HOLLY ENERGY PARTNERS LP
Form 10-K
February 20, 2019

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, 2018
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 every Interactive Data File required to be submitted 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 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

On June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the common limited partner units held by non-affiliates of the registrant was approximately $1.3 billion, based upon the closing price on the New York Stock Exchange on such date. (This is not deemed an admission that any person whose shares were not included in the computation of the amount set forth in the preceding sentence necessarily is an “affiliate” of the registrant.)

105,440,201 shares of common limited partner units were outstanding on February 15, 2019.

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 and refinery processing units;
- 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 and cyber 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 Texas, New Mexico, Utah, Nevada, Oklahoma, Wyoming, Kansas, 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 Director, 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 and other refineries 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, 2018, HFC owned approximately 57% 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 15 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 ("IDRs") 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 (the "IDR Restructuring Transaction"). 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 as well as other unaffiliated 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 64% of the petroleum products transported on our refined product pipelines, 99.5% of the throughput volumes transported on our intermediate pipelines, and 75% of the throughput on our crude pipelines in 2018.

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,				
	2018	2017	2016	2015	2014
Volumes transported for barrels per day ("bpd"):					
HFC	622,088	556,516	542,762	558,027	457,014
Third parties	187,717	99,847	75,909	73,555	64,055
Total	809,805	656,363	618,671	631,582	521,069
Total barrels in thousands (“mbbls”)	295,579	239,572	226,434	230,527	190,190

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 and Magellan Midstream Partners' ("Magellan") 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's 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 $547,000 (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 Marathon Petroleum Corporation'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

Three pipelines 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. The Bisti connector pipeline was reversed in the fourth quarter of 2018.

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 pipeline owned by UNEV Pipeline, LLC ("UNEV") origin

pump station (3) a 4-mile segment from HFC's Woods Cross refinery to Andeavor Logistics LP’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. HEP owns a 75% interest in UNEV and HEP is the operator of this pipeline.

SLC Pipeline
This 95-mile crude oil pipeline (the "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 Colorado via the Andeavor Wamsutter system. 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 (the "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	80,000	
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	62,000	
SLC Pipeline	16	95	120,000	
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 Osage Pipe Line Company, LLC's ("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,				
	2018	2017	2016	2015	2014
Refined products and crude terminalled for (bpd):					
HFC	413,525	428,001	413,487	391,292	261,888
Third parties	61,367	68,687	72,342	78,403	69,100
Total	474,892	496,688	485,829	469,695	330,988
Total (mbbls)	173,336	181,291	177,813	171,439	120,811

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 10,251,000 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 units that unload crude oil from tanker trucks.

El Dorado, Kansas crude tankage

This 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.

Catoosa, Oklahoma terminal

On June 1, 2018, HEP acquired the Catoosa terminal from a third party. The terminal is a water port terminal close to HFC's Tulsa refinery and stores specialty lubricant products. HFC is the primary customer utilizing this terminal.

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 HFC's Tulsa refinery. 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 2018. 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

As of April 2018, we no longer operate at the Tucson, Arizona terminal. We previously owned 100% of the improvements and leased a portion of the underlying ground at this terminal, which expired in February 2018. Refined product received at the Tucson terminal originated from HFC's Navajo refinery Artesia facility and was transported, on our pipelines, to HFC's El Paso terminal where it connected to Kinder Morgan Energy Partners, L.P.'s East system pipeline that delivers into the Tucson terminal. Refined product received at this terminal was sold locally, via the truck rack.

Wichita Falls, Texas terminal

This terminal receives refined product from Delek's Big Spring refinery, which accounted for all of its volumes in 2018. 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

Frontier Anshutz and Frontier Arepi Stations
Tankage at these two terminals on the Frontier Pipeline in Wyoming is used to store various grades of crude shipped on the Frontier Pipeline.

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
Mountain Home, ID(2)	122,000	4	Pipeline	Pipeline
Spokane, WA	532,000	32	Pipeline/Rail	Truck
Abilene, TX	157,000	6	Pipeline	Truck/Pipeline
Wichita Falls, TX	260,000	12	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
Stations along the SLC and Frontier pipelines	267,000	7	Pipeline	Pipeline
Stations in the Texas, New Mexico crude system	333,000	18	Pipeline	Pipeline
Catoosa, OK	138,000	8	Truck/Rail	Truck
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	4,115,000			

(1) Inactive
(2) 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	3,732,000	Crude oil and refined product	62
Cheyenne, WY	1,944,000	Crude oil and refined product	55
El Dorado, KS	3,896,000	Refined and intermediate product	91
Total	10,251,000		

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CONTROL OPERATIONS OF PIPELINES AND TERMINALS

All of our pipelines are operated via 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.

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 calendar 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 commitments, and HEP charges a tolling fee per barrel or thousand standard cubic feet of 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 seconded refinery personnel; 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 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, 2018, these agreements with HFC require minimum annualized payments to us of $314 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 for a portion of the capacity under this lease agreement expired in 2018 and were not renewed, and the remaining portions of the capacity expire in 2020 and 2022. As of December 31, 2018, these agreements with Delek require minimum annualized payments to us of $32 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 2018) 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 2019 capital budget is comprised of approximately $10 million for maintenance capital expenditures and approximately $20 million to $25 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, 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 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 maintain 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 "ICA"). The ICA 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 ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

The Energy Policy Act of 1992 deemed petroleum products pipeline tariff rates that were (i) in effect for the 365-day period ending on the date of enactment or (ii) in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period, in each case, to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates.

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, 2018, we have an accrual of $6.3 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. 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 283 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, 2018, HFC accounted for 68% 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, 2018, production from the Navajo refinery accounted for 34% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 53% 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, 2018, Delek accounted for 7% 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, 2018, the principal amount of our total outstanding debt was $1,423 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, including U.S. government shutdowns, 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 and other pipelines 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 stringent 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 agencies have also issued a stay delaying implementation of the rule for two years. On December 11, 2018, the EPA and the Corps proposed a revised definition of "waters of the United States" that is subject to public comment and final agency action. To the extent this final rule on the scope of the CWA results in waters associated with our operations as being considered "waters of the United States", 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. In October 2018, proposed amendments to the 2016 standards were published in the Federal Register and the public comment period has closed, but a final rule has not yet been published. As a result, the June 2016 rule and associated stay are still in effect. 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 2019. In addition, Congress is likely to make further substantive changes to the Pipeline Safety Laws in 2019 or 2020 as part of its periodic reauthorization of PHMSA’s national safety programs. These changes could result in additional requirements. 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. These regulatory agencies periodically implement new rules, regulations and terms and conditions of services, which 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.

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.

In March and July of 2018, the FERC issued a revised policy statement and order on rehearing in which it expressed a general policy that it will no longer permit an income tax allowance to be included in the cost-of-service rates for interstate pipelines structured as pass-through entities. The FERC also indicated that it will incorporate the effects of the revised policy statement and the effects of the income tax rate reductions provided by the Tax Cuts and Jobs Act of 2017 in its review of the oil pipeline index level to be effective July 1, 2021. Depending on how the FERC incorporates its most recent tax policy statement and the tax rate reduction into its next index review, which is scheduled to become effective in 2021, our ability to increase our index-based rates could be negatively impacted.

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.

In addition, our industry is subject to potentially disruptive activities by those concerned with the possible environmental impacts of pipeline routes. Activists, non-governmental organizations and others may seek to restrict the transportation of crude oil and refined products by exerting social or political pressure to influence when, and whether, such rights-of-way or permits are granted. This interference could impact future pipeline development, which could interfere with or block expansion or development projects and could have a material adverse effect on our business, financial condition, results of operations and our ability to make cash distributions to our unitholders.

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 and certain of its subsidiaries collectively own 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 is 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, 2018, HEP has issued 2.4 million units under this program for gross consideration of $82.3 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 and current Treasury Regulations, 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 would affect publicly traded partnerships, including a prior legislative proposal that 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.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future, which 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.

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 affected current and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our affected current and former unitholders take such audit adjustment into account and pay any resulting taxes (including any applicable penalties or interest) 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. With respect to taxable years beginning after

December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses/activities issued by the Treasury Department, 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. Treasury Regulations allow 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, 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
In the ordinary course of business, we may become party to legal, regulatory or administrative proceedings or governmental investigations, including environmental and other matters. Damages or penalties may be sought from us in some matters and certain matters may require years to resolve. While the outcome and impact of these proceedings and investigations on us cannot be predicted with certainty, based on advice of counsel, management believes that the resolution of these proceedings and investigations, 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.

Environmental Matters

We are reporting the following proceeding to comply with SEC regulations which require us to disclose proceedings arising under federal, state or local provisions regulating the discharge of materials into the environment or protecting the environment if we reasonably believe that such proceedings may result in monetary sanctions of $100,000 or more. Our respective subsidiaries have or will develop corrective action plans regarding the subject of this proceeding that will be implemented in consultation with the respective federal and state agencies. It is not possible to predict the ultimate outcome of this proceeding, although it is not currently expected to have a material effect on our financial condition, results of operations or cash flows.

Written Safety Compliance Program
Holly Energy Partners - Operating, L.P. (“HEP Operating”) received a Notice of Probable Violation ("NOPV") dated June 20, 2018 from the Pipeline and Hazardous Materials Safety Administration (“PHMSA”). The NOPV follows a routine inspection of HEP's facilities and records and was not issued in response to an incident. In the NOPV,

PHMSA alleges certain regulatory violations involving HEP Operating's written safety compliance program for its pipelines, terminals and tanks. PHMSA has proposed a civil penalty and a compliance order that would require HEP Operating to take certain remedial actions. HEP Operating is currently working with PHMSA to resolve this matter.

Other

We are a party to various other legal and regulatory proceedings, which we believe, based on the advice of counsel, will not either individually or in the aggregate have a materially adverse impact 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."

As of February 13, 2019, we had approximately 18,909 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.

Common Unit Repurchases Made in the Quarter

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

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plan or Program	Maximum Number of Units that May Yet be Purchased Under a Publicly Announced Plan or Program
October 2018	—	$ —	—	$ —
November 2018	—	$ —	—	$ —
December 2018	17,606	$ 28.96	—	$ —
Total for October to December 2018	17,606		—	

The units reported represent the delivery of 17,606 common units (which units were previously issued to certain officers and other employees pursuant to restricted unit awards or phantom 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.

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,				
	2018	2017	2016	2015	2014
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$506,220	$454,362	$402,043	$358,875	$332,545
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	146,430	137,605	123,986	105,556	106,185
Depreciation and amortization	98,492	79,278	70,428	63,306	62,529
General and administrative	11,040	14,323	12,532	12,556	10,824
	255,962	231,206	206,946	181,418	179,538
Operating income	250,258	223,156	195,097	177,457	153,007
Equity in earnings of equity method investments	5,825	12,510	14,213	4,803	2,987
Interest expense	(71,899)	(58,448)	(52,552)	(37,418)	(36,101)
Interest income	2,108	491	440	526	3
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	121	422	677	486	82
	(63,845)	(20,996)	(37,222)	(31,603)	(40,706)
Income before income taxes	186,413	202,160	157,875	145,854	112,301
State income tax expense	(26)	(249)	(285)	(228)	(235)
Net income	186,387	201,911	157,590	145,626	112,066
Allocation of net loss attributable to Predecessor	—	—	10,657	2,702	1,747
Allocation of net income attributable to noncontrolling interests	(7,540)	(6,871)	(10,006)	(11,120)	(8,288)
Net income attributable to the partners	178,847	195,040	158,241	137,208	105,525
General partner interest in net income, including incentive distributions(1)	—	(35,047)	(57,173)	(42,337)	(34,667)
Limited partners’ interest in net income	$178,847	$159,993	$101,068	$94,871	$70,858
Limited partners’ earnings per unit – basic and diluted(1)	$1.70	$2.28	$1.69	$1.60	$1.20
Distributions per limited partner unit	$2.6475	$2.5475	$2.3625	$2.2025	$2.0750

Other Financial Data:

Cash flows from operating activities	$295,213	$238,487	$243,548	$231,442	$185,256
Cash flows from investing activities	$(52,343)	$(286,273)	$(143,030)	$(246,680)	$(198,423)
Cash flows from financing activities	$(247,601)	$51,905	$(111,874)	$27,421	$9,645
EBITDA(2)	$347,156	$332,524	$277,545	$237,180	$204,024
Distributable cash flow(3)	$265,087	$242,955	$218,810	$197,046	$172,718
Maintenance capital expenditures(4)	$8,182	$7,748	$9,658	$8,926	$4,616
Expansion capital expenditures	39,118	37,062	50,046	30,467	75,343
Acquisition capital expenditures	6,841	245,446	44,119	153,728	118,727
Total capital expenditures	$54,141	$290,256	$103,823	$193,121	$198,686
Balance Sheet Data (at period end):					
Net property, plant and equipment	$1,538,655	$1,569,471	$1,328,395	$1,293,060	$1,163,631
Total assets	$2,102,540	$2,154,114	$1,884,237	$1,777,646	$1,584,114
Long-term debt(5)	$1,418,900	$1,507,308	$1,243,912	$1,008,752	$866,986
Total liabilities	$1,586,979	$1,669,049	$1,412,446	$1,151,424	$989,324
Total equity(6)	$515,561	$485,065	$471,791	$626,222	$594,790

(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, net of interest income, (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 the 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.

Set forth below is our calculation of EBITDA.

	Years Ended December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Net income attributable to the partners	$178,847	$195,040	$158,241	$137,208	$105,525
Add (subtract):					
Interest expense	68,858	55,385	49,306	35,490	34,280
Interest income	(2,108)	(491)	(440)	(526)	(3)
Amortization of discount and deferred debt issuance costs	3,041	3,063	3,246	1,928	1,821
State income tax expense	26	249	285	228	235
Depreciation and amortization	98,492	79,278	70,428	63,306	62,529
Predecessor depreciation and amortization	—	—	(3,521)	(454)	(363)
EBITDA	$347,156	$332,524	$277,545	$237,180	$204,024

(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,				
	2018	2017	2016	2015	2014
	(In thousands)				
Net income attributable to the partners	$178,847	$195,040	$158,241	$137,208	$105,525
Add (subtract):					
Depreciation and amortization	98,492	79,278	70,428	63,306	62,529
Remeasurement gain on preexisting equity interests	—	(36,254)	—	—	—
Amortization of discount and deferred debt issuance costs	3,041	3,063	3,246	1,928	1,821
Loss on early extinguishment of debt	—	12,225	—	—	7,677
Increase (decrease) in deferred revenue related to minimum revenue commitments	(786)	(1,283)	(1,292)	(1,233)	(2,503)
Maintenance capital expenditures [4]	(8,182)	(7,748)	(9,658)	(8,926)	(4,616)
Increase (decrease) in environmental liability	(237)	(581)	(584)	1,107	1,596
Increase (decrease) in reimbursable deferred revenue	(5,179)	(3,679)	(2,733)	176	(2,274)
Other non-cash adjustments	(909)	2,894	4,683	3,934	3,326
Predecessor depreciation and amortization	—	—	(3,521)	(454)	(363)
Distributable cash flow	$265,087	$242,955	$218,810	$197,046	$172,718

(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 $923 million, $1,012 million, $553 million, $712 million and $571 million in Credit Agreement advances that were classified as long-term debt at December 31, 2018, 2017, 2016, 2015 and 2014, respectively.

(6) As a master limited partnership, we distribute our available cash, which historically has exceeded our net income attributable to the partners 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 partners. 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, Washington, Idaho, Oklahoma, Utah, Nevada, Wyoming and Kansas as well as refinery processing units in Utah and Kansas. HFC owned 57% of our outstanding common units and the non-economic general partner interest as of December 31, 2018.

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 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 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.

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, 2018, these agreements with HFC require minimum annualized payments to us of $314 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 for a portion of the capacity under this lease agreement expired in 2018 and were not renewed, and the remaining portions of capacity expire in 2020 and 2022. As of December 31, 2018, these agreements with Delek require minimum annualized payments to us of $32 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 2018), 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, 2018, 2017 and 2016. 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, 2018	2017	Change from 2017
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$82,998	$80,030	$2,968
Affiliates—intermediate pipelines	29,639	28,732	907
Affiliates—crude pipelines	79,741	65,960	13,781
	192,378	174,722	17,656
Third parties—refined product pipelines	54,524	52,379	2,145
Third parties—crude pipelines	36,605	7,939	28,666
	283,507	235,040	48,467
Terminals, tanks and loading racks:			
Affiliates	130,251	125,510	4,741
Third parties	17,283	16,908	375
	147,534	142,418	5,116
Affiliates—refinery processing units	75,179	76,904	(1,725)
Total revenues	506,220	454,362	51,858
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	146,430	137,605	8,825
Depreciation and amortization	98,492	79,278	19,214
General and administrative	11,040	14,323	(3,283)
	255,962	231,206	24,756
Operating income	250,258	223,156	27,102
Other income (expense):			
Equity in earnings of equity method investments	5,825	12,510	(6,685)
Interest expense, including amortization	(71,899)	(58,448)	(13,451)
Interest income	2,108	491	1,617
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	121	422	(301)
	(63,845)	(20,996)	(42,849)
Income before income taxes	186,413	202,160	(15,747)
State income tax expense	(26)	(249)	223
Net income	186,387	201,911	(15,524)
Allocation of net income attributable to noncontrolling interests	(7,540)	(6,871)	(669)
Net income attributable to the partners	178,847	195,040	(16,193)
General partner interest in net income attributable to the partners [1]	—	(35,047)	35,047
Limited partners' interest in net income	$178,847	$159,993	$18,854
Limited partners' earnings per unit—basic and diluted [1]	$1.70	$2.28	$(0.58)
Weighted average limited partners' units outstanding	105,042	70,291	34,751
EBITDA [2]	$347,156	$332,524	$14,632
Distributable cash flow [3]	$265,087	$242,955	$22,132

Volumes (bpd)

Pipelines:			
Affiliates—refined product pipelines	127,865	133,822	(5,957)
Affiliates—intermediate pipelines	144,537	141,601	2,936
Affiliates—crude pipelines	349,686	281,093	68,593
	622,088	556,516	65,572
Third parties—refined product pipelines	71,784	78,013	(6,229)
Third parties—crude pipelines	115,933	21,834	94,099
	809,805	656,363	153,442
Terminals and loading racks:			
Affiliates	413,525	428,001	(14,476)
Third parties	61,367	68,687	(7,320)
	474,892	496,688	(21,796)
Affiliates—refinery processing units	62,787	63,572	(785)
Total for pipelines, terminals and refinery processing unit assets (bpd)	1,347,484	1,216,623	130,861

	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]	$332,524	$277,545	$54,979
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, terminals and refinery processing unit assets (bpd)	1,216,623	1,156,278	60,345

(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, 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, 2018 Compared with Year Ended December 31, 2017

Summary

Net income attributable to the partners for the year ended December 31, 2018, was $178.8 million, a $16.2 million decrease compared to the year ended December 31, 2017. The decrease in earnings was primarily due to the recognition of a $36.3 million remeasurement gain related to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017. Excluding this remeasurement gain, net income attributable to the partners increased $20.1 million primarily due to higher pipeline throughputs and revenues as well as increased earnings related to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017, which were partially offset by higher interest expense.

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, 2018, include the recognition of $3.3 million of prior shortfalls billed to shippers in 2017. As of December 31, 2018, deferred revenue on our consolidated balance sheet related to shortfalls billed was $1.8 million.

Revenues

Revenues for the year ended December 31, 2018, were $506.2 million, a $51.9 million increase compared to the same period in 2017. The increase was primarily attributable to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017 and the turnaround at HFC's Navajo refinery in the first quarter of 2017.

Revenues from our refined product pipelines were $137.5 million, an increase of $5.1 million, on shipments averaging 199.6 mbpd compared to 211.8 mbpd for the year ended December 31, 2017. The volume decrease was mainly due to pipelines servicing HFC's Woods Cross refinery, which had lower throughput due to operational issues at the refinery beginning in the first quarter of 2018. These decreases were partially offset by higher volumes on our product pipelines in New Mexico due to the turnaround at HFC's Navajo refinery in the first quarter of 2017. Revenue increased as a result of the higher volumes on the New Mexico product pipelines and remained relatively consistent around pipelines servicing HFC's Woods Cross refinery due to contractual minimum volume commitments and tariff escalators.

Revenues from our intermediate pipelines were $29.6 million, an increase of $0.9 million, on shipments averaging 144.5 mbpd compared to 141.6 mbpd for the year ended December 31, 2017. These increases were principally due to the turnaround at HFC's Navajo refinery in the first quarter of 2017 and increased production of base oil and lubricants at HFC's Tulsa refinery.

Revenues from our crude pipelines were $116.3 million, an increase of $42.4 million, on shipments averaging 465.6 mbpd compared to 302.9 mbpd for the year ended December 31, 2017. The increases were mainly attributable to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017, as well as increased volumes on our crude pipeline systems in New Mexico and Texas.

Revenues from terminal, tankage and loading rack fees were $147.5 million, an increase of $5.1 million compared to the year ended December 31, 2017. Refined products and crude oil terminalled in the facilities averaged 474.9 mbpd compared to 496.7 mbpd for the year ended December 31, 2017. Despite the decrease in volume, revenue increased primarily due to tariff escalators on minimum revenue commitments.

Revenues from refinery processing units were $75.2 million, a decrease of $1.7 million on throughputs averaging 62.8 mbpd compared to 63.6 mbpd for the year ended December 31, 2017. The reduction in revenue and volume was due to an unplanned outage on our fluid catalytic cracking unit at HFC's Woods Cross refinery in the fourth quarter of 2018.

Operations Expense

Operations (exclusive of depreciation and amortization) expense for the year ended December 31, 2018, increased by $8.8 million compared to the year ended December 31, 2017. The increase was primarily due to new operating expenses related to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2018, increased by $19.2 million compared to the year ended December 31, 2017. The increase was primarily due to depreciation and amortization related to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017.

General and Administrative

General and administrative costs for the year ended December 31, 2018, decreased by $3.3 million compared to the year ended December 31, 2017, mainly due to higher legal and consulting costs incurred in the year ended December 31, 2017, associated with the IDR Restructuring Transaction.

Equity in Earnings of Equity Method Investments

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

	Years Ended December 31,	
Equity Method Investment	2018	2017
	(in thousands)	
SLC Pipeline LLC	$—	$2,267
Frontier Aspen LLC	—	4,089
Osage Pipe Line Company, LLC	1,961	2,447
Cheyenne Pipeline LLC	3,864	3,707
Total	$5,825	$12,510

Interest Expense

Interest expense for the year ended December 31, 2018, totaled $71.9 million, an increase of $13.5 million compared to the year ended December 31, 2017. The increase was mainly due to interest expense associated with the private placement of an additional $100 million in aggregate principal amount of our 6% Senior Notes due 2024 completed in the third quarter of 2017, higher average balances outstanding under the Credit Agreement, and market interest rate increases under the Credit Agreement. Our aggregate weighted-average interest rates were 5.1% and 4.4% for the years ended December 31, 2018 and 2017, respectively.

State Income Tax

We recorded state income tax expense of $26,000 and $249,000 for the years ended December 31, 2018 and 2017, respectively. All state income tax expense is solely attributable to the Texas margin tax.

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 million increase compared to the year ended December 31, 2016. The increase in earnings is primarily due to (a) the Woods Cross refinery 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 of 6.5% senior notes due 2020 (the "6.5% Senior Notes") 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 $5.6 million of prior shortfalls billed to shippers in 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 SLC Pipeline and Frontier Aspen 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 in previously deferred revenues 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 primarily due to revenues received from the acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017, 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 HFC in the first quarter of 2016.
Revenues from refinery processing units were $76.9 million, an increase of $43.9 million 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 was 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 was 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 the remaining interests on October 31, 2017. SLC Pipeline and Frontier Aspen operations for 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 was 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.

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, 2018, we received advances totaling $337.0 million and repaid $426.0 million, resulting in a net decrease of $89.0 million under the Credit Agreement and an outstanding balance of $923.0 million at December 31, 2018. As of December 31, 2018, we had no letters of credit outstanding under the Credit Agreement, and the available capacity under the Credit Agreement was $477 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, 2018, HEP has issued 2,413,153 units under this program, providing $82.3 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 our 6.5% Senior Notes 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 2018, we paid regular quarterly cash distributions of $0.6500, $0.6550, $0.6600 and $0.6650, on all units in an aggregate amount of $265.0 million. In February 2019, we paid a regular cash distribution of $0.6675 on all units in an aggregate amount of $68.0 million after deducting HEP Logistics' waiver of $2.5 million of limited partner cash distributions.

Cash and cash equivalents decreased by $4.7 million during the year ended December 31, 2018. The cash flows provided by operating activities of $295.2 million were less than the cash flows used for investing and financing activities of $52.3 million and $247.6 million, respectively. Working capital decreased by $10.3 million to a surplus of $8.6 million at December 31, 2018 from a surplus of $18.9 million at December 31, 2017.

Cash Flows—Operating Activities
Year Ended December 31, 2018 Compared with Year Ended December 31, 2017
Cash flows provided by operating activities increased by $56.7 million from $238.5 million for the year ended December 31, 2017, to $295.2 million for the year ended December 31, 2018. This increase was due principally to higher receipts from customers partially offset by higher payments for interest and operating expenses in the year ended December 31, 2018, as compared to the prior year. The increase in customer receipts was primarily attributable to our acquisition of the remaining interests in SLC Pipeline and Frontier Aspen in the fourth quarter of 2017.

Year Ended December 31, 2017 Compared with Year Ended December 31, 2016
Cash flows from 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 was 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.

Cash Flows—Investing Activities
Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

Cash flows used for investing activities decreased by $233.9 million from $286.3 million for the year ended December 31, 2017, to $52.3 million for the year ended December 31, 2018. During the years ended December 31, 2018 and 2017, we invested $47.3 million and $44.8 million in additions to properties and equipment, respectively. During the year ended December 31, 2018, we acquired businesses and assets for $5.1 million. Additionally, we acquired the remaining 75% interest in SLC Pipeline and 50% interest in Frontier Aspen for $245.4 million in October 2017.

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.

Cash Flows—Financing Activities
Year Ended December 31, 2018 Compared with Year Ended December 31, 2017
Cash flows used for financing activities were $247.6 million for the year ended December 31, 2018, compared to cash flows provided by financing activities of $51.9 million for the year ended December 31, 2017, a decrease of $299.5 million. During the year ended December 31, 2018, we received $337.0 million and repaid $426.0 million in advances under the Credit Agreement. We also received net proceeds of $114.8 million from issuance of common units. Additionally, we paid $265.0 million in regular quarterly cash distributions to our general and limited partners and $7.5 million to our noncontrolling interest. 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 the 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.

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 for 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 acquisitions of $317.5 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 2019 capital budget is comprised of approximately $10 million for maintenance capital expenditures and approximately $20 million to $25 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, 2018, we had outstanding borrowings of $923 million under the Credit Agreement, no letters of credit outstanding, and the available capacity was $477 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, 2018.

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 for the years ending December 31, 2018 and 2017, were 4.238% and 3.734%, respectively. We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.25% 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 our 6.5% Senior Notes 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, 2018. 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, 2018	December 31, 2017
	(In thousands)	
Credit Agreement	$923,000	$1,012,000
6% Senior Notes		
Principal	500,000	500,000
Unamortized debt issuance costs	(4,100)	(4,692)
	495,900	495,308
Total long-term debt	$1,418,900	$1,507,308

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, 2018.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Over 5 Years
	(In thousands)				
Long-term debt – principal	$1,423,000	$—	$—	$923,000	$500,000
Long-term debt - interest	313,303	70,784	141,568	83,451	17,500
Site service fees	246,180	5,286	10,573	10,573	219,748
Pipeline operating lease	55,814	6,566	13,133	13,133	22,982
Right-of-way agreements and other	21,095	5,828	6,739	3,072	5,456
Total	$2,059,392	$88,464	$172,013	$1,033,229	$765,686

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, 2018.

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, 2018. 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, 2018, 2017 and 2016. PPI has increased an average of 0.8% annually over the past five calendar years, including an increases of 3.0% and 3.2% in 2018 and 2017, 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.

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, 2018, we have an accrual of $6.3 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. 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 generally recognized as products are shipped through our pipelines and terminals, feedstocks are processed through our refinery processing units or other services are rendered. The majority of our contracts with customers meet the definition of a lease since (1) performance of the contracts is dependent on specified property, plant, or equipment and (2) the possibility is remote that one or more parties other than the customer will take more than a minor amount of the output associated with the specified property, plant, or equipment. As a result, we bifurcate the consideration received between lease and service revenue. The service component is within the scope of Accounting Standards Codification 606, which largely codified ASU 2014-09.

Several of our contracts include incentive or reduced tariffs once a certain quarterly volume is met. Revenue from the variable element of these transactions is recognized based on the actual volumes shipped as it relates specifically to rendering the services during the applicable quarter.

The majority of our long-term transportation contracts specify minimum volume requirements, whereby, we bill a customer for a minimum level of shipments in the event a customer ships below their contractual requirements. If there are no future performance obligations, we will recognize these deficiency payments in revenue.

In certain of these throughput agreements, a customer may later utilize such shortfall billings as credit towards future volume shipments in excess of its minimum levels within its respective contractual shortfall make-up period. Such amounts represent an obligation to perform future services, which may be initially deferred and later recognized as revenue based on estimated future shipping levels, including the likelihood of a customer's ability to utilize such amounts prior to the end of the contractual shortfall make-up period. We recognize the service portion of these deficiency payments in revenue when we do not expect we will be required to satisfy these performance obligations in the future based on the pattern of rights exercised by the customer.

Prior to the adoption of ASC 606 on January 1, 2018, billings to customers for their obligations under their quarterly minimum revenue commitments were recorded as deferred revenue liabilities if the customer had the right to receive future services for these billings. The revenue was recognized at the earlier of:

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

We determined that we would not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems would 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. Our goodwill impairment testing first entails a comparison of our reporting unit fair values relative to their respective carrying values, including goodwill. If carrying value exceeds fair value for a reporting unit, we measure goodwill impairment as the excess of the carrying amount of reporting unit goodwill over the implied fair value of that goodwill based on estimates of the fair value of all assets and liabilities in the reporting unit.

In 2018, 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, could result in the recognition of 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 was not more likely than not that the fair value of our reporting units were less than the respective carrying value. Therefore, in accordance with GAAP, 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, 2018.

Accounting Pronouncement Adopted During the Periods Presented

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 had an effective date of January 1, 2018, and we accounted for the new guidance using the modified retrospective implementation method, whereby a cumulative effect adjustment was recorded to retained earnings as of the date of initial application. In preparing for adoption, we evaluated the terms, conditions and performance obligations under our existing contracts with customers. Furthermore, we implemented policies to comply with this new standard. See above and Note 3 to the consolidated financial statements for additional information on our revenue recognition policies.

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 had an effective date of January 1, 2018, and had no effect on our financial condition, results of operations or cash flows.

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 was effective beginning with our 2018 reporting year and had no effect on our financial condition, results of operations or cash flows.

Accounting Pronouncements Not Yet Adopted

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 plan to apply practical expedients provided in the standards update that allow us, among other things, not to reassess contracts that commenced prior to the adoption. The primary effect of adopting the new standard will be to record assets and obligations for current operating leases on our consolidated balance sheet. Adoption of the standard is not expected to have a material impact on our results of operations or cash flows.

In preparing for adoption, we have identified, reviewed and evaluated contracts containing lease and embedded lease arrangements. Additionally, we have acquired and implemented software and systems to facilitate lease capture and related accounting treatment.

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, 2018, 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, 2018, the fair value of our 6% Senior Notes was $488 million. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6% Senior Notes at December 31, 2018, 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, 2018, borrowings outstanding under the Credit Agreement were $923 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, 2018, 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, 2018, the Partnership maintained effective internal control over financial reporting.

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, 2018. That report appears on page 62.

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, 2018, 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, 2018, based on the COSO criteria.

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, 2018 and 2017, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2018, and the related notes of the Partnership and our report dated February 20, 2019 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 20, 2019

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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, 2018 and 2017, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 20, 2019 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 20, 2019

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

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,045	$ 7,776
Accounts receivable:		
Trade	12,332	12,803
Affiliates	46,786	51,501
	59,118	64,304
Prepaid and other current assets	4,311	2,311
Total current assets	66,474	74,391
Properties and equipment, net	1,538,655	1,569,471
Intangible assets, net	115,329	129,463
Goodwill	270,336	266,716
Equity method investments	83,840	85,279
Other assets	27,906	28,794
Total assets	$ 2,102,540	$ 2,154,114
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 16,435	$ 14,547
Affiliates	14,222	7,725
	30,657	22,272
Accrued interest	13,302	13,256
Deferred revenue	8,697	9,598
Accrued property taxes	1,779	4,652
Other current liabilities	3,462	5,707
Total current liabilities	57,897	55,485
Long-term debt	1,418,900	1,507,308
Other long-term liabilities	15,307	15,843
Deferred revenue	48,714	47,272
Class B unit	46,161	43,141
Equity:		
Partners' equity:		
Common unitholders (105,440,201 and 101,568,955 units issued and outstanding at December 31, 2018 and 2017, respectively)	427,435	393,959
Total partners' equity	427,435	393,959
Noncontrolling interest	88,126	91,106
Total equity	515,561	485,065

Total liabilities and equity	$ 2,102,540	$ 2,154,114

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
Revenues:			
Affiliates	$397,808	$377,136	$333,116
Third parties	108,412	77,226	68,927
	506,220	454,362	402,043
Operating costs and expenses:			
Operations (exclusive of depreciation and amortization)	146,430	137,605	123,986
Depreciation and amortization	98,492	79,278	70,428
General and administrative	11,040	14,323	12,532
	255,962	231,206	206,946
Operating income	250,258	223,156	195,097
Other income (expense):			
Equity in earnings of equity method investments	5,825	12,510	14,213
Interest expense	(71,899)	(58,448)	(52,552)
Interest income	2,108	491	440
Loss on early extinguishment of debt	—	(12,225)	—
Remeasurement gain on preexisting equity interests	—	36,254	—
Gain on sale of assets and other	121	422	677
	(63,845)	(20,996)	(37,222)
Income before income taxes	186,413	202,160	157,875
State income tax expense	(26)	(249)	(285)
Net income	186,387	201,911	157,590
Allocation of net loss attributable to Predecessor	—	—	10,657
Allocation of net income attributable to noncontrolling interests	(7,540)	(6,871)	(10,006)
Net income attributable to the partners	178,847	195,040	158,241
General partner interest in net income attributable to the Partnership, including incentive distributions	—	(35,047)	(57,173)
Limited partners' interest in net income	$178,847	$159,993	$101,068
Limited partners' per unit interest in earnings—basic and diluted	$1.70	$2.28	$1.69
Weighted average limited partners' units outstanding	105,042	70,291	59,872

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
Net income	$186,387	$201,911	$157,590
Other comprehensive income:			
Change in fair value of cash flow hedging instruments	—	88	(607)
Reclassification adjustment to net income on partial settlement of cash flow hedge	—	(179)	508
Other comprehensive loss	—	(91)	(99)
Comprehensive income before noncontrolling interest	186,387	201,820	157,491
Allocation of net loss attributable to Predecessor	—	—	10,657
Allocation of comprehensive income to noncontrolling interests	(7,540)	(6,871)	(10,006)
Comprehensive income attributable to the partners	$178,847	$194,949	$158,142

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
Cash flows from operating activities			
Net income	$186,387	$201,911	$157,590
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	98,492	79,278	70,428
Gain on sale of assets	(196)	(319)	(150)
Remeasurement gain on preexisting equity interests	—	(36,254)	—
Amortization of deferred charges	3,041	3,063	3,247
Equity-based compensation expense	3,203	2,520	3,519
Equity in earnings of equity method investments, net of distributions	(149)	1,450	(2,032)
Loss on early extinguishment of debt	—	12,225	—
(Increase) decrease in operating assets:			
Accounts receivable—trade	471	(38)	279
Accounts receivable—affiliates	4,715	(8,939)	(10,080)
Prepaid and other current assets	(2,000)	830	1,598
Increase (decrease) in operating liabilities:			
Accounts payable—trade	(329)	(1,975)	(365)
Accounts payable—affiliates	6,497	(8,699)	(16)
Accrued interest	46	(4,813)	11,317
Deferred revenue	1,862	(1,267)	7,058
Accrued property taxes	(2,873)	(2,179)	1,633
Other current liabilities	(2,081)	2,091	(553)
Other, net	(1,873)	(398)	75
Net cash provided by operating activities	295,213	238,487	243,548
Cash flows from investing activities			
Additions to properties and equipment	(47,300)	(44,810)	(59,704)
Business and asset acquisitions	(5,051)	—	(44,119)
Purchase of interest in Cheyenne Pipeline	—	—	(42,627)
Purchase of controlling interests in SLC Pipeline and Frontier Aspen	(1,790)	(245,446)	—
Proceeds from sale of assets	210	849	427
Distributions in excess of equity in earnings of equity investments	1,588	3,134	2,993
Net cash used for investing activities	(52,343)	(286,273)	(143,030)
Cash flows from financing activities			
Borrowings under credit agreement	337,000	969,000	554,000
Repayments of credit agreement borrowings	(426,000)	(510,000)	(713,000)
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	114,771	52,110	125,870
Contributions from general partner	882	1,072	2,577
Distributions to HEP unitholders	(264,979)	(234,575)	(192,037)
Distributions to noncontrolling interest	(7,500)	(6,500)	(5,750)
Distribution to HFC for acquisitions		—	(317,500)

Contributions from HFC for acquisitions	—	—	51,262
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)
Units withheld for tax withholding obligations	(568)	(605)	(800)
Deferred financing costs	6	(9,382)	(3,995)
Other	(1,213)	(1,112)	(1,735)
Net cash provided by (used for) financing activities	(247,601)	51,905	(111,874)
Cash and cash equivalents			
Increase (decrease) for the year	(4,731)	4,119	(11,356)
Beginning of year	7,776	3,657	15,013
End of year	$3,045	$7,776	$3,657

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, 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)
Contribution 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	3,519	—	—	—	3,519
Class B unit accretion	(6,250)	(128)	—	—	(6,378)
Other	(800)	(451)	—	—	(1,251)
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	2,520	—	—	—	2,520
Class B unit accretion	(2,780)	(42)	—	—	(2,822)
Other	(238)	—	—	—	(238)
Net income	162,815	35,047	—	4,049	201,911
Equity restructuring transaction	(149,994)	149,994	—	—	—
Other comprehensive income	—	—	(91)	—	(91)
Balance December 31, 2017	$393,959	$—	$ —	$ 91,106	$485,065
Issuance of common units	114,771	—	—	—	114,771
Distributions to HEP unitholders	(264,979)	—	—	—	(264,979)
Distributions to noncontrolling interests	—	—	—	(7,500)	(7,500)
Amortization of restricted and performance units	3,203	—	—	—	3,203
Class B unit accretion	(3,020)	—	—	—	(3,020)
Other	1,634	—	—	—	1,634
Net income	181,867	—	—	4,520	186,387
Balance December 31, 2018	$427,435	$—	$ —	$ 88,126	$515,561

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2018

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. As of December 31, 2018, HollyFrontier Corporation (“HFC”) and its subsidiaries own a 57% limited partner interest and the non-economic general partner interest in HEP. 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 ("IDRs") 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 a result of this transaction, no distributions were made on the general partner interest after October 31, 2017.

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 partner 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 revolving credit facility.

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 15.

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. Certain prior period balances have been reclassified for consistency with current year presentation.

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. Our goodwill impairment testing first entails a comparison of our reporting unit fair values relative to their respective carrying values, including goodwill. If carrying value exceeds fair value for a reporting unit, we measure goodwill impairment as the excess of the carrying amount of reporting unit goodwill over the implied fair value of that goodwill based on estimates of the fair value of all assets and liabilities in the reporting unit.

In 2018, 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, could result in the recognition of 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 was not more likely than not that the fair value of our reporting units were 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, 2018.

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.

	Balance at December 31, 2018		
	Underlying Equity	Recorded Investment Balance	Difference
	(in thousands)		
Equity Method Investments			
Osage Pipe Line Company, LLC	$9,964	$ 40,483	$(30,519)
Cheyenne Pipeline LLC	29,358	43,357	(13,999)
Total	$39,322	$ 83,840	$(44,518)

	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)

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, 2018 and 2017, we have asset retirement obligations of $8.9 million and $8.6 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 $46.2 million at December 31, 2018, and $43.1 million at December 31, 2017.

Revenue Recognition

Revenues are generally recognized as products are shipped through our pipelines and terminals, feedstocks are processed through our refinery processing units or other services are rendered. The majority of our contracts with customers meet the definition of a lease since (1) performance of the contracts is dependent on specified property, plant, or equipment and (2) it is remote that one or more parties other than the customer will take more than a minor amount of the output associated with the specified property, plant, or equipment. As a result, we bifurcate the consideration received between lease and service revenue. The service component is within the scope of Accounting Standards Codification (“ASC”) 606, which largely codified ASU 2014-09.

Several of our contracts include incentive or reduced tariffs once a certain quarterly volume is met. Revenue from the variable element of these transactions is recognized based on the actual volumes shipped as it relates specifically to rendering the services during the applicable quarter.

The majority of our long-term transportation contracts specify minimum volume requirements, whereby, we bill a customer for a minimum level of shipments in the event a customer ships below their contractual requirements. If there are no future performance obligations, we will recognize these deficiency payments in revenue.

In certain of these throughput agreements, a customer may later utilize such shortfall billings as credit towards future volume shipments in excess of its minimum levels within its respective contractual shortfall make-up period. Such amounts represent an obligation to perform future services, which may be initially deferred and later recognized as revenue based on estimated future shipping levels, including the likelihood of a customer’s ability to utilize such amounts prior to the end of the contractual shortfall make-up period. We recognize the service portion of these deficiency payments in revenue when we do not expect we will be required to satisfy these performance obligations in the future based on the pattern of rights exercised by the customer.

Prior to the adoption of ASC 606 on January 1, 2018, billings to customers for their obligations under their quarterly minimum revenue commitments were recorded as deferred revenue liabilities if the customer had the right to receive future services for these billings. The revenue was recognized at the earlier of:

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

We determined that we would not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems would 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, 2018, 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 $2.3 billion including $356 million for the year ending December 31, 2019, $308 million for the year ending December 31, 2020, $298 million for the year ending December 31, 2021, $271 million for the year ending December 31, 2022 and $236 million for the year ending December 31, 2023. 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

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 had an effective date of January 1, 2018, and we accounted for the new guidance using the modified retrospective implementation method, whereby a cumulative effect adjustment was recorded to retained earnings as of the date of initial application. In preparing for adoption, we evaluated the terms, conditions and performance obligations under our existing contracts with customers. Furthermore, we implemented policies to comply with this

new standard. See above and Note 3 for additional information on our revenue recognition policies.

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 had an effective date of January 1, 2018, and had no effect on our financial condition, results of operations or cash flows.

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 was effective beginning with our 2018 reporting year and had no effect on our financial condition, results of operations or cash flows.

Accounting Pronouncements Not Yet Adopted

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 plan to apply practical expedients provided in the standards update that allow us, among other things, not to reassess contracts that commenced prior to the adoption. The primary effect of adopting the new standard will be to record assets and obligations for current operating leases on our consolidated balance sheet. Adoption of the standard is not expected to have a material impact on our results of operations or cash flows.

In preparing for adoption, we have identified, reviewed and evaluated contracts containing lease and embedded lease arrangements. Additionally, we have acquired and implemented software and systems to facilitate lease capture and related accounting treatment.

Note 2: Acquisitions

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 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 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 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 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 ("SLC Pipeline") and the remaining 50% interest in Frontier Aspen LLC ("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 $363.8 million, consisting of cash consideration of $250 million, working capital adjustments of $1.8 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 final estimated value of assets and liabilities acquired:

	(in thousands)
Cash and cash equivalents	$ 4,609
Accounts receivable	5,164
Prepaid and other current assets	8
Properties and equipment	275,061
Intangible assets	70,182
Goodwill	13,845
Accounts payable	(3,598)
Accrued property taxes	(1,438)
Net assets acquired	$ 363,833

During 2018, goodwill was increased by $3.6 million in connection with our finalization of preliminary estimates recorded in 2017 for the purchase price allocation.
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 ended 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 (defined below) and from Wahsatch Station. Frontier Aspen is the owner of a 289-mile crude pipeline from Casper, Wyoming to Frontier Station, Utah (the "Frontier Pipeline") 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; and
(3) To eliminate the remeasurement gain on preexisting equity interests in SLC Pipeline and Frontier Aspen.

Note 3: Revenues

Effective January 1, 2018, as described in Note 1, we adopted ASC 606, using the modified retrospective method, whereby the cumulative effect of applying the new standard was recorded as an adjustment to the opening balance of retained earnings as well as the carrying amounts of assets and liabilities as of January 1, 2018, which had no impact on our cash flows. The following table reflects the cumulative effect of adoption as of January 1, 2018:

	Prior to Adoption	Increase (Decrease)	As Adjusted
	(In thousands)		
Deferred revenue	$9,598	$ (1,320)	$8,278
Partners’ equity: Common unitholders	$393,959	$ 1,320	$395,279

Revenues are generally recognized as products are shipped through our pipelines and terminals, feedstocks are processed through our refinery processing units or other services are rendered. The majority of our contracts with customers meet the definition of a lease since (1) performance of the contracts is dependent on specified property, plant, or equipment and (2) it is remote that one or more parties other than the customer will take more than a minor amount of the output associated with the specified property, plant, or equipment. Therefore, we bifurcate the consideration received between lease and service revenue. The service component is within the scope of ASC 606, which largely codified ASU 2014-09.

Several of our contracts include incentive or reduced tariffs once a certain quarterly volume is met. Revenue from the variable element of these transactions is recognized based on the actual volumes shipped as it relates specifically to rendering the services during the applicable quarter.

The majority of our long-term transportation contracts specify minimum volume requirements, whereby, we bill a customer for a minimum level of shipments in the event a customer ships below their contractual requirements. If there are no future performance obligations, we will recognize these deficiency payments in revenue.

In certain of these throughput agreements, a customer may later utilize such shortfall billings as credit towards future volume shipments in excess of its minimum levels within its respective contractual shortfall make-up period. Such amounts represent an obligation to perform future services, which may be initially deferred and later recognized as revenue based on estimated future shipping levels, including the likelihood of a customer’s ability to utilize such amounts prior to the end of the contractual shortfall make-up period. We recognize the service portion of these deficiency payments in revenue when we do not expect we will be required to satisfy these performance obligations in the future based on the pattern of rights exercised by the customer. During the twelve months ended December 31, 2018, 2017 and 2016, we recognized $17.6 million, $11.9 million and $10.5 million, respectively, of these deficiency payments in revenue, of which $3.3 million, $5.6 million and $7.8 million, respectively, related

to deficiency payments billed in prior periods. As of December 31, 2018, deferred revenue reflected in our consolidated balance sheet related to shortfalls billed was $1.8 million.
A contract liability exists when an entity is obligated to perform future services to a customer for which the entity has received consideration. Since HEP may be required to perform future services for these deficiency payments received, the deferred revenues on our balance sheet as of December 31, 2018 were considered contract liabilities. A contract asset exists when an entity has a right to consideration in exchange for goods or services transferred to a customer. Our consolidated balance sheet as of December 31, 2018, included the contract assets and liabilities in the table below.

	December 31, 2018	January 1, 2018
	(In thousands)	
Contract assets	$1,818	$—
Contract liabilities	$(1,821)	$(2,713)

The contract assets and liabilities include both lease and service components. We recognized $2.7 million of revenue that was previously included in contract liability as of January 1, 2018, during the twelve months ended December 31, 2018.
As of December 31, 2018, we expect to recognize $2.3 billion in revenue related to our unfulfilled performance obligations under the terms of our long-term throughput agreements and operating leases expiring in 2019 through 2036. These agreements provide for changes in the minimum revenue guarantees annually for increases or decreases in the Producer Price Index ("PPI") or Federal Energy Regulatory Commission ("FERC") index, with certain contracts having provisions that limit the level of the rate increases or decreases. We expect to recognize revenue for these unfulfilled performance obligations as shown in the table below (amounts shown in table include both service and lease revenues):

Years Ending December 31,	(In millions)
2019	$ 356
2020	308
2021	298
2022	271
2023	236
Thereafter	838
Total	$ 2,307

Payment terms under our contracts with customers are consistent with industry norms and are typically payable within 10 to 30 days of the date of invoice.
Disaggregated revenues are as follows:

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Pipelines	$283,507	$235,040	$232,634
Terminals, tanks and loading racks	147,534	142,418	136,365
Refinery processing units	75,179	76,904	33,044
	$506,220	$454,362	$402,043

During the year ended December 31, 2018, lease revenues amounted to $278.6 million, and service revenues amounted to $227.6 million. Both of these revenues were recorded within affiliates and third parties revenues on our consolidated statement of income.

Note 4: Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and debt. 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 were as follows:

Financial Instrument	Fair Value Input Level	December 31, 2018		December 31, 2017	
		Carrying Value	Fair Value	Carrying Value	Fair Value
		(In thousands)			
Liabilities:					
6.0% Senior Notes	Level 2	$495,900	$488,310	$495,308	$525,120

Level 2 Financial Instruments

Our senior notes 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.

See Note 8 for additional information on these instruments.

Note 5: Properties and Equipment

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

	December 31, 2018	December 31, 2017
	(In thousands)	
Pipelines, terminals and tankage	$1,571,338	$1,541,722
Refinery assets	347,338	347,338
Land and right of way	86,298	86,484
Construction in progress	23,482	12,029
Other	41,250	35,659
	2,069,706	2,023,232
Less accumulated depreciation	531,051	453,761
	$1,538,655	$1,569,471

We capitalized $0.3 million and $1.0 million in interest related to construction projects during the years ended December 31, 2018 and 2017, respectively.

Depreciation expense was $83.3 million, $71.1 million, and $62.9 million for the years ended December 31, 2018, 2017 and 2016, respectively, and includes depreciation of assets acquired under capital leases. Asset abandonment charges of $1.0 million,

$0.3 million and $0.6 million for assets permanently removed from service were included in depreciation expense for the years ended December 31, 2018, 2017 and 2016, respectively.

Note 6: 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, from Plains in 2017, and from other minor acquisitions in 2018.

The carrying amounts of our intangible assets are as follows:

	Useful Life	December 31, 2018	December 31, 2017
		(In thousands)	
Delek transportation agreement	30 years	$59,933	$ 59,933
HFC transportation agreements	10-15 years	75,131	75,131
Customer relationships	10 years	69,683	69,282
Other		50	50
		204,797	204,396
Less accumulated amortization		89,468	74,933
		$115,329	$ 129,463

Amortization expense was $14.5 million, $7.6 million and $6.9 million for the years ending December 31, 2018, 2017 and 2016, respectively. We estimate amortization expense to be $14 million for each of the next four years and $9.9 million in 2023.

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 7: 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 $6.9 million, $5.9 million and $5.7 million for the years ended December 31, 2018, 2017 and 2016, respectively. These costs include retirement costs of $3.1 million, $2.7 million and $2.6 million for the years ended December 31, 2018, 2017 and 2016, 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, 2018, we have two types of incentive-based awards outstanding, which are described below. The compensation cost charged against income was $3.0 million, $2.7 million and $2.7 million for the years ended December 31, 2018, 2017 and 2016, 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, 2018, 2,500,000 units were authorized to be granted under our Long-Term Incentive Plan, of which 1,210,341 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. In the years ending December 31, 2017 and 2016, we granted restricted units to selected employees who performed 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 grant date 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, 2018, is presented below:

Restricted and Phantom Units	Units	Weighted-Average Grant-Date Fair Value
Outstanding at January 1, 2018 (nonvested)	119,009	$ 34.77
Granted	93,955	29.30
Vesting and transfer of common units to recipients	(72,537)	34.20
Forfeited	(2,411)	34.63
Outstanding at December 31, 2018 (nonvested)	138,016	$ 31.35

The grant date fair values of restricted units that were vested and transferred to recipients during the years ended December 31, 2018, 2017 and 2016 were $2.5 million, $2.0 million and $2.0 million, respectively. As of December 31, 2018, there was $2.8 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, 2017 and 2016, the grant date price applied to the number of restricted units awarded was $35.59 and $32.16 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 meeting certain criteria over the performance period. Under the terms of our performance unit grants, some awards are subject to the growth in our distributable cash flow per common unit over the performance period while other awards are subject to "financial performance" and "market performance." Financial performance is based on meeting certain earnings before interest, taxes, depreciation and amortization ("EBITDA") targets, while market performance is based on the relative standing of total unitholder return achieved by HEP compared to peer group companies. The number of units ultimately issued under these awards can range from 50% to 150% or 0% to 200%. As of December 31, 2018, estimated unit payouts for outstanding nonvested performance unit awards ranged between 100% and 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.

A summary of performance unit activity and changes for the year ended December 31, 2018, is presented below:

Performance Units	Units
Outstanding at January 1, 2018 (nonvested)	36,911

Granted	19,120
Vesting and transfer of common units to recipients	(4,283)
Outstanding at December 31, 2018 (nonvested)	51,748

The grant date fair values of performance units vested and transferred to recipients were $0.1 million, $0.1 million and $1.1 million for the years ended December 31, 2018, 2017 and 2016, respectively. Based on the weighted average fair value of performance units outstanding at December 31, 2018, of $1.7 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 1.7 years.

During the year ended December 31, 2018, we did not purchase any common units in the open market for the issuance and settlement of unit awards under our Long-Term Incentive Plan.

Note 8: Debt

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.

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.

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 for the years ending December 31, 2018 and 2017, were 4.238% and 3.734%, respectively. We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.25% 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, 2018.

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 principal amount 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, 2018. 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 due in 2020 (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 were 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, 2018	December 31, 2017
	(In thousands)	
Credit Agreement		
Amount outstanding	$923,000	$1,012,000
6% Senior Notes		
Principal	500,000	500,000
Unamortized debt issuance costs	(4,100)	(4,692)
	495,900	495,308
Total long-term debt	$1,418,900	$1,507,308

Maturities of our long-term debt are as follows:

Years Ending December 31,	(In thousands)
2019	$—
2020	—
2021	—
2022	923,000
2023	—
Thereafter	500,000
Total	$1,423,000

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.

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swaps	$37,266	$28,928	$17,621
6% Senior Notes	30,000	25,813	10,811
6.5% Senior Notes	—	—	19,507
Amortization of discount and deferred debt issuance costs	3,041	3,063	3,246
Commitment fees and other	1,904	1,648	2,069
Total interest incurred	72,211	59,452	53,254
Less capitalized interest	312	1,004	702

Net interest expense	$71,899	$58,448	$52,552
Cash paid for interest	$69,112	$62,395	$38,530

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 $5.8 million and $5.1 million as of December 31, 2018 and 2017, respectively, with accumulated depreciation of $4.3 million and $3.3 million as of December 31, 2018 and 2017, respectively. We include depreciation of capital leases in depreciation and amortization in our consolidated statements of income.

At December 31, 2018, future minimum annual lease payments, including interest, for the capital leases are as follows:

Years Ending December 31,	(in thousands)
2019	$ 1,069
2020	589
2021	140
Total minimum lease payments	1,798
Less amount representing interest	(109)
Capital lease obligations	$ 1,689

Note 9: 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 2035.

As of December 31, 2018, 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)
2019	$ 7,252
2020	7,196
2021	7,147
2022	7,127
2023	7,045
Thereafter	24,619
Total	$ 60,386

Rental expense charged to operations was $9.8 million, $9.1 million and $8.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, we expect to receive aggregate payments totaling $1.5 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, 2018.

At December 31, 2018, these minimum future contractual obligations and other miscellaneous obligations having terms in excess of one year are as follows:

Years Ending December 31,	(In thousands)
2019	$ 9,360
2020	7,683
2021	7,689
2022	7,069
2023	5,536
Thereafter	223,567
Total	$ 260,904

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 10: Significant Customers

All revenues are domestic revenues, of which 86% 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,		
	2018	2017	2016
HFC	79%	83%	83%
Delek	7 %	8 %	8 %

Note 11: 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, 2018, these agreements with HFC require minimum annualized payments to us of $314 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 2018) 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 $397.8 million, $377.1 million and $333.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.
- HFC charged us general and administrative services under the Omnibus Agreement of $2.5 million for each of the years ended December 31, 2018, 2017 and 2016.
- We reimbursed HFC for costs of employees supporting our operations of $51.7 million, $46.6 million and $40.9 million for the years ended December 31, 2018, 2017 and 2016, respectively.

- HFC reimbursed us $10.0 million, $7.2 million and $14.0 million for the years ended December 31, 2018, 2017 and 2016, respectively, for expense and capital projects.
- We distributed $146.8 million, in the year ended December 31, 2018 to HFC as regular distributions on its common units and $130.7 million and $105.2 million in the years ended December 31, 2017 and 2016, respectively, to HFC as regular distributions on its common units and general partner interest, including general partner incentive distributions.
- Accounts receivable from HFC were $46.8 million and $51.5 million at December 31, 2018 and 2017, respectively.
- Accounts payable to HFC were $14.2 million and $7.7 million at December 31, 2018 and 2017, respectively.
- Revenues for the years ended December 31, 2018, 2017 and 2016 include $3.1 million, $4.8 million and $6.1 million, respectively, of shortfall payments billed to HFC in 2017, 2016 and 2015, respectively. Deferred revenue in the consolidated balance sheets at December 31, 2018 and 2017, includes $1.7 million and $4.4 million, respectively, relating to certain shortfall billings to HFC.
- We received lease payments from HFC for use of our Artesia and Tulsa railyards of $2.0 million, $0.5 million and $0.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.
- 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 12: Partners' Equity, Income Allocations and Cash Distributions

At December 31, 2018, HFC held 59,630,030 of our common units, constituting a 57% 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, 2018, HEP has issued 2,413,153 units under this program, providing $82.3 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 the partners is allocated to the partners based on their weighted-average ownership percentage during the period.

Prior to the equity restructuring of the general partner interest owned by HEP Logistics described in Note 1 that occurred on October 31, 2017, net income attributable to the partners was 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 incentive distributions and other priority allocations are allocated to the general partner, the remaining net income attributable to HEP was allocated to the partners based on their weighted-average ownership percentage during the period.

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

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
General partner interest in net income	$—	$919	$3,165
General partner incentive distribution	—	34,128	54,008
Net loss attributable to Predecessor	—	—	(10,657)
Total general partner interest in net income	$—	$35,047	$46,516

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 24, 2019, we announced our cash distribution for the fourth quarter of 2018 of $0.6675 per unit. The distribution is payable on all common units and was paid February 14, 2019, to all unitholders of record on February 4, 2019. 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,		
	2018	2017	2016
	(In thousands, except per unit data)		
General partner interest in distribution	$—	$2,335	$4,088
General partner incentive distribution	—	34,128	54,008
Total general partner distribution	—	36,463	58,096
Limited partner distribution	269,284	206,846	143,796
Total regular quarterly cash distribution	$269,284	$243,309	$201,892
Cash distribution per unit applicable to limited partners	$2.6475	$2.5475	$2.3625

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 13: Net Income Per Limited Partner Unit

Net income per unit applicable to the limited partners was computed using the two-class method since we had more than one class of participating securities during the period from January 1, 2016 through October 31, 2017. The classes of participating securities during this period included common units, general partner units and 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,		
	2018	2017	2016
	(in thousands)		
Net income attributable to the partners	$178,847	$195,040	$158,241
Less: General partner’s distribution declared (including IDRs)	—	(36,463)	(58,096)
Limited partner’s distribution declared on common units	(269,284)	(206,846)	(143,796)
Distributions in excess of net income attributable to the partners	$(90,437)	$(48,269)	$(43,651)

	General Partner (including IDRs)	Limited Partners’ Common Units	Total
	(In thousands, except per unit data)		
Year Ended December 31, 2018			
Net income attributable to the partners:			
Distributions declared	$—	$269,284	$269,284
Distributions in excess of net income attributable to partnership	—	(90,437)	(90,437)
Net income attributable to the partners	$—	$178,847	$178,847
Weighted average limited partners' units outstanding		105,042	
Limited partners' per unit interest in earnings - basic and diluted		$1.70	
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:			