 million on throughputs averaging 63.6 mbpd compared to 51.8 mbpd for 2016. The increase in revenues and volumes is primarily due to the Woods Cross refinery processing units acquired in the fourth quarter of 2016.
Operations Expense
Operations (exclusive of depreciation and amortization) expense for the year ended December 31, 2017, increased by $13.6 million compared to the year ended December 31, 2016. The increase is primarily due to operating expenses for the Woods Cross refinery processing units acquired in the fourth quarter of 2016.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2017, increased by $8.9 million compared to the year ended December 31, 2016. The increase is mainly due to depreciation from the Woods Cross refinery processing units acquired in the fourth quarter of 2016.

General and Administrative
General and administrative costs for the year ended December 31, 2017, increased by $1.8 million compared to the year ended December 31, 2016, mainly due to higher legal and consulting costs offset by decreased employee compensation.

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

Equity Method Investment	Years Ended December 31, 2017	2016
	(in thousands)	
SLC Pipeline LLC	$2,267	$4,508
Frontier Aspen LLC	4,089	4,130
Osage Pipe Line Company, LLC	2,447	3,250
Cheyenne Pipeline LLC	3,707	2,325
Total	$12,510	$14,213

SLC Pipeline and Frontier Aspen equity earnings for the year ended December 31, 2017, reflect the ten months before we purchased their remaining interests on October 31, 2017. SLC Pipeline and Frontier Aspen operations for the two months of November and December 2017, are included in HEP's consolidated results.

Interest Expense
Interest expense for the year ended December 31, 2017, totaled $58.4 million, an increase of $5.9 million compared to the year ended December 31, 2016. The increase is primarily due to the issuance of new 6% Senior Notes in July

2016. Our aggregate effective interest rate was 4.4% and 4.7% for the years ended December 31, 2017 and 2016, respectively.

State Income Tax

We recorded state income tax expense of $249,000 and $285,000 for the years ended December 31, 2017 and 2016, respectively. All state income tax expense is solely attributable to the Texas margin tax.

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

Summary
Net income attributable to the partners 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:

Equity Method Investment	Years Ended December 31, 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 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 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.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We have a $1.4 billion senior secured revolving credit facility (the “Credit Agreement”) expiring in July 2022. The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. The Credit Agreement is also available to fund letters of credit up to a $50 million sub-limit, and it contains an accordion feature giving us the ability to increase the size of the facility by up to $300 million with additional lender commitments.

During the year ended December 31, 2017, we received advances totaling $969.0 million and repaid $510.0 million, resulting in a net increase of $459.0 million under the Credit Agreement and an outstanding balance of $1,012.0 million at December 31, 2017. As of December 31, 2017, we had no letters of credit outstanding under the Credit Agreement, and the available capacity under the Credit Agreement was $388 million.

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 January 25, 2018, we entered into a common unit purchase agreement in which certain purchasers agreed to purchase in a private placement 3,700,000 common units representing limited partnership interests, at a price of $29.73 per common unit. The private placement closed on February 6, 2018, and we received proceeds of approximately $110 million, which were used to repay indebtedness under the Credit Agreement. After this common unit issuance, HFC owns a 57% limited partner interest in us.

We have a continuous offering program under which we 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, 2017, HEP has issued 2,241,907 units under this program, providing $77.1 million in gross proceeds. We intend to use the net proceeds for general partnership purposes, which may include funding working capital, repayment of debt, acquisitions and capital expenditures.

On October 31, 2017, we closed on an equity restructuring transaction with HEP Logistics, a wholly-owned subsidiary of HFC and the general partner of HEP, pursuant to which the incentive distribution rights held by HEP Logistics were canceled, and HEP Logistics' 2% general partner interest in HEP was converted into a non-economic general partner interest in HEP. In consideration, we issued 37,250,000 of our common units to HEP Logistics. In addition, HEP Logistics agreed to waive $2.5 million of limited partner cash distributions for each of twelve consecutive quarters beginning with the first quarter the units issued as consideration were eligible to receive distributions.

On September 22, 2017, we closed a private placement of an additional $100 million in aggregate principal of our 6.0% senior notes for a combined aggregate principal amount outstanding of $500 million maturing in 2024. The proceeds were used to repay indebtedness outstanding under the Credit Agreement.

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 $309.8 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 2017, we paid regular quarterly cash distributions of $0.6075, $0.6200, $0.6325 and $0.6450, on all units in an aggregate amount of $234.6 million, including $49.7 million of incentive distribution payments to our general partner. In February 2018, we paid a regular cash distribution of $0.6500 on all units in an aggregate amount of $63.5 million after deducting HEP Logistics' waiver of $2.5 million of limited partner cash distributions.

Cash and cash equivalents increased by $4.1 million during the year ended December 31, 2017. The cash flows provided by operating and financing activities of $238.5 million and $51.9 million, respectively, were more than the cash flows used for investing activities of $286.3 million. Working capital increased by $26.7 million to a surplus of $18.9 million at December 31, 2017 from a deficiency of $7.8 million at December 31, 2016.

Cash Flows—Operating Activities

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

Cash flows provided by operating activities decreased by $5.1 million from $243.5 million for the year ended December 31, 2016, to $238.5 million for the year ended December 31, 2017. This decrease is due principally to higher payments for interest and operating expenses partially offset by increased receipts from customers in the year ended December 31, 2017, 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 $9.7 million during the year ended December 31, 2016, related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2017. Another $4.0 million is included as deferred revenue on our balance sheet at December 31, 2017, related to shortfalls billed during the year ended December 31, 2017.

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

Cash flows from operating activities increased by $12.1 million from $231.4 million for the year ended December 31, 2015, to $243.5 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

Cash Flows—Investing Activities

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

Cash flows used for investing activities increased by $143.2 million from $143.0 million for the year ended December 31, 2016, to $286.3 million for the year ended December 31, 2017. During the years ended December 31, 2017 and 2016, we invested $44.8 million and $59.7 million in additions to properties and equipment, respectively. We acquired the remaining 75% interest in SLC Pipeline and 50% interest in Frontier Aspen for $245.4 million in October 2017. We acquired a 50% interest in Cheyenne Pipeline LLC for $42.6 million in June 2016 as well as $44.1 million for the Woods Cross refinery processing units and Tulsa tanks.

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.

Cash Flows—Financing Activities

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

Cash flows provided by financing activities were $51.9 million for the year ended December 31, 2017, compared to cash flows used by financing activities of $111.9 million for the year ended December 31, 2016, an increase of $163.8 million. During the year ended December 31, 2017, we received $969.0 million and repaid $510.0 million in advances under the Credit Agreement. We also received net proceeds of $101.8 million from the issuance of our 6% Senior Notes and $52.1 million from issuance of common units. Additionally, we paid $309.8 million for the redemption of our 6.5% Senior notes, $234.6 million in regular quarterly cash distributions to our general and limited partners and $6.5 million to our noncontrolling interest. We also paid $9.4 million in deferred financing charges to amend the Credit Agreement. 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 the issuance of common units. We also paid $192.0 million in regular quarterly cash distributions to our general and limited partners, paid $5.8 million to our noncontrolling interest and paid $3.5 million for the purchase of common units for recipients of our incentive grants. In addition, we received $51.3 million for the Woods Cross Operating and Tulsa tank acquisitions, and recorded distributions to HFC for the acquisitions of $317.5 million.

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

Cash flows used for financing activities were $111.9 million for the year ended December 31, 2016, compared to cash flows provided by financing activities of $27.4 million for the year ended December 31, 2015, a decrease of $139.3 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.

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 2018 capital budget is comprised of $8 million for maintenance capital expenditures and approximately $40 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
We have a $1.4 billion senior secured revolving credit facility (the “Credit Agreement”) expiring in July 2022. The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. The Credit Agreement is also available to fund letters of credit up to a $50 million sub-limit, and it contains an accordion feature giving us the ability to increase the size of the facility by up to $300 million with additional lender commitments. As of December 31, 2017, we had outstanding borrowings of $1,012 million under the Credit Agreement, no letters of credit outstanding, and the available capacity was $388 million.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets, and indebtedness under the Credit Agreement is guaranteed by our material wholly-owned subsidiaries. The Credit Agreement requires us to maintain compliance with certain financial covenants consisting of total leverage, senior secured leverage and interest coverage. It also limits or restricts our ability to engage in certain activities. If, at any time prior to the expiration of the Credit Agreement, HEP obtains two investment grade credit ratings, the Credit Agreement will become unsecured and many of the covenants, limitations, and restrictions will be eliminated.

We may prepay all loans at any time without penalty, except for tranche breakage costs. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of all loans outstanding and exercise other rights and remedies. We were in compliance with all covenants as of December 31, 2017.

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 0.50% to 1.50%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.50% to 2.50%). 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, 2017 and 2016, were 3.734% and 2.978%, 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.

Senior Notes
On January 4, 2017, we redeemed the $300 million aggregate principal amount of the 6.5% Senior Notes maturing 2020 at a redemption cost of $309.8 million, at which time we recognized a $12.2 million early extinguishment loss. We funded the redemption with borrowings under our Credit Agreement.

We have $500 million in aggregate principal amount of 6% Senior Notes due in 2024. We used the net proceeds from our offerings of the 6% Senior Notes to repay indebtedness under our Credit Agreement.

The 6% Senior Notes are unsecured and impose certain restrictive covenants, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. We were in compliance with the restrictive covenants for the 6% Senior Notes as of December 31, 2017. At any time when the 6% Senior Notes are rated investment grade by both Moody's and Standard & Poor's and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights at varying premiums over face value under the 6% Senior Notes.

Indebtedness under the 6% Senior Notes is guaranteed by our wholly-owned subsidiaries.

Long-term Debt
The carrying amounts of our long-term debt are as follows:

	December 31, 2017	December 31, 2016
	(In thousands)	
Credit Agreement	$1,012,000	$553,000
6% Senior Notes		
Principal	500,000	400,000
Unamortized debt issuance costs	(4,692)	(6,607)
	495,308	393,393
6.5% Senior Notes		
Principal	—	300,000
Unamortized discount and debt issuance costs	—	(2,481)
	—	297,519
Total long-term debt	$1,507,308	$1,243,912

See "Risk Management" for a discussion of our interest rate swaps.

Long-term Contractual Obligations
The following table presents our long-term contractual obligations as of December 31, 2017.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Over 5 Years
	(In thousands)				
Long-term debt – principal	$1,512,000	$—	$—	$1,012,000	$500,000
Long-term debt - interest	370,300	67,800	135,600	119,400	47,500

Site service fees	243,772	5,133	10,266	10,266	218,107
Pipeline operating lease	61,038	6,425	12,850	12,850	28,913
Right-of-way agreements and other	20,035	4,007	5,792	4,064	6,172
Total	$2,207,145	$83,365	$164,508	$1,158,580	$800,692

Long-term debt consists of outstanding principal under the Credit Agreement and the Senior Notes. Interest on the credit agreement is calculated using the rate in effect at December 31, 2017.

Site service fees consist of site service agreements with HFC, expiring in 2058 through 2066, for the provision of certain facility services and utility costs that relate to our assets located at HFC's refinery facilities. We are presenting obligations for the full term of these agreements; however, the agreements can be terminated with 180 day notice if we cease to operate the applicable assets.
The pipeline operating lease amounts above reflect the exercise of the second 10-year extension, expiring in 2027, on our lease agreement for the refined products pipeline between White Lakes Junction and Kuntz Station in New Mexico.
Most of our right-of-way agreements are renewable on an annual basis, and the right-of-way agreements payments above include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2017. For the foreseeable future, we intend to continue renewing these agreements and expect to incur right-of-way expenses in addition to the payments listed.
Other contractual obligations include capital lease obligations related to vehicles leases, office space leases, and other.

Impact of Inflation
Inflation in the United States has been relatively moderate in recent years and did not have a material impact on our results of operations for the years ended December 31, 2017, 2016 and 2015. PPI has increased an average of 0.4% annually over the past five calendar years, including an increase of 3.2% and a decrease of 1.0% in 2017 and 2016, respectively.

The substantial majority of our revenues are generated under long-term contracts that provide for increases or decreases in our rates and minimum revenue guarantees annually for increases or decreases in the PPI. Certain of these contracts have provisions that limit the level of annual PPI percentage rate increases or decreases. A significant and prolonged period of high inflation or a significant and prolonged period of negative inflation could adversely affect our cash flows and results of operations if costs increase at a rate greater than the fees we charge our shippers.

Environmental Matters
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. 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. 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. 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 Delek with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Delek in 2005, under which Delek will indemnify us subject to certain monetary and time limitations.

There are environmental remediation projects in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities retained by HFC. As of December 31, 2017, we have an accrual of $6.5 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.

CRITICAL ACCOUNTING POLICIES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from these estimates under different assumptions or conditions. We consider the following policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows.

Revenue Recognition
Revenues are recognized as products are shipped through our pipelines and terminals or feedstocks are processed by our refinery processing units. Additional pipeline transportation revenues result from an operating lease by Alon USA, L.P., which was acquired by Delek and is referred to herein as Delek, of an interest in the capacity of one of our pipelines.

Billings to customers for their obligations under their quarterly minimum revenue commitments are recorded as deferred revenue liabilities if the customer has the right to receive future services for these billings. The revenue is recognized at the earlier of:

- the customer receiving the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- our determination that we will not be required to provide services within the allowed period.

We determine that we will not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems will not have the necessary capacity to enable a customer to exceed its minimum volume levels to such a degree as to utilize the shortfall credit within its respective contractual shortfall make-up period.

Goodwill and Long-Lived Assets
Goodwill represents the excess of our cost of an acquired business over the fair value of the assets acquired, less liabilities assumed. Goodwill is not amortized. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. In prior years, we used the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss. In 2017, we assessed qualitative factors such as macroeconomic conditions, industry considerations, cost factors, and reporting unit financial performance and determined it is not more likely than not that the fair value of our reporting units are less than the respective carrying value. Therefore, in accordance with generally accepted accounting principles, further testing was not required.

We evaluate long-lived assets, including finite-lived intangible assets, for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset’s carrying value exceeds its fair value.

There have been no impairments to goodwill or our long-lived assets through December 31, 2017.

Contingencies
It is common in our industry to be subject to proceedings, lawsuits and other claims related to environmental, labor, product and other matters. We are required to assess the likelihood of any adverse judgments or outcomes to these types of matters as well as potential ranges of probable losses. A determination of the amount of reserves required, if any, for these types of contingencies is made after careful analysis of each individual issue. The required reserves may change in the future due to developments in each matter or changes in approach such as a change in settlement strategy in dealing with these potential matters.

Accounting Pronouncement Adopted During the Periods Presented

Share-Based Compensation

In March 2016, an accounting standard update was issued which simplifies the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. We adopted this standard effective January 1, 2017, with no impact to our financial condition or results of operations. The new standard also requires that employee taxes paid when an employer withholds units for tax-withholding purposes be reported as financing activities in the statement of cash flows on a retrospective basis. Previously, this activity was included in operating activities. The impact of this change for the years ended December 31, 2017, 2016 and 2015 was $0.6 million, $0.8 million and $0.7 million, respectively. Finally, consistent with our existing policy, we have elected to account for forfeitures on an estimated basis.

Accounting Pronouncements Not Yet Adopted

Revenue Recognition

In May 2014, an accounting standard update was issued requiring revenue to be recognized when promised goods or services are transferred to customers in an amount that reflects the expected consideration for these goods or services. This standard has an effective date of January 1, 2018, and we intend to account for the new guidance using the modified retrospective implementation method, whereby a cumulative effect adjustment is recorded to retained earnings as of the date of initial application. In preparing for adoption, we have evaluated the terms, conditions and performance obligations under our existing contracts with customers. Furthermore, we have implemented policies to comply with this new standard, which we do not anticipate will have a material impact on our financial condition, results of operations or cash flows.

Business Combinations

In December 2014, an accounting standard update was issued to provide new guidance on the definition of a business in relation to accounting for identifiable intangible assets in business combinations. This standard has an effective date of January 1, 2018, and we are evaluating its impact.

Financial Assets and Liabilities

In January 2016, an accounting standard update was issued requiring changes in the accounting and disclosures for financial instruments. This standard will become effective beginning with our 2018 reporting year. We are evaluating the impact of this standard.

Leases

In February 2016, an accounting standard update was issued requiring leases to be measured and recognized as a lease liability, with a corresponding right-of-use asset on the balance sheet. This standard has an effective date of January 1, 2019, and we are evaluating the impact of this standard.

RISK MANAGEMENT

The two interest rate swaps that hedged our exposure to the cash flow risk caused by the effects of LIBOR changes on $150 million of Credit Agreement matured on July 31, 2017. The swaps had effectively converted $150 million of our LIBOR based debt to fixed rate debt.

The market risk inherent in our debt positions is the potential change arising from increases or decreases in interest rates as discussed below.

At December 31, 2017, we had an outstanding principal balance of $500 million on our 6% Senior Notes. A change in interest rates generally would affect the fair value of the 6% Senior Notes, but not our earnings or cash flows. At December 31, 2017, the fair value of our 6% Senior Notes was $525 million. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6% Senior Notes at December 31, 2017, would result in a change of approximately $15 million in the fair value of the underlying 6% Senior Notes.

For the variable rate Credit Agreement, changes in interest rates would affect cash flows, but not the fair value. At December 31, 2017, borrowings outstanding under the Credit Agreement were $1,012 million. A hypothetical 10% change in interest rates applicable to the Credit Agreement would not materially affect our cash flows.

Our operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. We maintain various insurance coverages, including business interruption insurance, subject to certain deductibles. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

We have a risk management oversight committee that is made up of members from our senior management. This committee monitors our risk environment and provides direction for activities to mitigate, to an acceptable level, identified risks that may adversely affect the achievement of our goals.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. See “Risk Management” under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for a discussion of market risk exposures that we have with respect to our long-term debt. We utilize derivative instruments to hedge our interest rate exposure, as discussed under “Risk Management.”

Since we do not own products shipped on our pipelines or terminalled at our terminal facilities, we do not have direct market risks associated with commodity prices.

Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON ITS ASSESSMENT OF THE PARTNERSHIP'S INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Holly Energy Partners, L.P. (the "Partnership") is responsible for establishing and maintaining adequate internal control over financial reporting.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the Partnership's internal control over financial reporting as of December 31, 2017, using the criteria for effective control over financial reporting established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on this assessment, management concluded that, as of December 31, 2017, the Partnership maintained effective internal control over financial reporting.

Management excluded SLC Pipeline and Frontier Aspen, which were acquired on October 31, 2017, from our assessment of internal control over financial reporting as of December 31, 2017. See Note 2 of the 2017 consolidated financial statements for additional information. SLC Pipeline and Frontier Aspen represent approximately 17% of consolidated total assets as of December 31, 2017, and 2% of total revenues for the year ended December 31, 2017.

The Partnership's independent registered public accounting firm has issued an attestation report on the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2017. That report appears on page 60.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Holly Energy Partners, L.P. and the Board of Directors of Holly Logistic Services, L.L.C.

Opinion on Internal Control over Financial Reporting

We have audited Holly Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Holly Energy Partners, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

As indicated in the accompanying Management's Report on its Assessment of the Partnership's Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of SLC Pipeline LLC and Frontier Aspen LLC acquired on October 31, 2017, which are included in the 2017 consolidated financial statements of the Partnership and constituted 17% of total assets as of December 31, 2017 and 2% of revenues for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of SLC Pipeline LLC and Frontier Aspen LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2017, and the related notes of the Partnership and our report dated February 21, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 21, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To Unitholders of Holly Energy Partners, L.P. and the Board of Directors of Holly Logistic Services, L.L.C.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Holly Energy Partners, L.P. (the Partnership) as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 21, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

/s/ ERNST & YOUNG LLP
We have served as the Partnership's auditor since 2003.
Dallas, Texas
February 21, 2018

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,776	$ 3,657
Accounts receivable:		
Trade	12,803	7,846
Affiliates	51,501	42,562
	64,304	50,408
Prepaid and other current assets	2,311	2,888
Total current assets	74,391	56,953
Properties and equipment, net	1,569,471	1,328,395
Intangible assets, net	129,463	66,856
Goodwill	266,716	256,498
Equity method investments	85,279	165,609
Other assets	28,794	9,926
Total assets	$ 2,154,114	$ 1,884,237
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 14,547	$ 10,518
Affiliates	7,725	16,424
	22,272	26,942
Accrued interest	13,256	18,069
Deferred revenue	9,598	11,102
Accrued property taxes	4,652	5,397
Other current liabilities	5,707	3,225
Total current liabilities	55,485	64,735
Long-term debt	1,507,308	1,243,912
Other long-term liabilities	15,843	16,445
Deferred revenue	47,272	47,035
Class B unit	43,141	40,319
Equity:		
Partners' equity:		
Common unitholders (101,568,955 and 62,780,503 units issued and outstanding at December 31, 2017 and 2016, respectively)	393,959	510,975
General partner interest	—	(132,832)
Accumulated other comprehensive income	—	91
Total partners' equity	393,959	378,234

Noncontrolling interest	91,106	93,557
Total equity	485,065	471,791
Total liabilities and equity	$ 2,154,114	$ 1,884,237

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit data)

	Years Ended December 31,		
	2017	2016	2015
Revenues:			
Affiliates	$377,136	$333,116	$292,221
Third parties	77,226	68,927	66,654
	454,362	402,043	358,875
Operating costs and expenses:			
Operations (exclusive of depreciation and amortization)	137,605	123,986	105,556
Depreciation and amortization	79,278	70,428	63,306
General and administrative	14,323	12,532	12,556
	231,206	206,946	181,418
Operating income	223,156	195,097	177,457
Other income (expense):			
Equity in earnings of equity method investments	12,510	14,213	4,803
Interest expense	(58,448)	(52,552)	(37,418)
Interest income	491	440	526
Loss on early extinguishment of debt	(12,225)	—	—
Remeasurement gain on preexisting equity interests	36,254	—	—
Gain on sale of assets and other	422	677	486
	(20,996)	(37,222)	(31,603)
Income before income taxes	202,160	157,875	145,854
State income tax expense	(249)	(285)	(228)
Net income	201,911	157,590	145,626
Allocation of net loss attributable to Predecessor	—	10,657	2,702
Allocation of net income attributable to noncontrolling interests	(6,871)	(10,006)	(11,120)
Net income attributable to the partners	195,040	158,241	137,208
General partner interest in net income attributable to the Partnership, including incentive distributions	(35,047)	(57,173)	(42,337)
Limited partners’ interest in net income	$159,993	$101,068	$94,871
Limited partners’ per unit interest in earnings—basic and diluted	$2.28	$1.69	$1.60
Weighted average limited partners’ units outstanding	70,291	59,872	58,657

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Net income	$201,911	$157,590	$145,626
Other comprehensive income:			
Change in fair value of cash flow hedging instruments	88	(607)	(1,864)
Reclassification adjustment to net income on partial settlement of cash flow hedge	(179)	508	2,100
Other comprehensive income (loss)	(91)	(99)	236
Comprehensive income before noncontrolling interest	201,820	157,491	145,862
Allocation of net loss attributable to Predecessor	—	10,657	2,702
Allocation of comprehensive income to noncontrolling interests	(6,871)	(10,006)	(11,120)
Comprehensive income attributable to the partners	$194,949	$158,142	$137,444

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net income	$201,911	$157,590	$145,626
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	79,278	70,428	63,306
Gain on sale of assets	(319)	(150)	(375)
Remeasurement gain on preexisting equity interests	(36,254)	—	—
Amortization of deferred charges	3,063	3,247	1,928
Equity-based compensation expense	2,520	3,519	4,180
Equity in earnings of equity method investments, net of distributions	1,450	(2,032)	(122)
Loss on early extinguishment of debt	12,225	—	—
(Increase) decrease in operating assets:			
Accounts receivable—trade	(38)	279	(1,820)
Accounts receivable—affiliates	(8,939)	(10,080)	1,419
Prepaid and other current assets	830	1,598	(626)
Increase (decrease) in operating liabilities:			
Accounts payable—trade	(1,975)	(365)	(1,996)
Accounts payable—affiliates	(8,699)	(16)	6,396
Accrued interest	(4,813)	11,317	137
Deferred revenue	(1,267)	7,058	9,255
Accrued property taxes	(2,179)	1,633	1,061
Other current liabilities	2,091	(553)	(499)
Other, net	(398)	75	3,572
Net cash provided by operating activities	238,487	243,548	231,442
Cash flows from investing activities			
Additions to properties and equipment	(44,810)	(59,704)	(39,393)
Acquisition of tanks and refinery processing units	—	(44,119)	(153,728)
Purchase of interest in Cheyenne Pipeline	—	(42,627)	—
Purchase of interest in Frontier Aspen	—	—	(55,032)
Purchase of controlling interests in SLC Pipeline and Frontier Aspen	(245,446)	—	—
Proceeds from sale of assets	849	427	1,279
Distributions in excess of equity in earnings of equity investments	3,134	2,993	194
Net cash used for investing activities	(286,273)	(143,030)	(246,680)
Cash flows from financing activities			
Borrowings under credit agreement	969,000	554,000	973,900
Repayments of credit agreement borrowings	(510,000)	(713,000)	(832,900)
Redemption of 6.5% Senior Notes	(309,750)	—	—
Proceeds from issuance of 6% Senior Notes	101,750	394,000	—
Proceeds from issuance of common units	52,110	125,870	—
Contributions from general partner	1,072	2,577	—
Distributions to HEP unitholders	(234,575)	(192,037)	(169,063)
Distributions to noncontrolling interest	(6,500)	(5,750)	(4,625)

Distribution to HFC for acquisitions	—	(317,500)	(62,000)
Contributions from HFC for acquisitions	—	51,262	128,476
Contributions to HFC for El Dorado Operating Tanks	(103)	—	—
Distributions to HFC for Osage acquisition	—	(1,245)	—
Purchase of units for incentive grants	—	(3,521)	(3,555)
Units withheld for tax withholding obligations	(605)	(800)	(696)
Deferred financing costs	(9,382)	(3,995)	(962)
Other	(1,112)	(1,735)	(1,154)
Net cash provided by (used for) financing activities	51,905	(111,874)	27,421
Cash and cash equivalents			
Increase (decrease) for the year	4,119	(11,356)	12,183
Beginning of year	3,657	15,013	2,830
End of year	$7,776	$3,657	$15,013

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands)

	Holly Energy Partners, L.P. Partners' Equity (Deficit):				
	Common Units	General Partner Interest	Accumulated Other Comprehensive Income/(Loss)	Noncontrolling Interest	Total
Balance December 31, 2014	$468,813	$30,941	$ (46)	$ 95,082	$594,790
Distributions to HEP unitholders	(127,152)	(41,911)	—	—	(169,063)
Distributions to noncontrolling interests	—	—	—	(4,625)	(4,625)
Contribution from HFC for acquisitions	—	128,477	—	—	128,477
Distribution to HFC for acquisitions	—	(62,000)	—	—	(62,000)
Purchase of units for incentive grants	(3,555)	—	—	—	(3,555)
Amortization of restricted and performance units	3,484	—	—	—	3,484
Class B unit accretion	(7,005)	(143)	—	—	(7,148)
Net income	93,434	48,220	—	3,972	145,626
Other comprehensive income	—	—	236	—	236
Balance December 31, 2015	$428,019	$103,584	$ 190	$ 94,429	$626,222
Issuance of common units	125,870	—	—	—	125,870
Capital contribution	—	2,577	—	—	2,577
Distributions to HEP unitholders	(138,779)	(53,258)	—	—	(192,037)
Distributions to noncontrolling interests	—	—	—	(5,750)	(5,750)
Contributions from HFC for acquisitions	—	82,549	—	—	82,549
Distribution to HFC for acquisitions	—	(317,500)	—	—	(317,500)
Purchase of units for incentive grants	(3,521)	—	—	—	(3,521)
Amortization of restricted and performance units	2,719	—	—	—	2,719
Class B unit accretion	(6,250)	(128)	—	—	(6,378)
Other	—	(451)	—	—	(451)
Net income	102,917	49,795	—	4,878	157,590
Other comprehensive income	—	—	(99)	—	(99)
Balance December 31, 2016	$510,975	$(132,832)	$ 91	$ 93,557	$471,791
Issuance of common units	52,100	—	—	—	52,100
Capital contribution	—	1,072	—	—	1,072
Distributions to HEP unitholders	(181,439)	(53,136)	—	—	(234,575)
Distributions to noncontrolling interests	—	—	—	(6,500)	(6,500)
Distribution to HFC for acquisitions	—	(103)	—	—	(103)
Amortization of restricted and performance units	1,915	—	—	—	1,915
Class B unit accretion	(2,780)	(42)	—	—	(2,822)
Other	367	—	—	—	367
Net income	162,815	35,047	—	4,049	201,911
Equity restructuring transaction	(149,994)	149,994	—	—	—
Other comprehensive loss	—	—	(91)	—	(91)
Balance December 31, 2017	$393,959	$—	$ —	$ 91,106	$485,065

See accompanying notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017

Note 1: Description of Business and Summary of Significant Accounting Policies

Holly Energy Partners, L.P. (“HEP”) together with its consolidated subsidiaries, is a publicly held master limited partnership which is 59% owned (including the non-economic general partner interest) by HollyFrontier Corporation (“HFC”) and its subsidiaries. We commenced operations on July 13, 2004, upon the completion of our initial public offering. In these consolidated financial statements, the words “we,” “our,” “ours” and “us” refer to HEP unless the context otherwise indicates.

On October 31, 2017, we closed on an equity restructuring transaction with HEP Logistics Holdings, L.P. (“HEP Logistics”), a wholly-owned subsidiary of HFC and the general partner of HEP, pursuant to which the incentive distribution rights held by HEP Logistics were canceled, and HEP Logistics' 2% general partner interest in HEP was converted into a non-economic general partner interest in HEP. In consideration, we issued 37,250,000 of our common units to HEP Logistics. In addition, HEP Logistics agreed to waive $2.5 million of limited partner cash distributions for each of twelve consecutive quarters beginning with the first quarter the units issued as consideration were eligible to receive distributions. As of October 31, 2017, HFC held approximately 59.6 million HEP common units, representing approximately 59% of the outstanding common units. As a result of this transaction, no distributions were made on the general partner interest after October 31, 2017.

We own and operate petroleum product and crude oil pipelines, terminal, tankage and loading rack facilities and refinery processing units that support HFC’s refining and marketing operations in the Mid-Continent, Southwest and Northwest regions of the United States and Delek US Holdings, Inc.’s (“Delek”) refinery in Big Spring, Texas. Additionally, we own a 75% interest in the UNEV Pipeline, LLC (“UNEV”), a 50% interest in Osage Pipe Line Company, LLC (“Osage”), and a 50% interest in Cheyenne Pipeline LLC.

We operate in two reportable segments, a Pipelines and Terminals segment and a Refinery Processing Unit segment. Disclosures around these segments are discussed in Note 14.

Our Pipelines and Terminals segment consists of:
- 26 main pipeline segments
- Crude gathering networks in Texas and New Mexico
- 10 refined product terminals
- 1 crude terminal
- 31,800 track feet of rail storage located at two facilities
- 7 locations with truck and/or rail racks
- Tankage at all six of HFC's refining facility locations

Our Refinery Processing Unit segment consists of five refinery processing units at two of HFC's refining facility locations.

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 by charging fees for processing hydrocarbon feedstocks through our refinery processing units. We do not take ownership of products that we transport, terminal, store or process, and therefore, we are not exposed directly to changes in commodity prices.

Principles of Consolidation and Common Control Transactions

The consolidated financial statements include our accounts, our Predecessor's (defined below) and those of subsidiaries and joint ventures that we control. All significant intercompany transactions and balances have been eliminated.

Most of our acquisitions from HFC occurred while we were a consolidated variable interest entity of HFC. Therefore, as an entity under common control with HFC, we recorded these acquisitions on our balance sheets at HFC's historical basis instead of our purchase price or fair value. U.S. generally accepted accounting principles ("GAAP") require transfers of a business between entities under common control to be accounted for as though the transfer occurred as of the beginning of the period of transfer, and prior period financial statements and financial information are retrospectively adjusted to include the historical results and assets of the acquisitions from HFC for all periods presented prior to the effective dates of each acquisition. We refer to the historical results of the acquisitions prior to their respective acquisition dates as those of our "Predecessor." Many of these transactions are cash purchases and do not involve the issuance of equity; however, GAAP requires the retrospective adjustment of financial statements. Therefore, in such transactions, the prior year balance sheet includes as equity the amount of cost incurred by HFC to that date.

Use of Estimates
The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and Cash Equivalents
For purposes of the statements of cash flows, we consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The carrying amounts reported on the balance sheets approximate fair value due to the short-term maturity of these instruments.

Accounts Receivable
The majority of the accounts receivable are due from affiliates of HFC, Delek or independent companies in the petroleum industry. Credit is extended based on evaluation of the customer's financial condition and, in certain circumstances, collateral such as letters of credit or guarantees, may be required. Credit losses are charged to income when accounts are deemed uncollectible and historically have been minimal.

Properties and Equipment
Properties and equipment are stated at cost. Properties and equipment acquired from HFC while under common control of HFC are stated at HFC's historical basis. Depreciation is provided by the straight-line method over the estimated useful lives of the assets, primarily 15 to 25 years for terminal facilities and tankage, 25 to 32 years for pipelines, 25 years for refinery processing units and 5 to 10 years for corporate and other assets. We depreciate assets acquired under capital leases over the lesser of the lease term or the economic life of the assets. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvements are capitalized.

Intangible Assets
Intangible assets include transportation agreements and acquired customer relationship intangible assets. Intangible assets are stated at acquisition date fair value and are being amortized over their useful lives using the straight-line method.

Goodwill and Long-Lived Assets
Goodwill represents the excess of our cost of an acquired business over the fair value of the assets acquired, less liabilities assumed. Goodwill is not amortized. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. In prior years, we used the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss. In 2017 and 2016, we assessed qualitative factors such as macroeconomic conditions, industry considerations, cost factors, and reporting unit financial performance and determined it is not more likely than not that the fair value of our reporting units are less than the respective carrying value. Therefore, in accordance with GAAP, further testing was not required.

We evaluate long-lived assets, including finite intangible assets, for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value.

There have been no impairments to goodwill or our long-lived assets through December 31, 2017.

Investment in Equity Method Investments
We account for our interests in noncontrolling joint venture interests using the equity method of accounting, whereby we record our pro-rata share of earnings of these companies, and contributions to and distributions from the joint ventures as adjustments to our investment balances. The difference between the cost of an investment and our proportionate share of the underlying equity in net assets recorded on the investee's books is allocated to the various assets and liabilities of the equity method investment.

The following table summarizes our recorded investments compared to our share of underlying equity for each investee. We are amortizing the differences as adjustments to our pro-rata share of earnings over the useful lives of the underlying assets of these joint ventures. See SLC Pipeline LLC ("SLC Pipeline") and Frontier Aspen LLC ("Frontier Aspen") discussion in Note 2 regarding our purchase of a controlling interest in joint ventures previously accounted for under the equity method.

	Balance at December 31, 2017		
	Underlying Equity	Recorded Investment Balance	Difference
	(in thousands)		
Equity Method Investments			
Osage Pipe Line Company, LLC	$10,631	$ 42,071	$(31,440)
Cheyenne Pipeline LLC	28,706	43,208	(14,502)
Total	$39,337	$ 85,279	$(45,942)

	Balance at December 31, 2016		
	Underlying Equity	Recorded Investment Balance	Difference
	(in thousands)		
Equity Method Investments			
SLC Pipeline LLC	$57,273	$ 24,417	$32,856
Frontier Aspen LLC	11,630	53,160	(41,530)
Osage Pipe Line Company, LLC	10,730	43,375	(32,645)
Cheyenne Pipeline LLC	29,658	44,657	(14,999)
Total	$109,291	$ 165,609	$(56,318)

Asset Retirement Obligations
We record legal obligations associated with the retirement of certain of our long-lived assets that result from the acquisition, construction, development and/or the normal operation of our long-lived assets. The fair value of the estimated cost to retire a tangible long-lived asset is recorded in the period in which the liability is incurred and when a reasonable estimate of the fair value of the liability can be made. For our pipeline assets, the right-of-way agreements typically do not require the dismantling, removal and reclamation of the right-of-way upon cessation of the pipeline service. Additionally, management is unable to predict when, or if, our pipelines and related facilities would become obsolete and require decommissioning. Accordingly, we have recorded no liability or corresponding asset related to an asset retirement obligation for the majority of our pipelines as both the amounts and timing of such potential future costs are indeterminable. For our remaining assets, at December 31, 2017 and 2016, we have asset retirement obligations of $8.6 million and $8.0 million, respectively, that are recorded under “Other long-term liabilities” in our consolidated balance sheets.

Class B Unit
Under the terms of the transaction to acquire HFC's 75% interest in UNEV, we issued 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. Such contingent redemption payments are limited to the unredeemed value of the Class B Unit. However, to the extent earnings thresholds are not achieved, no redemption payments are required. No redemption payments have been required to date.

Contemporaneously with this transaction, HFC (our general partner) agreed to forego its right to incentive distributions of up to $1.25 million per quarter over twelve consecutive quarterly periods following the closing 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.

Pursuant to the terms of the transaction agreements, the Class B unit increases by the amount of each foregone incentive distribution and by a 7% factor compounded annually on the outstanding unredeemed balance through its expiration date. At our option, we may redeem, in whole or in part, the Class B unit at the current unredeemed value based on the calculation described. The Class B unit had a carrying value of $43.1 million at December 31, 2017, and $40.3 million at December 31, 2016.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals, feedstocks are processed through our refinery processing units or other services are rendered. Billings to customers for their obligations under their quarterly minimum revenue commitments are recorded as deferred revenue liabilities if the customer has the right to receive future services for these billings. The revenue is recognized at the earlier of:

- the customer receiving the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- our determination that we will not be required to provide services within the allowed period.

We determine that we will not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems will not have the necessary capacity to enable a customer to exceed its minimum volume levels to such a degree as to utilize the shortfall credit within its respective contractual shortfall make-up period.

We have additional revenues under an operating lease to a third party of an interest in the capacity of one of our pipelines.

As of December 31, 2017, customers' minimum revenue commitments per the terms of long-term throughput agreements expiring in 2019 through 2036 and the third party operating lease require minimum annualized payments to us in the aggregate of $2.6 billion including $367 million for the year ending December 31, 2018, $341 million for the year ending December 31, 2019, $291 million for the year ending December 31, 2020, $284 million for the year ending December 31, 2021 and $258 million for the year ending December 31, 2022. These agreements provide for changes in the minimum revenue guarantees annually for increases or decreases in the PPI or the FERC index, with certain contracts having provisions that limit the level of the rate increases or decreases.

We have other cost reimbursement provisions in our throughput / storage agreements providing that customers (including HFC) reimburse us for certain costs. Such reimbursements are recorded as revenue or deferred revenue depending on the nature of the cost. Deferred revenue is recognized over the remaining contractual term of the related throughput agreement.

Taxes billed and collected from our pipeline and terminal customers are recorded on a net basis with no effect on net income.

Environmental Costs

Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation, cleanup and other obligations are either known or considered probable and can be reasonably estimated. Such estimates require judgment with respect to costs, time frame and extent of required remedial and clean-up activities and are subject to periodic adjustments based on currently available information.

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 occurring or existing prior to the date of such transfers. We have an environmental agreement with Delek with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Delek in 2005, under which Delek will indemnify us subject to certain monetary and time limitations. Environmental costs recoverable through insurance, indemnification agreements or other sources are included in other assets to the extent such recoveries are considered probable.

Income Tax

We are subject to the Texas margin tax that is based on our Texas sourced taxable margin. The tax is calculated by applying a tax rate to a base that considers both revenues and expenses and therefore has the characteristics of an income tax.

We are organized as a pass-through entity for federal income tax purposes. As a result, our partners are responsible for federal income taxes based on their respective share of taxable income.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

Net Income per Limited Partners' Unit
We use the two-class method when calculating the net income per unit applicable to limited partners since we had more than one class of participating securities prior to the October 31, 2017 equity restructuring transaction discussed above. Under the two-class method, net income per unit applicable to limited partners is computed by dividing limited partners' interest in net income, after adjusting for the allocation of net income or loss attributable to the Predecessor, the allocation of net income or loss attributable to noncontrolling interests and the general partner's 2% interest and incentive distributions, both of which were applicable prior to the October 31, 2017 equity restructuring transaction discussed above, and other participating securities, by the weighted-average number of common units outstanding during the year and other dilutive securities. Other participating securities and dilutive securities are not significant.

Accounting Pronouncement Adopted During the Periods Presented

Share-Based Compensation
In March 2016, an accounting standard update was issued which simplifies the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. We adopted this standard effective January 1, 2017, with no impact to our financial condition or results of operations. The new standard also requires that employee taxes paid when an employer withholds units for tax-withholding purposes be reported as financing activities in the statement of cash flows on a retrospective basis. Previously, this activity was included in operating activities. The impact of this change for the years ended December 31, 2017, 2016 and 2015 was $0.6 million, $0.8 million and $0.7 million, respectively. Finally, consistent with our existing policy, we have elected to account for forfeitures on an estimated basis.

Accounting Pronouncements Not Yet Adopted

Revenue Recognition
In May 2014, an accounting standard update was issued requiring revenue to be recognized when promised goods or services are transferred to customers in an amount that reflects the expected consideration for these goods or services. This standard has an effective date of January 1, 2018, and we intend to account for the new guidance using the modified retrospective implementation method, whereby a cumulative effect adjustment is recorded to retained earnings as of the date of initial application. In preparing for adoption, we have evaluated the terms, conditions and performance obligations under our existing contracts with customers. Furthermore, we have implemented policies to comply with this new standard, which we do not anticipate will have a material impact on our financial condition, results of operations or cash flows.

Business Combinations
In December 2014, an accounting standard update was issued to provide new guidance on the definition of a business in relation to accounting for identifiable intangible assets in business combinations. This standard has an effective date of January 1, 2018, and we are evaluating its impact.

Financial Assets and Liabilities
In January 2016, an accounting standard update was issued requiring changes in the accounting and disclosures for financial instruments. This standard will become effective beginning with our 2018 reporting year. We are evaluating the impact of this standard.

Leases

In February 2016, an accounting standard update was issued requiring leases to be measured and recognized as a lease liability, with a corresponding right-of-use asset on the balance sheet. This standard has an effective date of January 1, 2019, and we are evaluating the impact of this standard.

Note 2: Acquisitions

El Dorado Tank Farm
On March 6, 2015, we completed the acquisition of an existing crude tank farm adjacent to HFC's El Dorado Refinery from an unrelated third-party for $27.5 million in cash. Substantially all of the purchase price was allocated to properties and equipment and no goodwill was recorded. HFC is the main customer of this crude tank farm.

Frontier Pipeline
On August 31, 2015, we purchased a 50% interest in Frontier Aspen (formerly known as Frontier Pipeline Company), which owns a 289-mile crude oil pipeline running from Casper, Wyoming to Frontier Station, Utah (the "Frontier Pipeline"), from an affiliate of Enbridge, Inc. for cash consideration of $54.6 million. As described below, on October 31, 2017, we acquired the remaining 50% interest in this entity. The Frontier Pipeline supplies Canadian and Rocky Mountain crudes to Salt Lake City area refiners through a connection to the SLC Pipeline.

El Dorado Operating
On November 1, 2015, we acquired from a wholly owned subsidiary of HFC, all the outstanding membership interests in El Dorado Operating LLC (“El Dorado Operating”), which owns the newly constructed naphtha fractionation and hydrogen generation units at HFC’s El Dorado refinery, for cash consideration of $62.0 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 $15 million as of the acquisition date. As we are a consolidated VIE of HFC, this transaction was recorded as a transfer between entities under common control and reflects HFC’s carrying basis in El Dorado Operating’s assets and liabilities.

Osage
On February 22, 2016, HFC obtained a 50% membership interest in 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 requiring 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 connects to the Jayhawk pipeline serving the CHS Inc. refinery in McPherson, Kansas. The Osage Pipeline is the primary pipeline supplying 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 agreed to build two connections on our south products pipeline system that will permit HFC access to Magellan’s El Paso terminal. These connections were in service in the fourth quarter of 2017. 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. Since we are a consolidated VIE of HFC, this transaction was recorded as a transfer between entities under common control and reflects HFC’s carrying basis of its 50% membership interest in Osage of $44.5 million offset by our net carrying basis in the El Paso terminal of $12.1 million with the difference recorded as a contribution from HFC. However, since these transactions were concurrent, there was no impact on periods prior to February 22, 2016.

Tulsa Tanks
On March 31, 2016, we acquired crude oil tanks (the "Tulsa Tanks") located at HFC’s Tulsa refinery from an affiliate of Plains All American pipeline, L. P. ("Plains") for cash consideration of $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. As we are a consolidated VIE of HFC, this transaction was recorded as a transfer between entities under common control and reflects HFC’s carrying basis in the net assets acquired.

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 is 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.

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, fluid catalytic cracking unit, and polymerization unit located at HFC's Woods Cross refinery, for cash consideration of $278 million. The consideration was funded with $103 million in proceeds from a private placement of 3,420,000 common units 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 $57 million as of the acquisition date. As we are a consolidated variable interest entity ("VIE") of HFC, this transaction was recorded as a transfer between entities under common control and reflect HFC's carrying basis in the net assets acquired.

SLC Pipeline and Frontier Aspen

On October 31, 2017, we acquired the remaining 75% interest in SLC Pipeline LLC and the remaining 50% interest in Frontier Aspen from subsidiaries of Plains, for cash consideration of $250 million. Prior to this acquisition, we held noncontrolling interests of 25% of SLC Pipeline and 50% of Frontier Aspen. As a result of the acquisitions, SLC Pipeline and Frontier Aspen are wholly-owned subsidiaries of HEP.

These acquisitions were accounted for as a business combination achieved in stages. Our preexisting equity method investments in SLC Pipeline and Frontier Aspen were remeasured at an acquisition date fair value of $112 million since we now have a controlling interest, and we recognized a gain on the remeasurement in the fourth quarter of 2017 of $36.3 million. The fair value of our preexisting equity method investments in SLC Pipeline and Frontier Aspen was estimated using Level 3 Inputs under the income method for these entities, adjusted for lack of control and marketability.

The total consideration of $362 million, consisting of cash consideration of $250 million and the fair value of our preexisting equity method investments in SLC Pipeline and Frontier Aspen of $112 million, was allocated to the acquisition date fair value of assets and liabilities acquired as of the October 31, 2017 acquisition date, with the excess purchase price recorded as goodwill.

The following summarizes the value of assets and liabilities acquired:

	(in thousands)
Cash and cash equivalents	$ 4,609
Accounts receivable	4,919
Prepaid and other current assets	253
Properties and equipment	277,016
Intangible assets	70,182
Goodwill	10,218
Accounts payable	(3,694)
Accrued property taxes	(1,438)
Other current liabilities	(65)
Net assets acquired	$ 362,000

We have assigned a preliminary estimate of fair value to the assets acquired and liabilities assumed, and, therefore, our allocation may change once all needed information has become available and we complete our valuations.

Our consolidated financial and operating results reflect the SLC Pipeline and Frontier Aspen operations beginning November 1, 2017. Our results of operations for the year ending December 31, 2017 included revenues of $7.9

million and net income of $4.1 million, excluding the $36.3 million remeasurement gain as of the acquisition date discussed above, for the period from November 1, 2017 through December 31, 2017.
SLC Pipeline is the owner of a 95-mile crude pipeline that transports crude oil into the Salt Lake City area from the Utah terminal of the Frontier Pipeline and from Wahsatch Station. Frontier Aspen is the owner of a 289-mile crude pipeline from Casper, Wyoming to Frontier Station, Utah that supplies Canadian and Rocky Mountain crudes to Salt Lake City area refiners through a connection to the SLC Pipeline.

The following unaudited pro forma financial information combines the historical operations of HEP, SLC Pipeline and Frontier Aspen as if the acquisition had occurred on January 1, 2016:

	Years Ended December 31,	
	2017	2016
	(in thousands)	
Revenues	$489,382	$445,017
Net income attributable to the partners	$161,900	$162,862

The unaudited pro forma net income attributable to the partners reflects the following adjustments:

(1) To retrospectively reflect depreciation and amortization of intangible assets based on the preliminary fair value of the assets as if that fair value had been reflected January 1, 2016

(2) To eliminate HEP's equity income previously recorded on its equity method investments in SLC Pipeline and Frontier Aspen

(3) To eliminate the remeasurement gain on preexisting equity interests in SLC Pipeline and Frontier Aspen

Note 3: Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, debt and interest rate swaps. The carrying amounts of cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturity of these instruments. Debt consists of outstanding principal under our revolving credit agreement (which approximates fair value as interest rates are reset frequently at current interest rates) and our fixed interest rate senior notes.

Fair value measurements are derived using inputs (assumptions that market participants would use in pricing an asset or liability) including assumptions about risk. GAAP categorizes inputs used in fair value measurements into three broad levels as follows:

- (Level 1) Quoted prices in active markets for identical assets or liabilities.
- (Level 2) Observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets, similar assets and liabilities in markets that are not active or can be corroborated by observable market data.
- (Level 3) Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. This includes valuation techniques that involve significant unobservable inputs.

The carrying amounts and estimated fair values of our senior notes and interest rate swaps were as follows:

Financial Instrument	Fair Value Input Level	December 31, 2017		December 31, 2016	
		Carrying Value	Fair Value	Carrying Value	Fair Value
		(In thousands)			
Assets:					
Interest rate swaps	Level 2	$—	$—	$91	$91
Liabilities:					
6.0% Senior Notes	Level 2	$495,308	$525,120	$393,393	$415,500
6.5% Senior Notes	Level 2	—	—	297,519	308,250

$495,308	$525,120	$690,912	$723,750

Level 2 Financial Instruments
Our senior notes and interest rate swaps are measured at fair value using Level 2 inputs. The fair value of the senior notes is based on market values provided by a third-party bank, which were derived using market quotes for similar type debt instruments. The fair value of our interest rate swaps is based on the net present value of expected future cash flows related to both variable and fixed-rate legs of the swap agreement. This measurement is computed using the forward London Interbank Offered Rate ("LIBOR") yield curve, a market-based observable input.

See Note 7 for additional information on these instruments.

Note 4: Properties and Equipment

The carrying amounts of our properties and equipment are as follows:

	December 31, 2017	December 31, 2016
	(In thousands)	
Pipelines, terminals and tankage	$1,541,722	$1,246,746
Refinery assets	347,338	346,058
Land and right of way	86,484	65,331
Construction in progress	12,029	28,753
Other	35,659	27,133
	2,023,232	1,714,021
Less accumulated depreciation	453,761	385,626
	$1,569,471	$1,328,395

We capitalized $1.0 million and $0.7 million in interest related to construction projects during the years ended December 31, 2017 and 2016, respectively.

Depreciation expense was $71.1 million, $62.9 million, and $55.8 million for the years ended December 31, 2017, 2016 and 2015, respectively, and includes depreciation of assets acquired under capital leases. Asset abandonment charges of $0.3 million, $0.6 million and $1.1 million for assets permanently removed from service were included in depreciation expense for the years ended December 31, 2017, 2016 and 2015, respectively.

Note 5: Intangible Assets

Intangible assets include transportation agreements and customer relationships that represent a portion of the total purchase price of certain assets acquired from Delek in 2005, from HFC in 2008 prior to HEP becoming a consolidated VIE of HFC and from Plains in 2017.

The carrying amounts of our intangible assets are as follows:

	Useful Life	December 31, 2017	December 31, 2016
		(In thousands)	
Delek transportation agreement	30 years	$59,933	$ 59,933
HFC transportation agreements	10-15 years	75,131	74,231
Customer relationships	10 years	69,282	—
Other		50	50
		204,396	134,214

Less accumulated amortization	74,933	67,358
	$129,463	$ 66,856

Amortization expense was $7.6 million for the year ended December 31, 2017, and $6.9 million for the years ending December 31, 2016 and 2015. We estimate amortization expense to be $14 million for each of the next five years.

We have additional transportation agreements with HFC resulting from historical transactions consisting of pipeline, terminal and tankage assets contributed to us or acquired from HFC. These transactions occurred while we were a consolidated variable interest entity of HFC; therefore, our basis in these agreements is zero and does not reflect a step-up in basis to fair value.

Note 6: Employees, Retirement and Incentive Plans

Direct support for our operations is provided by Holly Logistic Services, L.L.C., ("HLS"), an HFC subsidiary, which utilizes personnel employed by HFC who are dedicated to performing services for us. Their costs, including salaries, bonuses, payroll taxes, benefits and other direct costs, are charged to us monthly in accordance with an omnibus agreement that we have with HFC. These employees participate in the retirement and benefit plans of HFC. Our share of retirement and benefit plan costs was $5.9 million, $5.7 million and $5.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. These costs include retirement costs of $2.7 million, $2.6 million and $2.2 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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

We have a Long-Term Incentive Plan for employees and non-employee directors who perform services for us. The Long-Term Incentive Plan consists of four components: restricted or phantom units, performance units, unit options and unit appreciation rights. Our accounting policy for the recognition of compensation expense for awards with pro-rata vesting (a significant proportion of our awards) is to expense the costs ratably over the vesting periods.

As of December 31, 2017, we have two types of incentive-based awards outstanding, which are described below. The compensation cost charged against income was $2.7 million, $2.7 million and $3.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. We currently purchase units in the open market instead of issuing new units for settlement of all unit awards under our Long-Term Incentive Plan. As of December 31, 2017, 2,500,000 units were authorized to be granted under our Long-Term Incentive Plan, of which 1,338,743 have not yet been granted, assuming no forfeitures of the unvested units and full achievement of goals for the unvested performance units.

Restricted and Phantom Units

Under our Long-Term Incentive Plan, we grant restricted units to non-employee directors and phantom units to selected employees who perform services for us, with awards vesting over a period of one to three years. We previously granted restricted units to selected employees who perform services for us, which vest over a period of three years. Although full ownership of the units does not transfer to the recipients until the units vest, the recipients have distribution rights on these units from the date of grant, and the recipients of the restricted units have voting rights on the restricted units from the date of grant.

The fair value of each restricted or phantom unit award is measured at the market price as of the date of grant and is amortized on a straight-line basis over the requisite service period for each separately vesting portion of the award.

A summary of restricted and phantom unit activity and changes during the year ended December 31, 2017, is presented below:

Restricted and Phantom Units	Units	Weighted-

		Average Grant-Date Fair Value
Outstanding at January 1, 2017 (nonvested)	123,988	$ 32.96
Granted	81,883	35.59
Vesting and transfer of common units to recipients	(59,241)	33.97
Forfeited	(27,621)	30.79
Outstanding at December 31, 2017 (nonvested)	119,009	$ 34.77

The fair values of restricted units that were vested and transferred to recipients during the years ended December 31, 2017, 2016 and 2015 were $2.0 million, $2.0 million and $2.5 million respectively. As of December 31, 2017, there was $2.9 million of total unrecognized compensation expense related to unvested restricted and phantom unit grants, which is expected to be recognized over a weighted-average period of 1.6 years. For the years ended December 31, 2016 and 2015, the grant date price applied to the number of restricted units awarded was $32.16 and $34.16 respectively.

Performance Units
Under our Long-Term Incentive Plan, we grant performance units to selected executives who perform services for us. Performance units granted are payable in common units at the end of a three-year performance period based upon the growth in our distributable cash flow per common unit over the performance period. As of December 31, 2017, estimated unit payouts for outstanding nonvested performance unit awards ranged between 100% and 150% of the target number of performance units granted.

We granted 10,881 performance units during the year ended December 31, 2017. Performance units granted in 2016 and 2017 vest over a three-year performance period ending December 31, 2019 and 2020, respectively, and are payable in HEP common units. The number of units actually earned will be based on the growth of our distributable cash flow per common unit over the performance period, and can range from 50% to 150% of the target number of performance units granted. Although common units are not transferred to the recipients until the performance units vest, the recipients have distribution rights with respect to the common units from the date of grant. The fair value of these performance units is based on the grant date closing unit price of $35.62 and will apply to the number of units ultimately awarded. For the year ended December 31, 2016, the grant date closing unit price applied to the number of units awarded was $24.48 and $33.33 for the performance units granted in February and October, respectively, and for the year ended December 31, 2015, the grant date closing unit price was $34.21.

A summary of performance unit activity and changes for the year ended December 31, 2017, is presented below:

Performance Units	Units
Outstanding at January 1, 2017 (nonvested)	49,520
Granted	10,881
Vesting and transfer of common units to recipients	(2,262)
Forfeited	(21,228)
Outstanding at December 31, 2017 (nonvested)	36,911

The grant date fair value of performance units vested and transferred to recipients was $0.1 million for the year ended December 31, 2017, $1.1 million for the year ended December 31, 2016, and $0.5 million for the year ended December 31, 2015. Based on the weighted average fair value of performance units outstanding at December 31, 2017, of $1.3 million, there was $0.9 million of total unrecognized compensation expense related to nonvested performance units, which is expected to be recognized over a weighted-average period of 1.6 years.

During the year ended December 31, 2017, we did not purchase any common units in the open market for the issuance and settlement of all unit awards under our Long-Term Incentive Plan.

Note 7: Debt

Credit Agreement
In July 2017, we amended our senior secured revolving credit facility (the "Credit Agreement") increasing the size of the Credit Agreement from $1.2 billion to $1.4 billion and extending the expiration to July 2022. The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. The Credit Agreement is also available to fund letters of credit up to a

$50 million sub-limit, and it contains an accordion feature giving us the ability to increase the size of the facility by up to $300 million with additional lender commitments.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is guaranteed by our material, wholly-owned subsidiaries. The Credit Agreement requires us to maintain compliance
with certain financial covenants consisting of total leverage, senior secured leverage, and interest coverage. It also limits or restricts our ability to engage in certain activities. If, at any time prior to the expiration of the Credit Agreement, HEP obtains two investment grade credit ratings, the Credit Agreement will become unsecured and many of the covenants, limitations, and restrictions will be eliminated.

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 0.50% to 1.50%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.50% to 2.50%). 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, 2017 and 2016, were 3.734% and 2.978%, 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.

We may prepay all loans at any time without penalty, except for tranche breakage costs. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of all loans outstanding and exercising other rights and remedies. We were in compliance with the covenants as of December 31, 2017.

Senior Notes
On July 19, 2016, we closed a private placement of $400 million in aggregate principal amount of 6% senior unsecured notes due in 2024 (the “6% Senior Notes”). On September 22, 2017, we closed a private placement of an additional $100 million in aggregate offering of the 6% Senior Notes for a combined aggregate principal amount outstanding of $500 million maturing in 2024.

The 6% Senior Notes are unsecured and impose certain restrictive covenants, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. We were in compliance with the restrictive covenants for the 6% Senior Notes as of December 31, 2017. At any time when the 6% Senior Notes are rated investment grade by both Moody’s and Standard & Poor’s and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights at varying premiums over face value under the 6% Senior Notes.

Indebtedness under the 6% Senior Notes is guaranteed by our wholly-owned subsidiaries.

On January 4, 2017, we redeemed the $300 million aggregate principal amount of 6.5% senior notes (the "6.5% Senior Notes") at a redemption cost of $309.8 million, at which time we recognized a $12.2 million early extinguishment loss consisting of a $9.8 million debt redemption premium and unamortized discount and financing costs of $2.4 million. We funded the redemption with borrowings under our Credit Agreement.

Our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to below $171 million prior to 2018, subject to certain limited exceptions.

Long-term Debt

The carrying amounts of our long-term debt are as follows:

	December 31, 2017	December 31, 2016
	(In thousands)	
Credit Agreement		
Amount outstanding	$1,012,000	$553,000
6% Senior Notes		
Principal	500,000	400,000
Unamortized debt issuance costs	(4,692)	(6,607)
	495,308	393,393
6.5% Senior Notes		
Principal	—	300,000
Unamortized discount and debt issuance costs	—	(2,481)
	—	297,519
Total long-term debt	$1,507,308	$1,243,912

Maturities of our long-term debt are as follows:

Years Ending December 31,	(In thousands)
2018	$—
2019	—
2020	—
2021	—
2022	1,012,000
Thereafter	500,000
Total	$1,512,000

Interest Rate Risk Management

The two interest rate swaps that hedged our exposure to the cash flow risk caused by the effects of LIBOR changes on $150 million of Credit Agreement advances matured on July 31, 2017. The swaps effectively converted $150 million of our LIBOR based debt to fixed rate debt.

Additional information on our interest rate swaps is as follows:

Derivative Instrument	Balance Sheet Location	Fair Value	Location of Offsetting Balance	Offsetting Amount
	(In thousands)			
December 31, 2016				
Interest rate swaps designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($150 million of LIBOR based debt interest)	Other current assets	$ 91	Accumulated other comprehensive loss	$ 91
		$ 91		$ 91

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swaps	$28,928	$17,621	$16,107
6% Senior Notes	25,813	10,811	—
6.5% Senior Notes	—	19,507	19,507
Amortization of discount and deferred debt issuance costs	3,063	3,246	1,928
Commitment fees and other	1,648	2,069	638
Total interest incurred	59,452	53,254	38,180
Less capitalized interest	1,004	702	762
Net interest expense	$58,448	$52,552	$37,418
Cash paid for interest	$62,395	$38,530	$35,938

Capital Lease Obligations

Our capital lease obligations relate to vehicle leases with initial terms of 33 to 48 months. The total cost of assets under capital leases was $5.1 million and $4.9 million as of December 31, 2017 and 2016, respectively, with accumulated depreciation of $3.3 million and $2.4 million as of December 31, 2017 and 2016, respectively. We include depreciation of capital leases in depreciation and amortization in our consolidated statements of income.

At December 31, 2017, future minimum annual lease payments, including interest, for the capital leases are as follows:

Years Ending December 31,	(in thousands)
2018	$ 1,019
2019	765
2020	228
2021	—
Total minimum lease payments	2,012
Less amount representing interest	(129)
Capital lease obligations	$ 1,883

Note 8: Commitments and Contingencies

We lease certain facilities and pipelines under operating leases, most of which contain renewal options. These operating leases have various termination dates through 2027.

As of December 31, 2017, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year are as follows:

Years Ending December 31,	(In thousands)
2018	$ 7,278
2019	6,861
2020	6,805
2021	6,755
2022	6,753
Thereafter	29,861

Total	$ 64,313

Rental expense charged to operations was $9.1 million, $8.5 million and $8.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017, we expect to receive aggregate payments totaling $1.6 million over the life of our noncancelable sublease of office space, expiring in 2026.
We also have other long-term contractual obligations consisting of long-term site service agreements with HFC, expiring in 2058 through 2066, for the provision of certain facility services and utility costs that relate to our assets located at HFC's refinery facilities. We are presenting obligations for the full term of these agreements; however, the agreements can be terminated with 180 day notice if we cease to operate the applicable assets.
In addition, we have long-term contractual obligations associated with rights-of-way agreements, which have various termination dates through 2061. The related payments below include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2017.
At December 31, 2017, these minimum future contractual obligations having terms in excess of one year are as follows:

Years Ending December 31,	(In thousands)
2018	$ 5,616
2019	5,559
2020	5,385
2021	5,380
2022	5,375
Thereafter	223,331
Total	$ 250,646

We are a party to various legal and regulatory proceedings, none of which we believe will have a material adverse impact on our financial condition, results of operations or cash flows.

Note 9: Significant Customers

All revenues are domestic revenues, of which 91% are currently generated from our two largest customers: HFC and Delek.

The following table presents the percentage of total revenues generated by each of these customers:

	Years Ended December 31,		
	2017	2016	2015
HFC	83 %	83 %	81 %
Delek	8 %	8 %	10 %

Note 10: Related Party Transactions

We serve HFC's refineries under long-term pipeline, terminal and tankage throughput agreements, and refinery processing unit tolling 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, terminals, 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 Producer Price Index ("PPI") or Federal Energy Regulatory Commission ("FERC") index. As of December 31, 2017, these agreements with HFC require minimum annualized payments to us of $324 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 these agreements, a shortfall payment may be applied as a credit in the following four quarters after its minimum obligations are met.

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 2017) 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 charged to us separately by HFC. Also, we reimburse HFC and its affiliates for direct expenses they incur on our behalf.

Related party transactions with HFC are as follows:

- Revenues received from HFC were $377.1 million, $333.1 million and $292.2 million for the years ended December 31, 2017, 2016 and 2015, respectively.
- HFC charged us general and administrative services under the Omnibus Agreement of $2.5 million for the year ended December 31, 2017, $2.5 million for the year ended December 31, 2016, and $2.4 million for the year ended December 31, 2015.
- We reimbursed HFC for costs of employees supporting our operations of $46.6 million, $40.9 million and $34.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.
- HFC reimbursed us $7.2 million, $14.0 million and $13.5 million for the years ended December 31, 2017, 2016 and 2015, respectively, for expense and capital projects.
- We distributed $130.7 million, $105.2 million and $90.4 million, for the years ended December 31, 2017, 2016 and 2015, respectively, to HFC as regular distributions on its common units and general partner interest, including general partner incentive distributions.
- Accounts receivable from HFC were $51.5 million and $42.6 million at December 31, 2017 and 2016, respectively.
- Accounts payable to HFC were $7.7 million and $16.4 million at December 31, 2017 and 2016, respectively.
- Revenues for the years ended December 31, 2017, 2016 and 2015 include $4.8 million, $6.1 million and $7.3 million, respectively, of shortfall payments billed in 2016, 2015 and 2014, respectively. Deferred revenue in the consolidated balance sheets at December 31, 2017 and 2016, includes $4.4 million and $5.6 million, respectively, relating to certain shortfall billings. It is possible that HFC may not exceed its minimum obligations to receive credit for any of the $4.4 million deferred as of December 31, 2017.
- We received operating lease payments from HFC for use of our Artesia and Tulsa railyards of $0.5 million for each of the years ended December 31, 2017, 2016 and 2015.

- In November 2015, we acquired from HFC all the outstanding membership interests in El Dorado Operating which owns the newly constructed naphtha fractionation and hydrogen generation units at HFC's El Dorado refinery. See Note 2 for a description of this transaction.
- On February 22, 2016, HFC obtained a 50% membership interest in Osage in a non-monetary exchange, whereby a subsidiary of Magellan will provide terminalling services for all HFC products originating in Artesia, New Mexico that require terminalling in or through El Paso, Texas. 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. See Note 2 for a description of this transaction.
- On March 31, 2016, we acquired crude oil tanks located at HFC's Tulsa refinery from an affiliate of Plains for $39.5 million. See Note 2 for a description of this transaction.
- Effective 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. See Note 2 for a description of this transaction.
- On October 31, 2017, we closed on an equity restructuring transaction with HEP Logistics, a wholly-owned subsidiary of HFC and the general partner of HEP, pursuant to which the incentive distribution rights held by HEP Logistics were canceled, and HEP Logistics' 2% general partner interest in HEP was converted into a non-economic general partner interest in HEP. In consideration, we issued 37,250,000 of our common units to HEP Logistics. In addition, HEP Logistics agreed to waive $2.5 million of limited partner cash distributions for each of twelve consecutive quarters beginning with the first quarter the units issued as consideration were eligible to receive distributions.

Note 11: Partners' Equity, Income Allocations and Cash Distributions

At December 31, 2017, HFC held 59,630,030 of our common units, constituting a 59% limited partner interest in us and held the non-economic general partner interest. Additionally, HFC owned all incentive distribution rights through October 31, 2017, when an agreement was reached with HEP Logistics, our general partner, impacting its equity interest in HEP including canceling these incentive distribution rights. See Note 1 for a description of this equity restructuring transaction.

Common Unit Private Placements

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 in Note 2.

On January 25, 2018, we entered into a common unit purchase agreement in which certain purchasers agreed to purchase in a private placement 3,700,000 common units representing limited partnership interests, at a price of $29.73 per common unit. The private placement closed on February 6, 2018, and we received proceeds of approximately $110 million, which were used to repay indebtedness under our Credit Agreement. After this common unit issuance, HFC owns a 57% limited partner interest in us.

Continuous Offering Program

We have a continuous offering program under which we 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, 2017, HEP has issued 2,241,907 units under this program, providing $77.1 million in gross proceeds.

We intend to use our net proceeds for general partnership purposes, which may include funding working capital, repayment of debt, acquisitions and capital expenditures. Amounts repaid under our credit facility may be reborrowed from time to time.

Allocations of Net Income

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 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.

See Note 1 for a description of the equity restructuring of the general partner interest owned by HEP Logistics, our general partner, and its IDRs that occurred on October 31, 2017. After this restructuring, the general partner interest is no longer entitled to any distributions. As a result of this transaction, no distributions will be made on the general partner interest and no net income will be allocated to the general partner after October 31, 2017.

The following table presents the allocation of the general partner interest in net income for the periods presented below:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
General partner interest in net income	$919	$3,165	$1,936
General partner incentive distribution	34,128	54,008	40,401
Net loss attributable to Predecessor	—	(10,657)	(2,702)
Total general partner interest in net income	$35,047	$46,516	$39,635

Cash Distributions

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.

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.

Prior to the equity restructuring transaction discussed in Note 1, we made distributions in the manner displayed in the table below. Subsequent to the financial restructuring, distributions are made equally to all common unit holders regardless of the amount of the distribution per unit.

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	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%

On January 26, 2018, we announced our cash distribution for the fourth quarter of 2017 of $0.6500 per unit. The distribution is payable on all common units and was paid February 14, 2018, to all unitholders of record on February 5, 2018. However, HEP Logistics waived $2.5 million in limited partner cash distributions due to them as discussed in Note 1.

The following table presents the allocation of our regular quarterly cash distributions to the general and limited partners for the periods in which they apply. Our distributions are declared subsequent to quarter end; therefore, the amounts presented do not reflect distributions paid during the periods presented below.

	Years Ended December 31,		
	2017	2016	2015
	(In thousands, except per unit data)		
General partner interest in distribution	$2,335	$4,088	$3,563
General partner incentive distribution	34,128	54,008	40,401
Total general partner distribution	36,463	58,096	43,964
Limited partner distribution	206,846	143,796	129,192
Total regular quarterly cash distribution	$243,309	$201,892	$173,156
Cash distribution per unit applicable to limited partners	$2.5475	$2.3625	$2.2025

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 our partners' equity since our regular quarterly distributions have exceeded our quarterly net income attributable to HEP. Additionally, if the asset contributions and acquisitions from HFC had occurred while we were not a consolidated variable interest entity of HFC, our acquisition cost, in excess of HFC's historical basis in the transferred assets, would have been recorded in our financial statements at the time of acquisition as increases to our properties and equipment and intangible assets instead of decreases to our partners' equity.

Note 12: Net Income Per Limited Partner Unit

Net income per unit applicable to the limited partners is computed using the two-class method since we had more than one class of participating securities during the period from January 1, 2017 through October 31, 2017. The classes of participating securities during this period included common units, general partner units and incentive distribution rights ("IDRs"). Due to the equity restructuring transaction described in Note 1, as of December 31, 2017, we had one class of security outstanding, common units. To the extent net income attributable to the partners exceeds or is less than cash distributions, this difference is allocated to the partners based on their weighted-average ownership percentage during the period, after consideration of any priority allocations of earnings. The dilutive securities are immaterial for all periods presented.

See Note 1 for a description of the equity restructuring of the general partner interest owned by HEP Logistics, our general partner, and its IDRs that occurred on October 31, 2017. After this equity restructuring, the general partner interest is no longer entitled to any distributions and none were made on the general partner interest after October 31, 2017. In connection with this equity restructuring, HEP issued 37,250,000 of its common units to HEP Logistics on October 31, 2017.

When our financial statements are retrospectively adjusted after a dropdown transaction, the earnings of the acquired business, prior to the closing of the transaction, are allocated entirely to our general partner and presented as net income (loss) attributable to Predecessors. The earnings per unit of our limited partners prior to the close of the transaction do not change as a result of the dropdown. After the closing of a dropdown transaction, the earnings of the acquired business are allocated in accordance with our partnership agreement as previously described.

For purposes of applying the two-class method including the allocation of cash distributions in excess of earnings, net income per limited partner unit is computed as follows:

	Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net income attributable to the partners	$195,040	$158,241	$137,208
Less: General partner’s distribution declared (including IDRs)	(36,463)	(58,096)	(43,964)
Limited partner’s distribution declared on common units	(206,846)	(143,796)	(129,192)
Distributions in excess of net income attributable to the partners	$(48,269)	$(43,651)	$(35,948)

	General Partner (including IDRs)	Limited Partners’ Common Units	Total
	(In thousands, except per unit data)		
Year Ended December 31, 2017			
Net income attributable to the partners:			
Distributions declared	$36,463	$206,846	$243,309
Distributions in excess of net income attributable to partnership	(1,416)	(46,853)	(48,269)
Net income attributable to the partners	$35,047	$159,993	$195,040
Weighted average limited partners' units outstanding		70,291	
Limited partners' per unit interest in earnings - basic and diluted		$2.28	
Year Ended December 31, 2016			
Net income attributable to the partners:			
Distributions declared	$58,096	$143,796	$201,892
Distributions in excess of net income attributable to partnership	(873)	(42,778)	(43,651)
Net income attributable to the partners	$57,223	$101,018	$158,241
Weighted average limited partners' units outstanding		59,872	
Limited partners' per unit interest in earnings - basic and diluted		$1.69	
Year Ended December 31, 2015			
Net income attributable to the partners:			
Distributions declared	$43,964	$129,192	$173,156
Distributions in excess of net income attributable to partnership	(719)	(35,229)	(35,948)
Net income attributable to the partners	$43,245	$93,963	$137,208

Weighted average limited partners' units outstanding	58,657
Limited partners' per unit interest in earnings - basic and diluted	$1.60

Note 13: Environmental

We expensed $0.5 million, $0.7 million and $3.6 million for the years ended December 31, 2017, 2016 and 2015, respectively, for environmental remediation obligations. The accrued environmental liability, net of expected recoveries from indemnifying parties, reflected in our consolidated balance sheets was $6.5 million and $7.1 million at December 31, 2017 and December 31, 2016, respectively, of which $5.0 million and $5.4 million, respectively, were classified as other long-term liabilities. These accruals include remediation and monitoring costs expected to be incurred over an extended period of time.

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. As of December 31, 2017 and December 31, 2016, our consolidated balance sheets include additional accrued environmental liabilities of $0.8 million and $0.9 million, respectively, for HFC indemnified liabilities, and other assets included equal and offsetting balances representing amounts due from HFC related to indemnifications for environmental remediation liabilities.

Note 14: Operating Segments

Although financial information is reviewed by our chief operating decision makers from a variety of perspectives, they view the business in two operating segments: pipelines and terminals, and refinery processing units. These operating segments adhere to the accounting polices used for our consolidated financial statements. For a discussion of these accounting policies and a summary of our operating segments' assets and derivation of revenue, see Note 1.

The pipelines and terminals segment has been aggregated as both pipeline and terminals (1) have similar economic characteristics, (2) similarly provide logistics services of transportation and storage of petroleum products, (3) similarly support the petroleum refining business, including distribution of its products, (4) have principally the same customers and (5) are subject to similar regulatory requirements.

We evaluate the performance of each segment based on its respective operating income. Certain general and administrative expenses and interest and financing costs are excluded from segment operating income as they are not directly attributable to a specific operating segment. Identifiable assets are those used by the segment, whereas other assets are principally equity method investments, cash, deposits and other assets that are not associated with a specific reportable operating segment.

	Years Ended December 31, 2017	2016	2015
	(in thousands)		
Revenues:			
Pipelines and terminals - affiliate	$300,232	$300,072	$289,258
Pipelines and terminals - third-party	77,226	68,927	66,654
Refinery processing units - affiliate	76,904	33,044	2,963
Total segment revenues	$454,362	$402,043	$358,875
Segment operating income:			
Pipelines and terminals	$204,970	$204,923	$191,451
Refinery processing units	32,509	2,706	(1,438)
Total segment operating income	237,479	207,629	190,013
Unallocated general and administrative expenses	(14,323)	(12,532)	(12,556)
Interest and financing costs, net	(57,957)	(52,112)	(36,892)
Loss on early extinguishment of debt	(12,225)	—	—
Equity in earnings of unconsolidated affiliates	12,510	14,213	4,803
Gain on sale of assets and other	36,676	677	486
Income before income taxes	$202,160	$157,875	$145,854
Capital Expenditures:			
Pipelines and terminals	$289,993	$59,704	$67,406
Refinery processing units	263	44,119	125,715
Total capital expenditures	$290,256	$103,823	$193,121

	December 31, 2017	December 31, 2016
	(in thousands)	
Identifiable assets:		
Pipelines and terminals[(1)]	$1,728,074	$1,369,756
Refinery processing units	328,585	342,506
Other	97,455	171,975
Total identifiable assets	$2,154,114	$1,884,237

(1) Includes goodwill of $266.7 million and $256.5 million as of December 31, 2017 and December 31, 2016, respectively.

Note 15: Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
Year Ended December 31, 2017					
Revenues	$105,634	$109,143	$110,364	$129,221	$454,362
Operating income	51,734	52,486	51,736	67,200	223,156
Income before income taxes	27,985	42,983	42,992	88,200	202,160
Net income	27,879	42,856	43,061	88,115	201,911
Net income attributable to Holly Energy Partners	25,563	41,335	42,071	86,071	195,040
Limited partners' per unit interest in net income – basic and diluted	$0.13	$0.36	$0.66	$0.96	$2.28
Distributions per limited partner unit	$0.6200	$0.6325	$0.6450	$0.6500	$2.5475
Year Ended December 31, 2016					

Revenues	$102,010	$94,897	$92,610	$112,526	$402,043
Operating income	54,513	47,111	38,924	54,549	195,097
Income before income taxes	46,847	39,569	28,464	42,995	157,875
Net income	46,751	39,516	28,404	42,919	157,590
Net income attributable to Holly Energy Partners	42,975	39,120	34,785	41,361	158,241
Limited partners' per unit interest in net income – basic and diluted	$0.52	$0.45	$0.33	$0.40	$1.69
Distributions per limited partner unit	$0.5750	$0.5850	$0.5950	$0.6075	$2.3625

Note 16: Supplemental Guarantor/Non-Guarantor Financial Information

Obligations of HEP ("Parent") under the 6% Senior Notes have been jointly and severally guaranteed by each of its direct and indirect 100% owned subsidiaries ("Guarantor Subsidiaries"). These guarantees are full and unconditional, subject to certain customary release provisions. These circumstances include (i) when a Guarantor Subsidiary is sold or sells all or substantially all of its assets, (ii) when a Guarantor Subsidiary is declared "unrestricted" for covenant purposes, (iii) when a Guarantor Subsidiary's guarantee of other indebtedness is terminated or released and (iv) when the requirements for legal defeasance or covenant defeasance or to discharge the senior notes have been satisfied.

The following financial information presents condensed consolidating balance sheets, statements of comprehensive income, and statements of cash flows of the Parent, the Guarantor Subsidiaries and the Non-Guarantor subsidiaries. The information has been presented as if the Parent accounted for its ownership in the Guarantor Subsidiaries and the Guarantor Restricted Subsidiaries accounted for the ownership of the Non-Guarantor Non-Restricted Subsidiaries, using the equity method of accounting.

In conjunction with the preparation of our Condensed Consolidating Balance Sheet and Statements of Comprehensive Income included below, we identified and corrected the presentation of noncontrolling interests presented in the eliminations column in prior periods to reflect such balances and activity within the respective guarantor and non-guarantor subsidiaries columns.

Condensed Consolidating Balance Sheet

December 31, 2017	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$511	$ 7,263	$—	$7,776
Accounts receivable	—	59,448	5,038	(182)	64,304
Prepaid and other current assets	13	2,016	282	—	2,311
Total current assets	15	61,975	12,583	(182)	74,391
Properties and equipment, net	—	1,213,626	355,845	—	1,569,471
Investment in subsidiaries	1,902,285	273,319	—	(2,175,604)	—
Intangible assets, net	—	129,463	—	—	129,463
Goodwill	—	266,716	—	—	266,716
Equity method investments	—	85,279	—	—	85,279
Other assets	11,753	17,041	—	—	28,794
Total assets	$1,914,053	$2,047,419	$ 368,428	$(2,175,786)	$2,154,114
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$20,928	$ 1,526	$(182)	$22,272
Accrued interest	12,500	756	—	—	13,256
Deferred revenue	—	8,540	1,058	—	9,598
Accrued property taxes	—	3,431	1,221	—	4,652
Other current liabilities	—	5,707	—	—	5,707
Total current liabilities	12,500	39,362	3,805	(182)	55,485
Long-term debt	1,507,308	—	—	—	1,507,308
Other long-term liabilities	286	15,359	198	—	15,843
Deferred revenue	—	47,272	—	—	47,272
Class B unit	—	43,141	—	—	43,141
Equity - partners	393,959	1,902,285	273,319	(2,175,604)	393,959
Equity - noncontrolling interest	—	—	91,106	—	91,106
Total liabilities and partners' equity	$1,914,053	$2,047,419	$ 368,428	$(2,175,786)	$2,154,114

Condensed Consolidating Balance Sheet

December 31, 2016	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$301	$ 3,354	$—	$3,657
Accounts receivable	—	45,056	5,554	(202)	50,408
Prepaid and other current assets	11	2,633	244	—	2,888
Total current assets	13	47,990	9,152	(202)	56,953
Properties and equipment, net	—	957,045	371,350	—	1,328,395
Investment in subsidiaries	1,086,008	280,671	—	(1,366,679)	—
Intangible assets, net	—	66,856	—	—	66,856
Goodwill	—	256,498	—	—	256,498
Equity method investments	—	165,609	—	—	165,609
Other assets	725	9,201	—	—	9,926
Total assets	$1,086,746	$1,783,870	$ 380,502	$(1,366,881)	$1,884,237
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$24,245	$ 2,899	$(202)	$26,942
Accrued interest	17,300	769	—	—	18,069
Deferred revenue	—	8,797	2,305	—	11,102
Accrued property taxes	—	4,514	883	—	5,397
Other current liabilities	14	3,208	3	—	3,225
Total current liabilities	17,314	41,533	6,090	(202)	64,735
Long-term debt	690,912	553,000	—	—	1,243,912
Other long-term liabilities	286	15,975	184	—	16,445
Deferred revenue	—	47,035	—	—	47,035
Class B unit	—	40,319	—	—	40,319
Equity - partners	378,234	1,086,008	280,671	(1,366,679)	378,234
Equity - noncontrolling interest	—	—	93,557	—	93,557
Total liabilities and partners' equity	$1,086,746	$1,783,870	$ 380,502	$(1,366,881)	$1,884,237

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Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2017	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$ 351,395	$ 25,741	$—	$ 377,136
Third parties	—	55,400	21,826	—	77,226
	—	406,795	47,567	—	454,362
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	122,619	14,986	—	137,605
Depreciation and amortization	—	62,889	16,389	—	79,278
General and administrative	4,170	10,153	—	—	14,323
	4,170	195,661	31,375	—	231,206
Operating income (loss)	(4,170)	211,134	16,192	—	223,156
Equity in earnings of subsidiaries	254,695	12,148	—	(266,843)	—
Equity in earnings of equity method investments	—	12,510	—	—	12,510
Interest income	—	491	—	—	491
Interest expense	(43,260)	(15,188)	—	—	(58,448)
Loss on early extinguishment of debt	(12,225)	—	—	—	(12,225)
Remeasurement gain on preexisting equity interests	—	36,254	—	—	36,254
Gain on sale of assets and other	—	417	5	—	422
	199,210	46,632	5	(266,843)	(20,996)
Income (loss) before income taxes	195,040	257,766	16,197	(266,843)	202,160
State income tax expense	—	(249)	—	—	(249)
Net income (loss)	195,040	257,517	16,197	(266,843)	201,911
Allocation of net loss applicable to Predecessor	—	—	—	—	—
Allocation of net income attributable to noncontrolling interests	—	(2,822)	(4,049)	—	(6,871)
Net income (loss) attributable to the Partnership	195,040	254,695	12,148	(266,843)	195,040
Other comprehensive income (loss)	(91)	(91)	—	91	(91)
Comprehensive income (loss) attributable to the Partnership	$ 194,949	$ 254,604	$ 12,148	$ (266,752)	$ 194,949

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2016	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$ 307,049	$ 26,067	$—	$ 333,116
Third parties	—	47,326	21,601	—	68,927
	—	354,375	47,668	—	402,043
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	111,181	12,805	—	123,986
Depreciation and amortization	—	55,083	15,345	—	70,428
General and administrative	3,804	8,728	—	—	12,532
	3,804	174,992	28,150	—	206,946
Operating income (loss)	(3,804)	179,383	19,518	—	195,097
Equity in earnings of subsidiaries	193,432	14,634	—	(208,066)	—
Equity in earnings of equity method investments	—	14,213	—	—	14,213
Interest income	—	421	19	—	440
Interest expense	(31,387)	(21,165)	—	—	(52,552)
Gain on sale of assets and other	—	702	(25)	—	677
	162,045	8,805	(6)	(208,066)	(37,222)
Income (loss) before income taxes	158,241	188,188	19,512	(208,066)	157,875
State income tax expense	—	(285)	—	—	(285)
Net income (loss)	158,241	187,903	19,512	(208,066)	157,590
Allocation of net loss applicable to Predecessor	—	10,657	—	—	10,657
Allocation of net income attributable to noncontrolling interests	—	(5,128)	(4,878)	—	(10,006)
Net income (loss) attributable to the Partnership	158,241	193,432	14,634	(208,066)	158,241
Other comprehensive income (loss)	(99)	(99)	—	99	(99)
Comprehensive income (loss) attributable to the Partnership	$158,142	$ 193,333	$ 14,634	$ (207,967)	$ 158,142

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2015	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$ 269,277	$ 22,944	$—	$ 292,221
Third parties	—	47,189	19,465	—	66,654
	—	316,466	42,409	—	358,875
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	94,087	11,469	—	105,556
Depreciation and amortization	—	48,302	15,004	—	63,306
General and administrative	3,616	8,940	—	—	12,556
	3,616	151,329	26,473	—	181,418
Operating income (loss)	(3,616)	165,137	15,936	—	177,457
Equity in earnings (loss) of subsidiaries	161,097	11,915	—	(173,012)	—
Equity in earnings of equity method investments	—	4,803	—	—	4,803
Interest income	—	526	—	—	526
Interest expense	(20,273)	(17,145)	—	—	(37,418)
Gain on sale of assets and other	—	535	(49)	—	486
	140,824	634	(49)	(173,012)	(31,603)
Income (loss) before income taxes	137,208	165,771	15,887	(173,012)	145,854
State income tax expense	—	(228)	—	—	(228)
Net income (loss)	137,208	165,543	15,887	(173,012)	145,626
Allocation of net loss applicable to Predecessors	—	2,702	—	—	2,702
Allocation of net income attributable to noncontrolling interests	—	(7,148)	(3,972)	—	(11,120)
Net income (loss) attributable to the Partnership	137,208	161,097	11,915	(173,012)	137,208
Other comprehensive income (loss)	236	236	—	(236)	236
Comprehensive income (loss) attributable to the Partnership	$137,444	$ 161,333	$ 11,915	$(173,248)	$ 137,444

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2017	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(51,235)	$ 268,978	$ 32,892	$ (12,148)	$ 238,487
Cash flows from investing activities					
Additions to properties and equipment	—	(41,827)	(2,983)	—	(44,810)
Purchase of controlling interests in SLC Pipeline and Frontier Aspen	—	(245,446)	—	—	(245,446)
Proceeds from the sale of assets	—	849	—	—	849
Distributions in excess of equity in earnings of equity method investments	—	3,134	—	—	3,134
Distributions from UNEV in excess of earnings	—	7,352	—	(7,352)	—
	—	(275,938)	(2,983)	(7,352)	(286,273)
Cash flows from financing activities					
Net repayments under credit agreement	1,012,000	(553,000)	—	—	459,000
Net intercompany financing activities	(561,675)	561,675	—	—	—
Redemption of notes	(309,750)	—	—	—	(309,750)
Proceeds from issuance of 6% Senior Notes	101,750	—	—	—	101,750
Proceeds from issuance of common units	52,100	10	—	—	52,110
Contributions from general partner	1,440	(368)	—	—	1,072
Distributions to HEP unitholders	(234,575)	—	—	—	(234,575)
Distributions to noncontrolling interest	—	—	(26,000)	19,500	(6,500)
Contributions to HFC for El Dorado Operating Tanks	(103)	—	—	—	(103)
Deferred financing costs	(9,347)	(35)	—	—	(9,382)
Units withheld for tax withholding obligations	(605)	—	—	—	(605)
Other	—	(1,112)	—	—	(1,112)
	51,235	7,170	(26,000)	19,500	51,905
Cash and cash equivalents					
Increase for the period	—	210	3,909	—	4,119
Beginning of period	2	301	3,354	—	3,657
End of period	$2	$ 511	$ 7,263	$ —	$ 7,776

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2016	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(19,641)	$ 245,771	$ 32,052	$ (14,634)	$ 243,548
Cash flows from investing activities					
Additions to properties and equipment	—	(44,447)	(15,257)	—	(59,704)
Acquisition of tanks and refinery processing units	—	(44,119)	—	—	(44,119)
Purchase of interest in Cheyenne Pipeline	—	(42,627)	—	—	(42,627)
Proceeds from sale of assets	—	427	—	—	427
Distributions from UNEV in excess of earnings	—	2,616	—	(2,616)	—
Distribution in excess of equity in earnings in equity investments	—	2,993	—	—	2,993
	—	(125,157)	(15,257)	(2,616)	(143,030)
Cash flows from financing activities					
Net borrowings under credit agreement	—	(159,000)	—	—	(159,000)
Net intercompany financing activities	(302,600)	302,600	—	—	—
Proceeds from issuance of 6% Senior Notes	394,000	—	—	—	394,000
Proceeds from issuance of common units	125,870	—	—	—	125,870
Contributions from General partner	2,577	—	—	—	2,577
Distributions to noncontrolling interests	—	—	(23,000)	17,250	(5,750)
Distributions to HEP unitholders	(192,037)	—	—	—	(192,037)
Distributions to HFC for acquisitions	(30,378)	(287,122)	—	—	(317,500)
Contributions from HFC for acquisitions	(3,397)	54,659	—	—	51,262
Distributions to HFC for acquisitions	31,287	(31,287)	—	—	—
Distribution to HFC for Osage acquisition	—	(1,245)	—	—	(1,245)
Deferred financing costs	(910)	(3,085)	—	—	(3,995)
Purchase of units for incentive grants	(3,521)	—	—	—	(3,521)
Units withheld for tax withholding obligations	(800)	—	—	—	(800)
Other	(450)	(1,285)	—	—	(1,735)
	19,641	(125,765)	(23,000)	17,250	(111,874)
Cash and cash equivalents					
Increase (decrease) for the period	—	(5,151)	(6,205)	—	(11,356)
Beginning of period	2	5,452	9,559	—	15,013
End of period	$2	$ 301	$ 3,354	$ —	$ 3,657

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Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2015	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(18,794)	$ 232,650	$ 29,501	$ (11,915)	$ 231,442
Cash flows from investing activities					
Additions to properties and equipment	—	(37,951)	(1,442)	—	(39,393)
Acquisition of tanks and operating units	—	(153,728)	—	—	(153,728)
Purchase of investment in Frontier Pipeline	—	(55,032)	—	—	(55,032)
Proceeds from sale of assets	—	1,279	—	—	1,279
Distributions from UNEV in excess of earnings	—	1,960	—	(1,960)	—
Distributions in excess of equity in earnings in equity investments	—	194	—	—	194
	—	(243,278)	(1,442)	(1,960)	(246,680)
Cash flows from financing activities					
Net borrowings under credit agreement	—	141,000	—	—	141,000
Net intercompany financing activities	192,108	(192,108)	—	—	—
Distributions to noncontrolling interests	—	—	(18,500)	13,875	(4,625)
Distributions to HEP unitholders	(169,063)	—	—	—	(169,063)
Contributions from HFC for acquisitions	—	128,476	—	—	128,476
Distributions to HFC for acquisitions	—	(62,000)	—	—	(62,000)
Purchase of units for incentive grants	(3,555)	—	—	—	(3,555)
Deferred financing costs	—	(962)	—	—	(962)
Units withheld for tax withholding obligations	(696)	—	—	—	(696)
Other	—	(1,154)	—	—	(1,154)
	18,794	13,252	(18,500)	13,875	27,421
Cash and cash equivalents					
Increase for the period	—	2,624	9,559	—	12,183
Beginning of period	2	2,828	—	—	2,830
End of period	$2	$ 5,452	$ 9,559	$ —	$ 15,013

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We have had no change in, or disagreement with, our independent registered public accounting firm on matters involving accounting and financial disclosure.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2017, at a reasonable level of assurance.

(b) Changes in internal control over financial reporting

We acquired additional equity interests in SLC Pipeline and Frontier Aspen from Plains effective October 31, 2017, and we accounted for their acquisition as a business combination achieved in stages. We have included SLC Pipeline and Frontier Aspen’s operating results, assets and liabilities in our consolidated financial statements as of December 31, 2017, and for the two months then ended. Pursuant to a Transition Service Agreement with Plains, Plains provides certain accounting support services for SLC Pipeline and Frontier Aspen. Other than internal controls for SLC Pipeline and Frontier Aspen, there have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

See Item 8 for “Management’s Report on its Assessment of the Partnership’s Internal Control Over Financial Reporting” and “Report of Independent Registered Public Accounting Firm.”

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2017 that would need to be reported on Form 8-K that have not been previously reported.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Holly Logistic Services, L.L.C. ("HLS"), the general partner of HEP Logistics Holdings, L.P. ("HEP Logistics"), our general partner, manages our operations and activities. Neither our general partner nor our directors are elected by our unitholders. Unitholders are not entitled to directly or indirectly participate in our management or operations. The sole member of HLS, which is a subsidiary of HFC, appoints the directors of HLS to serve until their death, resignation or removal.

Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations that are non-recourse.

Executive Officers

The following sets forth information regarding the executive officers of HLS as of February 14, 2018:

Name	Age	Position with HLS
George J. Damiris	57	Chief Executive Officer and President
Richard L. Voliva III	40	Executive Vice President and Chief Financial Officer
Mark T. Cunningham	58	Senior Vice President, Operations and Engineering
Denise C. McWatters	58	Senior Vice President, General Counsel and Secretary

During 2017, Mr. Cunningham was the only HLS executive officer who spent all of his professional time managing our business and affairs. The other executive officers listed above are also executive officers of HFC and devote as much of professional time as is necessary to oversee the management of our business and affairs.

Information regarding Mr. Damiris is included below under "Directors."

Richard L. Voliva III was appointed as Executive Vice President and Chief Financial Officer of HLS in March 2017. He has also served as Executive Vice President and Chief Financial Officer of HFC since March 2017. Mr. Voliva served as Senior Vice President and Chief Financial Officer of HLS from July 2016 to March 2017, Vice President and Chief Financial Officer of HLS from October 2015 until July 2016, Vice President, Corporate Development of HLS from February 2015 until October 2015 and Senior Director, Business Development of HLS from April 2014 until February 2015. Mr. Voliva also served as Senior Vice President, Strategy for HFC from June 2016 to March 2017. Prior to joining HLS, Mr. Voliva was an analyst at Millennium Management LLC, an institutional asset manager, from April 2011 until April 2014, an analyst at Partner Fund Management, L.P., a hedge fund, from March 2008 until March 2011 and Vice President, Equity Research at Deutsche Bank from June 2005 to March 2008. Mr. Voliva is a CFA Charterholder.

Mark T. Cunningham was appointed Senior Vice President, Operations and Engineering in January 2018. He previously served as Senior Vice President, Engineering and Technical Services from July 2016 to January 2018, Senior Vice President, Operations from January 2013 to July 2016 and Vice President, Operations from July 2007 to January 2013. He served Holly Corporation as Senior Manager of Special Projects from December 2006 through June 2007 and as Senior Manager of Integrity Management and Environmental, Health and Safety from July 2004 through December 2006. Prior to joining Holly Corporation, Mr. Cunningham served Diamond Shamrock/Ultramar Diamond

Shamrock for 20 years in several engineering and pipeline operations capacities.

Denise C. McWatters was appointed Senior Vice President, General Counsel and Secretary in January 2013. Ms. McWatters also serves in a similar capacity for HFC. Ms. McWatters previously served as Vice President, General Counsel and Secretary from April 2008 until January 2013. She joined Holly Corporation in October 2007 with more than 20 years of legal experience and served as Deputy General Counsel of Holly Corporation until April 2008 and as Vice President, General Counsel and Secretary of HFC (formerly Holly Corporation) from April 2008 until January 2013. Ms. McWatters served as the General Counsel of The Beck Group from 2005 through 2007. Prior to joining The Beck Group, Ms. McWatters practiced law in various capacities at the predecessor firm to Locke Lord Bissell & Liddell LLP, the Law Offices of Denise McWatters, the legal department at Citigroup, N.A., and the law firm of Cox Smith Matthews Incorporated.

Board Leadership Structure

The Board of Directors of HLS (the "Board") is responsible for selecting the Board leadership structure that is in the best interest of HLS and HEP. At this time, the Board believes that separating the positions of Chairman and Chief Executive Officer is in the best interest of HLS and HEP. Currently, Mr. Michael C. Jennings serves as Chairman of the Board in a non-employee capacity, and Mr. Damiris serves as the Chief Executive Officer of HLS. The Board believes that at this time the separation of these positions enhances the oversight of management by the Board and HLS's and HEP's overall leadership structure. In addition, as a result of his former role as HFC's and HLS's Chief Executive Officer, Mr. Jennings has company-specific experience and expertise and as Chairman of the Board can identify strategic priorities, lead the discussion and execution of strategy, and facilitate the flow of information between management and the Board.

Chairman of the Board

Mr. Jennings was selected by the directors of HLS to serve as the Chairman of the Board. The Chairman has the following responsibilities:

- designating and calling meetings of the Board;
- presiding at all Board meetings;
- consulting with management on Board and committee meeting agendas;
- facilitating teamwork and communication between the Board and management; and
- acting as a liaison between management and the Board.

Since Mr. Jennings is not an employee of HLS or HEP, he also presides at all executive sessions of the non-employee directors of the Board.

Persons wishing to communicate with the non-employee directors are invited to email the Chairman at presiding.director.HEP@hollyenergy.com or write to: Michael C. Jennings, Chairman, c/o Secretary, Holly Logistic Services, L.L.C., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. Communications to the Board generally may be sent certified mail to Holly Logistic Services, L.L.C., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507, Attention: Secretary. The Secretary will forward all communication to the appropriate director or directors, other than those communications that are merely solicitations for products or services or relate to matters that are of a type that are clearly improper or irrelevant to the functioning of the Board or the business and affairs of HLS and HEP.

Risk Management

The Board has an active role in overseeing management of the risks affecting HLS and HEP. The Board regularly reviews information regarding HLS and HEP's credit, liquidity and business and operations, as well as the risks associated with each. The Board committees are also engaged in overseeing risk associated with HLS and HEP.

- The Compensation Committee oversees the management of risks relating to HLS's executive compensation plans and arrangements.

- The Audit Committee oversees management of financial reporting and controls risks.
- The Conflicts Committee oversees specific matters that the Board or the Conflicts Committee believes may involve conflicts of interest with HFC.

While each committee is responsible for evaluating certain risks and overseeing the management of such risks, the entire Board is ultimately responsible for the risk management of HLS and HEP and is regularly informed through committee reports about such risks.

The sole member of HLS manages risks associated with the independence of the Board. The Audit Committee and the Board also receive input and reports from HLS's risk management oversight committee on management's views of the risks facing HLS and HEP. The risk management oversight committee is made up of management personnel, none of whom serve on the Board and all of whom have a range of different backgrounds, skills and experiences with regard to the operational, financial and strategic risk profile of HLS and HEP. The risk management oversight committee monitors the risk environment for HLS and HEP as a whole, and reviews the activities that mitigate risks to an achievable and acceptable level.

Director Qualifications

The Board believes that it is necessary for each of HLS's directors to possess a variety of qualities and skills. When searching for new candidates, the sole member of HLS considers the evolving needs of the Board and searches for candidates that fill any current or anticipated future needs. The Board also believes that all directors must possess a considerable amount of business management, business leadership and educational experience. When considering director candidates, the sole member of HLS first considers a candidate's management experience and then considers issues of judgment, background, stature, conflicts of interest, integrity, ethics, industry knowledge, ability to commit adequate time to the Board, and commitment to the goal of maximizing unitholder value. The sole member of HLS also focuses on issues of diversity, such as diversity of education, professional experience and differences in viewpoints and skills. The sole member of HLS does not have a formal policy with respect to diversity; however, the Board and the sole member of HLS believe that it is essential that the Board members represent diverse viewpoints. In considering candidates for the Board, the sole member of HLS considers the entirety of each candidate's credentials in the context of these standards. All our directors bring to the Board executive leadership experience derived from their service in many areas.

Pursuant to the Governance Guidelines of HLS and HEP, a director must submit his or her resignation to the Board in the first quarter of the calendar year in which the director will attain the age of 75 or greater. If the resignation is accepted by the Board, the resignation will be effective on December 31 of the year in which the resignation was accepted by the Board. In the first quarter of 2016, Mr. Jerry W. Pinkerton submitted his resignation in accordance with the policy. His resignation was not accepted by the Board at that time. In the fourth quarter of 2016, the Board reconsidered his resignation, but decided to not accept his resignation at that time. In the first quarter of 2017, the Board again reconsidered his resignation and accepted his resignation effective June 30, 2017.

On February 7, 2018, the sole member of HLS appointed Christine B. LaFollette and Eric L. Mattson to the Board effective March 1, 2018. In addition, on February 7, 2018, Mr. R. Kevin Hardage notified the Board that he will resign from the Board effective February 28, 2018.

Director Independence

The Board has determined that Messrs. Larry R. Baldwin, R. Kevin Hardage and James H. Lee meet the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange ("NYSE"). The Board previously determined that Matthew P. Clifton, Charles M. Darling IV, Jerry W. Pinkerton, William P. Stengel and James G. Townsend were "independent" as defined by the NYSE listing standards during the time they served on the Board. Messrs. Clifton, Darling, Stengel and Townsend retired from the Board effective November 2017, and, as previously discussed, the Board accepted Mr. Pinkerton's resignation pursuant to the Board retirement policy effective June 2017. The Board has also determined that Ms. LaFollette and Mr. Mattson meet the applicable criteria for independence under the current applicable rules of NYSE.

Audit Committee. The Audit Committee of HLS is currently composed of three directors, Messrs. Baldwin, Hardage and Lee. The Board has determined that each member of the Audit Committee is "independent" as defined by the NYSE listing standards and Rule 10A-3 of the Securities Exchange Act of 1934 (the "Exchange Act"). The Board previously determined that Messrs. Clifton, Pinkerton and Darling were "independent" as defined by the NYSE listing standards and Rule 10A-3 of the Exchange Act during the time they served on the Audit Committee. Mr. Hardage notified the Board that he will resign from the Board on February 28, 2018. The Board has appointed Mr. Mattson to the Audit Committee effective March 1, 2018. The Board has determined that Mr. Mattson is "independent" as defined by the

NYSE listing standards and Rule 10A-3 of the Exchange Act.

Conflicts Committee. The Conflicts Committee of HLS is currently composed of Mr. Baldwin. The Board has determined that he is “independent” as defined by the NYSE listing standards and Rule 10A-3 of the Exchange Act, as required by the Conflicts Committee Charter. The Board previously determined that Messrs. Clifton, Stengel, Pinkerton and Townsend were “independent” as defined by the NYSE listing standards and Rule 10A-3 of the Exchange Act during the time they served on the Conflicts Committee. The Board has appointed Ms. LaFollette and Mr. Mattson to the Conflicts Committee effective March 1, 2018. The Board has determined that Ms. LaFollette and Mr. Mattson are “independent” as defined by the NYSE listing standards and Rule 10A-3 of the Exchange Act.

Compensation Committee. The Compensation Committee of HLS is currently composed of three directors, Messrs. Jennings, Damiris and Lee. The Board has determined that Mr. Lee is “independent” as defined by the NYSE listing standards. Because we are a master limited partnership, Rule 303A.05 of the NYSE Listed Company Manual, which requires a publicly traded company to have a compensation committee composed entirely of independent directors, does not apply to us. The Board previously determined that Messrs. Darling, Stengel and Townsend were “independent” as defined by the NYSE listing standards during the time they served on the Compensation Committee. The Board has appointed Ms. LaFollette to the Compensation Committee effective March 1, 2018. The Board has determined that Mr. LaFollette is “independent” as defined by the NYSE listing standards.

Independence Determinations. In making its independence determinations, the Board considered certain transactions, relationships and arrangements. In determining Mr. Townsend’s independence during the time he served on the Board, the Board considered that Mr. Townsend has not been employed by HFC or HLS since 2011 and has not received compensation in excess of $120,000 since 2011. In determining Mr. Clifton’s independence during the time he served on the Board, the Board considered that Mr. Clifton has not been employed by HFC or HLS since 2014 and has not received compensation in excess of $120,000 since 2013. In determining Ms. LaFollette’s independence, the Board considered that during fiscal year 2017, Akin Gump Strauss Hauer & Feld LLP served as outside counsel to the Conflicts Committee. Ms. LaFollette did not represent the Conflicts Committee of the Board on any matters, and Akin Gump Strauss Hauer & Feld LLP will no longer represent the Conflicts Committee of the Board in light of Ms. LaFollette’s appointment to the Board.

Code of Ethics

HLS has adopted a Code of Business Conduct and Ethics that applies to all of its officers, directors and employees, including HLS’s principal executive officer, principal financial officer, and principal accounting officer. The purpose of the Code of Business Conduct and Ethics is to, among other things, affirm HLS’s and HEP’s commitment to a high standard of integrity and ethics. The Code sets forth a common set of values and standards to which all of HLS’s officers, directors and employees must adhere. We will post information regarding an amendment to, or a waiver from, the Code of Business Conduct and Ethics on our website.

Copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics are available on our website at www.hollyenergy.com. Copies of these documents may also be obtained free of charge upon written request to Holly Energy Partners, L.P., Attention: Director, Investor Relations, 2828 N. Harwood, Suite 1300, Dallas, Texas, 75201-1507.

The Board, Its Committees and Director Compensation

Directors

The following individuals currently serve as directors of HLS:

Michael C. Jennings Director since October 2011. Age 52.

Principal Occupation: Chairman of the Board of HLS and Chairman of the Board of HFC

Business Experience:	Mr. Jennings has served as Chairman of the Board of HLS since November 2017 and Chairman of the Board of HFC since January 2017, a position he previously held from January 2013 until January 2016. Mr. Jennings served as Chief Executive Officer of HLS from January 2014 to November 2016 and as President of HLS from October 2015 to February 2016. Mr. Jennings served as Executive Chairman of HFC from January 2016 until January 2017 and as the Chief Executive Officer and President of HFC from the merger of Holly Corporation and Frontier Oil Corporation in July 2011 until January 2016. Mr. Jennings previously served as the President and Chief Executive Officer of Frontier Oil Corporation from 2009 until the merger in July 2011 and as the Executive Vice President and Chief Financial Officer

	of Frontier Oil Corporation from 2005 until 2009.
Additional Directorships:	Mr. Jennings currently serves as the Chairman and a director of HFC and a director of ION Geophysical Corporation. Mr. Jennings served as a director of Frontier Oil Corporation from 2008 until the merger in July 2011 and as Chairman of the board of directors of Frontier Oil Corporation from 2010 until the merger in July 2011.
Qualifications:	Mr. Jennings provides valuable and extensive industry knowledge and experience. His knowledge of the day-to-day operations of HFC provides a significant resource for the Board and facilitates discussions between the Board and HFC management.

George J. Damiris Director since February 2016. Age 57.

Principal Occupation: Chief Executive Officer and President of HFC and Chief Executive Officer and President of HLS

Business Experience: Mr. Damiris has served as the Chief Executive Officer of HLS since November 2016, as President of HLS since February 2017 and as Chief Executive Officer and President of HFC since January 2016. He previously served as Executive Vice President and Chief Operating Officer of HFC from September 2014 until January 2016 and as Senior Vice President, Supply and Marketing of HFC from January 2008 until September 2014. Mr. Damiris joined HFC in 2007 as Vice President, Corporate Development after an 18-year career with Koch Industries, where he was responsible for managing various refining, chemical, trading, and financial businesses.

Additional Directorships: Mr. Damiris currently serves as a director of Eagle Materials Inc. and of HFC.

Qualifications: Mr. Damiris has extensive industry experience and significant insight into issues facing the industry. His knowledge of the day-to-day operations of HFC provides a significant resource for the Board and facilitates discussions between the Board and HFC management.

Larry R. Baldwin Director since May 2016. Age 65.

Principal Occupation: Former Partner at Deloitte LLP.

Business Experience: Mr. Baldwin was employed for 41 years as an auditor by Deloitte LLP and predecessor firms, including 31 years as a partner, prior to retiring from such position in May 2015. While he was a partner at Deloitte LLP, Mr. Baldwin held a number of practice management positions.

Qualifications: Mr. Baldwin brings to the Board his audit, accounting and financial reporting expertise, which also qualify him as an audit committee financial expert. Due to his audit and practice management experience with Deloitte LLP, Mr. Baldwin possesses business, industry and management expertise that provide valuable insight to the Board and the management of the Company.

R. Kevin Hardage Director since November 2017. Age 56.

Principal Occupation: Chief Executive Officer of Turtle Creek Trust Company, Co-founder, President and Portfolio Manager of Turtle Creek Management, LLC and a non-controlling manager and member of TCTC Holdings, LLC

Business Experience: Mr. Hardage has served as Chief Executive Officer of Turtle Creek Trust Company, a private trust and investment management firm, since 2009 and has served as President and Portfolio Manager of Turtle Creek Management, a registered investment advisory firm, since 2006. In addition, Mr. Hardage serves as a non-controlling manager and member of TCTC Holdings, LLC, a bank holding company that is a banking, securities and investment management firm.

Additional Directorships: Mr. Hardage currently serves as a director of HFC.

Qualifications:

Mr. Hardage brings to the Board executive and general management experience as well as significant financial expertise.

James H. Lee Director since November 2017. Age 69.

Principal Occupation: Managing General Partner and Principal Owner of Lee, Hite & Wisda Ltd.

Business Experience:	Mr. Lee has served as the Managing General Partner of Lee, Hite & Wisda Ltd., a private company with investments in oil and gas working, royalty and mineral interests, since founding the firm in 1984.

Additional Directorships: Mr. Lee currently serves as a director of HFC. He served as a director of Frontier Oil Corporation from 2000 until July 2011 and as a director of Forest Oil Corporation from 1991 until December 2014.

Qualifications: Mr. Lee brings to the Board his extensive experience as a consultant and investor in the oil and gas industry, which provides him with significant insights into relevant industry issues.

The following directors are appointed to the Board effective March 1, 2018:

Christine B. LaFollette Director effective March 1, 2018. Age 65.

Principal Occupation: Partner at Akin Gump Strauss Hauer & Feld LLP

Business Experience: Ms. LaFollette has served as a partner at Akin Gump Strauss Hauer & Feld LLP since June 2004. Prior to that, Ms. LaFollette served as a partner at King & Spalding LLP from 1997 to June 2004, as a partner at Andrews & Kurth LLP from 1987 to 1997 and as an associate at Andrews & Kurth LLP from 1980 to 1987.

Qualifications: Ms. LaFollette's experience as a transactional and securities attorney provides her with valuable insight into corporate finance, global compliance, and governance matters. In addition, Ms. LaFollette brings to the Board a broad range of experiences and skills as a result of her involvement in numerous charitable, community and civic activities.

Eric L. Mattson Director effective March 1, 2018. Age 66.

Principal Occupation: Executive Vice President, Finance of Select Energy Services, Inc.

Business Experience: Mr. Mattson has served as Executive Vice President, Finance of Select Energy Services, Inc., a provider of total water solutions to the U.S. unconventional oil and gas industry, since November 2016 and served as Executive Vice President and Chief Financial Officer of Select Energy Services, Inc. from November 2008 through January 2016. Prior to that, Mr. Mattson served as Senior Vice President and Chief Financial Officer of VeriCenter, Inc., a private provider of managed hosting services, from 2003 until its acquisition in August, 2007. Mr. Mattson worked as an independent consultant from November 2002 to October 2003. Mr. Mattson served as the Chief Financial Officer of Netrail, Inc., a private Internet backbone and broadband service provider, from September 1999 until November 2002. From July 1993 until May 1999, Mr. Mattson served as Senior Vice President and Chief Financial Officer of Baker Hughes Incorporated, a provider of products and services to the oil, gas and process industries. Mr. Mattson joined Baker International, Inc. in 1980, and served in a number of capacities, including Treasurer, prior to the merger of Baker International, Inc. and Hughes Tool Company in 1987, at which time he became Vice President and Treasurer of Baker Hughes, Inc., a position he held until 1993.

Additional Directorships: Mr. Mattson has served as a director of National Oilwell Varco, Inc. since March 2005 (having served as a director of Varco (and its predecessor, Tuboscope Inc.) from January 1994 until its merger with National Oilwell Varco in March 2005) and as a director of Rex Energy Corporation since April 2010.

Qualifications:

Mr. Mattson brings strong executive leadership skills and financial and risk management experience to the Board. His knowledge of the oil industry as well as the financial and capital markets enables him to provide critical insight to the Board.

None of our directors reported any litigation for the period from 2008 to 2018 that is required to be reported in this Annual Report on Form 10-K.

The Board

Under the Company's Governance Guidelines, Board members are expected to prepare for, attend and participate in all meetings of the Board and Board committees on which they serve. During 2017, the Board held 17 meetings. Each director attended at least 75% of the total number of meetings of the Board and committees on which he served.

Board Committees

The Board currently has three standing committees:

- an Audit Committee;
- a Compensation Committee;
- a Conflicts Committee.

Each of these committees operates under a written charter adopted by the Board.

During 2017, the Audit Committee held nine meetings, the Conflicts Committee held 16 meetings and the Compensation Committee held four meetings.

The Board appoints committee members annually. The following table sets forth the current composition of our committees:

Name (1)	Audit Committee	Compensation Committee	Conflicts Committee
Larry Baldwin	x (Chair)		x
George J. Damiris		x	
R. Kevin Hardage	x		
Michael C. Jennings		x (Chair)	
James H. Lee	x	x	

(1) Effective February 28, 2018, Mr. Hardage will resign from the Board. Effective March 1, 2018, Ms. LaFollette will serve on the Compensation Committee and the Conflicts Committee, and Mr. Mattson will serve on the Conflicts Committee, as Chairman, and the Audit Committee.

Audit Committee

The functions of the Audit Committee pursuant to its charter include the following:

- selecting, compensating, retaining and overseeing our independent registered public accounting firm and conducting an annual review of the independence and performance of that firm;

- reviewing the scope and the planning of the annual audit performed by the independent registered public accounting firm;

- overseeing matters related to the internal audit function;

- reviewing the audit report issued by the independent registered public accounting firm;

-

reviewing HEP’s annual and quarterly financial statements with management and the independent registered public accounting firm;

- discussing with management HEP’s significant financial risk exposures and the actions management has taken to monitor and control such exposures;
- reviewing and, if appropriate, approving transactions involving conflicts of interest, including related party transactions, when required by HEP’s Code of Business Conduct and Ethics;
- reviewing and discussing HEP’s internal controls over financial reporting with management and the independent registered public accounting firm;

- establishing procedures for the receipt, retention and treatment of complaints received by HEP regarding accounting, internal accounting controls or accounting matters, potential violations of applicable laws, rules and regulations or of our codes, policies and procedures;
- reviewing the type and extent of any non-audit work to be performed by the independent registered public accounting firm and its compatibility with their continued objectivity and independence, and to the extent consistent, pre-approving all non-audit services to be performed;
- reviewing and approving the Audit Committee Report to be included in the Annual Report of Form 10-K; and
- reviewing the adequacy of the Audit Committee charter on an annual basis.

Each current member of the Audit Committee and Mr. Mattson have the ability to read and understand fundamental financial statements. The Board has determined that Mr. Baldwin meets the requirements of an “audit committee financial expert” as defined by the rules of the SEC.

Conflicts Committee

The functions of the Conflicts Committee include reviewing specific matters that the Board or the Conflicts Committee believes may involve conflicts of interest with HFC. The Conflicts Committee determines if the resolution of the conflict of interest is fair and reasonable to HEP. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, the Conflicts Committee reviews the adequacy of the Conflicts Committee charter on an annual basis.

Compensation Committee

The functions of the Compensation Committee pursuant to its charter include:

- reviewing and approving the goals and objectives of HLS and HEP relevant to the compensation of the officers of HLS for whom the Compensation Committee determines compensation;
- determining compensation for the officers of HLS for whom the Compensation Committee determines compensation;
- reviewing director compensation and making recommendations to the Board regarding the same;
- overseeing the preparation of the Compensation Discussion and Analysis to be included in the Annual Report and preparing the Compensation Committee Report to be included in the Annual Report;
- reviewing the Company’s executive compensation plans with respect to behavioral, operational and other risks;
- administering and making recommendations to the Board with respect to HEP’s equity plan and HLS’s annual incentive plan; and
- reviewing the adequacy of the Compensation Committee charter on an annual basis

During 2017, the Compensation Committee had a subcommittee comprised of Mr. Lee, who is “independent” as defined by the NYSE listing standards, for purposes of approving equity awards, including performance goals applicable to such awards, if applicable, and any other matters that are within the responsibilities of the Compensation Committee requiring approval solely by independent members of the Board. During 2017, the subcommittee of the Compensation Committee held two meetings. Messrs. Darling, Stengel and Townsend served on the subcommittee prior to their retirement from the Board. Effective February 2018, equity awards, including performance goals applicable to such awards, if applicable, will be approved by the full Board. As a result, the subcommittee is no longer needed.

During 2017, the Compensation Committee had engaged Frederic W. Cook & Co. (the "Compensation Consultant" or "FWC"), an executive compensation consulting firm, to advise it regarding the compensation of HLS's officers and directors. In selecting FWC as its independent compensation consultant, the Compensation Committee assessed the independence of FWC pursuant to SEC rules and considered, among other things, whether FWC provides any other services to HLS or us, the fees paid by us to FWC as a percentage of FWC's total revenues, the policies of FWC that are designed to prevent any conflict of interest between

FWC, the Compensation Committee, HLS and us, any personal or business relationship between FWC and a member of the Compensation Committee or one of HLS's executive officers and whether FWC owned any of our common units. In addition to the foregoing, the Compensation Committee received an independence letter from FWC, as well as other documentation addressing the firm's independence. FWC reports exclusively to the Compensation Committee and does not provide any additional services to HLS or us. The Compensation Committee has discussed these considerations and has concluded that FWC is independent and that neither we nor HLS have any conflicts of interest with FWC.

In January 2018, the Compensation Committee engaged Meridian Compensation Partners, LLC ("Meridian") to provide advice relating to non-management director compensation matters beginning with the 2018 fiscal year. Meridian did not provide any information or advice to the Compensation Committee with respect to matters related to executive and non-management director compensation in 2017.

Compensation Committee Interlocks and Insider Participation

The members of the Compensation Committee of the Board at year-end 2017 were Messrs. Jennings, Damiris and Lee. Messrs. Darling, Stengel and Townsend also served as Compensation Committee members until their retirement in November 2017. During his service as a member of the Compensation Committee, Mr. Damiris also served as the Chief Executive Officer and President of HLS. None of the members who served on the Compensation Committee at any time during 2017 had any relationship requiring disclosure under Item 13 of this annual report on Form 10-K entitled "Certain Relationships and Related Transactions, and Director Independence." No executive officer of HLS served as a member of the compensation committee of another entity that had an executive officer serving as a member of our Board or our Compensation Committee. No executive officer of HLS served as a member of the board of another entity that had an executive officer serving as a member of our Compensation Committee, except that Mr. Damiris, the Chief Executive Officer and President of HLS, also served as the Chief Executive Officer and President of HFC.

Report of the Audit Committee for the Year Ended December 31, 2017

Management of Holly Logistic Services, L.L.C. is responsible for Holly Energy Partners, L.P.'s system of internal controls over financial reporting. The Audit Committee selected, and the Board approved, the selection of, Ernst & Young LLP as Holly Energy Partners, L.P.'s independent registered public accounting firm to audit the books, records and accounts of Holly Energy Partners, L.P. for the year ended December 31, 2017. Ernst & Young LLP is responsible for performing an independent audit of Holly Energy Partners, L.P.'s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and to issue a report thereon. The Audit Committee also is responsible for selecting, engaging and overseeing the work of the independent registered public accounting firm, which reports directly to the Audit Committee, and evaluating its qualifications and performance. Among other things, to fulfill its responsibilities, the Audit Committee:

- reviewed and discussed Holly Energy Partners, L.P.'s quarterly unaudited consolidated financial statements and its audited annual consolidated financial statements for the year ended December 31, 2017 with management and Ernst & Young LLP, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements, including those in management's discussion and analysis thereof;

- discussed with Ernst & Young LLP the matters required to be discussed by Auditing Standard No. 16, Communications with Audit Committees, as adopted by the Public Company Accounting Oversight Board;

- discussed with Ernst & Young LLP matters relating to its independence and received the written disclosures and letter from Ernst & Young required by applicable requirements of PCAOB regarding the independent accountant's communications with the Audit Committee concerning the firm's independence;

- discussed with Holly Energy Partners, L.P.'s internal auditors and Ernst & Young LLP the overall scope and plans for their respective audits and met with the internal auditors and Ernst & Young LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of Holly Energy Partners, L.P.'s financial reporting; and

- considered whether Ernst & Young LLP's provision of non-audit services to Holly Energy Partners, L.P. is compatible with the auditor's independence

The Audit Committee charter requires the Audit Committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All fees for audit, audit-related and tax services as well as all other fees presented under Item 14 “Principal Accountant Fees and Services” were approved by the Audit Committee in accordance with its charter.

Based on the foregoing review and discussions and such other matters the Audit Committee deemed relevant and appropriate, the Audit Committee recommended to the Board that the audited consolidated financial statements of Holly Energy Partners, L.P. for the year ended December 31, 2017 be included in Holly Energy Partners, L.P.’s Annual Report on Form 10-K for the year ended December 31, 2017 for filing with the SEC.

Members of the Audit Committee:
Larry R. Baldwin, Chairman
R. Kevin Hardage
James H. Lee

Director Compensation

The Compensation Committee annually evaluates the compensation program for members of the Board who are not officers or employees of HLS or HFC (“non-employee directors”). Directors who also serve as officers or employees of HLS or HFC do not receive additional compensation for serving on the Board. We reimburse directors for all reasonable expenses incurred in attending Board and Board committee meetings upon submission of appropriate documentation.

For 2017, non-employee directors were entitled to receive a cash retainer and meeting fees payable in cash in addition to equity awards described in the following table.

In November 2017, the Board approved non-employee director compensation for 2018. For 2018, the Board eliminated meeting fees until the thirteenth meeting of the Board or the Committee. As a result, several changes were made to the equity and cash payments received by the non-employee directors, which are reflected in the table below.

	Compensation in 2017 (1)	Compensation in 2018 (1)
Annual cash retainer	$60,000	$100,000
Meeting fee (also paid to non-members of committees who are invited to attend by such committee’s chairman) (2)	$1,500	$1,500
Annual equity retainer of restricted units (3)	$80,000	$90,000
Annual cash retainer for the Chairman of the Board	$100,000	$75,000
Annual cash retainer for Chairmen of committees and subcommittees	$15,000	$25,000 (4)

(1) Because Mr. Hardage was appointed to fill a temporary vacancy on the HLS Board, Mr. Hardage did not participate in the non-employee director compensation program. Instead, he received cash compensation of $18,000 per month for his service on the Board.

(2) Represents fees paid for meetings attended in person or telephonically. Beginning in 2018, no meeting fees will be paid for the first 12 Board or Committee meetings. Meeting fees will be paid beginning with the thirteenth meeting of the Board or Committee.

(3) The annual award is comprised of a number of restricted units equal to the annual equity retainer divided by the closing price of a common unit on the date of grant, with the number of restricted units rounded up in the case of fractional shares.

(4) Beginning in 2018, no cash retainer will be paid to the Chairman of the Compensation Committee since he also serves as Chairman of the Board.

Annual Equity Awards

Non-employee directors receive an annual equity award grant under the Holly Energy Partners, L.P. Amended and Restated Long-Term Incentive Plan ("Long-Term Incentive Plan") in the form of restricted units, with the number of restricted units calculated as described above. Continued service on the Board through the vesting date, which is approximately one year following the date of grant, is required for the restricted units to vest. Vesting of all unvested units will accelerate upon a change in control of HFC, HLS, HEP or HEP Logistics. In addition, vesting of unvested units will accelerate on a pro-rata basis upon the director's death, total and permanent disability or retirement. Directors are entitled to receive all distributions paid with respect to outstanding restricted units. The distributions are not subject to forfeiture. The directors also have a right to vote with respect to the restricted units.

Non-Qualified Deferred Compensation

Non-employee directors are eligible to participate in the HollyFrontier Corporation Executive Nonqualified Deferred Compensation Plan, which is not tax-qualified under Section 401 of the Internal Revenue Code and allows participants to defer receipt of certain compensation (the “NQDC Plan”). The NQDC Plan allows non-employee directors the ability to defer up to 100% of their cash retainers and meeting fees for a calendar year. Participating directors have full discretion over how their contributions to the NQDC Plan are invested among the investment options. Earnings on amounts contributed to the NQDC Plan are calculated in the same manner and at the same rate as earnings on actual investments. Neither HLS nor HFC subsidizes a participant’s earnings under the NQDC Plan.

None of our non-employee directors participated in the NQDC Plan in 2017. For additional information on the NQDC Plan, see “Compensation Discussion and Analysis-Overview of 2017 Executive Compensation Components and Decisions-Retirement and Benefit Plans-Deferred Compensation Plan” and the narrative preceding the “Nonqualified Deferred Compensation Table.”

Unit Ownership and Retention Policy for Directors

Effective October 2013, our directors became subject to a new unit ownership and retention policy. Pursuant to the policy, each director is required to hold during service on the Board common units equal in value to at least two times the annual equity retainer paid to non-employee directors. As of January 1, 2017, each non-employee director was required to hold common units equal in value to $160,000. Beginning in November 2017, each non-employee director was required to hold common units equal in value to $180,000. Each subject director is required to meet the applicable requirements within five years of first being subject to the policy.

Directors are also required to continuously own sufficient units to meet the unit ownership and retention requirements once attained. Until directors meet the requirements, they will be required to hold 25% of the units received from any equity award. If a director attains compliance with the policy and subsequently falls below the requirement because of a decrease in the price of our common units, the director will be deemed in compliance provided that the director retains the units then held.

As of December 31, 2017, all of our then-current directors were in compliance with the unit ownership and retention policy or were within the five-year grace period provided in the policy.

Anti-Hedging and Anti-Pledging Policy

Members of the Board are subject to the HEP Insider Trading Policy, which, among other things, prohibits such directors from entering into short sales or hedging or pledging our common units and HFC common stock.

Director Compensation Table

The table below sets forth the compensation earned in 2017 by each of the non-employee directors of HLS:

Name (1)	Fees Earned or Paid in Cash	Unit Awards (2)	All Other Compensation	Total

Larry R. Baldwin	$138,000	$90,026	—	$228,026
Matthew P. Clifton (3)	218,500	80,003	$160,705 (4)	459,208
Charles M. Darling, IV (3)	133,500	80,003	160,705 (4)	374,208
R. Kevin Hardage (5)(6)	28,200	—	—	28,200
Michael C. Jennings	120,630	90,026	—	210,656
James H. Lee (5)	12,978	90,032	—	103,010
Jerry W. Pinkerton (3)	49,500	—	—	49,500
William P. Stengel (3)	126,000	80,003	160,705 (4)	366,708
James G. Townsend (3)	106,500	80,003	160,705 (4)	347,208

(1) Mr. Damiris is not included in this table because he received no additional compensation for his service on the Board since, during 2017, Mr. Damiris was an executive officer of HFC and HLS. The compensation paid by HFC to Mr. Damiris in 2017 will be shown in HFC's 2018 Proxy Statement. A portion of the compensation paid to Mr. Damiris by HFC in 2017 is allocated to the services he performed for us in his capacity as an executive officer of HLS and is disclosed in the "Summary Compensation Table" below. Ms. LaFollette and Mr. Mattson are not included in the table because they did not serve as directors in 2017.

(2) Reflects the aggregate grant date fair value of restricted units granted to non-employee directors, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 ("FASB ASC Topic 718"), determined without regard to forfeitures. See Note 6 to our consolidated financial statements for the fiscal year ended December 31, 2017, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards.

On November 1, 2017, Messrs. Baldwin, Clifton, Darling, Jennings, Stengel and Townsend received an award of 2,246 restricted units that vests on December 1, 2018, subject to continued service on the Board. Messrs. Clifton, Darling, Stengel and Townsend forfeited these restricted units in connection with their retirement from the Board on November 9, 2017. On November 10, 2017, Mr. Lee received an award of 2,443 restricted units that vests on December 1, 2018, subject to continued service on the Board, in connection with his appointment to the Board. On November 15, 2017, the Board approved an increase in the director equity retainer for 2018 from $80,000 to $90,000. As a result, on November 15, 2017, Messrs. Baldwin, Jennings and Lee received an additional award of 311 restricted units that vests on December 1, 2018, subject to continued service on the Board, since their prior awards in 2017 were based on a grant value of $80,000. As of December 31, 2017, Messrs. Baldwin and Jennings held 2,557 restricted units and Mr. Lee held 2,754 restricted units. Mr. Hardage was not eligible to receive a grant of equity awards. For additional information regarding the annual restricted unit grants, please refer to the "Director Compensation" narrative above.

(3) In accordance with our director retirement policy, Mr. Pinkerton resigned from the Board effective June 30, 2017. On November 9, 2017, Messrs. Clifton, Darling, Stengel and Townsend retired from the Board. Each of them is included in the table since he served as a non-employee director during 2017.

(4) Represents cash payment made to the director at the time of retirement as compensation for forfeited restricted units as a result of his retirement.

(5) Mr. Lee was appointed to the Board effective November 10, 2017. Mr. Hardage was appointed to the Board effective November 14, 2017.

(6) Because Mr. Hardage was appointed to fill a temporary vacancy on the HLS Board, he did not participate in the director compensation program and instead received $18,000 per month for his service on the Board.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, executive officers and persons who beneficially own more than 10% of HEP's units to file certain reports with the SEC and New York Stock Exchange concerning their beneficial ownership of HEP's equity securities. Based on a review of these reports, other information available to us and written representations from reporting persons indicating that no other reports were required, all such reports concerning beneficial ownership were filed in a timely manner by reporting persons during the year ended December 31, 2017.

Item 11. Executive Compensation

Compensation Discussion and Analysis

This Compensation Discussion and Analysis provides information about our compensation objectives and policies for the HLS executive officers who are our “Named Executive Officers” for 2017 to the extent the Compensation Committee determines the compensation of these individuals and about the compensation for our other Named Executive Officers that is allocated to us pursuant to Compensation Committee action or SEC rules. In addition, the Compensation Discussion and Analysis is intended to place in perspective the information contained in the executive compensation tables that follow this discussion and provide a description of our policies relating to reimbursement to HFC and HLS for compensation expenses.

Overview

We are managed by HLS, the general partner of HEP Logistics, our general partner. HLS is a subsidiary of HFC. The employees providing services to us are either provided by HLS, which utilizes people employed by HFC to perform services for us, or seconded to us by subsidiaries of HFC, as we do not have any employees.

For 2017, our “Named Executive Officers” were:

Name	Position with HLS in 2017
George J. Damiris	Chief Executive Officer and President
Richard L. Voliva III	Executive Vice President and Chief Financial Officer
Mark T. Cunningham	Senior Vice President, Engineering and Technical Services (1)
Denise C. McWatters	Senior Vice President, General Counsel and Secretary

(1) Mr. Cunningham was appointed Senior Vice President, Operations and Engineering in January 2018.

Certain of our Named Executive Officers are also officers of HFC or provide services to HFC. During 2017:

- Mr. Cunningham spent all of his professional time managing our business and affairs and did not provide any services to HFC.

- Messrs. Damiris and Voliva and Ms. McWatters, who we generally refer to as the “HFC Shared Officers,” also served as executive officers of HFC and devoted as much of their professional time as was necessary to oversee the management of our business and affairs. All compensation paid to such executive officers is paid and determined by HFC, without input from the Compensation Committee.

Fees and Reimbursements for Compensation of Named Executive Officers

- Administrative Fee Covers HFC Shared Officers. Under the terms of the Omnibus Agreement we pay an annual administrative fee to HFC (currently $2.5 million) for the provision of general and administrative services for our benefit, which may be increased or decreased as permitted under the Omnibus Agreement. The administrative services covered by the Omnibus Agreement include, without limitation, the costs of corporate services provided to us by HFC such as accounting, tax, information technology, human resources, in-house legal support, and office space, furnishings and equipment. None of the services covered by the administrative fee is assigned any particular value individually. Although the administrative fee covers the services provided to us by the Named Executive Officers who are HFC Shared Officers, no portion of the administrative fee is specifically allocated to services provided by those Named Executive Officers to us. Rather, the administrative fee generally covers services provided to us by HFC and, except as described below, there is no reimbursement by us for the specific costs of such services. See Item 13, “Certain Relationships and Related Transactions, and Director Independence” of this Annual Report on Form 10-K for additional discussion of our relationships and transactions with HFC.

- Reimbursements for Compensation of Dedicated HLS Officers. Under the Omnibus Agreement, we also reimburse HFC for certain expenses incurred on our behalf, such as for salaries and employee benefits for certain personnel employed by HFC who perform services for us on behalf of HLS, including the dedicated HLS officers, as described in greater detail below. The partnership agreement provides that our general partner will determine the expenses that are allocable to us. In 2017, we reimbursed HFC for 100% of the compensation expenses incurred by HFC for salary, bonus, retirement and other benefits provided to Mr. Cunningham. With respect to equity compensation paid by us to Mr. Cunningham, HLS purchases the units delivered pursuant to awards under our Long-Term Incentive Plan, and we reimburse HLS for the purchase price of the units.

Compensatory Decisions for Dedicated HLS Officers

- Generally. The Compensation Committee generally makes compensation decisions for Mr. Cunningham, other than with respect to pension and retirement benefits as described below. All compensation provided to Mr. Cunningham for 2017 is discussed and reported, in accordance with SEC rules, in the narratives and tables that follow.

Pension and Retirement Benefits. The Compensation Committee does not review or approve pension or retirement benefits for any of the Named Executive Officers. Rather, all pension and retirement benefits provided to the executives are the same pension and retirement benefits that are provided to employees of HFC generally, and such benefits are sponsored and administered entirely by HFC without input from HLS or the Compensation Committee. The pension and retirement benefits provided to Mr. Cunningham in 2017 are described below and were charged to us monthly in accordance with the Omnibus Agreement.

Allocation of Compensation and Compensatory Decisions for HFC Shared Officers

Generally. HFC makes all decisions regarding the compensation paid to the HFC Shared Officers, which compensation is covered by the administrative fee under the Omnibus Agreement (and therefore not subject to reimbursement by us); however, in accordance with SEC rules, for purposes of these disclosures, a portion of the compensation paid by HFC to the HFC Shared Officers for 2017 is allocated to the services they performed for us during 2017. The allocation was made based on the assumption that each of Messrs. Damiris and Voliva and Ms. McWatters spent, in the aggregate, the following percentage of his or her professional time on our business and affairs in 2017:

Name	Percentage of Time
George J. Damiris	20%
Richard L. Voliva III	20%
Denise C. McWatters	30%

Because HFC made all decisions regarding the compensation paid to Messrs. Damiris and Voliva and Ms. McWatters for 2017, those decisions are not discussed in this Compensation Discussion and Analysis. The total compensation paid by HFC to Messrs. Damiris and Voliva and Ms. McWatters in 2017 will be disclosed in HFC's 2018 Proxy Statement.

Objectives of Compensation Program

Our compensation program is designed to attract and retain talented and productive executives who are motivated to protect and enhance our long-term value for the benefit of our unitholders. Our objective is to be competitive with our industry and encourage high levels of performance from our executives.

In supporting our objectives, the Compensation Committee balances the use of cash and equity compensation in the total direct compensation package provided to the dedicated HLS officers; however, the Compensation Committee has not adopted any formal policies for allocating their compensation among salary, bonus and long-term equity compensation.

In the fourth quarter of 2016, the Compensation Committee, with the assistance of the Chief Executive Officer, reviewed the mix and level of cash and long-term equity incentive compensation for Mr. Cunningham with a goal of providing competitive compensation for 2017 to retain him, while at the same time providing him incentives to maximize long-term value for us and our unitholders. After reviewing internal evaluations, input by management, and market data provided by the Compensation Consultant, the Compensation Committee believes that the 2017 compensation paid to Mr. Cunningham reflects an appropriate allocation of compensation between salary, bonus and equity compensation.

Role of the Compensation Consultant and the Compensation Committee in the Compensation Setting Process

In 2017, the Compensation Committee retained Frederic W. Cook & Co. (the “Compensation Consultant” or “FWC”), a consulting firm specializing in executive compensation, to advise the Compensation Committee on matters related to executive and non-employee director compensation and long-term equity incentive awards. The Compensation Consultant provided the Compensation Committee with market data, updates on related trends and developments, advice on program design, and input on compensation decisions for executive officers and non-employee directors. As discussed above under “-The Board, Its Committees and Director Compensation-Board Committees-Compensation Committee,” the Compensation Committee has concluded that we do not have any conflicts of interest with FWC.

The Compensation Committee generally makes compensation decisions for a given fiscal year in the fourth quarter of the prior year. The Compensation Consultant does not have authority to determine the ultimate compensation paid to executive officers or non-employee directors, and the Compensation Committee is under no obligation to utilize the information provided by the Compensation Consultant when making compensation decisions. The Compensation Consultant provides external context and other input to the Compensation Committee prior to the Compensation Committee approving salaries and fees, awarding bonuses and equity compensation or establishing awards for the upcoming year.

In January 2018, the Compensation Committee engaged Meridian Compensation Partners, LLC (“Meridian”). Meridian did not provide any information or advice to the Compensation Committee with respect to 2017 executive compensation.

Review of Market Data

Market pay levels are one of many factors considered by the Compensation Committee in setting compensation for the Named Executive Officers. The Compensation Committee regularly reviews comparison data provided by the Compensation Consultant with respect to salary, annual incentive levels and long-term incentive levels as one point of reference in evaluating the reasonableness and competitiveness of the compensation paid to our executive officers as compared to companies with which we compete for executive talent. In addition, the Compensation Committee reviews such data to evaluate whether our compensation reflects practices of comparable companies of generally similar size and scope of operations. The Compensation Consultant obtains market information primarily from SEC filings of publicly traded companies that the Compensation Consultant and the Compensation Committee consider appropriate peer group companies and, from time to time, from published compensation surveys (such as the Liquid Pipeline Roundtable Compensation Survey). The purpose of the peer group is to provide a frame of reference with respect to executive compensation at companies of generally comparable size and scope of operations, rather than to set specific benchmarks for the compensation provided to the Named Executive Officers. We select peer group companies that we believe provide relevant data points for our consideration.

The peer group used in determining 2017 compensation included the following publicly traded master limited partnerships, which are representative of the companies with which we compete for executives:

Boardwalk Pipeline Partners LP	NGL Energy Partners LP
Calumet Specialty Products Partners LP	NuStar Energy LP
Crestwood Equity Partners LP	Rose Rock Midstream LP
DCP Midstream Partners LP	Summit Midstream Partners LP
EnLink Midstream Partners LP	Targa Resources Partners LP
Genesis Energy LP	USA Compression Partners LP

The peer group used in 2017 was changed from the peer group used in 2016 due to merger activity.

Our objective generally is to position pay at levels approximately in the middle range of market practice, taking into account median levels derived from our peer group analysis. Following advice from the Compensation Consultant, we consider our salary and non-salary compensation components relative to the median compensation levels generally within the peer group rather than to an exact percentile above or below the median. For these purposes, if compensation is generally within plus or minus 20% of the market median, it is considered to be in the middle range of the market.

In 2017, the total direct compensation paid to Mr. Cunningham was generally in the middle range of the market. As noted, however, this market analysis is just one of many factors considered when making overall compensation decisions for our executives.

Role of Named Executive Officers in Determining Executive Compensation

In making executive compensation decisions, the Compensation Committee reviews the total compensation provided to each executive in the prior year, the executive's overall performance and market data provided by the Compensation Consultant. The Compensation Committee also considers recommendations by the Chief Executive Officer and other factors in determining the appropriate final compensation amounts.

Various members of management facilitate the Compensation Committee's consideration of compensation for Named Executive Officers by providing data for the Compensation Committee's review. This data includes, but is not limited to, performance evaluations, performance-based compensation provided to the Named Executive Officers in previous years, tax-related considerations and accounting-related considerations. Management provides the Compensation Committee with guidance as to how such data impacts performance goals set by the Compensation Committee during the previous year. Given the day-to-day familiarity that management has with the work performed, the Compensation Committee values management's recommendations, although no Named Executive Officer has authority to determine or comment on compensation decisions directly related to himself. As described above, the Compensation Committee makes the final decision as to the compensation of Mr. Cunningham.

Overview of 2017 Executive Compensation Components and Decisions

In 2017, the Compensation Committee made compensation decisions for Mr. Cunningham. The components of compensation received by Mr. Cunningham in 2017 are as follows:

- base salary;
- annual incentive cash bonus compensation;
- long-term equity incentive compensation;
- severance and change in control benefits;
- health and retirement benefits; and
- perquisites.

Each of these components is described in further detail in the narrative that follows.

Base Salary

The Compensation Committee conducted its annual review of base salary for Mr. Cunningham in the fourth quarter of 2016. The Compensation Committee considered his position, level of responsibility and performance in 2016, where applicable. The Compensation Committee also reviewed competitive market data relevant to his position provided by the Compensation Consultant. Following a review of the various factors listed above, the Compensation Committee determined the following 2017 base salary for Mr. Cunningham:

Name	2016 Base Salary	2017 Base Salary (1)	Percentage Increase from 2016
Mark T. Cunningham	$300,000	$303,000	1%

(1) Represents salary effective January 1, 2017.

Annual Incentive Cash Bonus Compensation

The Board adopted the HLS Annual Incentive Plan (the “Annual Incentive Plan”) in August 2004 to motivate eligible employees to produce outstanding results, encourage growth and superior performance, increase productivity, contribute to health and safety goals, and aid in attracting and retaining key employees. The Compensation Committee oversees the administration of the Annual Incentive Plan, and any potential awards granted pursuant to the plan are subject to final determination by the Compensation Committee of achievement of the performance metrics for the applicable performance periods.

In the fourth quarter of 2016, the Compensation Committee approved target awards under the Annual Incentive Plan for 2017 based on a pre-established percentage of Mr. Cunningham’s base salary and determined that the applicable performance period for the Annual Incentive Plan awards would be the 12-month period beginning October 1, 2016 and ending September 30, 2017, with determination and payment of the cash bonus amounts occurring in the fourth quarter of 2017.

The 2017 Annual Incentive Plan award for Mr. Cunningham was subject to achievement of the following metrics:

- Actual Distributable Cash Flow vs. Budget: Half of the target award may be earned based upon our actual distributable cash flow during the performance period compared to the budgeted distributable cash flow for the performance period, adjusted for differences in estimated and actual Producers Price Index adjustments and differences in the timing of known acquisitions.

The payout on this metric is based on the following:

Actual Distributable Cash Flow vs. Budget	Bonus Achievement (1)
Less than 100%	Actual Distributable Cash Flow as Percentage of Budget
100%	100%
Greater than 100%	100% plus 3% for each 1% Actual Distributable Cash Flow exceeds Budget

(1) The percentages are interpolated between percentage points and rounded to the nearest hundredth percent.

The performance metric of actual distributable cash flow is used because it is a widely accepted financial indicator for comparing partnership performance. We believe that this measure provides an enhanced perspective of the operating performance of our assets and the cash our business is generating, and is therefore a useful criterion in evaluating management's performance and in linking the payout of the award to our performance.

- Individual Performance: The other half of the target award may be earned based on the employee's individual performance during the performance period, as determined in the discretion of the employee's immediate supervisor. The employee's individual performance is evaluated through a performance review by the employee's immediate supervisor, which includes a written assessment. The assessment reviews several criteria, including how well the employee performed his or her pre-established individual goals during the performance period and the employee's interpersonal effectiveness, integrity, and business conduct.

The Compensation Committee also has discretion to approve an increase or a decrease in the bonus amount an executive officer would otherwise earn. Any increases or decreases are determined based on a variety of factors, including performance with respect to the pre-defined performance metrics as well as environmental, health and safety and conditions outside the control of the executive that could have affected the performance metrics. If the Compensation Committee believes additional compensation is warranted to reward an executive for outstanding performance, the Compensation Committee may increase the executive's bonus amount in its discretion. Alternatively, poor results could, in the discretion of the Compensation Committee, result in a decrease in a bonus. In making the determination as to whether such discretion should be applied (either to decrease or increase a bonus), the Compensation Committee reviews recommendations from management.

The following table sets forth the target and maximum award opportunities (as a percentage of annual base salary) for Mr. Cunningham for 2017, and the portion of his target award opportunity allocated to each performance metric. The award opportunity amounts and allocations were not changed from 2016 for Mr. Cunningham.

	Allocation Between Performance Metrics		Award Opportunities	
Name	Actual vs. Budgeted DCF	Individual	Target	Maximum
Mark T. Cunningham	20.0%	20.0%	40.0%	80.0%

Following the end of the performance period, the Chief Executive Officer evaluates the extent to which the applicable performance metrics have been achieved and recommends a bonus amount for the executive officer to the Compensation Committee. The Compensation Committee then determines the actual amount of the bonus award earned by and payable to the executive officer. Pursuant to our Annual Incentive Plan, the Compensation Committee determines actual achievement of each performance metric individually and the percentages determined with respect to the two performance metrics are then added together and multiplied by the individual's base salary to calculate the bonus amount.

For the 2017 performance period, the actual distributable cash flow ($238.9 million) exceeded the budgeted distributable cash flow ($232.0 million) by approximately 2.9%. As a result, the payout on this metric was approximately 110% of the portion of the target award related to this metric. The following table sets forth the actual payout for 2017 for Mr. Cunningham as a percentage of base salary, including payments made based on actual distributable cash flow versus budget and discretionary bonuses awarded for individual performance.

Name	Actual vs. Budgeted DCF	Individual	Total

Mark T. Cunningham	22.0%	20.0%	42.0%

Long-Term Equity Incentive Compensation

The Long-Term Incentive Plan was adopted by the Board in August 2004 with the objective of:

- promoting our interests by providing equity incentive compensation awards to eligible individuals,
- enhancing our ability to attract and retain the services of individuals who are essential for our growth and profitability,
- encouraging those individuals to devote their best efforts to advancing our business, and

• aligning the interests of those individuals with the interests of our unitholders.

The Compensation Committee typically grants long-term equity incentive awards to dedicated HLS officers on an annual basis. The Compensation Committee makes annual long-term equity incentive award grants in the fourth quarter of the year preceding the year to which the award relates, in order to align the timing of the long-term equity incentive award grants with the timing of the other compensation decisions made for the dedicated HLS officers. As a result, annual long-term equity incentive awards for the 2017 year were granted in October 2016 to the individuals who were dedicated HLS officers at that time. Pursuant to SEC rules, the long-term equity incentive awards granted in October 2016 for the 2017 year are disclosed as 2016 compensation in the Summary Compensation Table (with respect to those Named Executive Officers who received long-term equity incentive awards from us in October 2016 and who were Named Executive Officers for 2016) and are not included in the 2017 Grants of Plan-Based Awards table; however, because these awards relate to the 2017 year, they are described in greater detail below.

In determining the appropriate amount and type of long-term equity incentive awards to be granted each year, the Compensation Committee considers the executive's position, scope of responsibility, base salary and available compensation information for executives in comparable positions in similar companies. Our goal is to reward the creation of value and strong performance with variable compensation dependent on that performance.

For the 2017 year, the Compensation Committee awarded both restricted units and performance units to Mr. Cunningham. It is our practice not to make long-term equity incentive award grants to the HFC Shared Officers. Any equity compensation awards granted by HFC for 2017 to any of the HFC Shared Officers will be disclosed in HFC's 2018 Proxy Statement.

Restricted Unit Awards

In October 2016, Mr. Cunningham was granted restricted units. The number of restricted units awarded is initially approved by the Compensation Committee in dollar amounts established according to the pay grade of the executive officer. The award is then converted to a number of units by dividing the targeted dollar amount by the closing price of our common units on the grant date of the award. The following table sets forth the number of restricted units awarded to Mr. Cunningham in October 2016 for the 2017 year:

Name	Number of Restricted Units
Mark T. Cunningham	4,128

Restricted unitholders have all the rights of a unitholder with respect to the restricted units, including the right to receive all distributions paid with respect to such restricted units (at the same rate as distributions paid on our common units) and any right to vote with respect to the restricted units, subject to limitations on transfer and disposition of the units during the restricted period. The distributions are not subject to forfeiture.

The restricted units granted in October 2016 vest in three equal annual installments as noted in the following table and will be fully vested and nonforfeitable after December 15, 2019.

Restricted Unit Vesting Criteria

Vesting Date (1)	Cumulative Amount of Restricted Units Vested
Immediately following December 15, 2017	1/3
Immediately following December 15, 2018	2/3
Immediately following December 15, 2019	All

(1) Vesting will occur on the first business day following December 15 if December 15 falls on a Saturday or a Sunday. The provisions affecting the vesting of these awards upon a change in control or certain terminations of employment are described in greater detail below in the section titled “Potential Payments upon Termination and Change in Control.”

Performance Unit Awards

A performance unit is a notational phantom unit that entitles the grantee to receive a common unit upon the attainment of pre-established performance targets over a specified performance period, which may include the achievement of specified financial objectives determined by the Compensation Committee, and satisfaction of certain continued service conditions.

In October 2016, Mr. Cunningham was granted performance units with a performance period that began on January 1, 2017 and ends on December 31, 2019. An executive officer generally must remain employed through the end of the performance period to be eligible to earn any of the performance units. The provisions affecting the vesting of these awards upon a change in control or certain terminations of employment are described below in the section titled "Potential Payments upon Termination and Change in Control."

With respect to the performance unit awards for the 2017 year, Mr. Cunningham was granted a target number of performance units. The target number is initially approved by the Compensation Committee in dollar amounts established according to the pay grade of the executive officer. The target award is then converted to a number of units by dividing the targeted dollar amount by the closing price of our common units on the grant date of the award. The following table sets forth the target number of performance units granted to Mr. Cunningham in October 2016 for the 2017 year:

Name	Target Number of Performance Units
Mark T. Cunningham	4,128

The Compensation Committee determined that the increase in distributable cash flow per common unit during the performance period should be used as the performance objective for the performance unit awards granted in October 2016. The actual number of units earned at the end of the performance period is based on the "Achieved Distributable Cash Flow/Unit" as compared to the "Base Distributable Cash Flow/Unit," "Target Distributable Cash Flow/Unit" and "Incentive Distributable Cash Flow/Unit." Specifically, the actual number of units earned at the end of the performance period will be determined by multiplying the target number of performance units awarded by the applicable performance percentage as follows:

Achieved Distributable Cash Flow/Unit Equals	Performance Percentage (%) (1)
Base Distributable Cash Flow/Unit or Less	50%
Target Distributable Cash Flow/Unit	100%
Incentive Distributable Cash Flow/Unit	150%

(1) The percentages above are interpolated between points up to a maximum of 150% but no less than 50%. The result is rounded to the nearest whole percentage, but not to a number in excess of 150%.

For the performance units:

Term	What It Means
Achieved Distributable Cash Flow/Unit	Actual Distributable Cash Flow in 2019 adjusted, on an annualized basis, to the extent such adjustment is not reflected in Actual Distributable Cash Flow in 2019, to include the effect of the closing of any acquisition to income and/or outstanding HEP common units and/or to eliminate any general partner give-back and any other aberrational event, as determined by the Compensation Committee, divided by the number of common units outstanding as of year-end 2019
Base Distributable Cash Flow/Unit	Actual Distributable Cash Flow for 2016 adjusted, on an annualized basis, to include the effect of the closing of any acquisition to income and/or outstanding HEP common units and/or to eliminate any general partner give-back and any other aberrational event, as determined by the Compensation Committee, divided by the number of common units outstanding as of year-end 2016
Target Distributable Cash Flow/Unit	Base Distributable Cash Flow/Unit x (100% + $WAIA_1$) x (100% + $WAIA_2$) x (100% + $WAIA_3$)
Incentive Distributable Cash Flow/Unit	Base Distributable Cash Flow/Unit x (100% + ($WAIA_1$ + 4%)) x (100% + ($WAIA_2$ + 4%)) x (100% + ($WAIA_3$ + 4%))
WAIA	The weighted after inflation adjustment for each of years 1, 2 and 3 of the performance period (identified as $WAIA_1$, $WAIA_2$, and $WAIA_3$, respectively) to HEP's applicable sources of revenue calculated as follows: annual percentage increase of the Producers Price Index - Commodities-Finished Goods published by the U.S. Department of Labor, Bureau of Labor Statistics For purposes of calculating Target Distributable Cash Flow/Unit and Incentive Distributable Cash Flow/Unit, the WAIA is rounded to the nearest 0.1%

Prior to vesting, distributions are paid on each outstanding performance unit, based on the target number of performance units subject to the award, at the same rate as distributions paid on our common units. The distributions are not subject to forfeiture.

On October 18, 2017, we entered into an equity restructuring agreement (the "Equity Restructuring Agreement") with our general partner HEP Logistics pursuant to which the incentive distribution rights held by HEP Logistics were cancelled and the 2% general partner interest held by HEP Logistics was converted into a non-economic general partner interest (together, the "GP/IDR Restructuring"). In consideration for the GP/IDR Restructuring, we issued to HEP Logistics 37,250,000 common units, and HEP Logistics agreed to forgo $2.5 million in distributions per quarter for 12 consecutive quarters (for an aggregate of $30 million) beginning with the first quarter in which units issued as consideration for the GP/IDR Restructuring are eligible to receive distributions.

Because the performance unit payouts are based on growth in Distributable Cash Flow per Unit, the GP/IDR Restructuring would have substantially increased the unit count, which would have reduced the Distributable Cash Flow per Unit and thus impacted performance unit payouts notwithstanding performance. Accordingly, in conjunction with the GP/IDR Restructuring, we retroactively adjusted the historical unit count (for purposes of calculating Base Distributable Cash Flow/Unit) by the amount of units issued in conjunction with the GP/IDR Restructuring to reset the "reference period" distributable cash flow per unit and remove any impact of the GP/IDR Restructuring on performance unit payouts.

Acquisition of Common Units for Long-Term Incentive Plan Awards

Common units delivered in connection with long-term equity incentive awards may be common units acquired by HLS on the open market, common units already owned by HLS, common units acquired by HLS directly from us or any other person or any combination of the foregoing. We currently do not hold treasury units. HLS is entitled to reimbursement by us for the cost of acquiring the common units utilized for the grant or settlement of long-term equity incentive awards.

Retirement and Other Benefits

Our Named Executive Officers participate in certain retirement plans sponsored and maintained by HFC. The cost of retirement benefits for dedicated HLS officers are charged monthly to us in accordance with the terms of the Omnibus Agreement. The terms of these benefit arrangements are described below.

Defined Contribution Plan

For 2017, Mr. Cunningham was eligible to participate in the HollyFrontier Corporation 401(k) Retirement Savings Plan, a tax qualified defined contribution plan (the “401(k) Plan”). Employees who are not eligible to participate in the NQDC Plan may contribute amounts between 0% and 75% of their eligible compensation to the 401(k) Plan, while employees who participate in the NQDC Plan may contribute amounts between 0% and 50% of their eligible compensation to the 401(k) Plan. Employee contributions that were made on a tax-deferred basis were generally limited to $18,000 for 2016, with employees 50 years of age or over able to make additional tax-deferred contributions of $6,000.

For 2017, all employees received an employer retirement contribution to the 401(k) Plan of 3% to 8% of the participating employee’s eligible compensation under the 401(k) Plan, subject to applicable Internal Revenue Code limitations, based on years of service, as follows:

Years of Service	Retirement Contribution (as percentage of eligible compensation)
Less than 5 years	3%
5 to 10 years	4%
10 to 15 years	5.25%
15 to 20 years	6.5%
20 years and over	8%

In addition to the retirement contribution, in 2017, employees received employer matching contributions to the 401(k) Plan equal to 100% of the first 6% of the employee’s eligible compensation contributed to the 401(k) plan up to compensation limits. Matching contributions vest immediately, and retirement contributions are subject to a three-year cliff-vesting period.

The 401(k) Plan benefits for Mr. Cunningham were charged to us in 2017 pursuant to the Omnibus Agreement.

Deferred Compensation Plan

In 2017, Mr. Cunningham was eligible to participate in the NQDC Plan. The NQDC Plan provides certain management and other highly compensated employees an opportunity to defer compensation in excess of qualified retirement plan limitations on a pre-tax basis and accumulate tax-deferred earnings to achieve their financial goals.

Participants in the NQDC Plan can contribute between 1% and 50% of their eligible earnings, which includes base salary and bonuses, to the NQDC Plan. Participants in the NQDC Plan may also receive certain employer-provided contributions, including, for 2017, matching restoration contributions, retirement restoration contributions, and nonqualified nonelective contributions. Matching restoration contributions and retirement restoration contributions represent contribution amounts that could not be made under the 401(k) Plan due to Internal Revenue Code limitations on tax-qualified plans. See the narrative preceding the “Nonqualified Deferred Compensation Table” for additional information regarding these contributions and the other terms and conditions of the NQDC Plan.

The NQDC Plan benefits for Mr. Cunningham were charged to us in 2017 pursuant to the Omnibus Agreement.

Retirement Pension Plans

HFC traditionally maintained the Holly Retirement Plan, a tax-qualified defined benefit retirement plan (the "Retirement Plan"), and the Holly Retirement Restoration Plan, an unfunded plan that provides additional payments to participating executives whose Retirement Plan benefits were subject to certain Internal Revenue Code limitations (the "Restoration Plan"). The Retirement Plan was liquidated in its entirety in June 2013. HFC continues to maintain the Restoration Plan, but all participants in that plan ceased accruing additional benefits as of May 1, 2012.

Mr. Cunningham is the only Named Executive Officer who previously participated in the Retirement Plan. None of our Named Executive Officers ever participated in the Restoration Plan.

Other Benefits and Perquisites

Our Named Executive Officers are eligible to participate in the same health and welfare benefit plans, including medical, dental, life insurance, and disability programs sponsored and maintained by HFC, that are generally made available to all full-time employees of HFC. Health and welfare benefits for Mr. Cunningham were charged to us in 2017 pursuant to the Omnibus Agreement.

It is the Compensation Committee's policy to provide only limited perquisites to our Named Executive Officers. We provided a reserved parking space for Mr. Cunningham in 2017.

Change in Control Agreements

Neither we nor HLS has entered into any employment agreements with any of the Named Executive Officers. On February 14, 2011, the Board adopted the Holly Energy Partners, L.P. Change in Control Policy (the "Change in Control Policy") and the related form of Change in Control Agreement for certain officers of HLS (each, a "Change in Control Agreement"). The Change in Control Agreements contain "double-trigger" payment provisions that require not only a change in control of HFC, HLS or HEP, but also a qualifying termination of the executive's employment within a specified period of time following the change in control in order for an officer to be entitled to benefits. We believe the Change in Control Agreements provide for management continuity in the event of a change in control and provide competitive benefits for the recruitment and retention of executives.

We entered into a Change in Control Agreement with Mr. Voliva, effective as of April 28, 2014, and Mr. Cunningham, effective as of February 14, 2011, in accordance with the Change in Control Policy. The Change in Control Agreement with Mr. Voliva was terminated effective October 31, 2016 when Mr. Voliva entered into a Change in Control Agreement with HFC. The material terms and the quantification of the potential amounts payable under the Change in Control Agreement in effect with Mr. Cunningham in 2017 are described below in the section titled "Potential Payments upon Termination or Change in Control." We bear all costs and expenses associated with this agreement.

HFC has entered into Change in Control Agreements with Messrs. Damiris and Voliva and Ms. McWatters, which were in effect during 2017 and the costs of which are fully borne by HFC (the "HFC Change in Control Agreements"). Payments and benefits under the HFC Change in Control Agreements are triggered only upon a change in control of HFC. The material terms, and the qualification, of the potential amounts payable under the HFC Change in Control Agreements with Messrs. Damiris and Voliva and Ms. McWatters will be described in HFC's 2018 Proxy Statement.

Unit Ownership and Retention Policy for Executives

The Board, the Compensation Committee and our executive officers recognize that ownership of our common units is an effective means by which to align the interests of our officers with those of our unitholders. In October 2013, the Compensation Committee recommended, and the Board approved, a new unit ownership and retention policy for dedicated HLS officers. During 2017, the unit retention requirement for Mr. Cunningham was as follows:

Executive Officer	Value of Units
Mark T. Cunningham	1x Base Salary

Each covered officer is required to meet the applicable requirements within five years of first being subject to the policy. Officers are required to continuously own sufficient units to meet the unit ownership and retention requirements once attained. Until the officers attain compliance with the unit ownership and retention policy, the officers will be required to hold 25% of the units received from any equity award, net of any units used to pay the exercise price or tax withholdings. If an officer attains compliance with the unit ownership and retention policy and subsequently falls below the requirement because of a decrease in the price of our common units, the officer will be deemed in compliance provided that the officer retains the units then held.

As of December 31, 2017, Mr. Cunningham was in compliance with the unit ownership and retention policy.

Anti-Hedging and Anti-Pledging Policy

Our Named Executive Officers are subject to the HEP Insider Trading Policy, which, among other things, prohibits such individuals from entering into short sales or hedging or pledging our common units and HFC common stock.

Tax and Accounting Implications

We account for equity compensation expenses under the rules of FASB ASC Topic 718, which requires us to estimate and record an expense for each award of equity compensation over the vesting period of the award. Accounting rules also require us to record cash compensation as an expense at the time the obligation is accrued. Because we are a partnership, Section 162(m) of the Code generally does not apply to compensation paid to our Named Executive Officers for services provided to us. Accordingly, the Compensation Committee does not consider its impact in determining compensation levels. The Compensation Committee has taken into account the tax implications to us in its decision to grant long-term equity incentive compensation awards in the form of restricted units and performance units as opposed to options or unit appreciation rights.

Recoupment of Compensation

To date, the Board has not adopted a formal clawback policy to recoup incentive based compensation upon the occurrence of a financial restatement, misconduct, or other specified events. However, equity awards granted to Named Executive Officers are subject to the terms of the Long-Term Incentive Plan, which states that such awards may be cancelled, repurchased and/or recouped to the extent required by applicable law or any clawback policy that we adopt. In addition, the award agreements for our long-term incentive compensation awards granted since October 2015 state that the award and amounts paid or realized with respect to the award may be subject to reduction, cancellation, forfeiture or recoupment to the extent required by applicable law or any clawback policy that we adopt. The Compensation Committee is reviewing the SEC’s proposed rules on incentive compensation clawbacks pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act and evaluating the practical, administrative and other implications of adopting, implementing and enforcing a clawback policy, and intends to implement a more specific clawback policy once the SEC’s rules are finalized.

2018 Compensation Decisions

Long-Term Equity Incentive Compensation

In November 2017, the Compensation Committee approved annual grants of phantom units and performance units for Mr. Cunningham. Pursuant to SEC rules, the long-term equity incentive awards granted in November 2017 for the 2018 year are disclosed as 2017 compensation in the Summary Compensation Table and are reported in the 2017 Grants of Plan-Based Awards table below. These awards are also described in greater detail in the narrative that follows.

Phantom Unit Awards

In November 2017, Mr. Cunningham was granted phantom units. The number of phantom units awarded is initially approved by the Compensation Committee in dollar amounts established according to the pay grade of the executive officer. The award is then converted to a number of units by dividing the targeted dollar amount by the closing price of our common units on the grant date of the award. The following table sets forth the number of phantom units awarded to Mr. Cunningham in November 2017 for the 2018 year:

Name	Number of Restricted Units

Mark T. Cunningham 3,861

Phantom unitholders have the right to receive distribution equivalents and other distributions paid with respect to such phantom units, and these distribution equivalents are paid at approximately the same time as distributions are paid on our common units. The distribution equivalents are not subject to forfeiture.

The phantom units granted in November 2017 to Mr. Cunningham vest in three equal annual installments as noted in the following table and will be fully vested and nonforfeitable after December 15, 2020.

Phantom Unit Vesting Criteria

Vesting Date (1)	Cumulative Amount of Restricted Units Vested
Immediately following December 15, 2018	1/3
Immediately following December 15, 2019	2/3
Immediately following December 15, 2020	All

(1) Vesting will occur on the first business day following December 15 if December 15 falls on a Saturday or a Sunday. The provisions affecting the vesting of these awards upon a change in control or certain terminations of employment are described in greater detail below in the section titled “Potential Payments upon Termination and Change in Control.”

Performance Unit Awards

In November 2017, Mr. Cunningham was granted performance units with a performance period that began on January 1, 2018 and ends on December 31, 2020. The target number of performance units granted to Mr. Cunningham was determined in the same manner as the October 2016 performance unit awards described above. The following table sets forth the target number of performance units granted to Mr. Cunningham in November 2017 for the 2018 year:

Name	Target Number of Performance Units
Mark T. Cunningham	3,861

The Compensation Committee determined that the increase in distributable cash flow per common unit during the performance period should be used as the performance objective for the performance unit awards granted in November 2017, which is the same performance objective utilized for the October 2016 awards. The actual number of units earned at the end of the performance period is based on the “Achieved Distributable Cash Flow/Unit” as compared to the “Base Distributable Cash Flow/Unit,” “Target Distributable Cash Flow/Unit” and “Incentive Distributable Cash Flow/Unit.” The actual number of units earned at the end of the performance period will be calculated in the same manner as the performance unit awards granted in October 2016, as adjusted to reflect the applicable performance period for the 2018 awards.

Prior to vesting, distributions are paid on each outstanding performance unit, based on the target number of performance units subject to the award, at the same rate as distributions paid on our common units. The distributions are not subject to forfeiture.

Compensation Committee Report

The Compensation Committee of the Holly Logistic Services, L.L.C. Board of Directors has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

Members of the Compensation Committee:
Michael C. Jennings, Chairman
George J. Damiris
James H. Lee

Executive Compensation Tables

The following executive compensation tables and related information are intended to be read together with the more detailed disclosure regarding our executive compensation program presented under the caption "Compensation Discussion and Analysis."

Summary Compensation Table

The table below summarizes the total compensation paid or earned by each of the Named Executive Officers for the years specified to the extent such compensation is allocable to us pursuant to SEC rules.

Name and Principal Position (1)	Year	Salary	Bonus (2)	Unit Awards (3)	Non-Equity Incentive Plan Compensation (4)	All Other Compensation (5)	Total
George J. Damiris	2017	$1,100,000	—	—	$881,430	—	$1,981,430
Chief Executive Officer and President (6)	2016	452,187	—	—	—	—	452,187
Richard L. Voliva III	2017	$468,750	—	—	$154,568	—	$623,318
Executive Vice President and Chief	2016	255,288	$193,130	$776,079	56,870	$45,225	1,326,592
Financial Officer (6)	2015	199,338	$90,000	$275,048	—	$25,838	590,224
Mark T. Cunningham	2017	$303,000	$60,600	$275,058	$66,660	$48,692	$754,010
Senior Vice President, Engineering and	2016	300,000	60,000	275,172	79,800	49,431	764,403
Technical Services	2015	288,112	95,512	325,132	62,808	50,189	821,753
Denise C. McWatters	2017	$500,000	—	—	$103,867	—	$603,867
Senior Vice President, General Counsel	2016	470,000	—	—	93,359	—	563,359
and Secretary (6)	2015	430,000	—	—	70,450	—	500,450

(1) Mr. Damiris was appointed President of HLS, effective as of February 1, 2017.

(2) Represents the discretionary bonus amount, if any, paid pursuant to the individual performance metric under our Annual Incentive Plan and any other bonus paid outside our Annual Incentive Plan. Other payments made under our Annual Incentive Plan are included in the "Non-Equity Incentive Plan Compensation" column.

(3) Represents the aggregate grant date fair value of awards of restricted units or phantom units and performance units made in the year indicated computed in accordance with FASB ASC Topic 718, determined without regard to forfeitures, and does not reflect the actual value that may be recognized by the executive. See Note 6 to our consolidated financial statements for the fiscal year ended December 31, 2017 for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards.

Awards for the 2016 fiscal year granted in October 2015 are reported in the "Unit Awards" column of the Summary Compensation Table for 2015, awards for the 2017 fiscal year granted in October 2016 are reported in the "Unit Awards" column of the Summary Compensation Table for 2016, and awards for the 2018 fiscal year granted in November 2017 are reported in the "Unit Awards" column of the Summary Compensation Table for 2017, in each case, in accordance with SEC rules.

With respect to performance units awarded in November 2017, the amounts in the Summary Compensation Table are based on a probable payout percentage of 100%. If the performance units granted in November 2017 are paid out at the maximum payout level of 150%, the grant date fair value of Mr. Cunningham's performance units would $206,293.

See “Compensation Discussion and Analysis - Overview of 2017 Executive Compensation Components and Decisions - Long-Term Equity Incentive Compensation - Performance Unit Awards.”

The terms of the phantom unit and performance unit awards granted in November 2017 for the 2018 fiscal year are described under “Compensation Discussion and Analysis - 2018 Compensation Decisions - Long-Term Equity Incentive Compensation.” For additional information on outstanding restricted unit, phantom unit and performance unit awards, see below under “Outstanding Equity Awards at Fiscal Year End.”

(4) Represents the bonus amount, if any, paid under our Annual Incentive Plan, other than with respect to the individual performance metric (which amounts are reported in the “Bonus” column). The 2017 bonus amounts under our Annual Incentive Plan are

described above in greater detail under "Compensation Discussion and Analysis-Overview of 2017 Executive Compensation Components and Decisions-Annual Incentive Cash Bonus Compensation." See note 6 to the Summary Compensation Table for a discussion of the amounts reported as "Non-Equity Incentive Plan Compensation" with respect to Messrs. Damiris and Voliva and Ms. McWatters for 2017.

(5) For 2017, includes the compensation as described under "All Other Compensation" below.

(6) During 2017, each of these officers split his or her professional time between HFC and us, and all compensation paid to him or her for 2017 was determined and paid by HFC. In accordance with SEC rules, for purposes of these disclosures, a portion of the total compensation paid by HFC to these officers for 2017 is allocated to the services he or she performed for us during 2017. The allocation was made based on the assumption that each officer spent, in the aggregate, approximately the following percentage of his or her professional time in 2017 on our business and affairs:

Name	Percentage of Time
George J. Damiris	20%
Richard L. Voliva III	20%
Denise C. McWatters	30%

As a result, only the designated percentage of the total amount of compensation each officer received from HFC for 2017 has been reported in this table, and the allocated amount has been solely attributed in the table above to his or her base salary and non-equity incentive plan compensation. This amount represents the aggregate dollar value of total compensation paid to the officer by HFC (including base salary, non-equity incentive plan compensation, equity awards and other compensation), calculated pursuant to SEC rules, multiplied by the percentage set forth next to her or her name above. The total compensation paid by HFC to Messrs. Damiris and Voliva and Ms. McWatters in 2017 (including the portion of his or her salary and non-equity incentive plan compensation reported in this table), including a discussion of how the total amount of his or her non-equity incentive plan compensation for 2017 was determined, will be disclosed in HFC's 2018 Proxy Statement.

All Other Compensation

The table below describes the components of the compensation included in the "All Other Compensation" column for 2017 in the Summary Compensation Table above.

Name (1)	401(k) Plan Company Matching Contributions	401(k) Plan Retirement Contributions	NQDC Plan Company Matching Contributions	NQDC Plan Retirement Contributions	Total
George J. Damiris	—	—	—	—	—
Richard L. Voliva III	—	—	—	—	—
Mark T. Cunningham	$16,200	$13,913	$9,909	$8,670	$48,692
Denise C. McWatters	—	—	—	—	—

(1) The value of the perquisites provided by us to our Named Executive Officers in 2017 did not exceed $10,000 in the aggregate, and therefore, in accordance with SEC rules, are not included in the table above or described in this footnote.

Grants of Plan-Based Awards

The following table sets forth information about plan-based awards granted to our Named Executive Officers under our equity and non-equity incentive plans during 2017. In this table, awards are abbreviated as "AICP" for the annual incentive cash awards under our Annual Incentive Plan (other than with respect to the discretionary individual performance portion of the awards, which are reported in the “Bonus” column of the Summary Compensation Table above and are not included below), as “PHUA” for phantom unit awards, and as “PUA” for performance unit awards. Messrs. Damiris and Voliva and Ms. McWatters did not receive any plan-based awards from us during 2017.

The phantom unit and performance unit grants reported below for Mr. Cunningham were granted in November 2017 for the 2018 fiscal year and are reported in this table as 2017 compensation in accordance with SEC rules. These awards are described in greater detail above under “Compensation Discussion and Analysis-2018 Compensation Decisions-Long-Term Equity Incentive Compensation.” Annual long-term equity incentive awards are made once each year in the fourth quarter of the year preceding the year to which the award relates in order to align the timing of the long-term equity incentive award grants with the timing of the other compensation decisions made for our executive officers. In accordance with SEC rules, the annual long-term equity incentive awards granted in October 2016 for the 2017 fiscal year were previously reported as 2016 compensation in the Grants of Plan-Based Awards table contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Name	Type	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All other Equity Awards (3)	Grant Date Fair Value (4)
			Threshold	Target	Maximum	Threshold	Target	Maximum		
George J. Damiris	—	—	—	—	—	—	—	—	—	—
Richard L. Voliva (5)	—	—	—	—	—	—	—	—	—	—
Mark T. Cunningham	AICP		$0	$60,600	$121,200					
	PUA	11/01/2017				1,931	3,861	5,792		$137,529
	PHUA	11/01/2017							3,861	137,529
Denise C. McWatters	—	—	—	—	—	—	—	—	—	—

(1) Represents the potential payouts for the awards under our Annual Incentive Plan, which were subject to the achievement of certain performance metrics. The performance metrics and awards are described under "Compensation Discussion and Analysis - Overview of 2017 Executive Compensation Components and Decisions - Annual Incentive Cash Bonus Compensation." Although these awards were granted in the fourth quarter of 2016, they represent the 2017 Annual Incentive Plan awards and any payouts with respect to these awards are reported in the Summary Compensation Table for 2017. Amounts reported do not include amounts potentially payable pursuant to the discretionary individual performance portion of the award. The amount actually paid with respect to the individual performance portion of the award is reported in the "Bonus" column of the Summary Compensation Table for 2017, and the amount actually paid with respect to the portion of the award reported in this table is reported in the "Non-Equity Incentive Plan Compensation" column of the Summary Compensation Table for 2017.

(2) Represents the potential number of performance units payable under the Long-Term Incentive Plan. The number of units paid at the end of the performance period may vary from the target amount, based on our achievement of specified performance measures. The terms of the performance unit awards granted in November 2017 for the 2018 fiscal year are described above under "Compensation Discussion and Analysis - 2018 Compensation Decisions - Long-Term Equity Incentive Compensation - Performance Unit Awards." See "Compensation Discussion and Analysis - Overview of 2018 Compensation Components and Decisions - Long-Term Equity Incentive Compensation - Performance Unit Awards."

(3) Represents awards of phantom units. The terms of the phantom unit awards granted in November 2017 for the 2018 fiscal year are described above under "Compensation Discussion and Analysis - 2018 Compensation Decisions - Long-Term Equity Incentive Compensation - Phantom Unit Awards."

(4) Represents the grant date fair value determined pursuant to FASB ASC Topic 718, based on a closing price of our common units of $35.62 on November 1, 2017. The value of performance units granted on November 1, 2017 reflect a probable payout percentage of 100%. See note 3 to the Summary Compensation Table for additional

information regarding the aggregate probable settlement percentage calculation.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth information regarding outstanding restricted units, phantom units and/or performance units held by each Named Executive Officer as of December 31, 2017, including awards that were granted prior to 2017. The value of these awards was calculated based on a price of $32.49 per unit, the closing price of our common units on December 29, 2017 (the last trading day in 2017). Mr. Damiris and Ms. McWatters do not hold any outstanding equity awards under our Long-Term Incentive Plan, and the table below does not reflect any outstanding HFC equity awards held by any of our Named Executive Officers.

Under SEC rules, the number and value of performance units reported is based on the number of units payable at the end of the performance period assuming the maximum level of performance is achieved. In this table, awards are abbreviated as “RUA” for restricted unit awards, “PHUA” for phantom unit awards and “PUA” for performance unit awards. The provisions applicable to these awards upon certain terminations of employment or a change in control are described below in the section titled “Potential Payments upon Termination or Change in Control.”

Name	Award Type	Number of Units That Have Not Vested (1)	Market Value of Units That Have Not Vested	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested
George J. Damiris	—	—	—	—	—
Richard L. Voliva III	RUA	447	$14,523		
	PUA			2,012	$65,370
Mark T. Cunningham	RUA	4,336	$140,877		
	PHUA	3,861	$125,444		
	PUA			19,112	$620,949
Denise C. McWatters	—	—	—	—	—

(1) Includes the following restricted unit awards granted by us:

- in October 2015 to Mr. Voliva (1,341, after giving effect to the forfeiture by Mr. Voliva on June 1, 2016 of 2,679 of the total 4,020 restricted units originally granted) and Mr. Cunningham (4,752), of which one third vested on December 15, 2016, one third vested on December 15, 2017 and the remaining one third vests on December 15, 2018;
- in October 2016 to Mr. Cunningham (4,128), of which one third vested on December 15, 2017, one third vests on December 15, 2018 and the remaining one third vests on December 15, 2019.

Includes the following phantom unit awards granted by us:

- in November 2017 to Mr. Cunningham (3,861), of which one third vests on December 15, 2018, one third vests on December 15, 2019 and the remaining one third vests on December 15, 2020.

(2) Includes the following performance unit awards granted by us (the amounts included in the parentheticals reflect the target number of performance units subject to each award):

- in October 2015 to Mr. Voliva (1,341, after giving effect to the forfeiture by Mr. Voliva on June 1, 2016 of 2,679 of the total 4,020 performance units originally granted) and Mr. Cunningham (4,752), in each case, with a performance period that ends on December 31, 2018;
- in October 2016 to Mr. Cunningham (4,128), with a performance period that ends on December 31, 2019; and
- in November 2017 to Mr. Cunningham (3,861), with a performance period that ends on December 31, 2020.

For the performance units, the actual number of units earned at the end of the performance period is based on the “Achieved Distributable Cash Flow/Unit” as compared to the “Base Distributable Cash Flow/Unit,” “Target Distributable Cash Flow/Unit” and “Incentive Distributable Cash Flow/Unit.” Under the terms of the grants, each of Messrs. Voliva and Cunningham may earn from 50% to 150% of the target number of performance units granted to him. See “Compensation Discussion and Analysis - Overview of 2017 Compensation Components and Decisions - Long-Term Equity Incentive Compensation - Performance Unit Awards.”

Option Exercises and Units Vested

The following table provides information regarding the vesting in 2017 of restricted unit and performance unit awards held by the Named Executive Officers. Mr. Damiris and Ms. McWatters do not currently hold any equity awards under our Long-Term Incentive Plan and did not have any equity awards under our Long-Term Incentive Plan that vested during 2017. The table below does not reflect any information regarding the vesting in 2017 of any HFC equity awards held by any of our Named Executive Officers. To date, we have not granted any unit options.

The value realized from the vesting of restricted unit awards is generally equal to the closing price of our common units on the vesting date (or, if the vesting date is not a trading day, on the trading day immediately following the vesting date, unless provided otherwise by the applicable award agreement) multiplied by the number of units acquired on vesting. The value is calculated before payment of any applicable withholding or other income taxes.

	Unit Awards	
Named Executive Officer	Number of Units Acquired on Vesting	Value Realized on Vesting
George J. Damiris	—	—
Richard L. Voliva III	1,440	$ 48,816
Mark T. Cunningham	8,547 (1)	$ 279,017
Denise C. McWatters	—	—

(1) Includes 3,352 units that became payable to Mr. Cunningham on February 7, 2018 upon the determination by the subcommittee of the Compensation Committee that the performance percentage applicable to the target number of 2,235 performance units granted to Mr. Cunningham in October 2014 with a performance period that ended on December 31, 2017 was 150%, which performance units are treated, in accordance with SEC rules, as vesting during 2017. The value realized with respect to such award is calculated based on the closing price of our common units on the date of payment.

Pension Benefits Table

As discussed in greater detail above under “Compensation Discussion and Analysis-Overview of 2017 Executive Compensation Components and Decisions-Retirement and Other Benefits-Retirement Pension Plans,” HFC previously maintained the Retirement Plan, a tax-qualified defined benefit retirement plan, that was liquidated in 2013. Mr. Cunningham was the only Named Executive Officer who was a participant in the Retirement Plan. As part of the liquidation of the Retirement Plan, the retirement benefits owed to Mr. Cunningham were distributed in a lump sum, and Mr. Cunningham is not owed any additional benefits under the Retirement Plan.

HFC continues to maintain the Restoration Plan, which is an unfunded non-qualified plan that provides supplemental retirement benefits to participating executives whose Retirement Plan benefits were subject to certain Internal Revenue Code limitations. As of May 1, 2012, all participants in the Restoration Plan ceased accruing additional benefits. None of our Named Executive Officers has accumulated benefits under the Restoration Plan.

Nonqualified Deferred Compensation

In 2017, all of the Named Executive Officers participated in the NQDC Plan. The NQDC Plan functions as a pour-over plan, allowing key employees to defer tax on income in excess of Internal Revenue Code limits that apply under the 401(k) Plan. For 2017, the annual deferral contribution limit under the 401(k) Plan was $18,000, and the annual compensation limit was $270,000. Deferral elections made by eligible employees under the NQDC Plan apply to the total amount of eligible earnings the employees want to contribute across both the 401(k) Plan and the NQDC Plan. Once eligible employees reach the Internal Revenue Code limits on contributions under the 401(k) Plan, contributions automatically begin being contributed to the NQDC Plan. Federal and state income taxes are generally not payable on income deferred under the NQDC Plan until funds are withdrawn.

Eligible employees may make salary deferral contributions between 1% and 50% of eligible earnings to the NQDC Plan. Eligible earnings include base pay, bonuses and overtime, but exclude extraordinary pay such as severance, accrued vacation, equity compensation, and certain other items. Eligible participants are required to make catch-up contributions to the 401(k) Plan before any contributions will be deposited into the NQDC Plan. For 2017, the catch-up contribution limit was $6,000. Deferral elections are irrevocable for an entire plan year and must be made prior to December 31 of the immediately preceding the plan year. Elections will carry over to the next plan year unless changed or otherwise revoked.

Participants in the NQDC Plan are eligible to receive a matching restoration contribution with respect to their elective deferrals made up to 6% of the participant's eligible earnings for the plan year in excess of the limits under Section 401(k) of the Internal Revenue Code. These matching restoration contributions are fully vested at all times. In addition, participants are eligible for a retirement restoration contribution ranging from 3% to 8% of the participant's eligible earnings for the plan year in excess of the limits under Section 401(k) of the Internal Revenue Code, based on years of service, as follows:

Years of Services	Retirement Contribution (as percentage of eligible compensation)
Less than 5 years	3%
5 to 10 years	4%
10 to 15 years	5.25%
15 to 20 years	6.5%
20 years and over	8%

Retirement restoration contributions are subject to a three-year cliff vesting period and will become fully vested in the event of the participant's death or a change in control. Participants may also receive nonqualified nonelective contributions under the NQDC Plan, which contributions may be subject to a vesting schedule determined at the time the contributions are made.

Participating employees have full discretion over how their contributions to the NQDC Plan are invested among the offered investment options, and earnings on amounts contributed to the NQDC Plan are calculated in the same manner and at the same rate as earnings on actual investments. Neither HLS nor HFC subsidizes a participant's earnings under the NQDC Plan. During 2017, the investment options offered under the NQDC Plan were the same as the investment options available to participants in the tax-qualified 401(k) Plan. The following table lists the investment options for the NQDC Plan in 2017 with the annual rate of return for each fund:

Investment Funds	Rate of Return
AllianzGI NFJ Small Cap Value I Fund	10.02%
American Century Mid-Cap Value I Fund	11.79%
Fidelity Contrafund	32.26%
Harbor Capital Appreciation Inst Fund	36.59%
Hartford SmallCap Growth Y Fund	20.06%
LargeCap S&P 500 Index Inst Fund	21.65%
MidCap S&P 400 Index Inst Fund	15.96%
Oppenheimer Developing Markets Institutional Fund	35.33%
Oppenheimer International Growth Institutional Fund	27.15%
PIMCO Total Return Instl Fund	5.13%
SmallCap S&P 600 Index Inst Fund	13.01%
T. Rowe Price Retirement 2005 Fund	10.67%
T. Rowe Price Retirement 2010 Fund	11.66%
T. Rowe Price Retirement 2015 Fund	13.34%
T. Rowe Price Retirement 2020 Fund	15.74%
T. Rowe Price Retirement 2025 Fund	17.68%
T. Rowe Price Retirement 2030 Fund	19.45%
T. Rowe Price Retirement 2035 Fund	20.88%
T. Rowe Price Retirement 2040 Fund	22.02%
T. Rowe Price Retirement 2045 Fund	22.41%
T. Rowe Price Retirement 2050 Fund	22.38%
T. Rowe Price Retirement 2055 Fund	22.33%
T. Rowe Price Retirement 2060 Fund	22.29%
Vanguard Equity-Income Adm. Fund	18.49%
Vanguard Federal Money Market Investor Fund	0.81%
Vanguard Total Bond Market Index Institutional Fund	3.57%
Vanguard Total International Stock Index Institutional Fund	27.55%
Victory Munder Mid-Cap Core Growth R6 Fund	24.73%

Benefits under the NQDC Plan may be distributed upon the earliest to occur of a separation from service (subject to a six month payment delay for certain specified employees under Section 409A of the Internal Revenue Code), the participant’s death, a change in control or a specified date selected by the participant in accordance with the terms of the NQDC Plan. Benefits are distributed from the NQDC Plan in the form of a lump sum payment or, in certain circumstances if elected by the participant, in the form of annual installments for up to a five-year period.

Nonqualified Deferred Compensation Table

The NQDC Plan benefits for Mr. Cunningham were charged to us in 2017 pursuant to the Omnibus Agreement. The following table provides information regarding all contributions to, and the year-end balance of, the NQDC Plan account for Mr. Cunningham. Even though Messrs. Damiris and Voliva and Ms. McWatters are also participants in the NQDC Plan, we have not provided any disclosure with respect to their NQDC Plan benefits since those benefits were entirely paid for by HFC during 2017. Additional information regarding the NQDC Plan, and participation in the NQDC Plan by Messrs. Damiris and Voliva and Ms. McWatters, will be provided in HFC’s 2018 Proxy Statement.

Name	Executive Contributions in 2017 (1)	Company Contributions in 2017 (2)	Aggregate Earnings in 2017	Aggregate Withdrawals/ Distributions in 2017	Aggregate Balance at December

					31, 2017 (3)
George J. Damiris	—	—	—	—	—
Richard L. Voliva III	—	—	—	—	—
Mark T. Cunningham	$72,330	$18,579	$41,387	—	$703,639
Denise C. McWatters	—	—	—	—	—

(1) The amounts reported were deferred at the election of the Named Executive Officer and are also included in the amounts reported in the "Salary," "Bonus" and/or "Non-Equity Incentive Plan Compensation" columns of the Summary Compensation Table for 2017.

(2) These amounts are also included in the "All Other Compensation" column of the Summary Compensation Table for 2017.

(3) The aggregate balance for Mr. Cunningham reflects the cumulative value, as of December 31, 2017, of his and employer-provided contributions to the NQDC Plan for his account, and any earnings on these amounts, since he began participating in the NQDC Plan in 2012. We reported executive and company contributions for Mr. Cunningham in the Summary Compensation Table in the following aggregate amounts:

Name	2017	Years Prior to 2017
Mark T. Cunningham	$90,909	$ 529,243

Potential Payments upon Termination or Change in Control

We have a Change in Control Agreement with Mr. Cunningham and maintain the Long-Term Incentive Plan, each of which provide for severance compensation and/or accelerated vesting of equity compensation in the event of a termination of employment following a change in control or under other specified circumstances. These arrangements are summarized below.

Change in Control Agreements

We entered into a Change in Control Agreement with Mr. Cunningham, effective as of February 14, 2011, and bear all costs and expenses associated with such agreement. We entered into a Change in Control Agreement with Mr. Voliva, effective as of April 28, 2014, which agreement was terminated on October 31, 2016 when he entered into a Change in Control Agreement with HFC.

In 2017, HFC had a Change in Control Agreement with each of Messrs. Damiris and Voliva and Ms. McWatters. Payments and benefits under the HFC Change in Control Agreements are triggered only upon certain termination events in connection with a change in control of HFC. A summary of the terms of the HFC Change in Control Agreements, and a quantification of potential benefits under the HFC Change in Control Agreements with Messrs. Damiris and Voliva and Ms. McWatters will be disclosed in HFC's 2018 Proxy Statement.

Each Change in Control Agreement under our Change in Control Policy terminates on the day prior to the three-year anniversary of its effective date, and thereafter automatically renews for successive one-year terms (on each anniversary date thereafter) unless a cancellation notice is given by us 60 days prior to the automatic extension date. The Change in Control Agreements provide that if, in connection with or within two years after a "Change in Control" of HFC, HLS or HEP (1) the executive's employment is terminated by HFC, HLS, HEP Logistics or HEP without "Cause," by the employee for "Good Reason," or as a condition of the occurrence of the transaction constituting the "Change in Control," or (2) the executive does not remain employed by HFC, HLS, HEP Logistics or HEP or any of their respective affiliates or the executive is not offered employment with HFC, HLS, HEP, HEP Logistics or any of their affiliates on substantially the same terms in the aggregate as his previous employment within 30 days after the termination, then the executive will receive the following cash severance amounts paid by us:

•

an amount equal to his accrued and unpaid salary, unreimbursed expenses and accrued vacation pay; and

- a lump sum amount equal to a designated multiplier times (i) the executive's annual base salary as of the date of termination or the date immediately prior to the "Change in Control," whichever is greater, and (ii) the executive's annual bonus amount, calculated as the average annual bonus paid to him for the prior three years. The severance multiplier is 1.0 for Mr. Cunningham.

The executive will also receive continued participation by the executive and his or her dependents in medical and dental benefits for the number of years equal to the executive's designated severance multiplier, which, in the case of Mr. Cunningham, is one year.

For purposes of the Change in Control Agreements, a “Change in Control” occurs if:

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries; HLS, HEP, HEP Logistics or any of their subsidiaries) becomes the beneficial owner of more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics or more than 50% of the outstanding common stock or membership interests, as applicable or HFC or HLS;
- the individuals who as of the date of grant constituted a majority of HFC’s Board of Directors and individuals whose election by HFC’s Board of Directors, or nomination for election by the holders of the voting securities of HFC, was approved by a vote of at least two-thirds of the directors, cease for any reason to constitute a majority of HFC’s Board of Directors;
- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 50% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;
- the holders of voting securities of HFC or HEP approve a plan of complete liquidation or dissolution of HFC or HEP, as applicable; or
- the holders of voting securities of HFC or HEP approve the sale or disposition of all or substantially all of the assets of HFC or HEP, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

For purposes of the Change in Control Agreements, “Cause” is defined as:

- the engagement in any act of willful gross negligence or willful misconduct on a matter that is not inconsequential; or
- conviction of a felony.

For purposes of the Change in Control Agreements, “Good Reason” is defined as, without the express written consent of the executive:

- a material reduction in the executive’s (or his supervisor’s) authority, duties or responsibilities;
- a material reduction in the executive’s base compensation; or
- the relocation of the executive to an office or location more than 50 miles from the location at which the executive normally performed the executive’s services, except for travel reasonably required in the performance of the executive’s responsibilities.

All payments and benefits due under the Change in Control Agreements will be conditioned on the execution and non-revocation by the executive of a release of claims for the benefit of HFC, HLS, HEP and HEP Logistics and their related entities and agents. The Change in Control Agreements also contain confidentiality provisions pursuant to which each executive agrees not to disclose or otherwise use the confidential information of HFC, HLS, HEP or HEP Logistics. Violation of the confidentiality provisions entitles HFC, HLS, HEP or HEP Logistics to complete relief, including injunctive relief. Further, in the event of a breach of the confidentiality covenants, the executive could be terminated for Cause (provided the breach constituted willful gross negligence or misconduct on the executive’s part that is not inconsequential). The agreements do not prohibit the waiver of a breach of these covenants.

If amounts payable to an executive under a Change in Control Agreement (together with any other amounts that are payable by HFC, HLS, HEP or HEP Logistics as a result of a change in ownership or control) exceed the amount allowed under Section 280G of the Internal Revenue Code for such executive by 10% or more, we will pay the executive an amount necessary to allow the executive to retain a net amount equal to the total present value of the payments on the date they are to be paid. Conversely, if the payments exceed the 280G limit for the executive by less than 10%, the payments will be reduced to the level at which no excise tax applies.

Long-Term Equity Incentive Awards

The outstanding long-term equity incentive awards granted under the Long-Term Incentive Plan to our Named Executive Officers vest upon a “Special Involuntary Termination,” which occurs when, within 60 days prior to or at any time after a “Change in Control”:

- the executive's employment is terminated, other than for "Cause," or
- the executive resigns within 90 days following an "Adverse Change."

All outstanding performance units will vest at 150% in the event of a Special Involuntary Termination.

In the event of an executive's death, disability or retirement, restricted units, phantom units and performance units vest as follows:

- Restricted Units: Upon death or disability, the executive will vest with respect to a pro rata number of units attributable to the period of service completed during the applicable vesting period and will forfeit any unvested units. Upon retirement, the executive will forfeit any unvested units.
- Phantom Units: Upon death or disability, the executive will vest with respect to a pro rata number of units attributable to the period of service completed during the applicable vesting period and will forfeit any unvested units. Upon "Retirement," the executive will fully vest in all phantom units.
- Performance Units: Pursuant to the terms of the November 2017 performance unit award agreement, upon retirement the award will remain outstanding and eligible to vest without proration subject to actual performance. Upon death, disability and retirement, other than with respect to retirement under the terms of the November 2017 performance unit award agreement, the executive will remain eligible to vest with respect to a pro rata number of units attributable to the period of service completed during the applicable performance period (rounded up to include the month of termination) and will forfeit any unvested units. The Compensation Committee will determine the number of remaining performance units earned and the amount to be paid to the executive as soon as administratively possible after the end of the performance period based upon the performance actually attained for the entire performance period (provided that executives will earn and receive payment with respect to no less than 50% of the performance units awarded). The foregoing also applies if the executive separates from employment for any other reason other than a voluntary separation, Special Involuntary Separation or for "Cause."

For purposes of the long-term equity incentive awards, a "Change in Control" occurs if:

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries or HLS, HEP, HEP Logistics or any of their subsidiaries) becomes the beneficial owner of more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics;
- the individuals who as of the date of grant constituted a majority of HFC's Board of Directors cease for any reason to constitute a majority of HFC's Board of Directors;
- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 60% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP, or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;
- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve a plan of complete liquidation or dissolution of HFC, HLS, HEP or HEP Logistics, as applicable; or
- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve the sale or disposition of all or substantially all of the assets of HFC, HLS, HEP or HEP Logistics, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

For purposes of the restricted unit awards, “Adverse Change” is defined as:

- a change in the city in which the executive is required to work;
- a substantial increase in travel requirements of employment;
- a substantial reduction in the duties of the type previously performed by the executive; or
- a significant reduction in compensation or benefits (other than bonuses and other discretionary items of compensation) that does not apply generally to executives.

For purposes of the phantom unit awards and the performance units granted in November 2017, “Retirement” is defined as termination of employment other than for Cause on or after the date on which the executive: (i) has achieved ten years of continuous service and (ii) has attained age sixty.

For purposes of the performance unit awards, “Adverse Change” is defined as, without the consent of the executive:

- a change in the executive’s principal office of employment of more than 25 miles from the executive’s work address at the time of grant of the award;
- a material increase (without adequate consideration) or material reduction in the duties to be performed by the executive; or
- a material reduction in the executive’s base compensation (other than bonuses and other discretionary items of compensation) that does not apply generally to employees.

For purposes of the long-term equity incentive awards, “Cause” is defined as:

- an act of dishonesty constituting a felony or serious misdemeanor and resulting (or intended to result in) gain or personal enrichment to the executive at the expense of HLS;
- gross or willful and wanton negligence in the performance of the executive’s material and substantial duties; or
- conviction of a felony involving moral turpitude.

Quantification of Benefits

The following table summarizes the compensation and other benefits that would have been payable to the Named Executive Officers under the arrangements described above assuming their employment terminated under various scenarios, including in connection with a change in control, on December 31, 2017. For these purposes, our common unit price was assumed to be $32.49, which was the closing price per unit on December 29, 2017 (the last trading day of 2017).

In reviewing the table, please note the following:

- For purposes of determining amounts under the “Cash Payments” column, accrued and unpaid salary and unreimbursed expenses were assumed to equal zero.

- Accrued vacation for a specific year is not allowed to be carried over to a subsequent year, so we assumed all accrued vacation for the 2017 year was taken prior to December 31, 2017. Because we accrue vacation in any given year for the following year, amounts reported as “Cash Payments” include vacation amounts accrued in 2017 for the 2018 year.

- For amounts payable to the Named Executive Officers with respect to performance units upon a termination due to death, disability, retirement, or other separation (other than a voluntary separation, a for “Cause” separation or a Special Involuntary Termination), we assumed the performance units would settle at 100%. The number of units paid at the end of the performance period may vary from the amounts reflected in the following tables, based on our actual achievement compared to the performance targets. Neither Mr. Voliva nor Mr. Cunningham were eligible for retirement vesting at December 31, 2017.

- With respect to the treatment of restricted and phantom unit awards upon termination due to death, disability or without Cause, we have reflected accelerated vesting based on the length of employment during the vesting period for each award.

- The amount shown for “Value of Welfare Benefits” represents amounts equal to the monthly premium payable pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended (“COBRA”), for medical and dental premiums, multiplied by 12 months for Mr. Cunningham.

- In calculating whether any tax reimbursements were owed to the Named Executive Officers, we used the following assumptions: (a) no amounts will be discounted as attributable to reasonable compensation, (b) all cash severance payments are contingent upon a change in control, and (c) the presumption required under applicable regulations that the equity awards granted in 2017 were contingent upon a change in control could be rebutted. Based on these assumptions, none of the Named Executive Officers would receive any tax reimbursement or "gross-up" payments with respect to any amounts reported in the table below.

- No amounts potentially payable pursuant to the NQDC Plan are included in the table below since neither the form nor amount of any such benefits would be enhanced nor vesting or other provisions accelerated in connection with any of the triggering events disclosed below. Please refer to the section titled "Nonqualified Deferred Compensation" for additional information regarding these benefits.

Named Executive Officer	Cash Payments	Value of Welfare Benefits	Vesting of Equity Awards	Total
George J. Damiris	—	—	—	—
Richard L. Voliva III				
Termination in connection with or following a Change in Control	—	—	$79,893	$79,893
Termination due to Death, Disability or without Cause	—	—	$39,142	$39,142
Mark T. Cunningham Termination in connection with or following a Change in Control	$473,927	$17,430	$887,270	$1,378,627
Termination due to Death, Disability or without Cause	—	—	$236,756	$236,756
Denise C. McWatters	—	—	—	—

Compensation Practices as They Relate To Risk Management

Although a significant portion of the compensation provided to the Named Executive Officers is performance-based, we believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees) because these programs are designed to encourage employees to remain focused on both our short- and long-term operational and financial goals.

While annual cash-based incentive bonus awards play an appropriate role in the executive compensation program, the Compensation Committee believes that payment determined based on an evaluation of our performance on a variety of measures, including comparing our performance over the last year to our past performance, mitigates excessive risk-taking that could produce unsustainable gains in one area of performance at the expense of our overall long-term interests. In addition, we set performance goals that we believe are reasonable in light of our past performance and market conditions.

For Named Executive Officers performing all or a majority of their services for us, an appropriate part of total compensation is fixed, while another portion is variable and linked to performance. A portion of the variable compensation we provide is comprised of long-term incentives. A portion of the long-term incentives we provide is in the form of restricted or phantom units subject to time-based vesting conditions, which retains value even in a depressed market, so executives are less likely to take unreasonable risks. With respect to our performance units, payouts result in some compensation at levels below full target achievement, in lieu of an “all or nothing” approach. Further, our unit ownership guidelines require certain of our executives to hold at least a specified level of units (in addition to unvested and unsettled equity-based awards), which aligns an appropriate portion of their personal wealth to our long-term performance and the interests of our unitholders.

Based on the foregoing and our annual review of our compensation programs, we do not believe that our compensation policies and practices are reasonably likely to have a material adverse effect on us or our unitholders.

CEO Pay Ratio

The employees providing services to us are either provided by HLS, which utilizes people employed by HFC to perform services for us, or seconded to us by subsidiaries of HFC, as we do not have any employees for purposes of the pay ratio rules. Rather than providing a pay ratio disclosure that contemplates no employees, we have determined that the disclosure that would be most aligned with the spirit of the pay ratio rules and that would provide our unitholders with more meaningful information would be to provide a ratio using the median employee from the HFC employee population. As a result, we have used the same median employee that was identified by HFC following HFC’s examination of the 2017 total cash and equity compensation for all individuals who were employed by HFC in the U.S. and Canada on December 15, 2017.

HFC identified the median employee by examining the 2017 W-2 (for U.S. employees) and T4 (for Canadian employees) taxable wages for all of its U.S. and Canadian employees, including its CEO, who were employed by HFC on December 15, 2017. HFC included all U.S. and Canadian employees, whether employed on a full-time, part-time, temporary or seasonal basis. As of December 15, 2017 HFC employed 3,447 such persons. As permitted by the SEC rules, HFC excluded its employees located in Europe and Asia since those employees comprise less than 5% of HFC's total worldwide employees. HFC did not make any assumptions, adjustments, or estimates with respect to the W-2 or T4 wages, and HFC did not annualize the compensation for any employees that were not employed by HFC for all of 2017. HFC believes the use of W-2 or T4 wages, as applicable, is the most appropriate compensation measure since it includes the total taxable compensation received by its employees in 2017.

After identifying the median employee based on total cash and equity compensation, HFC calculated annual 2017 compensation for the median employee using the methodology provided in the SEC rules. HFC's median employee's annual 2017 compensation was as follows:

Name	Year	Salary	Bonus	Stock Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Median Employee	2017	$115,400	—	—	$4,510	$11,702	$131,612

Our 2017 ratio of chief executive officer total compensation to the HFC median employee's total compensation is reasonably estimated to be 15:1.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth as of February 14, 2018 the beneficial ownership of common units of HEP held by:

- each person known to us to be a beneficial owner of 5% or more of the common units;
- directors of HLS, the general partner of our general partner;
- each Named Executive Officer of HLS; and
- all directors and executive officers of HLS as a group.

The percentage of common units noted below is based on 105,268,955 common units outstanding as of February 14, 2018. Unless otherwise indicated, the address for each unitholder is c/o Holly Energy Partners, L.P., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

Beneficial ownership of the common units of HEP is determined in accordance with SEC rules and regulations and generally includes voting power or investment power with respect to the common units held. Except as indicated and subject to applicable community property laws, to our knowledge the persons named in the tables below have sole voting and investment power with respect to all common units shown as beneficially owned by them.

Name of Beneficial Owner	Common Units	Percentage of Outstanding Common Units
HollyFrontier Corporation(1)	59,630,030	56.6%
Tortoise Capital Advisors, L.L.C.(2)	6,717,745	6.4%
Energy Income Partners, LLC(3)	6,425,272	6.1%
Oppenheimer Funds, Inc.(4)	5,551,785	5.3%
Mark T. Cunningham(5)	49,117	*
Michael C. Jennings(6)(7)	20,978	*
Richard L. Voliva III(5)(7)	5,506	*
Denise C. McWatters(7)	4,881	*
Larry R. Baldwin(6)	6,516	*
James H. Lee(6)(7)(8)	5,039	*
George J. Damiris(7)	—	*
R. Kevin Hardage(7)	—	*

All directors and executive officers as group (8 persons)(9)	92,037	*

* Less than 1%

(1) HollyFrontier Corporation directly holds 5,006 common units over which it has sole voting and dispositive power and 59,625,024 common units over which it has shared voting and dispositive power. HollyFrontier Corporation is the record

holder of 140,000 common units as nominee for Navajo Pipeline Co., L.P. The 59,625,024 common units over which HollyFrontier Corporation has shared voting and dispositive power are held as follows: HEP Logistics Holdings, L.P. directly holds 37,250,000 common units; Holly Logistics Limited LLC directly holds 21,615,230 common units; HollyFrontier Holdings LLC directly holds 184,800 common units; Navajo Pipeline Co., L.P. directly holds 254,880 common units; and other wholly-owned subsidiaries of HollyFrontier Corporation directly own 180,114 common units. HollyFrontier Corporation is the ultimate parent company of each such entity and may therefore be deemed to beneficially own the units held by each such entity. HollyFrontier Corporation files information with, or furnishes information to, the Securities and Exchange Commission pursuant to the information requirements of the Exchange Act. The address of HollyFrontier Corporation is 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

(2) Based on information provided to the Company by Tortoise Capital Advisors, L.L.C, pursuant to an investment advisory agreement or an investment management agreement entered into with certain investment companies, Tortoise Capital Advisors, L.L.C holds sole voting and dispositive power with respect to 6,717,745 common units held by such investment companies. The address of Tortoise Capital Advisors, L.L.C. is 1550 Ash Street, Suite 300, Leawood, Kansas 66211.

(3) Based on the Schedule 13G/A filed with the Securities and Exchange Commission on February 14, 2018 by Energy Income Partners, LLC, James J. Murchie, Eva Pao, Linda A. Longville, Saul Ballesteros and John K. Tysseland. James J. Murchie, Eva Pao, and John K. Tysseland are the Portfolio Managers with respect to the portfolios managed by Energy Income Partners, LLC. Linda A. Longville and Saul Ballesteros are control persons of Energy Income Partners, LLC. Each of the foregoing report shared voting and dispositive power over 6,425,272 common units. The address of each of the foregoing is 10 Wright Street, Westport, Connecticut 06880.

(4) Based on a Schedule 13G/A filed with the Securities and Exchange Commission on February 7, 2018, Oppenheimer Funds, Inc. has shared voting power and shared dispositive power with respect to 5,551,785 units. The address of Oppenheimer Funds, Inc. is Two World Financial Center, 225 Liberty Street, New York, NY 10281.

(5) The number reported includes restricted units for which the executive has sole voting power but no dispositive power, as follows: Mr. Voliva (447 units) and Mr. Cunningham (4,336 units). For Mr. Cunningham, also includes 3,861 common units to be issued upon settlement of phantom units, which may vest and be settled within 60 days of February 14, 2018 under certain circumstances. Until settled, Mr. Cunningham has no voting or dispositive power over the phantom units. The number does not include performance units held by the executive.

(6) For each of Mr. Jennings and Mr. Baldwin, includes 2,557 restricted units for which he has sole voting power but no dispositive power. For Mr. Lee, includes 2,754 restricted units for which he has sole voting power but no dispositive power.

(7) Messrs. Jennings, Damiris, Voliva, Lee and Hardage and Ms. McWatters each own common stock of HFC. Each of these individuals own common stock of HFC as set forth in the following table:

Name of Beneficial Owner	Number of Shares
George J. Damiris (a)	280,747
Denise C. McWatters (a)	63,258
Richard L. Voliva III (a)(b)	59,683
James H. Lee (c)	52,240
Michael C. Jennings (c)	45,917
R. Kevin Hardage (c)	30,819
Total	532,664

(a) The number reported includes shares of HFC restricted stock for which the individual has sole voting power but no dispositive power, as follows: Mr. Damiris (105,149 shares), Ms. McWatters (15,528 shares) and Mr. Voliva (16,444 shares). Also includes shares of HFC common stock to be issued to the individual upon settlement of restricted stock units, which may vest and be settled within 60 days of February 14, 2018 under certain circumstances, as follows: Mr. Damiris (77,961 shares), Mr. Voliva (19,491 shares) and Ms. McWatters (11,813 shares). Until settled, the individual has no voting or dispositive power over the restricted stock units. The number does not include unvested performance share units.

(b) The number reported includes 3,778 shares of HFC restricted stock and 2,271 restricted stock units held by Mr. Voliva's wife for which Mr. Voliva disclaims beneficial ownership except to the extent of his pecuniary interest therein.

(c) The number reported includes 3,190 shares of HFC common stock to be issued to the individual upon settlement of restricted stock units, which may vest and be settled within 60 days of February 14, 2018 under certain circumstances. Until settled, the individual has no voting or dispositive power over the common stock underlying the restricted stock units.

As of February 14, 2018, there were 256,015,579 shares of HFC common stock outstanding. Each of Messrs. Jennings, Damiris, Voliva, Lee and Hardage and Ms. McWatters owns less than 1% of the outstanding common stock of HFC.

(8) Includes 285 common units held by Mr. Lee's wife. Mr. Lee's wife has the right to receive distributions from, and the proceeds from the sale of, these common units. Mr. Lee disclaims beneficial ownership of the common units held by his wife except to the extent of his pecuniary interest therein.

(9) The number reported includes 4,783 restricted units held by executive officers for which they have sole voting power but no dispositive power, 3,861 common units to be issued to Mr. Cunningham upon settlement of phantom units, which may vest and be settled within 60 days of February 14, 2018 under certain circumstances and 7,868 restricted units held by non-employee directors for which they have sole voting power but no dispositive power. The number reported also includes 285 common units as to which Mr. Lee disclaims beneficial ownership, except to the extent of his pecuniary interest therein.

Equity Compensation Plan Table

The following table summarizes information about our equity compensation plans as of December 31, 2017:

Plan Category (1)	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders (2)	48,941 (3)	—	1,341,216
Equity compensation plans not approved by security holders	—	—	—
Total	48,941	—	1,341,216

(1) All stock-based compensation plans are described in Note 6 to our consolidated financial statements for the fiscal year ended December 31, 2017.

(2) On April 25, 2012, at a Special Meeting of the Unitholders of the Partnership, the unitholders approved the Amended and Restated Long-Term Incentive Plan, which, among other things, provided for an increase in the maximum number of common units reserved for delivery with respect to awards under the Long-Term Incentive Plan to 2,500,000 common units (as adjusted to reflect the two-for-one common unit split that occurred on January 16, 2013). All securities reported as available for future issuances are available from the additional common units approved by unitholders under the Amended and Restated Long-Term Incentive Plan. At the time the Long-Term Incentive Plan was originally adopted in 2004, it was not required to be approved by the Partnership's unitholders.

(3) Represents units subject to performance units granted to key individuals under the Long-Term Incentive Plan assuming the maximum payout level. If the performance units are paid at the target payout level, 32,628 units would be issued upon the vesting of such performance units. Performance units granted in October 2014 with a performance period that ended on December 31, 2017 were not settled until certification by the subcommittee of the Compensation Committee in February 2018 that a performance percentage of 150% was attained for performance units granted to Mr. Cunningham; however, such awards are not included in this column as outstanding since they are treated for purposes of the preceding executive compensation tables as vesting during 2017 in accordance with SEC rules.

For more information about our Amended and Restated Long-Term Incentive Plan, refer to Item 11, "Executive Compensation - Overview of 2017 Executive Compensation Components and Decisions - Long-Term Incentive

Equity Compensation."

Item 13. Certain Relationships and Related Transactions, and Director Independence

Our general partner and its affiliates own 59,630,030 of our common units representing a 57% limited partner interest in us. In addition, the general partner owns the non-economic general partner interest in us. Transactions with our general partner are discussed later in this section.

DISTRIBUTIONS AND PAYMENTS TO THE GENERAL PARTNER AND ITS AFFILIATES

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the ongoing operation and liquidation of HEP. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational stage	
Distributions of available cash to our general partner and its affiliates	We generally make cash distributions 98% to the unitholders, including our general partner and its affiliates as the holders of an aggregate of 22,380,030 of the common units and 2% to the general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner is entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.
Payments to our general partner and its affiliates	We pay HFC or its affiliates an administrative fee, $2.5 million per year, for the provision of various general and administrative services for our benefit. The administrative fee 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. In addition, the general partner is entitled to reimbursement for all expenses it incurs on our behalf, including other general and administrative expenses. These reimbursable expenses include the salaries and the cost of employee benefits of employees of HFC who provide services to us on behalf of HLS. Finally, HLS is required to reimburse HFC for our benefit 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 pipelines and tankage assets. Please read "Omnibus Agreement" and "Secondment Arrangement" below. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

OMNIBUS AGREEMENT

Our Omnibus Agreement with HFC and our general partner that addresses the following matters:

- our obligation to pay HFC an annual administrative fee, in the amount of $2.5 million for 2017, for the provision by HFC of certain general and administrative services;
- HFC's and its affiliates' agreement not to compete with us under certain circumstances and our right to notice of, and right of first offer to purchase, certain logistics assets constructed by HFC and acquired as part of an acquisition by HFC of refining assets;
- an indemnity by HFC for certain potential environmental liabilities;
- our obligation to indemnify HFC for environmental liabilities related to our assets existing on the date of our initial public offering to the extent HFC is not required to indemnify us; and
- HFC's right of first refusal to purchase our assets that serve HFC's refineries.

Payment of general and administrative services fee

Under the Omnibus Agreement we pay HFC an annual administrative fee, in the amount of $2.5 million for 2017, for the provision of various general and administrative services for our benefit. Our general partner may agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses.

The administrative fee includes expenses incurred by HFC and its affiliates to perform centralized corporate functions, such as legal, accounting, treasury, information technology and other corporate services, including the administration of employee benefit plans. The fee does not include salaries of pipeline and terminal personnel or other employees of HFC who perform services for us on behalf of HLS or the cost of their employee benefits, such as 401(k), pension, and health insurance benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct general and administrative expenses they incur on our behalf.

Noncompetition
HFC and its affiliates have agreed, for so long as HFC controls our general partner, not to engage in, whether by acquisition or otherwise, the business of operating crude oil pipelines or terminals, refined product pipelines or terminals, intermediate pipelines or terminals, truck racks or crude oil gathering systems in the continental United States. This restriction will not apply to:

- any business operated by HFC or any of its affiliates at the time of the closing of our initial public offering;
- any business conducted by HFC with the approval of our general partner;
- any business or asset that HFC or any of its affiliates 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 affiliates 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.

The limitations on the ability of HFC and its affiliates to compete with us will terminate if HFC ceases to control our general partner.

Indemnification
Under the Omnibus Agreement, certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain 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. The Omnibus Agreement provides environmental indemnification with respect to certain transferred assets of up to $2.5 million through 2019, $7.5 million through 2023 and $15 million through 2026. HFC's indemnification obligations under the Omnibus Agreement do not apply to assets we acquire from third parties, assets we construct or assets we relocate after they are transferred to us from HFC. For the Tulsa loading racks acquired from HFC in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009, HFC agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of these assets. Additionally, HFC agreed to indemnify us for any liabilities arising from its operation of our loading racks located at HFC's Tulsa refinery west facility.

We have indemnified HFC and its affiliates against environmental liabilities related to events that occur on our assets after the date we acquired such asset.
Right of first refusal to purchase our assets
The Omnibus Agreement also contains the terms under which HFC has a right of first refusal to purchase our assets that serve its refineries. Before we enter into any contract to sell pipeline and terminal assets serving HFC's refineries, we must give written notice of the terms of such proposed sale to HFC. The notice must set forth the name of the third-party purchaser, the assets to be sold, the purchase price, all details of the payment terms and all other terms and conditions of the offer. To the extent the third-party offer consists of consideration other than cash (or in addition to cash), the purchase price shall be deemed equal to the amount of any such cash plus the fair market value of such non-cash consideration, determined as set forth in the Omnibus Agreement. HFC will then have the sole and exclusive option for a period of thirty days following receipt of the notice, to purchase the subject assets on the terms specified in the notice.

SECONDMENT ARRANGEMENT

Under HLS's secondment arrangement with HFC, certain employees of HFC are seconded to HLS, our general partner's general partner, to provide operational and maintenance services with respect to certain of our pipelines, terminals and refinery processing units, including routine operational and maintenance activities. During their period of secondment, the seconded employees are under the management and supervision of HLS. HLS is required to reimburse HFC for our benefit for the cost of the seconded employees, including their wages and benefits, based on the percentage of the employee's time spent working for HLS. The secondment arrangement continues until HLS's mutual agreement with HFC to terminate.

PIPELINE AND TERMINAL, TANKAGE AND THROUGHPUT AGREEMENTS

We serve HFC's refineries under long-term pipeline, terminal, tankage and refinery processing unit throughput agreements expiring in 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 and 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 tariff rate adjustments on July 1st each year, based on the PPI or the FERC index. As of December 31, 2017, these agreements with HFC require minimum annualized payments to us of $324 million.

HFC's obligations under these agreements will not terminate if HFC and its affiliates no longer own the general partner. These agreements may be assigned by HFC only with the consent of our conflicts committee.

SUMMARY OF TRANSACTIONS WITH HFC

- On February 22, 2016, HFC obtained a 50% membership interest in 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 requiring terminalling in or through El Paso, Texas. Osage is the owner of the Osage Pipeline, the primary pipeline supplying 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. Since we are a consolidated Variable Interest Entity ("VIE") of HFC, this transaction was recorded as a transfer between entities under common control and reflects HFC's carrying basis of its 50% membership interest in Osage of $44.5 million offset by our net carrying basis in the El Paso terminal of $12.1 million with the difference treated as a contribution from HFC.

- 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.

- Effective 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.

- See "Acquisitions" under Item 1, "Business" of this Annual Report on Form 10-K for additional information on the acquisitions of the crude tanks at HFC's Tulsa refinery and Woods Cross Operating from HFC.

- On October 31, 2017, we closed on an equity restructuring transaction with HEP Logistics, a wholly-owned subsidiary of HFC and the general partner of HEP, pursuant to which the incentive distribution rights held by HEP Logistics were canceled, and HEP Logistics' 2% general partner interest in HEP was converted into a non-economic general partner interest in HEP. In consideration, we issued 37,250,000 of our common units to HEP Logistics. In addition, HEP Logistics agreed to waive $2.5 million of limited partner cash distributions for each of twelve consecutive quarters beginning with the first quarter the units issued as consideration were eligible to receive distributions.

- Revenues received from HFC were $377.1 million, $333.1 million and $292.2 million for the years ended December 31, 2017, 2016 and 2015, respectively.

- HFC charged us general and administrative services under the Omnibus Agreement of $2.5 million for the year ended December 31, 2017, $2.5 million for the year ended December 31, 2016, and $2.4 million for the year ended

December 31, 2015.

- We reimbursed HFC for costs of employees supporting our operations of $46.6 million, $40.9 million and $34.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

- HFC reimbursed us $7.2 million, $14.0 million and $13.5 million for the years ended December 31, 2017, 2016 and 2015, respectively, for expense and capital projects.

- We distributed $130.7 million, $105.2 million and $90.4 million for the years ended December 31, 2017, 2016 and 2015, respectively, to HFC as regular distributions on its common units, subordinated units and general partner interest, including general partner incentive distributions.

- We received operating lease payments from HFC for use of our Artesia and Tulsa railyards for $0.5 million for each of the years ended December 31, 2017, 2016 and 2015.

OTHER RELATED PARTY TRANSACTIONS

Julia Heidenreich, Vice President, Commercial Analysis and Pricing at HFC, is the wife of Richard Voliva, HFC's and HLS's Executive Vice President and Chief Financial Officer. Prior to being appointed as Vice President, Commercial Analysis and Pricing at HFC in March 2017, Ms. Heidenreich served as Vice President, Investor Relations for HLS and HFC. Ms. Heidenreich received cash and equity compensation totaling $461,075 in 2017. All the cash and equity compensation was paid to Ms. Heidenreich by HFC without any input from HLS. Ms. Heidenreich does not report to Mr. Voliva.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

The disclosure, review and approval of any transactions with related persons is governed by our Code of Business Conduct and Ethics, which provides guidelines for disclosure, review and approval of any transaction that creates a conflict of interest between us and our employees, officers or directors and members of their immediate family. Conflict of interest transactions may be authorized if they are found to be in the best interest of the Partnership based on all relevant facts. Pursuant to the Code of Business Conduct and Ethics, conflicts of interest are to be disclosed to and reviewed by a supervisor who does not have a conflict of interest, and the supervisor must report in writing on the action taken to the General Counsel. Conflicts of interest involving directors or senior executive officers are reviewed by the full Board of Directors or by a committee of the Board of Directors on which the related person does not serve. Related party transactions required to be disclosed in our SEC reports are reported through our disclosure controls and procedures.

There are no transactions disclosed in this Item 13 entered into since January 1, 2017, that were not required to be reviewed, ratified or approved pursuant to our Code of Business Conduct and Ethics or with respect to which our policies and procedures with respect to conflicts of interest were not followed.

See Item 10 for a discussion of “Director Independence.”

Item 14. Principal Accounting Fees and Services

The audit committee of the board of directors of HLS selected Ernst & Young LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of the HEP for the 2017 calendar year.
Fees paid to Ernst & Young LLP for 2017 and 2016 are as follows:

	2017	2016
Audit Fees [(1)]	$1,154,500	$937,000
Tax Fees	224,000	202,000
Total	$1,378,500	$1,139,000

(1) Represents fees for professional services provided in connection with the audit of our annual financial statements and internal controls over financial reporting, review of our quarterly financial statements, and procedures performed as part of our securities filings.

The audit committee of our general partner's board of directors operates under a written audit committee charter adopted by the board. A copy of the charter is available on our website at www.hollyenergy.com. The charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fee categories above were approved by the audit committee in advance.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report
(1) Index to Consolidated Financial Statements

(2) Index to Consolidated Financial Statement Schedules
All schedules are omitted since the required information is not present in or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or notes thereto.

(3) Exhibits
See Index to Exhibits on pages 147 to 151.

Exhibit Index

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated February 25, 2008, between Holly Corporation, Navajo Pipeline Co., L.P., Navajo Refining Company, L.L.C., Woods Cross Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C. and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 2.1 of Registrant's Current Report on Form 8-K dated February 27, 2008, File No. 1-32225).
2.2	Asset Sale and Purchase Agreement, dated October 19, 2009, between Holly Refining & Marketing - Tulsa LLC, HEP Tulsa LLC and Sinclair Tulsa Refining Company (incorporated by reference to Exhibit 2.1 of Registrant's Current Report on Form 8-K dated October 21, 2009, File No. 1-32225).
2.3†	Membership Interest Purchase Agreement between Plains Pipeline, L.P. and HEP Casper SLC LLC, dated as of August 7, 2017 (incorporated by reference to Exhibit 2.1 of Registrant’s Current Report on Form 8-K dated August 10, 2017, File No. 1-32225).
2.4*†	First Amendment to Membership Purchase Agreement, dated as of October 31, 2017, by and between Plains Pipeline, L.P. and HEP Casper SLC LLC.
2.5†	Membership Interest Purchase Agreement between Rocky Mountain Pipeline System LLC and HEP SLC, LLC, dated as of August 7, 2017 (incorporated by reference to Exhibit 2.2 of Registrant’s Current Report on Form 8-K dated August 10, 2017, File No. 1-32225).
2.6	Amendment to the Membership Interest Purchase Agreement, dated as of September 6, 2017, by and between Rocky Mountain Pipeline System LLC and HEP SLC LLC (incorporated by reference to Exhibit 2.3 of Registrant’s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, File No. 1-32225).
2.7*†	Second Amendment to Membership Purchase Agreement, dated as of October 31, 2017, by and between Rocky Mountain Pipeline System LLC and HEP SLC, LLC.
2.8	Equity Restructuring Agreement, dated as of October 18, 2017, by and between HEP Logistics Holdings, L.P. and Holly Energy Partners, L. P. (incorporated by reference to Exhibit 2.1 of Registrant’s Current Report on Form 8-K dated October 19, 2017, File No. 1-32225).
3.1	Second Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant’s Current Form on Form 8-K dated November 1, 2017, File No. 1-32225).
3.2	First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners - Operating Company, L.P. (incorporated by reference to Exhibit 3.2 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-32225).
3.3	First Amended and Restated Agreement of Limited Partnership of HEP Logistics Holdings, L.P. (incorporated by reference to Exhibit 3.4 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-32225).
3.4	First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 3.5 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-32225).
3.5	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C., dated April 27, 2011 (incorporated by reference to Exhibit 3.1 of Registrant's Current Report on Form 8-K dated May 3, 2011, File No. 1-32225).

3.6	First Amended and Restated Limited Liability Company Agreement of HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 3.6 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-32225).
4.1	Indenture dated July 19, 2016, among Holly Energy Partners, L.P., Holly Energy Finance Corp., and each of the Guarantors party thereto and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant's Current Report on Form 8-K dated July 19, 2016, File No. 1-32225).
4.2	First Supplemental Indenture dated November 2, 2016, among Woods Cross Operating LLC, Holly Energy Partners, L.P., and HollyEnergy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016, File No. 1-32225).
4.3	Second Supplemental Indenture, dated July 26, 2017, by and among Holly Energy Holdings LLC, HEP Cheyenne Shortline LLC, the Registrant, Holly Energy Finance Corp., the other guarantors therein and U.S. Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, File No. 1-32225).
4.4	Registration Rights Agreement, dated February 6, 2018, by and among Holly Energy Partners, L.P. and the various Purchases party thereto (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K dated February 7, 2018 File No 1-32225).

10.1	Third Amended and Restated Credit Agreement dated July 26, 2017, among Holly Energy Partners, L.P. as borrower, Wells Fargo Bank National Association, as administrative agent, an issuing bank and a lender, and certain other lenders party thereto (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated July 31, 2017, File No. 1-32225.)
10.2	Pipelines and Terminals Agreement, dated February 28, 2005, between Holly Energy Partners, L.P. and ALON USA, LP (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated February 28, 2005, File No. 1-32225).
10.3	First Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.4 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.4	Second Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated March 1, 2011 (incorporated by reference to Exhibit 10.5 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.5	Third Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 6, 2011 (incorporated by reference to Exhibit 10.6 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.6	Fourth Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated October 6, 2014 (incorporated by reference to Exhibit 10.3 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014, File No. 1-32225).
10.7	First Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated January 25, 2005 (incorporated by reference to Exhibit 10.1 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.8	Second Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 29, 2007 (incorporated by reference to Exhibit 10.2 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.9	Third Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated April 1, 2011 (incorporated by reference to Exhibit 10.3 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 1-32225).
10.10	Corrected Version dated October 10, 2007, of Amendment and Supplement to Pipeline Lease Agreement effective August 31, 2007 between HEP Pipeline Assets, Limited Partnership and Alon USA, LP (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated October 16, 2007, File No. 1-32225)
10.11	Amended and Restated Intermediate Pipelines Agreement, dated June 1, 2009, among Holly Corporation, Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C., Lovington-Artesia, L.L.C., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C. and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated June 5, 2009, File No. 1-32225).
10.12	Amendment to Amended and Restated Intermediate Pipelines Agreement, dated December 9, 2010, among Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C., Lovington-Artesia, L.L.C., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C. and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.23 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-32225).
10.13	Assignment and Assumption Agreement (Amended and Restated Intermediate Pipelines Agreement), effective January 1, 2011, between Navajo Refining Company, L.L.C. and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.24 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-32225).
10.14	Tulsa Equipment and Throughput Agreement, dated August 1, 2009, between Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.3 of Registrant's Current Report on

	Form 8-K dated August 6, 2009, File No. 1-32225).
10.15	Amendment to Tulsa Equipment and Throughput Agreement, dated December 9, 2010, among Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.28 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-32225).
10.16	Assignment and Assumption Agreement (Tulsa Equipment and Throughput Agreement), effective January 1, 2011, between Holly Refining & Marketing - Tulsa, LLC and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.29 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-32225).
10.17	Tulsa Purchase Option Agreement, dated August 1, 2009, between Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.4 of Registrant's Current Report on Form 8-K dated August 6, 2009, File No. 1-32225).

10.18	Third Amended and Restated Crude Pipelines and Tankage Agreement, dated as of March 12, 2015, by and among Navajo Refining Company, L.L.C., Holly Refining & Marketing Company - Woods Cross LLC, HollyFrontier Refining & Marketing LLC, Holly Energy Partners-Operating, L.P., HEP Pipeline, L.L.C. and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated March 16, 2015, File No. 1-32225).
10.19	Second Amended and Restated Refined Products Pipelines and Terminals Agreement, dated February 22, 2016, by and among HollyFrontier Refining & Marketing LLC, HollyFrontier Corporation, Holly Energy Partners - Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.3 of Registrant's Current Report on Form 8-K dated February 22, 2016, File No. 1-03876).
10.20	Second Amended and Restated Throughput Agreement (Tucson Terminal), dated September 19, 2013, to be effective June 1, 2013, by and among HollyFrontier Refining & Marketing LLC, HEP Refining, L.L.C., and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.4 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013, File No. 1-32225).
10.21*	Eighteenth Amended and Restated Omnibus Agreement, dated as of January 19, 2018, effective December 8, 2017, by and among HollyFrontier Corporation, Holly Energy Partners, L.P. and certain of their respective subsidiaries.
10.22	Amended and Restated Limited Liability Company Agreement of HEP UNEV Holdings LLC, dated July 12, 2012, among HEP UNEV Holdings LLC, Holly Energy Partners, L.P. and HollyFrontier Holdings LLC (incorporated by reference to Exhibit 10.7 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, File No. 1-32225).
10.23	Amended and Restated Unloading and Blending Services Agreement, dated January 18, 2017, effective September 16, 2016, by and between HollyFrontier Refining & Marketing LLC, Holly Energy Partners-Operating, L.P. and HEP Refining, L.L.C. (incorporated by reference to Exhibit 10.28 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.24	Third Amended and Restated Master Throughput Agreement, dated January 18, 2017, effective January 1, 2017, by and between HollyFrontier Refining & Marketing LLC and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.29 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.25	Construction Payment Agreement dated as of October 16, 2015, by and between HEP Refining, L.L.C. and HollyFrontier Refining & Marketing LLC (incorporated by reference to Exhibit 10.3 of Registrant's Current Report on Form 8-K dated October 21, 2015, File No. 1-32225).
10.26	Third Amended and Restated Services and Secondment Agreement dated as of October 3, 2016, by and among Holly Logistic Services, L.L.C., certain subsidiaries of Holly Energy Partners, L.P. and certain subsidiaries of HollyFrontier Corporation (incorporated by reference to Exhibit 10.4 of Registrant's Current Report on Form 8-K dated October 4, 2016, File No. 1-32225).
10.27	Fourth Amended and Restated Master Lease and Access Agreement, dated as of January 18, 2017, effective January 1, 2017, by and among certain subsidiaries of Holly Energy Partners, L.P. and certain subsidiaries of HollyFrontier Corporation. (incorporated by reference to Exhibit 10.32 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.28	First Amendment to Fourth Amended and Restated Master Lease and Access Agreement, dated as of October 13, 2017 by and among certain subsidiaries of Holly Energy Partners, L.P. and certain subsidiaries of HollyFrontier Corporation (incorporated by reference to Exhibit 10.1 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, File No. 1-32225).
10.29	Master Tolling Agreement (Refinery Assets) dated as of November 2, 2015, by and between Frontier El Dorado Refining LLC and Holly Energy Partners-Operating L.P. (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated November 3, 2015, File No. 1-32225).
10.30	Amendment to Master Tolling Agreement, dated as of January 1, 2017, by and among Holly Energy Partners-Operating, L.P., HollyFrontier El Dorado Refining LLC and HollyFrontier Woods Cross Refining

	LLC (incorporated by reference to Exhibit 10.9 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017, File No. 1-32225).
10.31	Amended and Restated Master Tolling Agreement (Operating Assets) dated as of October 3, 2016, by and between HollyFrontier El Dorado Refining LLC, HollyFrontier Woods Cross Refining LLC, Holly Energy Partners-Operating L.P., HollyFrontier Corporation and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated October 4, 2016, File No. 1-32225).
10.32	Amendment to Amended and Restated Master Tolling Agreement (Operating Assets), dated as of January 1, 2017, by and among Holly Energy Partners-Operating, L.P., HollyFrontier El Dorado Refining LLC and HollyFrontier Woods Cross Refining LLC (incorporated by reference to Exhibit 10.8 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017, File No. 1-32225.)
10.33	LLC Interest Purchase Agreement dated February 22, 2016, by and among HollyFrontier Refining & Marketing LLC, HollyFrontier Corporation, Holly Energy Partners - Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.89 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2015, File No. 1-32225).

10.34	Refined Products Terminal Transfer Agreement dated February 22, 2016 by and among HEP Refining Assets, L.P., Holly Energy Partners, L.P., El Paso Logistics LLC, HollyFrontier Corporation and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.90 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2015, File No. 1-32225).
10.35	Second Amended and Restated Pipelines and Terminals Agreement dated February 22, 2016, by and among HollyFrontier Refining & Marketing LLC, HollyFrontier Corporation, Holly Energy Partners - Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.4 of Registrant's Current Report on Form 8-K dated February 22, 2016, File No. 1-32225).
10.36	Equity Distribution Agreement, dated May 10, 2016, by and between Holly Energy Partners, L.P., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C. and Citigroup Global Markets Inc., Goldman, Sachs & Co., and Merrill Lynch, Pierce, Fenner & Smith Incorporated (incorporated by reference to Exhibit 10.1 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016, File No. 1-32225).
10.37	Amendment to Equity Distribution Agreement, dated as of July 28, 2017, by and among the Registrant, HEP Logistics Holdings, L.P., Holly Logistics Services, L.L.C. and Citigroup Global Markets Inc., Goldman, Sachs & Co., and Merrill Lynch, Pierce, Fenner & Smith Incorporated (incorporated by reference to Exhibit 10.4 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, File No. 1-32225).
10.38	Pipeline Deficiency Agreement dated as of August 8, 2016, by and between HollyFrontier Refining & Marketing LLC and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.5 of Registrant's Current Report on Form 8-K dated August 10, 2016, File No. 1-32225).
10.39	LLC Interest Purchase Agreement dated as of October 3, 2016, by and between HollyFrontier Corporation, HollyFrontier Woods Cross Refining LLC, Holly Energy Partners - Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated October 4, 2016, File No. 1-32225).
10.40+	Holly Energy Partners, L.P. Long-Term Incentive Plan (as amended and restated effective February 10, 2012) (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated April 30, 2012, File No. 1-32225).
10.41+	First Amendment to the Holly Energy Partners, L.P. Long-Term Incentive Plan, effective January 16, 2013 (incorporated by reference to Exhibit 10.68 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2012, File No. 1-32225).
10.42+	Form of Holly Energy Partners, L.P. Indemnification Agreement to be entered into with officers and directors of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated February 18, 2011, File No. 1-32225).
10.43+	HollyFrontier Corporation Executive Nonqualified Deferred Compensation Plan (incorporated by reference to Exhibit 10.73 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2012, File No. 1-32225).
10.44+	Holly Energy Partners, L.P. Change in Control Agreement Policy (incorporated by reference to Exhibit 10.3 of Registrant's Current Report on Form 8-K dated February 18, 2011, File No. 1-32225).
10.45+	Form of Change in Control Agreement (incorporated by reference to Exhibit 10.47 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.46+	Amended and Restated Annual Incentive Plan (incorporated by reference to Exhibit 10.77 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2012, File No. 1-32225).
10.47+	Form of Performance Unit Agreement (Executive) (incorporated by reference to Exhibit 10.2 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, File No. 1-3225).
10.48*+	Form of Performance Unit Agreement (Executive)
10.49+	Form of Notice of Grant of Restricted Units (Directors) (incorporated by reference to Exhibit 10.105 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2015, File No. 1-32225).

10.50+	Form of Restricted Unit Agreement (Directors) (incorporated by reference to Exhibit 10.107 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2015, File No. 1-32225).
10.51+	Form of Notice of Grant of Restricted Units (Employee) (incorporated by reference to Exhibit 10.52 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.52+	Form of Restricted Unit Agreement (Employee) (incorporated by reference to Exhibit 10.53 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2016, File No. 1-32225).
10.53*+	Form of Phantom Unit Agreement.
10.54*+	Form of Notice of Grant of Phantom Units.
21.1*	Subsidiaries of Registrant.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.

32.1**	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
101++	The following financial information from Holly Energy Partners, L.P.'s Annual Report on Form 10-K for its fiscal year ended December 31, 2017, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Comprehensive Income, (iv) Consolidated Statements of Cash Flows, (v) Consolidated Statement of Partners' Equity, and (vi) Notes to Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.
\+ Constitutes management contracts or compensatory plans or arrangements.
++ Filed electronically herewith.

HOLLY ENERGY PARTNERS, L.P.
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HOLLY ENERGY PARTNERS, L.P.
(Registrant)

By: HEP LOGISTICS HOLDINGS, L.P.
its General Partner

By: HOLLY LOGISTIC SERVICES, L.L.C.
its General Partner

Date: February 21, 2018	/s/ George J. Damiris George J. Damiris Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 21, 2018	/s/ George J. Damiris George J. Damiris President, Chief Executive Officer and Director
Date: February 21, 2018	/s/ Richard L. Voliva III Richard L. Voliva III Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 21, 2018	/s/ Kenneth P. Norwood Kenneth P. Norwood Vice President and Controller (Principal Accounting Officer)
Date: February 21, 2018	/s/ Michael C. Jennings Michael C. Jennings Chairman of the Board
Date: February 21, 2018	/s/ Larry R. Baldwin Larry R. Baldwin Director
Date: February 21, 2018	/s/ James H. Lee James H. Lee Director

Date: February 21, 2018	/s/ R. Kevin Hardage
	R. Kevin Hardage
	Director