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, 2012
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 (State or other jurisdiction of incorporation or organization)	20-0833098 (I.R.S. Employer Identification No.)
2828 N. Harwood, Suite 1300 Dallas, Texas (Address of principal executive offices)	75201-1507 (Zip Code)

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

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

Securities registered pursuant to 12(g) of the Act:
None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act.
Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $900 million on June 29, 2012, the last day of the registrant's most recently completed second fiscal quarter, based on the last sales price as quoted on the New York Stock Exchange on such date.

The number of the registrant’s outstanding common limited partners units at February 15, 2013 was 56,782,048.

DOCUMENTS INCORPORATED BY REFERENCE: None

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PART I

FORWARD-LOOKING STATEMENTS

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

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

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

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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:

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Item 1. Business
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 and loading rack facilities in west Texas, New Mexico, Utah, Nevada, Oklahoma, Wyoming, Kansas, Arizona, Idaho and Washington. We were formed in Delaware in 2004 and maintain our principal corporate offices at 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. Our telephone number is 214-871-3555 and our internet website address is www.hollyenergy.com. The information contained on our website does not constitute part of this Annual Report on Form 10-K. A copy of this Annual Report on Form 10-K will be provided without charge upon written request to the Vice President, Investor Relations at the above address. A direct link to our filings at the U.S. Securities and Exchange Commission ("SEC") website is available on our website on the Investors page. Also available on our website are copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics, all of which will be provided without charge upon written request to the Vice President, Investor Relations at the above address. In this document, the words "we," "our," "ours" and "us" refer to HEP and its consolidated subsidiaries or to HEP or an individual subsidiary and not to any other person. "HFC" refers to HollyFrontier Corporation and its subsidiaries, other than HEP and its subsidiaries and other than Holly Logistic Services, L.L.C. ("HLS"), a subsidiary of HollyFrontier Corporation that is the general partner of the general partner of HEP and manages HEP.
We own and operate petroleum product and crude pipelines and terminal, tankage and loading rack facilities that support HFC's refining and marketing operations in the Mid-Continent, Southwest and Rocky Mountain regions of the United States and Alon USA, Inc.'s ("Alon") refinery in Big Spring, Texas. HFC currently owns a 44% interest in us, including the 2% general partner interest. Additionally, we own a 75% interest in UNEV Pipeline, LLC ("UNEV"), which owns a 400-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada (the "UNEV Pipeline"), product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets, and a 25% joint venture interest in a 95-mile intrastate crude oil pipeline system (the "SLC Pipeline") that serves refineries in the Salt Lake City, Utah area.
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, and providing other services at our storage tanks and terminals. 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.
Our assets include:
Pipelines:

- approximately 810 miles of refined product pipelines, including 340 miles of leased pipelines, that transport gasoline, diesel and jet fuel principally from HFC's Navajo refinery in New Mexico to its customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Utah and northern Mexico;
- approximately 510 miles of refined product pipelines that transport refined products from Alon's Big Spring refinery in Texas to its customers in Texas and Oklahoma;
- three 65-mile intermediate pipelines that transport intermediate feedstocks and crude oil from HFC's Navajo refinery crude oil distillation and vacuum facilities in Lovington, New Mexico to its petroleum refinery facilities in Artesia, New Mexico;
- approximately 960 miles of crude oil trunk, gathering and connection pipelines located in west Texas, New Mexico and Oklahoma that deliver crude oil to HFC's Navajo refinery;
- approximately 10 miles of refined product pipelines that support HFC's Woods Cross refinery located near Salt Lake City, Utah;
- gasoline and diesel connecting pipelines located at HFC's Tulsa east refinery facility;
- five intermediate product and gas pipelines between HFC's Tulsa east and west refinery facilities;
- crude receiving assets located at HFC's Cheyenne refinery;
- a 75% interest in the UNEV Pipeline, a 400-mile refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada; and
-

a 25% joint venture interest in the SLC pipeline, a 95-mile intrastate crude oil pipeline system that transports crude oil into the Salt Lake City, Utah area from the Utah terminus of the Frontier Pipeline, as well as crude oil flowing from Wyoming and Utah via Plains All American Pipeline, L. P.'s ("Plains") Rocky Mountain Pipeline.

Refined Product Terminals and Refinery Tankage:

- four refined product terminals located in El Paso, Texas; Moriarty and Bloomfield, New Mexico; and Tucson, Arizona, with an aggregate capacity of approximately 1,300,000 barrels, that are integrated with our refined product pipeline system that serves HFC's Navajo refinery;
- three refined product terminals (two of which are 50% owned), located in Burley and Boise, Idaho and Spokane, Washington, with an aggregate capacity of approximately 500,000 barrels, that serve third-party common carrier pipelines;
- one refined product terminal near Mountain Home, Idaho with a capacity of 120,000 barrels, that serves a nearby United States Air Force Base;
- two refined product terminals, located in Wichita Falls and Abilene, Texas, and one tank farm in Orla, Texas with aggregate capacity of approximately 500,000 barrels, that are integrated with our refined product pipelines that serve Alon's Big Spring refinery;
- a refined product loading rack facility at each of HFC's refineries, heavy product / asphalt loading rack facilities at HFC's Navajo refinery Lovington facility, Tulsa refinery east facility and the Cheyenne refinery, liquefied petroleum gas ("LPG") loading rack facilities at HFC's Tulsa refinery west facility, Cheyenne refinery and El Dorado refinery, lube oil loading racks at HFC's Tulsa refinery west facility and crude oil Leased Automatic Custody Transfer ("LACT") units located at HFC's Cheyenne refinery;
- a leased jet fuel terminal in Roswell, New Mexico;
- on-site crude oil tankage at HFC's Navajo, Woods Cross, Tulsa and Cheyenne refineries having an aggregate storage capacity of approximately 1,100,000 barrels;
- on-site refined and intermediate product tankage at HFC's Tulsa, Cheyenne and El Dorado refineries having an aggregate storage capacity of approximately 8,200,000 barrels; and
- a 75% interest in UNEV Pipeline's product terminals near Cedar City, Utah and Las Vegas, Nevada with an aggregate capacity of approximately 460,000 barrels.

We have a long-term strategic relationship with HFC. Our growth plan is to continue to pursue purchases of logistic assets at HFC's existing refining locations in New Mexico, Utah, Oklahoma, Kansas and Wyoming. We also will 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 November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all periods presented.

2012 Acquisition

UNEV Pipeline Interest Acquisition

On July 12, 2012, we acquired from HFC a 75% interest in UNEV which owns a 400-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada, product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, we issued to HFC a Class B unit comprising an equity interest in a wholly-owned subsidiary that entitles HFC to an 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. 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. In connection with the transaction, we entered into 15-year throughput agreements with shippers containing minimum annual revenue commitments to us of $25 million.

2011 Acquisition

Legacy Frontier Tankage and Terminal Transaction

On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150 million and 7,615,230 of our common units. In connection with the transaction, we entered into 15-year throughput agreements with HFC containing minimum annual revenue commitments to us of $48.3 million.

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2010 Acquisitions

Tulsa East / Lovington Storage Asset Transaction

On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC’s Tulsa refinery east facility. Also, as part of this same transaction, we acquired HFC’s asphalt loading rack facility located at its Navajo refinery facility in Lovington, New Mexico for $4.4 million.

Agreements with HFC and Alon

We serve HFC’s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 2019 through 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (“PPI”) or the Federal Energy Regulatory Commission (“FERC”) index. Additionally, such agreements require HFC to reimburse us for certain costs. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall 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 also have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that also is subject to annual tariff rate adjustments. In addition, we have a capacity lease agreement with Alon under which we lease Alon space on our Orla to El Paso pipeline for the shipment of up to 15,000 barrels of refined product per day. The terms under this agreement expire beginning in 2018 through 2022. As of December 31, 2012, these agreements with Alon will result in minimum annualized payments to us of $31.4 million.

A significant reduction in revenues under these agreements would 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 10 to the Consolidated Financial Statements included in Item 8 of Part II of this Form 10-K.

Omnibus Agreement

Under certain provisions of an omnibus agreement with HFC (the “Omnibus Agreement”), we pay HFC an annual administrative fee for the provision by HFC or its affiliates of various general and administrative services to us, currently $2.3 million. This fee includes expenses incurred by HFC and its affiliates 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 HLS who perform services for us or the cost of their employee benefits, such as 401(k), pension and health insurance benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct expenses they incur on our behalf. In addition, we also pay for our own direct general and administrative costs, including costs relating to operating as a separate publicly held entity, such as costs for preparation of partners’ K-1 tax information, SEC filings, investor relations, directors’ compensation, directors’ and officers’ insurance and registrar and transfer agent fees.

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 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 do not extend their useful life are charged to operating expenses as incurred.

Each year the HLS board of directors 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 2013 regular capital budget is comprised of $10.1 million for maintenance capital expenditures and $2.0 million for expansion capital expenditures exclusive of the projects discussed below. In addition to our capital budget, we may spend funds periodically to do capital upgrades of our assets where a customer reimburses us for such costs. These reimbursements would be required under contractual agreements and would generally benefit the customer over the remaining life of such agreements.

We recently have made certain modifications to our crude oil gathering and trunk line system that effectively have increased our ability to gather and transport an additional 10,000 barrels per day ("bpd") of Delaware Basin crude oil in response to increased drilling activity in southeast New Mexico. We have a second project recently approved which consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. This project also includes the expansion and extension of several of our crude gathering systems and crude mainlines. Once in service, this system will be capable of transporting crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. This project is estimated to cost approximately $38.5 million and could be fully operational in late 2013.

We are also performing preliminary engineering, routing and cost estimates for two proposed new pipelines. The first proposed pipeline would be a new intrastate crude oil pipeline between Cushing, Oklahoma and HFC's Tulsa, Oklahoma refinery. The 50-mile line would provide safe and reliable transport of Cushing sourced domestic and Canadian crude oil to HFC's 125,000 BPD Tulsa facility. The pipeline would allow for a significant portion of crude oil transported to be heavy Canadian and sour crude oil. Crude oil processed at HFC's Tulsa facility is currently transported on pipelines owned by Sunoco Logistics and Magellan Pipeline Company. The second proposed pipeline would be a new 100-mile interstate petroleum products pipeline between the HFC's Cheyenne, Wyoming refinery and Denver, Colorado. The 52,000 BPD refinery, with its ability to process up to 35,000 BPD of heavy Canadian crude and its close proximity to growing domestic crude production, is a significant supplier of petroleum products to the Denver market. The project also will evaluate the construction of a new petroleum products terminal in North Denver or, alternatively, the routing of the new pipeline to existing third-party product terminals in the Denver area. This infrastructure addition would ensure safe and reliable transport of petroleum products from HFC's location-advantaged refinery to its largest market. Petroleum products produced at HFC's Cheyenne, Wyoming refinery are currently transported to Denver on the Rocky Mountain Pipeline's products line owned by Plains All-American. We anticipate that we will be in a position to decide whether to proceed with these projects in the second quarter of 2013 when preliminary engineering and detailed project cost estimates are completed and if necessary shipper commitments can be secured.

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 existing cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our $550 million senior secured revolving credit facility expiring in June 2017 (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.

SAFETY AND MAINTENANCE

We perform preventive and normal maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We also conduct routine and required inspections of our pipelines and other assets as required by code or regulation. 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 conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We regularly monitor, test and record the effectiveness of these corrosion-inhibiting systems.

We monitor the structural integrity of selected segments of our pipeline systems through a program of periodic internal inspections using both “dent pigs” and electronic “smart pigs”, as well as hydrostatic testing that conforms to federal standards. We follow these inspections with a review of the data and we make repairs as necessary to ensure the integrity of the pipeline. We have initiated a risk-based approach to prioritizing the pipeline segments for future smart pig runs or other approved integrity testing methods. We believe this approach will ensure that the pipelines that have the greatest risk potential receive the highest priority in being scheduled for inspections or pressure tests for integrity. Our inspection process complies with all Department of Transportation (“DOT”) and Code of Federal Regulations (“CFR”) 49 CFR Part 195 requirements.

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

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

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

COMPETITION

As a result of our physical integration with HFC’s refineries, our contractual relationship with HFC under the Omnibus Agreement and the HFC pipelines and terminals, tankage and throughput agreements, we believe that we will not face significant competition for barrels of refined products transported from HFC’s refineries, particularly during the terms of our long-term transportation agreements with HFC expiring in 2019 through 2026. Additionally, under our throughput agreement with Alon expiring in 2020, we believe that we will not face significant competition for those barrels of refined products we transport from Alon’s Big Spring refinery.

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

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

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

Historically, the significant majority of the throughput at our terminal facilities has come from HFC, with the exception of third-party receipts at the Spokane terminal, Alon volumes at El Paso, and the Abilene and Wichita Falls terminals that serve Alon’s Big Springs refinery.

Our twelve 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.

RATE REGULATION

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

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

ENVIRONMENTAL REGULATION AND REMEDIATION

Our operation of pipelines, terminals, and associated facilities in connection with the storage and transportation of refined products 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. Although these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position in that the operations of our competitors are similarly affected. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. A 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.

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

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

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.

There are environmental remediation projects 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 for future remediation activities retained by HFC. Additionally, as of December 31, 2012, we have an accrual of $3.0 million that relates to environmental clean-up projects for which we have assumed liability or for which the indemnity provided for by HFC has expired or will expire. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

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

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EMPLOYEES
Neither we nor our general partner has employees. Direct support for our operations is provided by HLS, which employs 232 people. We reimburse HFC for direct expenses that HFC or its affiliates incurs on our behalf for the employees of HLS. HLS considers its employee relations to be good.

Item 1A. Risk Factors
Investing in us involves a degree of risk, including the risks described below. 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 be affected also by economic, financial, competitive, and regulatory factors that are beyond our control. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to pay quarterly distributions at the current level for each quarter or to increase our quarterly distributions in the future.

We depend on HFC and particularly its Navajo refinery for a 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, 2012, HFC accounted for 79% of the revenues of our petroleum product and crude pipelines and 92% of the revenues of our terminals, tankage, and truck loading racks. 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 curtailing of production at the Navajo refinery could, by reducing throughput in our pipelines and terminals, result in our realizing materially lower levels of revenues and cash flow for the duration of the shutdown. For the year ended December 31, 2012, production from the Navajo refinery accounted for 82% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 100% of the petroleum products 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:

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- 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 or environmental proceedings or other litigation that compel the cessation 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 magnitude of 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; is responsible for all related costs; and 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 and throughput agreements with us would be temporarily suspended during the occurrence of a force majeure event that renders performance impossible with respect to an asset for at least 30 days. If such an event were to continue for a year, we or HFC could terminate the agreements. The occurrence of any of these events could reduce our revenues and cash flows.

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

For the year ended December 31, 2012, Alon accounted for 11% of the combined revenues of our petroleum product and crude pipelines and of our terminals and truck loading racks, including revenues we received from Alon under a capacity lease agreement.
A decline in production at Alon's Big Spring refinery would reduce materially the volume of refined products we transport and terminal for Alon and, as a result, our revenues would 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 factors for the Navajo refinery.

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

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

Due to our lack of asset 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 diversification, especially a large concentration of pipeline assets serving the Navajo refinery, an adverse development in our business could have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

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, 2012, the principal amount of our total outstanding debt was $871 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 indentures for our 8.25% senior notes due 2018 and our 6.50% senior notes due 2020 (collectively, the “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.

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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 prevailing 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 impair materially 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 assure you that we would be able to refinance our existing indebtedness at maturity or otherwise or sell assets on terms that are commercially reasonable.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain beneficial transactions. The agreements governing our debt generally require us to comply with various affirmative and negative covenants including the maintenance of certain financial ratios and restrictions on incurring additional debt, entering into mergers, consolidations and sales of assets, making investments and granting liens. Additionally, our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to 2015 and $171 million prior to 2018, subject to certain limited exceptions. Our leverage may affect adversely our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisitions, construction or development activities, or to otherwise realize fully the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage also may make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

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

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

Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Moreover, without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or construction projects, take advantage of other business opportunities or respond to competitive pressures, any of which 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.

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 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, 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

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costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

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. Our inability to execute our growth strategy may materially, adversely affect our ability to maintain or pay higher distributions in the future.

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

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers, vendors or other counterparties. We derive a significant portion of our revenues from contracts with key customers, including HFC and Alon under their respective pipelines and terminals, tankage and throughput agreements. To the extent that these and other 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 utilize 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 have agreed to indemnify us, subject to certain limitations, for (1) certain pre-closing environmental liabilities discovered within specified time periods after the date of the applicable acquisition, (2) certain matters arising from the pre-closing ownership and operation of assets, and (3) ongoing remediation related to the assets. Our results of operation, cash flows and our ability to make cash distributions to our unitholders could be adversely affected in the future if third parties fail to satisfy an indemnification obligation owed to us.

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

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

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

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

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

Fluctuations in crude oil prices can greatly affect production rates and investments by third parties in the development of new oil reserves. Drilling activity generally decreases as crude oil prices decrease. We and our shippers have no control over 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, or 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. 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 current 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 throughput agreements with HFC and Alon expire beginning in 2019 through 2026.

Meeting the requirements of evolving environmental, health and safety laws and regulations, including those related to climate change, could adversely affect our performance.

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, HFC and Alon to incur potentially material capital expenditures associated with the construction, maintenance, and upgrading of equipment and facilities. We may also be required to address conditions discovered in the future that require environmental response actions or remediation. Future environmental, health and safety requirements or changed interpretations of existing requirements, may impose more stringent requirements on our assets and operations and require us to incur potentially material expenditures to ensure our continued compliance. Future developments in federal laws and regulations governing environmental, health and safety and energy matters are especially difficult to predict.

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

Requiring a reduction in greenhouse gas emissions and the increased use of renewable fuels could also decrease demand for refined products, which could have an indirect, but material, adverse effect on our business, financial condition and results of operations. For example, in 2010, the EPA promulgated a rule establishing greenhouse gas emission standards for new-model passenger cars, light-duty trucks, and medium-duty passenger vehicles. Also in 2010, the EPA promulgated a rule establishing greenhouse gas emission thresholds for the permitting of certain stationary sources, which could require greenhouse emission controls for those sources. These requirements could 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.

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The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues and potentially the adoption of new regulatory requirements for existing pipelines. In addition, the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation has published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Such legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

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, there can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition and results of operations.

Our operations are subject to federal, state, and local laws and regulations relating to product quality specifications, environmental protection and operational safety that could require us to make substantial expenditures.

Our pipelines and terminals, tankage and loading rack operations are subject to increasingly strict environmental and safety laws and regulations. Also, 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. 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 also have been operated by third parties whose handling, disposal, or release of hydrocarbons and other wastes were not under our control. If we were to incur a significant liability pursuant to environmental laws or regulations, it could have a material adverse effect on us. Also we are subject to the requirements of the Federal Occupational Safety and Health Administration (“OSHA”), and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

Petroleum products that we store and transport are sold by our customers for consumption into the public market. 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.

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

Our operations are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of equipment or life or destruction of property, injury, or extensive property damage, 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.

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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. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position. With our distribution policy, we do not have the same flexibility as other legal entities to accumulate cash to protect against underinsured or uninsured losses.

There can be no assurance that insurance will cover all damages and losses resulting from these types of hazards. We are not fully insured against all risks incident to our business. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only certain lost revenues arising from physical damage to our facilities and HFC and Alon facilities. If a significant accident or event occurs that is not fully insured, our operations could be temporarily or permanently impaired, and our liabilities and expenses could be significant.

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

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

We could be subject to damages based on claims brought against us by our customers or lose customers as a result of the failure of products we distribute to meet certain quality specifications.

A significant portion of our operating responsibility on refined product pipelines is to insure the quality and purity of the products loaded at our loading racks. If our quality control measures were to 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.

If our assumptions concerning population growth are inaccurate or if HFC's growth strategy is not successful, our ability to grow may be adversely affected.

Our growth strategy is dependent upon:

- the accuracy of our assumption that many of the markets that we currently serve or have plans to serve in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States will experience population growth that is higher than the national average; and
- the willingness and ability of HFC to capture a share of this additional demand in its existing markets and to identify and penetrate new markets in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States.

If our assumptions about growth in 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. Furthermore, HFC is under no obligation to pursue a growth strategy. If HFC chooses not to gain, or is unable to gain additional customers in new or existing markets, our growth strategy would be adversely affected.

Moreover, HFC may not make acquisitions that would provide acquisition opportunities to us; or, if those opportunities arise, they may not be on terms attractive to us or on terms that allow us to obtain appropriate financing.

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. These projects may not be completed on schedule or at all or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time and we will not receive any material increases in revenues until after completion of the project. Moreover, we may construct facilities to capture anticipated future growth in demand for refined products in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

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

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

The primary rate-making methodology of the FERC is price indexing. We use this methodology in all of our interstate markets. If the FERC's petroleum pipeline rate-making methodology changes, the new methodology could result in tariffs that generate lower revenues and cash flow. The indexing method allows a pipeline to increase its rates based on a percentage change in the producer price index 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. In addition, changes in the index might not be large enough to fully reflect actual increases in our costs. The FERC's 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. Any of the foregoing would adversely affect our revenues and cash flow.

If a party with an economic interest were to file either a protest of our proposal for increased rates or a complaint against our existing tariff rates, or the FERC were to initiate an investigation of our existing rates, then our rates could be subject to detailed review. If our proposed rate increases were found to be in excess of levels justified by our cost of service, the FERC could order us to reduce our rates, and to refund the amount by which the rate increases were determined to be excessive, plus interest. If our existing rates were found to be in excess of our cost of services, we could be ordered to refund the excess we collected for as far back as 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 addition, a state commission also could investigate our intrastate rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our rates exceeded levels justified by our cost of service, the state commission could order us to reduce our rates. Any such reductions may result in lower revenues and cash flows if additional volumes and / or capacity are unavailable to offset such rate reductions.

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

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

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks, on the energy transportation industry in general, and on us in particular, is not known at this time. 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 may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

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.

Adverse changes in our credit ratings and risk profile, and that of our general partner, 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. 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 restrict or discontinue our ability to

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access capital markets at attractive rates, and could result in an increase in our borrowing costs, a reduced level of capital expenditures and an impact on future earnings and cash flows.

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. However, a downgrade in our credit rating could affect adversely our ability to borrow on, renew existing, or obtain access to new financing arrangements and would increase the cost of such financing arrangements.

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 of any future acquisitions 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. For example, in 2012 we completed the UNEV pipeline asset acquisition. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. Our capitalization and results of operations may change significantly as a result of the acquisitions we recently completed or as a result of 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, including the assets we acquired in 2012. 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.

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

Delays or cost increases related to capital spending programs involving construction of new facilities (or improvements and repairs to our existing facilities) could affect adversely 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 facilities are located. Our operations could be disrupted if we were to lose or were unable to renew existing rights-of-way.

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

Our business may suffer due to a change in the composition of our Board of Directors, or if any of our key senior executives or other key employees discontinue employment with HLS, who provide services to us. Furthermore, a shortage of skilled labor or disruptions in HLS's labor force 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. 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.

As of December 31, 2012, approximately 17% of HLS's employees were represented by labor unions under collective bargaining agreements with various expiration dates. We 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 strike or work stoppage in the future, and any work stoppage could negatively affect our results of operations and financial condition.

Many of our officers also allocate time to our general partner and its affiliates.

Our general partner shares officers and administrative personnel with HFC to operate both our business and HFC's business. Our general partners' officers, several of whom also are officers of HFC, will allocate the time they and the other employees of HFC spend on our behalf and on behalf of HFC. 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.

RISKS TO COMMON UNITHOLDERS

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

Currently, HFC indirectly owns the 2% general partner interest and a 42% limited partner interest in us and owns and controls the general partner of our general partner, HEP Logistics Holdings, L.P (“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;
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- 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 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 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.

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Under our Omnibus Agreement, we are currently obligated to pay HFC an administrative fee of $2.3 million per year for the provision by HFC or its affiliates of various general and administrative services for our benefit. We can provide no 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 is 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 properly 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 Holly Logistic Services, L.L.C. 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, for 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, for 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 our general partner's general partner and have no right to elect our general partner or the board of directors of our general partner's general partner on an annual or other continuing basis. The board of directors of our general partner's general partner is chosen by the members of our general partner's general partner. Furthermore, 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 or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to 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 taken by the board of directors and officers.

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

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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.

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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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 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 among us, HFC and our general partner, 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 may cause us to borrow funds in order to make cash distributions, even where the purpose or effect of the borrowing benefits our general partner or its affiliates.

In some instances, our general partner may cause us to borrow funds from affiliates of HFC or from third parties in order to permit the payment of cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make incentive distributions.

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, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, 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.

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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.

HFC currently holds 24,255,030 of our common units, which is approximately 42% of our outstanding common units. Additionally, we agreed to provide HFC registration rights with respect to our common units that it holds. The sale of these units in the public or private markets could have 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 our 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, as a result of legislative changes, we were to become subject to additional amounts of entity-level taxation for federal or state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (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, which is currently a maximum of 35%. Under current law, 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.

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 units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Currently, one such legislative proposal would eliminate the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the expectation for certain publicly traded partnerships to be treated as partnerships 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, our 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.

Unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will generally be treated as partners to whom we allocate taxable income, which could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from 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. Moreover, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation and deductions and certain other items. 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.

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

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

We treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to their tax returns.

We 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.

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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 use of this proration method may not be permitted under existing treasury regulations, and although the Department of the Treasury issued proposed treasury regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items, the proposed regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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 is no tax concept 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, 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 that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

We will be considered to have terminated our partnership for federal income tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders may receive two

Schedules K-1) for one fiscal year and may result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in its taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

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

Item 1B. Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2. Properties

PIPELINES

Our refined product pipelines transport light refined products from HFC’s Navajo refinery in New Mexico and Alon’s Big Spring refinery in Texas to their customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Utah, Oklahoma and northern Mexico and from 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 LPGs (such as propane, butane and isobutane).

Our intermediate product pipelines consist principally of three parallel pipelines that originate at the Navajo refinery Lovington facilities and terminate at its Artesia facilities. These pipelines transport intermediate feedstocks and crude oil for HFC’s refining operations in New Mexico.

Our crude pipelines consist of crude oil trunk, gathering and connection pipelines located in west Texas, New Mexico and Oklahoma that deliver crude oil to the Navajo refinery and crude oil and refined product pipelines that support HFC’s Woods Cross refinery.

Our pipelines are regularly inspected, are well maintained and we believe, are in good repair. Generally, other than as may be provided in certain pipelines and terminal agreements, substantially all of our pipelines are unrestricted as to the direction in which product flows and the types of refined products that we can transport on them. The FERC regulates the transportation tariffs for interstate shipments on our refined product pipelines and state regulatory agencies regulate the transportation tariffs for intrastate shipments on our pipelines.

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,				
	2012	2011	2010	2009	2008
Volumes transported for (bpd):					
HFC	405,718	345,990	324,382	295,039	253,484
Third parties[(1)]	63,152	52,361	38,910	43,709	22,756
Total	468,870	398,351	363,292	338,748	276,240
Total barrels in thousands (“mbbls”)[(1)]	171,606	145,398	132,602	123,643	101,104

(1) We sold our 70% interest in Rio Grande on December 1, 2009, therefore the Rio Grande volumes have been excluded.

The following table sets forth certain operating data for each of our refined product, intermediate and crude pipelines. Throughput is the total average number of barrels per day transported on a pipeline but does not aggregate barrels moved between different points on the same pipeline. Revenues reflect tariff revenues generated by barrels shipped from an origin to a delivery point on a pipeline. Revenues also include payments made by Alon under capacity lease arrangements on our Orla to El Paso pipeline. Under these arrangements, we provide space on our pipeline for the shipment of up to 15,000 barrels of refined product per day. Alon pays us whether or not it actually ships the full volumes of refined products it is entitled to ship. To the extent Alon does not use its capacity; we are entitled to use it. We calculate the capacity of our pipelines based on the throughput capacity for barrels of gasoline equivalent that may be transported in the existing configuration; in some cases, this includes the use of drag reducing agents.

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Origin and Destination	Diameter (inches)	Length (miles)	Capacity (bpd)	
Refined Product Pipelines:				
Artesia, NM to El Paso, TX	6	156	19,000	
Artesia, NM to Orla, TX to El Paso, TX	8/12/8	214	70,000	(1)
Artesia, NM to Moriarty, NM(2)	12/8	215	27,000	(3)
Moriarty, NM to Bloomfield, NM(2)	8	191	14,400	(3)
Big Spring, TX to Abilene, TX	6/8	105	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	36	5,300	
Woods Cross, UT	10/8	8	70,000	
Woods Cross, UT to Las Vegas, NV	12	400	62,000	
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	96,000	
Tulsa, OK(5)	8/10/12	10		(5)
Crude Pipelines:				
Lovington / Artesia, New Mexico	Various	861	31,000	
Roadrunner Pipeline	16	65	62,400	
Beeson Pipeline	8	37	35,000	
Woods Cross, Utah	12	4	40,000	

(1) Includes 15,000 bpd of capacity on the Orla to El Paso segment of this pipeline that is leased to Alon under capacity lease agreements.
(2) The White Lakes Junction to Moriarty segment of our Artesia to Moriarty pipeline and the Moriarty to Bloomfield pipeline is leased from Mid-America Pipeline Company, LLC (“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 of less than one mile.
(5) The pipe capacities with 3 gas pipes with capacities of 10 million standard cubic feet per day (“MMSCFD”), 22MMSCFD, and 10MMSCFD and 2 liquid pipes with capacities of 45,000 BPD and 60,000 BPD.

HFC shipped an aggregate of 63% of the petroleum products transported on our refined product pipelines and 100% of the petroleum products transported on our intermediate pipelines and crude oil pipelines in 2012. These pipelines transported 90% of the light refined products produced by HFC’s Navajo refinery in 2012.

Artesia, New Mexico to El Paso, Texas

The Artesia to El Paso refined product pipeline is regulated by the FERC. It was constructed in 1959 and consists of 156 miles of 6-inch pipeline. This pipeline is used primarily for the shipment of refined products produced at the Navajo refinery to our El Paso terminal, where we deliver to common carrier pipelines for transportation to Arizona, northern New Mexico, northern Mexico and to the terminal’s tank farm for truck rack loading for local delivery by tanker truck. Refined products produced at the Navajo refinery destined for El Paso are transported on either this pipeline or our Artesia to Orla to El Paso pipeline.

Artesia, New Mexico to Orla, Texas to El Paso, Texas

The Artesia to Orla to El Paso refined product pipeline is a common-carrier pipeline regulated by the FERC and consists of three segments:

- an 8-inch and a 12-inch, 82-mile segment from the Navajo refinery to Orla, Texas;
- a 12-inch, 124-mile segment from Orla to outside El Paso, Texas; and
- an 8-inch, 8-mile segment from outside El Paso to our El Paso terminal.

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There are two shippers on this pipeline, HFC and Alon. As mentioned above, refined products destined to our 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, 12-inch pipeline that was constructed in 1999 and extends from the Navajo refinery Artesia facility to White Lakes Junction, New Mexico, and 155 miles of 8-inch pipeline that was constructed in 1973 and extends from White Lakes Junction to our Moriarty terminal, where it also connects to our Moriarty to Bloomfield pipeline. We own the 12-inch pipeline from Artesia to White Lakes Junction. We lease the White Lakes Junction to Moriarty segment of this pipeline and the Moriarty to Bloomfield pipeline described below, from Mid-America Pipeline Company, LLC under a long-term lease agreement entered into in 1996, which expires in 2017 and has two ten-year extensions at our option. At our Moriarty terminal, volumes shipped on this pipeline can be transported to other markets in the area, including Albuquerque, Santa Fe and west Texas, via tanker truck. The 155-mile White Lakes Junction to Moriarty segment of this pipeline is operated by Mid-America (or its designee). HFC is the only shipper on this pipeline. Currently, we pay a monthly fee (which is subject to adjustments based on changes in the PPI) of $556,000 to Mid-America to lease the White Lakes Junction to Moriarty and Moriarty to Bloomfield pipelines.

Moriarty, New Mexico to Bloomfield, New Mexico

The Moriarty to Bloomfield refined product pipeline was constructed in 1973 and consists of 191 miles of 8-inch pipeline leased from Mid-America. This pipeline serves our terminal in Bloomfield. At our Bloomfield terminal, volumes shipped on this pipeline are transported to other markets in the Four Corners area via tanker truck. This pipeline is operated by Mid-America (or its designee). HFC is the only shipper on this pipeline.

Big Spring, Texas to Abilene, Texas

The Big Spring to Abilene refined product pipeline was constructed in 1957 and consists of 100 miles of 6-inch pipeline and 5 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery to the Abilene terminal. Alon is the only shipper on this pipeline.

Big Spring, Texas to Wichita Falls, Texas

Segments of the Big Spring to Wichita Falls refined product pipeline were constructed in 1969 and 1989, and consist of 95 miles of 6-inch pipeline and 132 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery to the Wichita Falls terminal. Alon is the only shipper on this pipeline.

Wichita Falls, Texas to Duncan, Oklahoma

The Wichita Falls to Duncan refined product pipeline is a common carrier and is regulated by the FERC. It was constructed in 1958 and consists of 47 miles of 6-inch pipeline. This pipeline is used for the shipment of refined products from the Wichita Falls terminal to Alon's Duncan terminal, which we do not own. Alon is the only shipper on this pipeline.

Midland, Texas to Orla, Texas

Segments of the Midland to Orla refined product pipeline were constructed in 1928 and 1998, and consist of 50 miles of 10-inch pipeline and 85 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery from Midland to our tank farm at Orla. Alon is the only shipper on this pipeline.

Artesia, New Mexico to Roswell, New Mexico

The 36-mile, 4-inch diameter Artesia to Roswell refined product pipeline delivers jet fuel only to tanks located at our jet fuel terminal in Roswell. HFC is the only shipper on this pipeline.

Woods Cross, Utah refined product pipelines
The Woods Cross refined product pipelines consist of three pipeline segments. The Woods Cross to Pioneer terminal segment consists of 2 miles of 8-inch pipeline, which is used for product shipments to and through the Pioneer terminal. The Woods Cross to Pioneer segment represents 2 miles of 10-inch pipeline that is also used for product shipments to and through the Pioneer terminal. The Woods Cross to Chevron Pipeline's Salt Lake Products Pipeline segment consists of 4 miles of 8-inch pipeline and is used for product shipments from HFC's Woods Cross refinery to Chevron's North Salt Lake pumping station. HFC is the only shipper on these pipelines.

UNEV refined product pipeline
The 400-mile, 12-inch refined products pipeline was completed in early 2012. This pipeline is used for the shipment of refined products from Woods Cross, Utah to terminals in Las Vegas, Nevada and Cedar City, Utah. HFC and Sinclair Transportation Company ("Sinclair") are the primary shippers on this pipeline.

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8” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 8-inch diameter pipeline was constructed in 1981. This pipeline is used for the shipment of intermediate feedstocks, crude oil and LPGs from the Navajo refinery Lovington facility to its Artesia facility. HFC is the primary shipper on this pipeline.

10” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 10-inch diameter pipeline was constructed in 1999. This pipeline is used for the shipment of intermediate feedstocks and crude oil from the Navajo refinery Lovington facility to its Artesia facility. HFC is the only shipper on this pipeline.

16” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 16-inch diameter pipeline was constructed in 2009. This pipeline is used for the shipment of intermediate feedstocks and crude oil from the Navajo refinery Lovington facility to its Artesia facility. HFC is the only shipper on this pipeline.

Lovington / Artesia, New Mexico crude oil pipelines
The crude oil gathering and trunk pipelines deliver crude oil to HFC’s Navajo refinery and consist of 850 miles of 4-inch, 6-inch and 8-inch diameter pipeline. The crude oil trunk pipelines consist of five pipeline segments that deliver crude oil to the Navajo refinery Lovington facility and seven pipeline segments that deliver crude oil to the Navajo refinery Artesia facility.

The Lovington system crude oil mainlines include five pipeline segments consisting of a 23-mile, 12-inch pipeline from Russell to Lovington, a 20-mile, 8-inch pipeline from Russell to Hobbs, an 11-mile, 6-inch and 8-inch pipeline from Crouch to Lovington, a 20-mile, 8-inch pipeline from Hobbs to Lovington and a 6-mile, 6-inch pipeline from Gaines to Hobbs.

The Artesia system crude oil mainlines include seven pipeline segments consisting of an 11-mile, 6-inch pipeline from Beeson to North Artesia, a 7-mile, 4-inch and 6-inch pipeline from Barnsdall to North Artesia, a 2-mile, 8-inch pipeline from the Barnsdall jumper line to Lovington, a 4-mile, 4-inch pipeline from the Artesia Station to North Artesia, a 6-mile, 8-inch pipeline from North Artesia to Evans Junction and a 1-mile, 6-inch pipeline from Abo to Evans Junction.

We operate a 12-mile, 8-inch pipeline from Evans Junction to Artesia, New Mexico that supplies natural gas to the Navajo refinery Artesia facility.

Roadrunner Pipeline
The Roadrunner crude oil pipeline connects the Navajo refinery Lovington facility to a west Texas terminal of the Centurion Pipeline that extends to Cushing, Oklahoma. It was constructed in 2009 and consists of 65 miles of 16-inch pipeline. This pipeline is used for the shipment of crude oil from Cushing to the Navajo refinery Lovington facility.

Beeson Pipeline
The Beeson crude oil pipeline delivers crude oil to the Navajo refinery Lovington facility. It was constructed in 2009 and consists of 37 miles of 8-inch pipeline. This pipeline ships crude oil from our crude oil gathering system to the Navajo refinery Lovington facility for processing.

Woods Cross, Utah crude oil pipeline
This 4-mile, 12-inch pipeline is used for the shipment of crude oil from Chevron Pipeline’s North Salt Lake City station to the Woods Cross refinery.

REFINED PRODUCT TERMINALS, LOADING RACKS AND REFINERY TANKAGE

Refined Product Terminals and Loading Racks

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

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

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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 blending, injecting additives, and filtering jet fuel. HFC currently accounts for the substantial majority of our refined product terminal revenues.

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

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Refined products terminalled for (bpd):					
HFC	271,549	193,645	178,903	114,431	109,539
Third parties	53,456	44,454	39,568	42,206	32,737
Total	325,005	238,099	218,471	156,637	142,276
Total (mbbls)	118,952	86,906	79,742	57,173	52,073

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
El Paso, TX	747,000	20	Pipeline/rail	Truck/Pipeline
Moriarty, NM	189,000	9	Pipeline	Truck
Bloomfield, NM	193,000	7	Pipeline	Truck
Tucson, AZ[(1)]	176,000	9	Pipeline	Truck
Mountain Home, ID[(2)]	120,000	3	Pipeline	Pipeline
Boise, ID[(3)]	111,000	9	Pipeline	Pipeline
Burley, ID[(3)]	70,000	7	Pipeline	Truck
Spokane, WA	333,000	32	Pipeline/Rail	Truck
Abilene, TX	156,100	6	Pipeline	Truck/Pipeline
Wichita Falls, TX	220,000	11	Pipeline	Truck/Pipeline
Las Vegas, NV	267,000	9	Pipeline/Truck	Truck
Cedar City, UT	194,000	7	Pipeline/Rail/Truck	Truck
Roswell, NM [(2)]	25,000	1	Pipeline	Truck
Orla tank farm	135,000	5	Pipeline	Pipeline
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	25,000	N/A	Refinery	Truck/Rail/Pipeline
Cheyenne facility truck and rail racks	N/A	N/A	Refinery	Truck/Rail
El Dorado facility truck racks	N/A	N/A	Refinery	Truck
Total	2,961,100			

(1) The underlying ground at the Tucson terminal is leased.
(2) Handles only jet fuel.
(3) We have a 50% ownership interest in these terminals. The capacity and throughput information represents the proportionate share of capacity and throughput attributable to our ownership interest.

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El Paso Terminal
We receive light refined products at this terminal from the Navajo refinery Artesia facility through our Artesia to El Paso and Artesia to Orla to El Paso pipelines and by rail that account for 90% of the volumes at this terminal. We also receive product from the Big Spring refinery that accounted for 10% of the volumes at this terminal in 2012. Refined products received at this terminal are sold locally via the truck rack or transported to our Tucson terminal and other terminals in Phoenix on Kinder Morgan's East System pipeline. Competition in this market includes a refinery and terminal owned by Western Refining, Inc., a joint venture pipeline and terminal owned by ConocoPhillips and NuStar Energy, L.P. ("NuStar").

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

Bloomfield Terminal
We receive light refined products at this terminal from the Navajo refinery Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack. HFC is our only customer at this terminal.

Tucson Terminal
We own 100% of the improvements and lease the underlying ground at this terminal. The Tucson terminal receives light refined products from Kinder Morgan's East System pipeline, which transports refined products from the Navajo refinery Artesia facility that it receives at our El Paso terminal. Refined products received at this terminal are sold locally, via the truck rack. Competition in this market includes terminals owned by Kinder Morgan.

Mountain Home Terminal
We receive jet fuel from third parties at this terminal that is transported on Chevron's Salt Lake City to Boise, Idaho pipeline. We then transport the jet fuel from the Mountain Home terminal through our 13-mile, 4-inch 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.

Boise Terminal
We and Sinclair each own a 50% interest in the Boise terminal. Sinclair is the operator of the terminal. The Boise terminal receives light refined products from HFC and Sinclair shipped through Chevron's pipeline originating in Salt Lake City, Utah. The Woods Cross refinery, as well as other refineries in the Salt Lake City area, and Pioneer Pipeline Co.'s terminal in Salt Lake City are connected to the Chevron pipeline. All loading of products out of the Boise terminal is conducted at Chevron's loading rack, which is connected to the Boise terminal by pipeline. HFC and Sinclair are the only customers at this terminal.

Burley Terminal
We and Sinclair each own a 50% interest in the Burley terminal. Sinclair is the operator of the terminal. The Burley terminal receives product from HFC and Sinclair shipped through Chevron's pipeline originating in Salt Lake City, Utah. Refined products received at this terminal are sold locally, via the truck rack. HFC and Sinclair are the only customers at this terminal.

Spokane Terminal
This terminal is connected to the Woods Cross refinery via a Chevron common carrier pipeline. The Spokane terminal also is supplied by Chevron and Yellowstone pipelines and by rail and truck. Refined products received at this

terminal are sold locally, via the truck rack. We have several major customers at this terminal. Other terminals in the Spokane area include terminals owned by ExxonMobil and ConocoPhillips.

Abilene Terminal

This terminal receives refined products from Alon's Big Spring refinery, which accounted for all of its volumes in 2012. Refined products received at this terminal are sold locally via a truck rack or pumped over a 2-mile pipeline to Dyess Air Force Base. Alon is the only customer at this terminal.

Wichita Falls Terminal

This terminal receives refined products from the Alon's Big Spring refinery, which accounted for all of its volumes in 2012. Refined products received at this terminal are sold via a truck rack or shipped via pipeline connections to Alon’s terminal in Duncan, Oklahoma and also to NuStar’s Southlake Pipeline. Alon is the only customer at this terminal.

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Las Vegas Terminal
This terminal is owned by UNEV and receives product from HFC and Sinclair shipped through the UNEV Pipeline originating in Woods Cross, Utah. Refined products received at this terminal are sold locally. HFC and Sinclair are the only customers at this terminal.

Cedar City Terminal
This terminal is owned by UNEV and receives product from HFC and Sinclair shipped through the UNEV Pipeline originating in Woods Cross, Utah. Refined products received at this terminal are sold locally. HFC and Sinclair are the only customers at this terminal.

Roswell Terminal
This terminal receives jet fuel from the Navajo refinery for further transport to Cannon Air Force Base and to Albuquerque, New Mexico. We lease this terminal under an agreement that expires in September 2016.

Orla Tank Farm
The Orla tank farm was constructed in 1998. It receives refined products from Alon's Big Spring refinery that accounted for all of its volumes in 2012. Refined products received at the tank farm are delivered into our Orla to El Paso pipeline. Alon is the only customer at this tank farm.

Artesia Facility Truck Rack
The truck rack at the Navajo refinery Artesia facility loads light refined products 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.

Lovington Facility Asphalt Truck Rack
The asphalt loading rack facility at the Lovington refinery loads asphalt produced at the Lovington facility onto tanker trucks. HFC is the only customer of this truck rack.

Woods Cross Facility Truck Rack
The truck rack at the Woods Cross facility loads light refined products produced at the refinery onto tanker trucks for delivery to markets in the surrounding area. HFC is the only customer of this truck rack. HFC also makes transfers to a common carrier pipeline at this facility.

Tulsa 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 racks that load refined products and lube oil produced at the refinery onto rail car and a truck rack that loads lube oil onto 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.

Cheyenne Facility Truck and Rail Racks
The Cheyenne loading rack facilities consist of light refined products, heavy products and LPG truck and rail racks. These racks load refined products and propane onto tanker trucks for delivery to markets in surrounding areas. Additionally, these facilities include four crude oil LACT units that unload crude oil from tanker trucks.

El Dorado 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.

Refinery Tankage

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 9,300,000 barrels of storage.

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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	166,000	Crude oil	2
Lovington, NM	267,000	Crude oil	2
Woods Cross, UT	180,000	Crude oil	3
Tulsa, OK	3,171,600	Crude oil and refined product	57
Cheyenne, WY	1,842,000	Refined and intermediate product	58
El Dorado, KS	3,702,400	Refined and intermediate product	89
Total	9,329,000		

PIPELINE AND TERMINAL CONTROL OPERATIONS

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

Item 3. Legal Proceedings
We are a party to various legal and regulatory proceedings, which we believe will not have a material adverse impact on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures
Not applicable.

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PART II

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

Years Ended December 31,	High	Low	Cash Distributions	Trading Volume
2012				
Fourth quarter	$34.41	$30.19	$0.470	6,938,000
Third quarter	$36.98	$28.56	$0.463	6,420,200
Second quarter	$31.44	$26.12	$0.455	5,298,000
First quarter	$31.88	$26.64	$0.448	6,704,400
2011				
Fourth quarter	$29.98	$23.65	$0.443	6,609,800
Third quarter	$27.51	$22.70	$0.438	4,050,800
Second quarter	$29.46	$24.28	$0.433	5,781,800
First quarter	$30.53	$25.06	$0.428	4,675,200

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all periods presented.
The cash distribution for the fourth quarter of 2012 was declared on January 24, 2013 and is payable on February 14, 2013 to all unitholders of record on February 4, 2013.
As of February 13, 2013, we had approximately 14,400 common unitholders, including beneficial owners of common units held in street name.
We consider regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. See "Liquidity and Capital Resources" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of conditions and limitations prohibiting distributions under the Credit Agreement and indentures relating to our senior notes.
Within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, comply with applicable laws, any of our debt instruments, or other agreements; or provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.
We make distributions in the following manner: 98% to our common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distributions for any prior quarters, thereafter.
Our general partner, HEP Logistics, is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels presented below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.25	98%	2%

First target distribution	Up to $0.275	98%	2%
Second target distribution	above $0.275 up to $0.3125	85%	15%
Third target distribution	above $0.3125 up to $0.375	75%	25%
Thereafter	Above $0.375	50%	50%

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Item 6. Selected Financial Data

The following table shows selected financial information for HEP. 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,				
	2012	2011[1]	2010[1]	2009[1]	2008[1]
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$292,560	$214,268	$182,137	$146,612	$109,169
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	89,242	64,521	54,946	44,668	39,095
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
General and administrative	7,594	6,576	7,719	7,586	6,380
	154,297	108,055	94,028	80,236	68,090
Operating income	138,263	106,213	88,109	66,376	41,079
Equity in earnings of SLC Pipeline	3,364	2,552	2,393	1,919	—
SLC Pipeline acquisition costs	—	—	—	(2,500)	—
Interest income	—	—	7	11	118
Interest expense	(47,182)	(35,959)	(34,001)	(21,501)	(21,763)
Loss on early extinguishment of debt	(2,979)	—	—	—	—
Other income	10	17	17	67	1,026
	(46,787)	(33,390)	(31,584)	(22,004)	(20,619)
Income from continuing operations before income taxes	91,476	72,823	56,525	44,372	20,460
State income tax	(371)	(234)	(296)	(20)	(270)
Income from continuing operations	91,105	72,589	56,229	44,352	20,190
Add net loss attributable to Predecessor	4,200	6,351	70	1,411	379
Noncontrolling interest	(1,153)	859	24	471	127
Income from continuing operations attributable to Holly Energy Partners	94,152	79,799	56,323	46,234	20,696
Income from discontinued operations, net of noncontrolling interest[2]	—	—	—	19,780	4,671
Net income attributable to Holly Energy Partners	94,152	79,799	56,323	66,014	25,367
Less general partner interest in net income, including incentive distributions[3]	22,450	16,806	12,084	7,947	3,913
Limited partners' interest in net income	$71,702	$62,993	$44,239	$58,067	$21,454
Limited partners' per unit interest in net income – basic and diluted[3]	$1.29	$1.38	$1.00	$1.59	$0.66
Distributions per limited partner unit	$1.84	$1.74	$1.66	$1.58	$1.50
Other Financial Data:					
Cash flows from operating activities	$161,411	$99,042	$104,736	$68,503	$64,015
Cash flows from investing activities	$(42,861)	$(206,309)	$(142,051)	$(198,684)	$(298,557)
Cash flows from financing activities	$(119,682)	$105,584	$35,856	$131,023	$218,564
EBITDA[4]	$194,242	$149,766	$122,089	$100,707	$70,195
Distributable cash flow[5]	$153,125	$100,295	$91,054	$72,213	$60,365
Maintenance capital expenditures[5]	$5,649	$5,415	$4,487	$3,595	$3,133
Expansion capital expenditures	37,212	200,894	137,442	201,454	295,460

Total capital expenditures	$42,861	$206,309	$141,929	$205,049	$298,593
Balance Sheet Data (at period end):					
Net property, plant and equipment	$960,535	$960,499	$683,793	$553,233	$363,038
Total assets	$1,394,110	$1,399,196	$913,263	$779,035	$549,762
Long-term debt(6)	$864,674	$605,888	$491,648	$390,827	$355,793
Total liabilities	$927,351	$661,518	$548,402	$425,633	$434,821
Total equity(7)	$452,856	$737,678	$364,861	$353,402	$114,941

(1) The amounts presented have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.

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(2) On December 1, 2009, we sold our 70% interest in Rio Grande. Results of operations of Rio Grande and the $14.5 million gain on the sale are presented in discontinued operations.

(3) Net income is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. Net income allocated to the general partner includes incentive distributions declared subsequent to quarter end. Net income attributable to the limited partners is divided by the weighted average limited partner units outstanding in computing the limited partners' per unit interest in net income.

(4) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income plus (i) interest expense net of interest income, (ii) state income tax and (iii) depreciation and amortization. EBITDA is not a calculation based upon GAAP. However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements, with the exception of EBITDA from discontinued operations. EBITDA should not be considered 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. 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,				
	2012	2011(1)	2010(1) presented have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.	2009(1)	2008(1)
	(In thousands)				
Income from continuing operations attributable to HEP	$94,152	$79,799	$ 56,323	$46,234	$20,696
Add (subtract):					
Interest expense	40,141	34,706	30,453	20,620	18,479
Amortization of discount and deferred debt issuance costs	1,946	1,212	1,008	706	1,002
Loss on early extinguishment of debt	2,979	—	—	—	—
Increase in interest expense – non-cash charges attributable to interest rate swaps and swap settlement costs	5,095	41	2,540	175	2,282

Interest income	—	—	(7)	(11)	(118)
State income tax	371	234	296	20	270
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
Predecessor depreciation and amortization	(7,903)	(3,184)	113	(1,268)	(678)
EBITDA from discontinued operations (excludes gain on sale of Rio Grande in 2009)	—	—	—	6,249	5,647
EBITDA	$194,242	$149,766	$ 122,089	$100,707	$70,195

(5) 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 exceptions of maintenance capital expenditures and distributable cash flow from discontinued operations. 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 also is 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.

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Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2012	2011(1)	2010(1)	2009(1)	2008(1)
	(In thousands)				
Income from continuing operations attributable to HEP	$94,152	$79,799	$56,323	$46,234	$20,696
Add (subtract):					
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
Predecessor depreciation and amortization	(7,903)	(3,184)	113	(1,268)	(678)
Amortization of discount and deferred debt issuance costs	1,946	1,212	1,008	706	1,002
Increase in interest expense – non-cash charges attributable to interest rate swaps	5,095	41	2,540	175	2,282
Loss on early extinguishment of debt	2,979	—	—	—	—
Increase (decrease) in deferred revenue	462	(6,405)	2,035	(7,256)	11,958
Maintenance capital expenditures*	(5,649)	(5,415)	(4,487)	(3,595)	(3,133)
Crude revenue settlement	3,670	(4,588)	—	—	—
Distributable cash flow from discontinued operations (excludes gain on sale of Rio Grande in 2009)	—	—	—	6,183	5,623
SLC Pipeline acquisition costs**	—	—	—	2,500	—
Other non-cash adjustments	912	1,877	2,159	552	—
Distributable cash flow	$153,125	$100,295	$91,054	$72,213	$60,365

* 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.

** Under accounting standards, we were required to expense rather than capitalize certain acquisition costs of $2.5 million associated with our joint venture agreement with Plains that closed in March 2009. These costs directly relate to our interest in the new joint venture pipeline and are similar to expansion capital expenditures; accordingly, we have added back these costs to arrive at distributable cash flow.

(6) Includes $421 million, $200 million, $159 million, $206 million and $171 million in Credit Agreement advances that were classified as long-term debt at December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(7) As a master limited partnership, we distribute our available cash, which historically has exceeded our net income 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. Additionally, if the assets contributed and acquired from HFC while under common control of HFC had been acquired from third parties, our acquisition cost in excess of HFC's basis in the transferred assets of $305.6 million would have been recorded in our financial statements as increases to our properties and equipment and intangible assets instead of decreases to partners' equity.

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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 and terminal, tankage and loading rack facilities that support the refining and marketing operations of HFC in the Mid-Continent, Southwest and Rocky Mountain regions of the United States. At December 31, 2012, HFC owned a 44% interest in us including the 2% general partnership interest. We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon's refinery in Big Spring, Texas. Additionally, we own a 75% interest in UNEV, the owner of a pipeline running from Utah to Las Vegas, Nevada and related products terminals and a 25% joint venture interest in the SLC Pipeline, a 95-mile intrastate crude oil pipeline system that serves refineries in the Salt Lake City area.

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 and providing other services at our storage tanks and terminals. 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.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all periods presented.

UNEV Pipeline Interest Acquisition
On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, we issued to HFC a Class B unit comprising an equity interest in a wholly-owned subsidiary that entitles HFC to an 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. 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances.

Legacy Frontier Pipeline and Tankage Asset Transaction
On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC’s El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150 million and 7,615,230 of our common units. In connection with the transaction, we entered into 15-year throughput agreements with HFC containing minimum annual revenue commitments to us of $48.3 million.

Agreements with HFC and Alon

We serve HFC's refineries under long-term pipeline and terminal, tankage and throughput agreements expiring from 2019 to 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the PPI or FERC index. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall 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 also have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that also is subject to annual tariff rate adjustments. The terms under this agreement expire beginning in 2018 through 2022. We also

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have a capacity lease agreement under which we lease Alon space on our Orla to El Paso pipeline for the shipment of refined product. As of December 31, 2012, these agreements with Alon will result in minimum annualized payments to us of $31.4 million.

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

Under certain provisions of the Omnibus Agreement that we have with HFC, we pay HFC an annual administrative fee, currently $2.3 million, 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 HLS who perform services for us 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.

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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, 2012, 2011 and 2010.

	Year Ended December 31,		Change from
	2012	2011[1]	2011
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$67,682	$46,649	$21,033
Affiliates—intermediate pipelines	28,540	21,948	6,592
Affiliates—crude pipelines	45,888	47,542	(1,654)
	142,110	116,139	25,971
Third parties—refined product pipelines	37,521	38,216	(695)
	179,631	154,355	25,276
Terminals, tanks and loading racks:			
Affiliates	103,472	52,122	51,350
Third parties	9,457	7,791	1,666
	112,929	59,913	53,016
Total revenues	292,560	214,268	78,292
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	89,242	64,521	24,721
Depreciation and amortization	57,461	36,958	20,503
General and administrative	7,594	6,576	1,018
	154,297	108,055	46,242
Operating income	138,263	106,213	32,050
Equity in earnings of SLC Pipeline	3,364	2,552	812
Interest expense, including amortization	(47,182)	(35,959)	(11,223)
Loss on early extinguishment of debt	(2,979)	—	(2,979)
Other	10	17	(7)
	(46,787)	(33,390)	(13,397)
Income before income taxes	91,476	72,823	18,653
State income tax	(371)	(234)	(137)
Net income	91,105	72,589	18,516
Allocation of net loss attributable to Predecessors	4,200	6,351	(2,151)
Allocation of net loss (income) attributable to noncontrolling interests	(1,153)	859	(2,012)
Net income attributable to Holly Energy Partners	94,152	79,799	14,353
General partner interest in net income, including incentive distributions [2]	(22,450)	(16,806)	(5,644)
Limited partners' interest in net income	$71,702	$62,993	$8,709
Limited partners' earnings per unit—basic and diluted[2]	$1.29	$1.38	$(0.09)
Weighted average limited partners' units outstanding	55,696	45,672	10,024
EBITDA [3]	$194,242	$149,766	$44,476
Distributable cash flow [4]	$153,125	$100,295	$52,830
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	107,509	90,782	16,727

Affiliates—intermediate pipelines	127,169	93,419	33,750
Affiliates—crude pipelines	171,040	161,789	9,251
	405,718	345,990	59,728
Third parties—refined product pipelines	63,152	52,361	10,791
	468,870	398,351	70,519
Terminals and loading racks:			
Affiliates	271,549	193,645	77,904
Third parties	53,456	44,454	9,002
	325,005	238,099	86,906
Total for pipelines and terminal assets (bpd)	793,875	636,450	157,425

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	Years Ended December 31, 2011[1]	2010[1]	Change from 2010
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$46,649	$48,458	$(1,809)
Affiliates—intermediate pipelines	21,948	20,998	950
Affiliates—crude pipelines	47,542	38,932	8,610
	116,139	108,388	7,751
Third parties—refined product pipelines	38,216	27,962	10,254
	154,355	136,350	18,005
Terminals, tanks and loading racks:			
Affiliates	52,122	37,979	14,143
Third parties	7,791	7,808	(17)
	59,913	45,787	14,126
Total revenues	214,268	182,137	32,131
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	64,521	54,946	9,575
Depreciation and amortization	36,958	31,363	5,595
General and administrative	6,576	7,719	(1,143)
	108,055	94,028	14,027
Operating income	106,213	88,109	18,104
Equity in earnings of SLC Pipeline	2,552	2,393	159
Interest expense, including amortization	(35,959)	(33,994)	(1,965)
Other expense	17	17	—
	(33,390)	(31,584)	(1,806)
Income before income taxes	72,823	56,525	16,298
State income tax	(234)	(296)	62
Net income	72,589	56,229	16,360
Allocation of net loss attributable to Predecessors	6,351	70	6,281
Allocation of net loss attributable to noncontrolling interests	859	24	835
Net income attributable to Holly Energy Partners	79,799	56,323	23,476
General partner interest in net income, including incentive distributions [2]	(16,806)	(12,084)	(4,722)
Limited partners' interest in net income	$62,993	$44,239	$18,754
Limited partners' earnings per unit—basic and diluted[2]	$1.38	$1.00	$0.38
Weighted average limited partners' units outstanding	45,672	44,157	1,515
EBITDA [3]	$149,766	$122,089	$27,677
Distributable cash flow [4]	$100,295	$91,054	$9,241
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	90,782	96,094	(5,312)
Affiliates—intermediate pipelines	93,419	84,277	9,142
Affiliates—crude pipelines	161,789	144,011	17,778
	345,990	324,382	21,608
Third parties—refined product pipelines	52,361	38,910	13,451
	398,351	363,292	35,059
Terminals and loading racks:			

Affiliates	193,645	178,903	14,742
Third parties	44,454	39,568	4,886
	238,099	218,471	19,628
Total for pipelines and terminal assets (bpd)	636,450	581,763	54,687

(1) The amounts presented above have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.

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(2) Net income is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. Net income allocated to the general partner includes incentive distributions declared subsequent to quarter end. Net income attributable to the limited partners is divided by the weighted average limited partner units outstanding in computing the limited partners' per unit interest in net income.

(3) EBITDA is calculated as net income plus (i) interest expense, net of interest income, (ii) state income tax and (iii) depreciation and amortization. EBITDA is not a calculation based upon GAAP. However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements, with the exception of EBITDA from discontinued operations. EBITDA should not be considered 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. 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."

(4) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts presented in our consolidated financial statements, with the general exceptions of maintenance capital expenditures and distributable cash flow from discontinued operations. 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, 2012 Compared with Year Ended December 31, 2011

Summary

Net income attributable to HEP for the year ended December 31, 2012 was $94.2 million, a $14.4 million increase compared to the year ended December 31, 2011. This increase in earnings is due principally to increased pipeline shipments, earnings attributable to our November 2011 acquisition and annual tariff increases. These factors were offset partially by increased operating costs and expenses, higher interest expense and a loss on the early extinguishment of debt. Although net income attributable to HEP increased, limited partners' per unit interest in earnings decreased from $1.38 per unit in 2011 to $1.29 per unit in 2012. The principal factors causing the decrease in limited partners' per unit interest, relative to the overall net income attributable to HEP increase, were higher incentive distributions to the general partner and the UNEV acquisition not yet being accretive to earnings, although it was accretive to distributable cash flow.

Revenues for the year ended December 31, 2012 include the recognition of $4.0 million of prior shortfalls billed to shippers in 2011. Deficiency payments of $7.8 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2012. Such deferred revenue will be recognized in earnings either as payment for shipments in excess of guaranteed levels, if and to the extent the pipeline system will not have necessary capacity to provide for shipments in excess of guaranteed levels, or when shipping rights expire unused.

Revenues

Total revenues for the year ended December 31, 2012 were $292.6 million, a $78.3 million increase compared to the year ended December 31, 2011. This is due principally to increased pipeline shipments, revenues attributable to our recent acquisitions and the effect of annual tariff increases partially offset by a $4.6 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Overall pipeline volumes were up 18% compared to the year ended December 31, 2011.

Revenues from our refined product pipelines were $105.2 million, an increase of $20.3 million compared to the year ended December 31, 2011. This includes $15.0 million in revenues attributable to UNEV pipeline throughputs which commenced initial start-up activities in December 2011 partially offset by a $5.4 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our refined product pipelines averaged 170.7 thousand barrels per day (“mbpd“) compared to 143.1 mbpd for 2011.

Revenues from our intermediate pipelines were $28.5 million, an increase of $6.6 million compared to the year ended December 31, 2011. This includes $3.4 million of increased revenues attributable to the Tulsa interconnect pipelines, which were placed in service in September 2011, and a $0.8 million increase in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our intermediate pipelines averaged 127.2 mbpd compared to 93.4 mbpd for 2011.

Revenues from our crude pipelines were $45.9 million, a decrease of $1.7 million compared to the year ended December 31, 2011. Revenues for the year ended December 31, 2011 included $5.5 million attributable to a crude pipeline revenue settlement with HFC. Volumes shipped on our crude pipelines increased to an average of 171.0 mbpd compared to 161.8 mbpd for 2011.

Revenues from terminal, tankage and loading rack fees were $112.9 million, an increase of $53.0 million compared to year ended December 31, 2011. This increase is due principally to $45.4 million of increased revenues attributable to our terminal, tankage and loading racks serving HFC's El Dorado and Cheyenne refineries. Refined products terminalled in our facilities increased to an average of 325.0 mbpd compared to 238.1 mbpd for 2011.

Operations Expense
Operations expense for the year ended December 31, 2012 increased by $24.7 million compared to the year ended December 31, 2011. This increase is due principally to increased operating costs of $9.6 million and $5.2 million attributable to our recently acquired UNEV pipeline and assets serving HFC's El Dorado and Cheyenne refineries, respectively, higher throughput levels as well as year-over-year increases in property taxes, maintenance service and payroll costs.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2012 increased by $20.5 million compared to the year ended December 31, 2011. This increase is due principally to depreciation attributable to our recent acquisitions from HFC and capital projects. Also contributing were increases in asset abandonment charges related to tankage no longer in service.

General and Administrative
General and administrative costs for the year ended December 31, 2012 increased by $1.0 million compared to the year ended December 31, 2011 due to timing of professional fees related to recent acquisitions.

Equity in Earnings of SLC Pipeline
Our equity in earnings of the SLC Pipeline was $3.4 million and $2.6 million for the years ended December 31, 2012 and 2011.

Interest Expense
Interest expense for the year ended December 31, 2012 totaled $47.2 million, an increase of $11.2 million compared to the year ended December 31, 2011. This increase reflects interest on a year-over-year increase in debt levels. Our aggregate effective interest rate was 6.5% and 6.7% for the years ended December 31, 2012 and 2011, respectively.

Loss on Early Extinguishment of Debt
We recognized a charge of $3.0 million upon the early extinguishment of our 6.25% senior notes for the year ended December 31, 2012. This charge relates to the premium paid to noteholders upon their tender of an aggregate principal amount of $185.0 million and related financing costs that were previously deferred.

State Income Tax
We recorded state income tax expense of $371,000 and $234,000 for the years ended December 31, 2012 and 2011 which is solely attributable to the Texas margin tax.

Results of Operations—Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Summary

Net income attributable to HEP for the year ended December 31, 2011 was $79.8 million, a $23.5 million increase compared to the year ended December 31, 2010. This increase in overall earnings is due principally to increased pipeline shipments, earnings attributable to our November 2011 asset acquisition and an increase in previously deferred revenue realized under our guaranteed shipping contracts. Also contributing to earnings was a settlement with HFC relating to a clarification of the appropriate charges for certain past deliveries into our crude pipeline system. These factors were offset partially by an overall increase in operating costs and expenses.

Revenues for the year ended December 31, 2011 include the recognition of $12.4 million of prior shortfalls billed to shippers in 2010. Deficiency payments of $4.0 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2011.

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Revenues
Total revenues for the year ended December 31, 2011 were $214.3 million, a $32.1 million increase compared to the year ended December 31, 2010. This is due principally to an overall increase in pipeline shipments, revenues attributable to our November 2011 asset acquisitions, a $4 million increase in previously deferred revenue realized under our guaranteed shipping contracts, the effect of annual tariff increases and the HFC crude pipeline revenue settlement. Overall pipeline volumes were up 10% compared to the year ended December 31, 2010.

Certain related-party pipeline volumes were down during 2011 as a result of downtime at HFC's Navajo refinery following a plant-wide power outage in late January 2011 and the subsequent delay in restoring production to planned levels.

Revenues from our refined product pipelines were $84.9 million, an increase of $8.4 million compared to the year ended December 31, 2010. This is due to a $4.3 million increase in previously deferred revenue realized under our guaranteed shipping contracts and an increase in third-party refined product pipeline shipments. Volumes shipped on our refined product pipelines averaged 143.1 mbpd compared to 135.0 mbpd for the same period in 2010.

Revenues from our intermediate pipelines were $21.9 million, an increase of $1.0 million compared to the year ended December 31, 2010. This includes $0.8 million in revenues attributable to the Tulsa interconnect pipelines, and a $0.3 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our intermediate pipelines averaged 93.4 mbpd compared to 84.3 mbpd for the same period in 2010.

Revenues from our crude pipelines were $47.5 million, an increase of $8.6 million compared to the year ended December 31, 2010. This includes $5.5 million in revenues attributable to a crude pipeline revenue settlement with HFC. Volumes shipped on our crude pipelines increased to an average of 161.8 mbpd compared to 144.0 mbpd for the same period in 2010.

Revenues from terminal, tankage and loading rack fees were $59.9 million, an increase of $14.1 million compared to the year ended December 31, 2010. This increase is due principally to $7.1 million in revenues attributable to our terminal, tankage and loading racks serving HFC's El Dorado and Cheyenne refineries. Refined products terminalled in our facilities increased to an average of 238.1 mbpd compared to 218.5 mbpd for the same period last year.

Operations Expense
Operations expense for the year ended December 31, 2011 increased by $9.6 million compared to the year ended December 31, 2010. This increase is due principally to operating costs of $2.0 million and $3.8 million attributable to our recently acquired UNEV pipeline and assets serving HFC's El Dorado and Cheyenne refineries, respectively, as well as year-over-year increases in maintenance services and payroll costs. Additionally, in the year ended December 31, 2010, we recognized a charge for environmental remediation of $1.7 million.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2011 increased by $5.6 million compared to the year ended December 31, 2010. This increase is due principally to depreciation attributable to our acquisitions from HFC and capital projects.

General and Administrative
General and administrative costs for the year ended December 31, 2011 decreased by $1.1 million compared to the year ended December 31, 2010 due to lower professional fees and services.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $2.6 million and $2.4 million for the years ended December 31, 2011 and 2010.

Interest Expense

Interest expense for the year ended December 31, 2011 totaled $36.0 million, an increase of $2.0 million compared to the year ended December 31, 2010. This increase reflects interest on increased debt levels during 2011, partially offset by prior year costs of $1.1 million that relate to the partial settlement of an interest rate swap. Excluding the effects of fair value adjustments to this swap in 2010, our aggregate effective interest rate was 6.7% for the year ended December 31, 2011 compared to 6.8% for 2010.

State Income Tax

We recorded state income taxes of $234,000 and $296,000 for the years ended December 31, 2011 and 2010, respectively, which are solely attributable to the Texas margin tax.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

In June 2012, we amended the Credit Agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It also is available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012 we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million.

During the year ended December 31, 2012, we received advances totaling $587.0 million and repaid $366.0 million, resulting in net advances of $221.0 million under the Credit Agreement and an outstanding balance of $421.0 million at December 31, 2012.

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.

Under our registration statement filed with the SEC using a "shelf" registration process, we currently have the ability to raise up to $2.0 billion 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. Additionally, we funded $260.0 million of the cash portion of our UNEV Pipeline interest acquisition from HFC on July 12, 2012 with advances under the Credit Agreement.

In February, May, August and November 2012, we paid regular quarterly cash distributions of $0.443, $0.448, $0.455 and $0.463, respectively, on all units in an aggregate amount of $122.8 million. Included in these distributions were $20.6 million of incentive distribution payments to the general partner.

Contemporaneously with our UNEV Pipeline interest acquisition on July 12, 2012, HFC (our general partner) agreed to forego its right to incentive distributions of $1.25 million per quarter over the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances.

Cash and cash equivalents decreased by $1.1 million during the year ended December 31, 2012. The cash flows provided by operating activities of $161.4 million were less than the cash flows used for financing and investing activities of $119.7 million and $42.9 million, respectively. Working capital increased by $5.2 million to $11.8 million at December 31, 2012 from $6.6 million at December 31, 2011.

Cash Flows—Operating Activities

Year Ended December 31, 2012 Compared with Year Ended December 31, 2011

Cash flows from operating activities increased by $62.4 million from $99.0 million for the year ended December 31, 2011 to $161.4 million for the year ended December 31, 2012. This increase is due principally to $63.0 million in additional cash collections from our customers, partially offset by payments attributable to increased operating expenses.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Under certain agreements with these shippers, they have the right to recapture these amounts if future volumes exceed minimum levels. We billed $4.6 million during the year ended December 31, 2011 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2012. Another $7.8 million is included in our accounts receivable at December 31, 2012 related to shortfalls that occurred during the year ended December 31, 2012.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows from operating activities decreased by $5.7 million from $104.7 million for the year ended December 31, 2010 to $99.0 million for the year ended December 31, 2011. This decrease is due principally to payments attributable to increased interest and operating expenses, net of $11.1 million in additional cash collections from our customers.

We billed $10.4 million during the year ended December 31, 2010 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2011. We recognized an additional $2 million related to shortfalls billed in 2011 as a result of an amendment to our throughput agreement with Alon in June 2011 that limits the carryover term of credits attributable to such shortfall billings to the calendar year end in which the shortfalls occurred. Another $0.8 million was included in our accounts receivable at December 31, 2011 related to shortfalls that occurred in the fourth quarter of 2011.

Cash Flows—Investing Activities
Year Ended December 31, 2012 Compared with Year Ended December 31, 2011
Cash flows used for investing activities decreased by $163.4 million from $206.3 million for the year ended December 31, 2011 to $42.9 million for the year ended December 31, 2012. During the years ended December 31, 2012 and 2011, we invested $42.9 million and $206.3 million in additions to properties and equipment, respectively. The decrease is attributable to lower expenditures in 2012 as a result of the completion of the UNEV pipeline in 2011.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows used for investing activities increased by $64.3 million from $142.1 million for the year ended December 31, 2010 to $206.3 million for the year ended December 31, 2011. During the year ended December 31, 2011, we invested $206.3 million in additions to properties and equipment. During the year ended December 31, 2010, we paid $35.5 million in cash with respect to our asset acquisitions from HFC and invested $106.5 million in additions to properties and equipment. Capital expenditures for UNEV were $176.9 million and $84.4 million for the years ended December 31, 2011 and 2010, respectively.

Cash Flows—Financing Activities
Year Ended December 31, 2012 Compared with Year Ended December 31, 2011
Cash flows used for financing activities were $119.7 million for the year ended December 31, 2012 compared to cash provided of $105.6 million for the year ended December 31, 2011, a decrease of $225.3 million. During the year ended December 31, 2012, we received $587.0 million and repaid $366.0 million in advances under the Credit Agreement, received net proceeds of $294.8 million from the issuance of our 6.5% senior notes and repaid $260.2 million of our promissory notes. As partial consideration for the acquisition of HFC's 75% interest in UNEV on July 12, 2012, we paid HFC $260.9 million in cash (after a customary post-closing working capital adjustment). Additionally, we paid $122.8 million in regular quarterly cash distributions to our general and limited partners, paid $3.2 million in financing costs to amend our Credit Agreement and paid $4.9 million for the purchase of common units for recipients of our incentive grants. We also received contributions of $15.0 million from UNEV's joint venture partners. During the year ended December 31, 2011, we received $118.0 million and repaid $77.0 million in advances under the Credit Agreement, received proceeds of $75.8 million from the issuance of our common units, and repaid $77.1 million of our promissory notes. Additionally, we paid $91.5 million in regular quarterly cash distributions to our general and limited partners, we received $156.5 million from UNEV's joint venture partners, received $5.9 million from our general partner, incurred $3.2 million in financing costs upon the issuance of the 8.25% senior notes, and paid $1.6 million for the purchase of common units for recipients of our incentive grants.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows used for financing activities were $105.6 million for the year ended December 31, 2011, an increase of $69.7 million compared to $35.9 million for the year ended December 31, 2010. During the year ended December 31, 2011, we received $118.0 million and repaid $77.0 million in advances under the Credit Agreement, repaid $77.1

million on our promissory notes issued to HFC, received $75.8 million in proceeds from the issuance of our common units, received $5.9 million in capital contributions from our general partner, paid $91.5 million in regular quarterly cash distributions to our general and limited partners, we received $156.5 million from UNEV's joint venture partners, paid $1.6 million for the purchase of common units for recipients of our incentive grants and paid $3.2 million in financing costs to amend our previous credit agreement. During the year ended December 31, 2010, we received $66.0 million and repaid $113.0 million in advances under the Credit Agreement. Additionally, we received $147.5 million in net proceeds and incurred $0.5 million in financing costs upon the issuance of our 8.25% senior notes. Also in the year ended December 31, 2010, we paid $84.4 million in regular quarterly cash distributions to our general and limited partners, received $80.5 million from UNEV's joint venture partners, paid $57.6 million in excess of HFC’s transferred basis in the storage assets acquired in March 2010 and paid $2.7 million for the purchase of common units for recipients of our incentive grants.

Capital Requirements

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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 HLS board of directors 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 2013 regular capital budget is comprised of $10.1 million for maintenance capital expenditures and $2.0 million for expansion capital expenditures exclusive of the projects discussed below. In addition to our capital budget, we may spend funds periodically to do capital upgrades of our assets where a customer reimburses us for such costs. These reimbursements would be required under contractual agreements and would generally benefit the customer over the remaining life of such agreements.

We recently have made certain modifications to our crude oil gathering and trunk line system that effectively have increased our ability to gather and transport an additional 10,000 barrels per day (“bpd”) of Delaware Basin crude oil in response to increased drilling activity in southeast New Mexico. We have a second project recently approved which consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. This project also includes the expansion and extension of several of our crude gathering systems and crude mainline pipes. Once in service, this system will be capable of transporting crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. This project is estimated to cost approximately $38.5 million and could be fully operational in late 2013.

We also are performing preliminary engineering, routing and cost estimates for two proposed new pipelines. The first proposed pipeline would be a new intrastate crude oil pipeline between Cushing, Oklahoma and HFC's Tulsa, Oklahoma refinery. The 50-mile line would provide safe and reliable transport of Cushing sourced domestic and Canadian crude oil to HFC's 125,000 BPD Tulsa facility. The pipeline would allow for a significant portion of crude oil transported to be heavy Canadian and sour crude oil. Crude oil processed at HFC's Tulsa facility currently is transported on pipelines owned by Sunoco Logistics and Magellan Pipeline Company. The second proposed pipeline would be a new 100-mile interstate petroleum products pipeline between HFC's Cheyenne, Wyoming refinery and Denver, Colorado. The 52,000 BPD refinery, with its ability to process up to 35,000 BPD of heavy Canadian crude and its close proximity to growing domestic crude production, is a significant supplier of petroleum products to the Denver market. The project also will evaluate the construction of a new petroleum products terminal in North Denver or, alternatively, the routing of the new pipeline to existing third-party product terminals in the Denver area. This infrastructure addition would ensure safe and reliable transport of petroleum products from HFC's location-advantaged refinery to its largest market. Petroleum products produced at HFC's Cheyenne, Wyoming refinery are currently transported to Denver on the Rocky Mountain Pipeline’s products line owned by Plains All-American. We anticipate that we will be in a position to decide whether to proceed with these projects in the second quarter of 2013 when preliminary engineering and detailed project cost estimates are completed and if necessary shipper commitments can be secured.

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 existing 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.

On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.0 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). We paid an additional $0.9 million to HFC for a post-closing working capital adjustment as provided for by the acquisition agreement. As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, 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. Such contingent redemption payments are limited to a maximum payment amount calculated as described below. However, to the extent earnings thresholds are not achieved, no redemption payments are required. 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. The Class B unit has an initial value of $12.2 million which will increase with each foregone incentive distribution as described above 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. Noncontrolling interests reported in the Consolidated Statements of Income include the minority partner's 25% interest in UNEV and income attributable to the Class B unit representing foregone incentive distribution rights and the 7% accretion factor, which collectively amounted to $1.2 million for the period July 12, 2012 to December 31, 2012.

Credit Agreement

In June 2012, we amended our credit agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 (the “Credit Agreement”) and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is available also to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012 we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million.

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

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.75% to 1.75%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.75% to 2.75%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.30% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

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

Senior Notes

In March 2012, we issued $300 million in aggregate principal amount outstanding of 6.5% senior notes maturing March 1, 2020 (the “6.5% Senior Notes”). Net Proceeds of $294.8 million were used to redeem $157.8 million aggregate principal amount of 6.25% senior notes maturing March 1, 2015 (the “6.25 Senior Notes”) tendered pursuant to a cash tender offer and consent solicitation, to repay $72.9 million in promissory notes due to HFC as discussed below, to pay related fees, expenses and accrued interest in connection with these transactions and to repay borrowings under the Credit Agreement. In April 2012, we redeemed $27.2 million aggregate principal amount of 6.25% Senior Notes that remained outstanding following the cash tender offer and consent solicitation.

We also have $150 million in aggregate principal amount outstanding of 8.25% senior notes maturing March 15, 2018 (the “8.25 Senior Notes”).

Our 6.5% Senior Notes and 8.25% Senior Notes (collectively, the “Senior Notes”) are unsecured and impose certain restrictive covenants which we are currently in compliance with, 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. At any time when the Senior Notes are rated investment grade by both Moody’s and Standard & Poor’s and no default or event of default

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exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to 2015 and $171 million prior to 2018, subject to certain limited exceptions.

Promissory Notes
In November 2011, we issued senior unsecured promissory notes to HFC (the "Promissory Notes") having an aggregate principal amount of $150.0 million to finance a portion of our November 9, 2011 acquisition of assets located at HFC's El Dorado and Cheyenne refineries. In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. We repaid the remaining $72.9 million balance in March 2012.

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Credit Agreement	$421,000	$200,000
6.5% Senior Notes		
Principal	300,000	—
Unamortized discount	(4,725)	—
	295,275	—
6.25% Senior Notes		
Principal	—	185,000
Unamortized net discount	—	(105)
	—	184,895
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,601)	(1,907)
	148,399	148,093
Promissory Notes	—	72,900
Total long-term debt	$864,674	$605,888

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, 2012.

		Payments Due by Period			
	Total	Less than	1-3 Years	3-5 Years	Over 5

		1 Year			Years
	(In thousands)				
Long-term debt – principal	$ 871,000	$ —	$ —	$ 421,000	$ 450,000
Long-term debt - interest	260,951	42,239	84,478	79,296	54,938
Pipeline operating lease	36,693	6,672	13,343	13,343	3,335
Right-of-way leases	1,340	237	356	325	422
Other	16,210	1,519	2,967	2,725	8,999
Total	$ 1,186,194	$ 50,667	$ 101,144	$ 516,689	$ 517,694

Long-term debt consists of outstanding principal under the Credit Agreement, Senior Notes and Promissory Notes. Interest on the credit agreement is calculated using the rate in effect at December 31, 2012.
The pipeline operating lease amounts above reflect the exercise of the first of three 10-year extensions, expiring in 2017, on our lease agreement for the refined products pipeline between White Lakes Junction and Kuntz Station in New Mexico. However, these amounts exclude the second and third 10-year lease extensions, which based on the current outlook, are likely to be exercised.
Most of our right-of-way agreements are renewable on an annual basis, and the right-of-way lease payments above include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2012. 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 consist of site service agreements with HFC expiring in 2024 through 2027, for the provision of certain maintenance and utility costs that relate to our assets located at HFC's refinery facilities.

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, 2012, 2011 and 2010. Historically, the PPI has increased an average of 3.1% annually over the past 5 calendar years.

The substantial majority of our revenues are generated under long-term contracts that provide for increases in our rates and minimum revenue guarantees annually for increases in the PPI. Certain of these contracts have provisions that limit the level of annual PPI percentage rate increases. Although the recent PPI increase may not be indicative of additional increases to be realized in the future, a significant and prolonged period of 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. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. A 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.
Under the Omnibus Agreement and certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain monetary and time limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC and occurring or existing prior to the date of such transfers.
We have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations.

There are environmental remediation projects that are currently in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities of HFC as the obligation for future remediation activities was retained by HFC. At December 31, 2012, we have an accrual of $3.0 million that relates to environmental clean-up projects for which we have assumed liability or for which the indemnity provided for by HFC has expired or will expire. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

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CRITICAL ACCOUNTING POLICIES

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

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals. Additional pipeline transportation revenues result from an operating lease by Alon USA, L.P. of an interest in the capacity of one of our pipelines.

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

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

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

Goodwill and Long-Lived Assets

Goodwill represents the excess of our cost of an acquired business over the fair value of the assets acquired, less liabilities assumed. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate goodwill may be impaired. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. We use the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss.

We evaluate long-lived assets, including definite-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 as of December 31, 2012.

Contingencies

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

RISK MANAGEMENT

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of December 31, 2012, we have three interest rate swaps, designated as a cash flow hedge, that hedge our exposure to the cash flow risk caused by the effects of LIBOR changes on $305.0 million of Credit Agreement advances. Our first interest rate swap effectively converts $155.0 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.99% plus an applicable margin of 2.25% as of December 31, 2012, which equaled an effective interest rate of 3.24%. This swap contract matures in

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February 2016. In August 2012, we entered into two similar interest rate swaps with identical terms which effectively convert $150.0 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.74% plus an applicable margin of 2.25% as of December 31, 2012, which equaled an effective interest rate of 2.99%. Both of these swap contracts mature in July 2017.

We review publicly available information on our counterparties in order to review and monitor their financial stability and assess their ongoing ability to honor their commitments under the interest rate swap contracts. These counterparties are large financial institutions. Furthermore, we have not experienced, nor do we expect to experience, any difficulty in the counterparties honoring their respective commitments.

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, 2012, we had an outstanding principal balance on our 6.5% Senior Notes and 8.25% Senior Notes of $300 million and $150 million, respectively. A change in interest rates generally would affect the fair value of the Senior Notes, but not our earnings or cash flows. At December 31, 2012, the fair values of our 6.5% Senior Notes and 8.25% Senior Notes were $321.0 million and $163.1 million, respectively. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6.5% Senior Notes and 8.25% Senior Notes at December 31, 2012 would result in a change of approximately $9.9 million and $4.4 million, respectively, in the fair value of the underlying notes.

For the variable rate Credit Agreement, changes in interest rates would affect cash flows, but not the fair value. At December 31, 2012, borrowings outstanding under the Credit Agreement were $421.0 million. By means of our cash flow hedges, we have effectively converted the variable rate on $305.0 million of outstanding borrowings to a fixed rate. For the remaining unhedged Credit Agreement borrowings of $116.0 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” above 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, also 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.

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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, 2012 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. Based on this assessment, management concluded that, as of December 31, 2012, 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, 2012. That report appears on page 54.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Holly Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Holly Energy Partners, L.P.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Holly Energy Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Holly Energy Partners, L.P. as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2012, and our report dated February 27, 2013, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 27, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Holly Energy Partners, L.P. (the "Partnership") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Holly Energy Partners, L.P. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2012, 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), Holly Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 27, 2013

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011 (1)
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$5,237	$6,369
Accounts receivable:		
Trade	7,126	6,130
Affiliates	31,594	31,922
	38,720	38,052
Prepaid and other current assets	3,619	3,729
Total current assets	47,576	48,150
Properties and equipment, net	960,535	960,499
Transportation agreements, net	94,596	101,543
Goodwill	256,498	256,498
Investment in SLC Pipeline	25,041	25,302
Other assets	9,864	7,204
Total assets	$1,394,110	$1,399,196
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$7,045	$18,375
Affiliates	4,985	6,474
	12,030	24,849
Accrued interest	10,226	8,280
Deferred revenue	8,901	4,447
Accrued property taxes	2,688	2,196
Other current liabilities	1,905	1,777
Total current liabilities	35,750	41,549
Long-term debt	864,674	605,888
Other long-term liabilities	15,433	8,653
Deferred revenue	11,494	5,428
Class B unit	13,903	—
Equity:		
Partners' equity:		
Common unitholders (56,782,048 and 54,722,248 units issued and outstanding at December 31, 2012 and 2011, respectively)	502,809	481,439
General partner interest (2% interest)	(145,877)	163,701
Accumulated other comprehensive loss	(4,279)	(6,464)
Total partners' equity	352,653	638,676

Noncontrolling interest	100,203	99,002
Total equity	452,856	737,678
Total liabilities and equity	$1,394,110	$1,399,196

(1) Restated as described in Note 2.

See accompanying notes.

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HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2012	2011 (1)	2010 (1)
	(In thousands, except per unit data)		
Revenues:			
Affiliates	$245,582	$168,261	$146,367
Third parties	46,978	46,007	35,770
	292,560	214,268	182,137
Operating costs and expenses:			
Operations (exclusive of depreciation and amortization)	89,242	64,521	54,946
Depreciation and amortization	57,461	36,958	31,363
General and administrative	7,594	6,576	7,719
	154,297	108,055	94,028
Operating income	138,263	106,213	88,109
Other income (expense):			
Equity in earnings of SLC Pipeline	3,364	2,552	2,393
Interest expense	(47,182)	(35,959)	(33,994)
Loss on early extinguishment of debt	(2,979)	—	—
Other (income) expense	10	17	17
	(46,787)	(33,390)	(31,584)
Income before income taxes	91,476	72,823	56,525
State income tax expense	(371)	(234)	(296)
Net income	91,105	72,589	56,229
Allocation of net loss attributable to Predecessors	4,200	6,351	70
Allocation of net loss (income) attributable to noncontrolling interests	(1,153)	859	24
Net income attributable to Holly Energy Partners	94,152	79,799	56,323
General partner interest in net income, including incentive distributions	(22,450)	(16,806)	(12,084)
Limited partners’ interest in net income	$71,702	$62,993	$44,239
Limited partners’ per unit interest in earnings—basic and diluted	$1.29	$1.38	$1.00
Weighted average limited partners’ units outstanding	55,696	45,672	44,157

(1) Restated as described in Note 2.

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	2011 [1]	2010 [1]
	(In thousands)		
Net income	$91,105	$72,589	$56,229
Allocation of net loss attributable to Predecessors	4,200	6,351	70
Net income before noncontrolling interests	95,305	78,940	56,299
Other comprehensive income (loss):			
Change in fair value of cash flow hedge	(2,910)	3,521	(1,961)
Amortization of unrealized loss attributable to discontinued cash flow hedge	5,095	41	—
Reclassification adjustment to net income on partial settlement of cash flow hedge	—	—	1,076
Other comprehensive income (loss)	2,185	3,562	(885)
Comprehensive income before noncontrolling interest	97,490	82,502	55,414
Allocation of comprehensive (income) loss to noncontrolling interests	(1,153)	859	24
Comprehensive income	$96,337	$83,361	$55,438

[1] Restated as described in Note 2.

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	2011 [1]	2010 [1]
	(In thousands)		
Cash flows from operating activities			
Net income	$91,105	$72,589	$56,229
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	57,461	36,958	31,363
Amortization of deferred charges	7,556	1,253	1,008
Equity in earnings of SLC Pipeline, net of distributions	262	135	482
Change in fair value - interest rate swaps	—	—	1,464
Amortization of restricted and performance units	2,858	2,046	2,214
(Increase) decrease in operating assets:			
Accounts receivable—trade	(3,997)	489	1,149
Accounts receivable—affiliates	(135)	(13,032)	(4,888)
Prepaid and other current assets	110	(2,491)	(36)
Current assets of discontinued operations	—	—	2,195
Increase (decrease) in operating liabilities:			
Accounts payable—trade	(9,003)	3,894	2,684
Accounts payable—affiliates	(1,811)	2,137	1,487
Accrued interest	1,945	763	4,654
Deferred revenue	11,333	(2,127)	3,664
Accrued property taxes	492	206	918
Other current liabilities	113	515	5
Other, net	3,122	(4,293)	144
Net cash provided by operating activities	161,411	99,042	104,736
Cash flows from investing activities			
Additions to properties and equipment	(42,861)	(206,309)	(106,525)
Acquisition of assets from HFC	—	—	(35,526)
Net cash used for investing activities	(42,861)	(206,309)	(142,051)
Cash flows from financing activities			
Borrowings under credit agreement	587,000	118,000	66,000
Repayments of credit agreement borrowings	(366,000)	(77,000)	(113,000)
Proceeds from issuance of senior notes	294,750	—	147,540
Proceeds from issuance of common units	—	75,815	—
Cash distribution to HFC for UNEV Acquisition	(260,922)	—	—
Repayment of notes	(260,235)	(77,100)	—
Contributions from UNEV joint venture partners	15,000	156,500	80,500
Contributions from general partner	1,748	5,887	—
Distributions to HEP unitholders	(122,777)	(91,506)	(84,426)
Purchase price in excess of transferred basis in assets acquired from HFC	—	—	(57,560)
Purchase of units for incentive grants	(4,919)	(1,641)	(2,704)
Deferred financing costs	(3,238)	(3,150)	(494)

Other	(89)	(221)	—
Net cash provided (used) by financing activities	(119,682)	105,584	35,856
Cash and cash equivalents			
Increase (decrease) for the period	(1,132)	(1,683)	(1,459)
Beginning of year	6,369	8,052	9,511
End of year	$5,237	$6,369	$8,052

(1) Restated as described in Note 2.

See accompanying notes.

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HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Holly Energy Partners, L.P. Partners' Equity (Deficit):					
	Common Units (1)	Class B Subordinated Units (1)	General Partner Interest (1)	Accumulated Other Comprehensive Loss (1)	Noncontrolling Interest (1)	Total (1)
	(In thousands)					
Balance December 31, 2009	$275,553	$ 21,426	$25,678	$ (9,141)	$ 39,886	$353,402
Conversion of Class B subordinated units	20,588	(20,588)	—	—	—	—
Capital contribution			75,091		23,500	98,591
Distributions to unitholders	(70,886)	(1,519)	(12,021)	—	—	(84,426)
Purchase price in excess of transferred basis in assets acquired from HollyFrontier	—	—	(57,560)	—	—	(57,560)
Purchase of units for incentive grants	(2,704)	—	—	—	—	(2,704)
Amortization of restricted and performance units	2,214	—	—	—	—	2,214
Comprehensive income:						
Net income	44,388	681	11,254	—	(24)	56,299
Net loss - Predecessor	—	—	(70)	—	—	(70)
Other comprehensive loss	—	—	—	(885)	—	(885)
Balance December 31, 2010	269,153	—	42,372	(10,026)	63,362	364,861
Issuance of common units	75,815	—	—	—	—	75,815
Cost of issuing common units	(308)	—	—	—	—	(308)
Capital contribution	—	—	127,947	—	36,500	164,447
Distributions to unitholders	(75,951)	—	(15,555)	—	—	(91,506)
Tankage and terminal assets acquired from HFC:						
Transferred basis in properties and goodwill	295,110	—	—	—	—	295,110
Operating costs prior to acquisition	2,348	—	—	—	—	2,348
Promissory notes issued	(150,000)	—	—	—	—	(150,000)
Purchase of units for incentive grants	(2,168)	—	—	—	—	(2,168)
Amortization of restricted and performance units	2,046	—	—	—	—	2,046
Other	640	—	242	—	—	882
Comprehensive income:						
Net income	64,754	—	15,046	—	(860)	78,940
Net loss - Predecessor	—	—	(6,351)	—	—	(6,351)
Other comprehensive income	—	—	—	3,562	—	3,562
Balance December 31, 2011	481,439	—	163,701	(6,464)	99,002	737,678
Capital contribution	—	—	10,286	—	3,000	13,286
Distributions to HEP unitholders	(99,744)	—	(23,033)	—	—	(122,777)

Purchase of 75% interest in UNEV from HFC:						
Cash distribution	—	—	(260,922)	—	—	(260,922)
Issuance of common units	45,839	—	(45,839)	—	—	—
Issuance of Class B unit	—	—	(12,200)	—	—	(12,200)
Purchase of units for restricted grants	(4,713)	—	—	—	—	(4,713)
Amortization of restricted and performance units	2,858	—	—	—	—	2,858
Class B unit accretion	(1,694)	—	(9)	—	—	(1,703)
Tankage and terminal assets acquired from HFC:						
Transferred basis in properties	7,947	—	—	—	—	7,947
Other	—	—	112	—	—	112
Comprehensive income:						
Net income	70,877	—	26,227	—	(1,799)	95,305
Net loss - Predecessor	—	—	(4,200)	—	—	(4,200)
Other comprehensive income	—	—	—	2,185	—	2,185
Balance December 31, 2012	$502,809	$ —	$(145,877)	$ (4,279)	$ 100,203	$452,856

(1) Restated as described in Note 2.

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012

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

Holly Energy Partners, L.P. (“HEP”) together with its consolidated subsidiaries, is a publicly held master limited partnership which is 44% owned (including the 2% general partner interest) by HollyFrontier Corporation (“HFC”) and its subsidiaries.

We commenced operations on July 13, 2004 upon the completion of our initial public offering. In these consolidated financial statements, the words “we,” “our,” “ours” and “us” refer to HEP unless the context otherwise indicates.

We operate in one reportable segment which represents the aggregation of our petroleum product and crude pipelines business and terminals, tankage and loading rack facilities operations.

We own and operate petroleum product and crude oil pipelines and terminal, tankage and loading rack facilities that support HFC’s refining and marketing operations in the Mid-Continent, Southwest and Rocky Mountain regions of the United States and Alon USA, Inc.’s (“Alon”) refinery in Big Spring, Texas. Additionally, we own a 75% interest in the UNEV Pipeline, LLC (“UNEV”), which owns a recently constructed 400-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada (the “UNEV Pipeline”), product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets, and we own a 25% joint venture interest in a 95-mile intrastate crude oil pipeline system (the “SLC Pipeline”) that serves refineries in the Salt Lake City area.

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 and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore, we are not exposed directly to changes in commodity prices.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all periods presented.

Principles of Consolidation and Common Control Transactions
The consolidated financial statements include our accounts and those of subsidiaries and joint ventures that we control through a 50% or more ownership interest. All significant inter-company transactions and balances have been eliminated.

Most of our asset 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 assets on our balance sheets at HFC's historical basis instead of our purchase price or fair value. If these assets had been acquired from third parties, our acquisition cost in excess of HFC's basis in the transferred assets of $305.6 million would have been recorded as increases to our properties and equipment and intangible assets instead of reductions to our partners' equity.

Use of Estimates
The preparation of financial statements in accordance with U.S. generally accepted accounting principles (“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, Alon 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.

Inventories
Inventories consisting of materials and supplies used for operations are stated at the lower of cost, using the average cost method, or market and are shown under “Prepaid and other current assets” in our consolidated balance sheets.

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 and 5 to 10 years for corporate and other assets. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvements are capitalized.

Transportation Agreements
The transportation agreement assets are stated at acquisition date fair value and are being amortized over the periods of the agreements using the straight-line method. See Note 6 for additional information on our transportation agreements.

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 and is tested for impairment annually or more frequently if events or changes in circumstances indicate goodwill may be impaired. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. We use the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss.

We evaluate long-lived assets, including definite-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 as of December 31, 2012.

Investment in SLC Pipeline
We account for our 25% SLC Pipeline joint venture interest using the equity method of accounting, whereby we record our pro-rata share of earnings of the SLC Pipeline, and contributions to and distributions from the SLC Pipeline as adjustments to our investment balance. As of December 31, 2012, our underlying equity in the SLC Pipeline was \$60.0 million compared to our recorded investment balance of \$25.0 million, a difference of \$35.0 million. We are amortizing this difference as an adjustment to our pro-rata share of earnings over the useful lives of the underlying assets of SLC Pipeline.

Asset Retirement Obligations
We record legal obligations associated with the retirement 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. At December 31, 2012 and 2011, we have retirement obligations of \$5.6 million and \$3.6 million, respectively, that are recorded under “Other long-term liabilities” in our consolidated

balance sheets. During 2012 we increased our asset retirement obligations by an additional $2.9 million as a result of a change in our previous estimates.

Revenue Recognition

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

- the customer receiving the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or

- our determination that we will not be required to provide services within the allowed period.

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

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

As of December 31, 2012, billings to customers under their minimum revenue commitments per the terms of long-term throughput agreements expiring in 2019 through 2026 and the third party operating lease will result in minimum annualized payments to us of $256.7 million for each of the next five years. These agreements provide for increases in the minimum revenue guarantees annually for increases in the Producer Price Index ("PPI") or the Federal Energy Regulatory Commission ("FERC") index, with certain contracts having provisions that limit the level of the rate increases.

We have other cost reimbursement provisions in our throughput / storage agreements providing that customers (including HFC) reimburse us for certain costs. Such reimbursement receipts are recorded as revenue or deferred revenue depending on the nature of the cost. Deferred revenue is recognized over the 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. At December 31, 2012 and 2011, we had net accruals for environmental remediation obligations of $3.0 million and $2.7 million, respectively, measured on an undiscounted basis.
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 Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations. 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 bases and financial reporting bases 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, which is based on the weighted-average number of common and subordinated units outstanding during the year. 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 previous owners ("Predecessor"), the allocation of net income or loss attributable to noncontrolling interests and the general partner's 2% interest and incentive distributions, by the weighted-average number of outstanding common and subordinated units.

Note 2: Revisions to Prior Period Financial Statements

We have revised our previously reported consolidated financial statements. The revisions were due to accounting rules that require retrospective restatement of previously reported results in cases of business combinations between entities under common control. Additional revisions for the years ended December 31, 2011 and 2010 were done in order to correct items in certain previously reported amounts.

Our retrospective restatements for two acquisitions from HFC are described below. See Note 3 below for additional information on both acquisitions.

- On July 12, 2012, we acquired a 75% interest in UNEV. We have retrospectively adjusted our historical financial results for all periods to include UNEV for the periods we were under common control of HFC. Results of operations of UNEV prior to the acquisition on July 12, 2012 are herein referred to as the results of operations attributable to the Predecessor.

- In 2011, our operating results included $3.8 million of operating costs and depreciation incurred by HFC prior to our November 9, 2011 acquisition of certain assets located at HFC's El Dorado and Cheyenne refineries. This loss was allocated in the originally reported historical financial statements included in Form 10-K for the year ended December 31, 2011 principally to the limited partners. The pre-acquisition loss should have been reported as a loss attributable to the Predecessor. We have revised the 2011 presentation which resulted in an increase in limited partners' interest in net income of $3.8 million and limited partners' per unit interest in earnings - basic and diluted of $0.08 from the amounts originally reported.

During 2012, we identified the following additional items requiring revisions to our previously reported financial statements for the years ended December 31, 2011 and 2010, which have been corrected. We determined that the effects of these corrections in each of the periods in which the related items originated, as described below, were not material. We have concluded that the amounts, if corrected in 2012, would have been material to the consolidated financial statements as of and for the year ended December 31, 2012.

- Depreciation expense was understated related to property and equipment in both 2010 and 2011 due to inappropriate depreciable lives for certain property and equipment and untimely recording of acceleration of depreciation for tankage placed permanently out of service in prior periods.

- An environmental remediation liability and certain asset retirement obligations were identified that should have been recorded in 2010 and 2011.

- Reimbursement payments from HFC under contractual arrangements previously recognized as an offset against the related costs have been recorded as revenue, or deferred revenue in cases of capital cost reimbursements which are then amortized over the contractual term of the related throughput agreement. Additionally, we have revised our cash flow presentation for capital cost reimbursements to reflect receipts in cash flows provided by operating activities as opposed to netting the receipts in cash flows used for investing activities.

The tables below outline the impact of such corrections on individual financial statement line items.

	December 31, 2011 Increase (Decrease) (In thousands)
Consolidated Balance Sheets:	
Properties and equipment, net	$5,635
Deferred revenue - current portion	$415
Other long-term liabilities	$4,653
Deferred revenue - long-term	$5,428
Total equity	$(4,861)

	Years Ended December 31, 2011	2010
	Increase (Decrease) (In thousands)	
Consolidated Statements of Income:		
Revenues	$976	$55
Operating expenses	$898	$1,808
Depreciation and amortization	$2,050	$794
Net income attributable to Holly Energy Partners and comprehensive income	$(1,972)	$(2,547)
Limited partners' per unit interest in earnings - basic and diluted	$(0.04)	$(0.06)
Consolidated Statements of Cash Flows:		
Net cash provided by operating activities	$4,278	$1,629
Net cash used for investing activities	$(4,278)	$(1,629)

Note 3: Acquisitions

2012 UNEV Acquisition

On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.0 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). We paid an additional $0.9 million to HFC for a post-closing working capital adjustment as provided for by the acquisition agreement. As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, 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. Such contingent redemption payments are limited to a maximum payment amount calculated as described below. However, to the extent earnings thresholds are not achieved, no redemption payments are required. 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. The Class B unit has an initial value of $12.2 million which will increase with each foregone incentive distribution as described above 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. Noncontrolling interests reported in the Consolidated Statements of Income include the minority partner's 25% interest in UNEV and income attributable to the Class B unit representing foregone incentive distribution rights and the 7% accretion factor, which collectively amounted to $1.2 million for the period July 12, 2012 to December 31, 2012.

We are a consolidated variable interest entity of HFC. Therefore, this transaction was recorded as a transfer between entities under common control and reflects HFC's carrying basis in UNEV's assets and liabilities. We have retrospectively adjusted our financial position and operating results as if UNEV were a consolidated subsidiary for all periods while we were under common control of HFC. For the year ended December 31, 2012 and 2011, our consolidated statement of income includes revenues from UNEV of $18.7 million and $0.3 million, respectively, net losses of $7.2 million and $3.4 million, respectively. Predecessor revenues for the years ended December 31, 2012 and 2011 are $8.1 million and $0.3 million, respectively, and Predecessor net losses are $4.2 million and $2.6 million, respectively. For the year ended December 31, 2010, there were no Predecessor revenues as UNEV was not yet operational and Predecessor net losses were $0.1 million. At December 31, 2012, UNEV had transportation agreements with shippers that provide minimum annualized revenues of $25.0 million, of which $16.9 million relates to a transportation agreement with HFC.

The following table provides HFC's carrying basis related to UNEV on July 12, 2012, immediately prior to the acquisition, and at December 31, 2011.

	July 12, 2012	December 31, 2011 (1)
	(In thousands)	
Current assets	$7,083	$8,265
Properties and equipment, net	418,764	418,439
Total assets	$425,847	$426,704
Current liabilities	$7,040	$13,542
General partner interest related to Predecessor	318,310	314,160
Noncontrolling interest	100,497	99,002
Total liabilities and equity	$425,847	$426,704

(1) Our previously reported balance sheet as of December 31, 2011 has been recast to include such balances.

2011 Legacy Frontier Pipeline and Tankage Asset Transaction
On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC’s El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150.0 million and 7,615,230 of our common units. As an entity under common control with HFC, we recorded this transfer at HFC's carrying basis. We recorded properties and equipment of $88.1 million, goodwill of $207.4 million and a non-cash capital contribution of $295.5 million, representing HFC's cost basis in the acquired assets. On November 9, 2011, we recorded a $150.0 million liability representing the promissory notes issued to HFC at the time of the closing of this transaction. In 2012, we recorded additional properties and equipment of $7.6 million, and a related non-cash capital contribution of $7.6 million for newly constructed tankage conveyed in 2012 as part of the November 9, 2011 transaction.

Summary Pro Forma Information
Assuming both acquisitions had occurred on January 1, 2010 and our throughput agreements with HFC were in effect at that time, pro forma revenues, net income and earnings per unit are presented below:

	Years Ended December 31,	
	2011	2010
	(In thousands, except per share amounts)	
	(unaudited)	
Revenues	$214,268	$182,137
Net income	71,145	47,669
Earnings per unit	$1.19	$0.81

2010 Tulsa East / Lovington Storage Asset Transaction
On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC's Tulsa refinery east facility. Also, as part of this same transaction, we acquired HFC's asphalt loading rack facility located at its Navajo refinery facility in Lovington, New Mexico for $4.4 million. In accounting for the 2010 acquisition from HFC, we recorded total property and equipment at HFC's historical basis of $35.5 million and the purchase price in excess of HFC's basis in the assets of $57.6 million as a decrease to our partners' equity.

Note 4: Financial Instruments

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

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

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

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

Financial Instrument	Fair Value Input Level	December 31, 2012 Carrying Value	December 31, 2012 Fair Value	December 31, 2011 Carrying Value	December 31, 2011 Fair Value
		(In thousands)			
Liabilities:					
Senior notes:					
6.25% senior notes	Level 2	$—	$—	$184,895	$186,850
6.5% senior notes	Level 2	295,275	321,000	—	—
8.25% senior notes	Level 2	148,398	163,125	148,093	157,500
		443,673	484,125	332,988	344,350
Interest rate swaps	Level 2	3,430	3,430	520	520
		$447,103	$487,555	$333,508	$344,870

Level 2 Financial Instruments

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

See Note 8 for additional information on these instruments.

Note 5: Properties and Equipment

The carrying amounts of our properties and equipment after restatement as per Note 2 are as follows:

	December 31, 2012	December 31, 2011
	(In thousands)	
Pipelines, terminals and tankage	1,049,531	886,167
Land and right of way	63,248	43,904
Construction in progress	27,150	172,485
Other	24,462	17,554
	1,164,391	1,120,110
Less accumulated depreciation	203,856	159,611
	$960,535	$960,499

We capitalized $0.3 million and $0.9 million in interest related to construction projects during the years ended December 31, 2012 and 2011, respectively.

Depreciation expense was $50.1 million, $30.0 million, and $24.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. Included in depreciation expense were asset abandonment charges of $4.8 million, $1.2 million and $0.4 million for the years ended December 31, 2012, 2011 and 2010, respectively, for assets permanently removed from service.

Note 6: Transportation Agreements

Our transportation agreements represent a portion of the total purchase price of certain assets acquired from Alon in 2005 and from HFC in 2008. The Alon agreement is being amortized over 30 years ending 2035 (the initial 15-year term of the agreement plus an expected 15-year extension period) and the HFC agreement is being amortized over 15 years ending 2023 (the term of the HFC agreement).

The carrying amounts of our transportation agreements are as follows:

	December 31, 2012	December 31, 2011
	(In thousands)	
Alon transportation agreement	$59,933	$59,933
HFC transportation agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	39,568	32,621
	$94,596	$101,543

Amortization expense was $6.9 million, $6.9 million, and $6.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

We have additional transportation agreements with HFC that relate to assets contributed to us or acquired from HFC consisting of pipeline, terminal and tankage assets. 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

Employees who provide direct services to us are employed by Holly Logistic Services, L.L.C., an HFC subsidiary. 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, $3.6 million and $2.9 million for the years ended December 31, 2012, 2011 and 2010, respectively. These costs include retirement costs of $4.3 million, $2.2 million and $1.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. 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.

We have an incentive plan ("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 units, performance units, unit options and unit appreciation rights.

As of December 31, 2012, we have two types of incentive-based awards which are described below. The compensation cost charged against income was $2.7 million, $2.1 million and $2.2 million for the years ended December 31, 2012, 2011 and 2010, 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. Effective February 2012, the units authorized to be granted under our Long-Term Incentive Plan were increased from 700,000 to 2,500,000 units, of which 1,833,024 have not yet been granted, assuming no forfeitures of the unvested units and full achievement of goals for the performance units already granted.

Restricted Units
Under our Long-Term Incentive Plan, we grant restricted units to selected employees and non-employee directors who perform services for us, with most awards vesting over a period of one to three years. Although full ownership of the units does not transfer to the recipients until the units vest, the recipients have distribution and voting rights on these units from the date of grant. The fair value of each restricted unit award is measured at the market price as of the date of grant and is amortized over the vesting period.

A summary of restricted unit activity and changes during the year ended December 31, 2012 is presented below:

Restricted Units	Units		Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2012 (nonvested)	59,072		$25.23		
Granted	90,528		31.01		
Vesting and transfer of full ownership to recipients	(89,034	)	27.10		
Forfeited	(2,094	)	28.66		
Outstanding at December 31, 2012 (nonvested)	58,472		$31.21	1.1 years	$1,923

The fair values of restricted units that were vested and transferred to recipients during the years ended December 31, 2012, 2011 and 2010 were $2.4 million, $1.4 million and $1.6 million respectively. As of December 31, 2012, there was $1.0 million of total unrecognized compensation expense related to nonvested restricted unit grants which is expected to be recognized over a weighted-average period of 1.1 years. For the years ended December 31, 2011 and 2010, the grant date closing unit price applied to the number of units ultimately awarded was $29.05 and 21.57 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 based upon the growth in our distributable cash flow per common unit over the performance period, and vest over a period of 3 years. As of December 31, 2012, estimated unit payouts for outstanding nonvested performance unit awards were 110%.

We granted 11,436 performance units to certain officers in March 2012. These units will vest over a 3-year performance period ending December 31, 2014 and are payable in HEP common units. The number of units actually earned will be based on the growth of our distributable cash flow per common unit over the performance period, and can range from 50% to 150% of the 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. For the year ended December 31, 2012, the fair value of these performance units is based on the grant date closing unit price of $30.61 and will apply to the number of units ultimately awarded. For the years ended December 31, 2011 and 2010, the grant date closing unit price applied to the number of units ultimately awarded was $29.83 and $21.30 respectively.

A summary of performance unit activity and changes during the twelve months ended December 31, 2012 is presented below:

Performance Units	Units
Outstanding at January 1, 2012 (nonvested)	85,982
Granted	11,436
Vesting and transfer of common units to recipients	(42,920)
Outstanding at December 31, 2012 (nonvested)	54,498

The grant-date fair value of performance units vested and transferred to recipients during the years ended December 31, 2012, 2011 and 2010 was $0.5 million, $0.9 million and $0.6 million, respectively. Based on the weighted average fair value at December 31, 2012 of $26.06, there was $0.5 million of total unrecognized compensation expense related to nonvested performance units, which is expected to be recognized over a weighted-average period of 0.6 years.

During the year ended December 31, 2012, we paid $4.9 million for the purchase of our common units in the open market for the issuance and settlement of all unit awards under our Long-Term Incentive Plan.

Note 8: Debt

Credit Agreement

In June 2012, we amended our credit agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 (the “Credit Agreement”) and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is available also to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012, we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million. During the year ended December 31, 2012, we received advances totaling $587 million and repaid $366 million, resulting in net borrowings of $221 million under the Credit Agreement and an outstanding balance of $421 million at December 31, 2012.

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

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.75% to 1.75%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.75% to 2.75%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.30% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

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

Senior Notes
In March 2012, we issued $300 million in aggregate principal amount outstanding of 6.5% senior notes maturing March 1, 2020 (the “6.5% Senior Notes”). Net proceeds of $294.8 million were used to redeem $157.8 million aggregate principal amount of our 6.25% senior notes maturing March 1, 2015 (the “6.25% Senior Notes”) tendered pursuant to a cash tender offer and consent solicitation, to repay $72.9 million in promissory notes due to HFC as discussed below, to pay related fees, expenses and accrued interest in connection with these transactions and to repay borrowings under the Credit Agreement.

In April 2012, we redeemed $27.2 million aggregate principal amount of 6.25% Senior Notes that remained outstanding following the cash tender offer and consent solicitation.

We also have $150 million in aggregate principal amount outstanding of 8.25% senior notes maturing March 15, 2018 (the “8.25% Senior Notes”).

The 6.5% Senior Notes and 8.25% Senior Notes (collectively, the “Senior Notes”) are unsecured and impose certain restrictive covenants, which we are currently in compliance with, 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. At any time when the 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 under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics, our general partner, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to 2015 and $171 million prior to 2018, subject to certain limited exceptions.

Promissory Notes

In November 2011, we issued senior unsecured promissory notes to HFC (the “Promissory Notes”) having an aggregate principal amount of $150 million to finance a portion of our November 9, 2011 acquisition of assets located at HFC's El Dorado and Cheyenne refineries (see Note 3). In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. We repaid the remaining $72.9 million balance in March 2012.

Long-term Debt

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Credit Agreement	$421,000	$200,000
6.5% Senior Notes		
Principal	300,000	—
Unamortized discount	(4,725)	—
	295,275	—
6.25% Senior Notes		
Principal	—	185,000
Unamortized net discount	—	(105)
	—	184,895
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,601)	(1,907)
	148,399	148,093
Promissory Notes	—	72,900

Total long-term debt	$864,674	$605,888

Maturities of our long-term debt are as follows:

Years Ending December 31,	(In thousands)
2013	$—
2014	—
2015	—
2016	—
2017	421,000
Thereafter	450,000
Total	$871,000

Interest Rate Risk Management

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of December 31, 2012, we have three interest rate swaps that hedge our exposure to the cash flow risk caused by the effects of LIBOR changes on $305 million of Credit Agreement advances. Our first interest rate swap entered into in December 2011, effectively converts $155 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.99% plus an applicable margin of 2.25% as of December 31, 2012, which equaled an effective interest rate of 3.24%. This swap contract matures in February 2016. In August 2012, we entered into two similar interest rate swaps with identical terms which effectively convert $150 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.74% plus an applicable margin of 2.25% as of December 31, 2012, which equaled an effective interest rate of 2.99%. Both of these swap contracts mature in July 2017.

We have designated these interest rate swaps as cash flow hedges. Based on our assessment of effectiveness using the change in variable cash flows method, we have determined that these interest rate swaps are effective in offsetting the variability in interest payments on $305 million of our variable rate debt resulting from changes in LIBOR. Under hedge accounting, we adjust our cash flow hedges on a quarterly basis to their fair values with the offsetting fair value adjustments to accumulated other comprehensive loss. Also on a quarterly basis, we measure hedge effectiveness by comparing the present value of the cumulative change in the expected future interest to be paid or received on the variable leg of our swaps against the expected future interest payments on $305 million of our variable rate debt. Any ineffectiveness is recorded directly to interest expense. As of December 31, 2012, we had no ineffectiveness on our cash flow hedges.

Prior to entering into our swap contract in December 2011 (discussed above), we terminated our previous interest rate swap that prior to settlement also served to hedge our exposure to the effects of LIBOR changes on the same $155 million Credit Agreement advance. We terminated this swap at a cost of $6 million, to lock in a lower effective interest rate on this $155 million advance, which by means of the previous swap contract was effectively fixed at 6.24% at the time of termination.

At December 31, 2012, we have an accumulated other comprehensive loss of $4.3 million that relates to our current and previous cash flow hedging instruments. Of this amount, $0.8 million represents an unrecognized loss attributable to a cash flow hedge terminated in December 2011 and relates to the application of hedge accounting prior to termination. This amount is being amortized as a charge to interest expense through February 2013, the remaining term of the terminated swap contract. Of the remaining $3.4 million, approximately $1.0 million will be transferred from accumulated other comprehensive loss into interest expense as interest is paid on the underlying swap agreement over the next twelve-month period, assuming interest rates remain unchanged.

Additional information on our interest rate swaps is as follows:

Derivative Instrument	Balance Sheet Location (In thousands)	Fair Value	Location of Offsetting Balance	Offsetting Amount
December 31, 2012				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($305.0 million of LIBOR based debt interest)	Other long-term liabilities	$3,430	Accumulated other comprehensive loss	$3,430
December 31, 2011				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155.0 million of LIBOR based debt interest)	Other long-term liabilities	$520	Accumulated other comprehensive loss	$520

We previously had interest rate swap contracts that served as economic hedges on interest attributable to outstanding debt. For the year ended December 31, 2010, we recognized $1.5 million in non-cash charges to interest expense as a result of fair value adjustments to these swap contracts.

We have a deferred hedge premium that relates to the application of hedge accounting to a variable-rate swap associated with our 6.25% senior notes prior to its hedge dedesignation in 2008. This deferred hedge premium having a balance of $1.1 million at December 31, 2011 was amortized in 2012 and the unamortized balance was taken as a reduction to interest expense during the cash tender offer and consent solicitation of our 6.25% Senior Notes.

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swaps	$8,736	$10,477	$9,109
6.5% Senior Notes	15,716	—	—
6.25% Senior Notes	2,422	11,565	11,404
8.25% Senior Notes	12,380	12,380	10,298
Promissory Notes	543	745	—
Partial settlement of interest rate swap - cash flow hedge	—	—	1,076
Net fair value adjustments to interest rate swaps (1)	—	—	1,464
Amortization of unrealized loss attributable to discounted cash flow hedge	5,095	41	—
Amortization of discount and deferred debt issuance costs	1,946	1,212	713
Commitment fees	621	430	392
Total interest incurred	47,459	36,850	34,456
Less capitalized interest	277	891	462
Net interest expense	$47,182	$35,959	$33,994
Cash paid for interest (2)	$38,476	$34,825	$31,305

(1) Includes fair value adjustments to previous interest rate swap contracts settled during the first quarter of 2010.

(2) Presented net of cash received under previous interest rate swap contract of $1.9 million for the year ended December 31, 2010.

We recognized a charge of $3.0 million upon the early extinguishment of debt for the year ended December 31, 2012. This charge represents the premium paid to our 6.25% Senior Note holders upon their tender of an aggregate principal amount of $185.0 million and related net discount.

Note 9:Commitments and Contingencies

We lease certain facilities, pipelines and rights of way under operating leases, most of which contain renewal options. The right of way agreements have various termination dates through 2053.

As of December 31, 2012, 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)
2013	$6,908
2014	6,852
2015	6,848
2016	6,847
2017	6,821
Thereafter	3,758
Total	$38,034

Rental expense charged to operations was $8.1 million, $7.5 million and $7.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.
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 95% are currently generated from our two largest customers: HFC and Alon. The vast majority of our revenues are derived from activities conducted in the southwest United States.

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

	2012		2011		2010	
HFC	84	%	79	%	80	%
Alon	11	%	18	%	15	%

Note 11: Related Party Transactions

We serve HFC's refineries under long-term pipeline and terminal, tankage and throughput agreements expiring from 2019 to 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (“PPI”) or Federal Energy Regulatory Commission (“FERC”) index. Additionally such agreements require HFC to reimburse us for certain costs. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall 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.

In November 2011, we reached an agreement with HFC that clarifies certain terms of a crude pipelines and tankage throughput agreement, whereby HFC agreed to pay us $5.5 million for certain past deliveries on our crude pipeline system. We recognized this settlement as revenue in the fourth quarter of 2011 that will be billed in six equal quarterly installments through March 2013.

Under certain provisions of an omnibus agreement we have with HFC (the "Omnibus Agreement") we pay HFC an annual administrative fee for the provision by HFC or its affiliates of various general and administrative services to us, currently $2.3 million. This fee does not include the salaries of personnel employed by HLS who perform services for us 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 $245.6 million, $168.3 million and $146.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.
- HFC charged us general and administrative services under the Omnibus Agreement of $2.3 million for each of the three years ended December 31, 2012, 2011 and 2010.
- We reimbursed HFC for costs of employees supporting our operations of $31.1 million, $21.4 million and $18.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.
- HFC reimbursed us $13.4 million, $11.9 million and $3.7 million for the years ended December 31, 2012, 2011 and 2010, respectively, for certain reimbursable costs and capital projects.
- We distributed $64.0 million, $40.6 million and $35.9 million, for the years ended December 31, 2012, 2011 and 2010, respectively, to HFC as regular distributions on its common units and general partner interest, including general partner incentive distributions.
- Accounts receivable from HFC were $31.6 million and $31.9 million at December 31, 2012 and 2011, respectively.
- Accounts payable to HFC were $5.0 million and $6.5 million at December 31, 2012 and 2011, respectively.
- Revenues for the years ended December 31, 2012, 2011 and 2010 include $7.8 million, $3.3 million and $3.6 million of shortfall payments billed in 2011, 2010 and 2009, respectively, as HFC did not exceed its minimum volume commitment in any of the subsequent four quarters in 2012, 2011 and 2010. Additionally revenues for the year ended December 31, 2012 include $3.8 million due to capacity constraints on our UNEV pipeline system. Deferred revenue in the consolidated balance sheets at December 31, 2012 and 2011, includes $5.1 million and $4.0 million, respectively, relating to certain shortfall billings. It is possible that HFC may not exceed its minimum obligations to receive credit for any of the $5.1 million deferred at December 31, 2012.
- We acquired from HFC a 75% interest in the UNEV Pipeline in July 2012 and certain tankage and terminal assets in November 2011 and March 2010. See Note 3 for a description of these transactions.

Note 12: Partners' Equity, Income Allocations and Cash Distributions

As of December 31, 2012, HFC held 24,255,030 of our common units and the 2% general partner interest, which together constituted a 44% ownership interest in us.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all periods presented.

Common Unit Issuances

2012 Issuances

On July 12, 2012, we issued HFC 2,059,800 of our common units as partial consideration for our acquisition of its 75% interest in UNEV.

We received aggregate capital contributions of $1.7 million from our general partner to maintain its 2% general partner interest concurrent with the 2012 common unit issuance described above.

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2011 Issuances
We issued in a public offering 2,950,000 of our common units priced at $26.75 per unit in December 2011. Aggregate net proceeds of $75.8 million were used to pay a portion of outstanding principal of the Promissory Notes.

We issued 7,615,230 of our common units to HFC in November 2011 as partial consideration for the purchase of certain tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries.

We received aggregate capital contributions of $5.9 million from our general partner to maintain its 2% general partner interest concurrent with the 2011 common unit issuances described above.

Under our registration statement filed with the SEC using a “shelf” registration process, we currently have the ability to raise up to $2 billion 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.

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

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

	Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
General partner interest in net income	$1,464	$1,287	$903
General partner incentive distribution	20,986	15,519	11,181
Total general partner interest in net income	$22,450	$16,806	$12,084

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.

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

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

	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, 2013 we announced our cash distribution for the fourth quarter of 2012 of $0.47 per unit. The distribution is payable on all common and general partner units and will be paid February 14, 2013 to all unitholders of record on February 4, 2013.

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,		
	2012	2011	2010
	(In thousands, except per unit data)		
General partner interest	$2,566	$1,981	$1,724
General partner incentive distribution	20,986	15,519	11,181
Total general partner distribution	23,552	17,500	12,905
Limited partner distribution	102,222	81,508	73,223
Total regular quarterly cash distribution	$125,774	$99,008	$86,128
Cash distribution per unit applicable to limited partners	$1.835	$1.740	$1.660

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 of $305.6 million, exclusive of depreciation and amortization, would have been recorded in our financial statements, as increases to our properties and equipment and intangible assets instead of decreases to our partners' equity.

Note 13: Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
Year Ended December 31, 2012 [(1)]					
Revenues	$68,415	$68,660	$74,054	$81,431	$292,560
Operating income	$31,602	$30,116	$35,572	$40,973	$138,263
Income before income taxes	$19,431	$19,204	$23,909	$28,932	$91,476
Net income	$19,356	$19,128	$23,773	$28,848	$91,105
Net income attributable to Holly Energy Partners	$21,774	$22,003	$23,336	$27,039	$94,152
Limited partners’ per unit interest in net income – basic and diluted	$0.30	$0.30	$0.32	$0.37	$1.29
Distributions per limited partner unit	$0.448	$0.455	$0.462	$0.470	$1.835
Year Ended December 31, 2011 [(1)]					
Revenues	$45,122	$50,908	$49,151	$69,087	$214,268
Operating income	$22,262	$26,648	$20,598	$36,705	$106,213
Income before income taxes	$14,441	$18,391	$12,431	$27,560	$72,823
Net income	$14,213	$18,373	$12,508	$27,495	$72,589
Net income attributable to Holly Energy Partners	$14,600	$18,673	$15,632	$30,894	$79,799
Limited partners’ per unit interest in net income – basic and diluted	$0.25	$0.34	$0.26	$0.51	$1.38
Distributions per limited partner unit	$0.428	$0.433	$0.438	$0.443	$1.740

(1) Prior period amounts have been revised. See Note 2 for additional information. The table below outlines the impact of such corrections on quarterly limited partners' interest in net income. Other differences in amounts previously reported relate to the acquisitions as discussed in Notes 2 and 3.

	First	Second	Third	Fourth	Total
	Increase (Decrease)				
	(In thousands, except per unit data)				
Year Ended December 31, 2012					
Net income attributable to Holly Energy Partners	$(205)	$(1,159)	$(1,157)	$—	$—
Limited partners’ per unit interest in net income – basic and diluted	$—	$(0.02)	$(0.02)	$—	$—
Year Ended December 31, 2011					
Net income attributable to Holly Energy Partners	$(569)	$(339)	$(1,112)	$48	$(1,972)
Limited partners’ per unit interest in net income – basic and diluted	$(0.01)	$—	$(0.03)	$—	$(0.04)

Note 14: Supplemental Guarantor/Non-Guarantor Financial Information

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

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

Prior period amounts have been recast to include UNEV operations acquired July 12, 2012, as if it had been acquired March 1, 2008, the date we were under common control with HFC. The tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries acquired on November 9, 2011 were recast as if they had been acquired on July 1, 2011, the date upon which HFC obtained control of such assets. This treatment is required under GAAP as the transactions were between entities under common control. Additionally, we corrected certain amounts previously reported in 2011 and 2010. See Note 2 for additional information.

Condensed Consolidating Balance Sheet

December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$823	$ 4,412	$—	$5,237
Accounts receivable	—	32,319	6,401	—	38,720
Intercompany accounts receivable (payable)	42,194	(42,194)	—	—	—
Prepaid and other current assets	224	2,395	1,000	—	3,619
Total current assets	42,420	(6,657)	11,813	—	47,576
Properties and equipment, net	—	563,701	396,834	—	960,535
Investment in subsidiaries	777,472	300,607	—	(1,078,079)	—
Transportation agreements, net	—	94,596	—	—	94,596
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	25,041	—	—	25,041
Other assets	1,154	8,710	—	—	9,864
Total assets	$821,046	$1,242,496	$ 408,647	$(1,078,079)	$1,394,110
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$10,745	$ 1,285	$—	$12,030
Accrued interest	10,198	28	—	—	10,226
Deferred revenue	—	3,319	5,582	—	8,901
Accrued property taxes	—	1,923	765	—	2,688
Other current liabilities	563	1,274	68	—	1,905
Total current liabilities	10,761	17,289	7,700	—	35,750
Long-term debt	443,674	421,000	—	—	864,674
Other long-term liabilities	55	15,241	137	—	15,433
Deferred revenue	—	11,494	—	—	11,494
Class B unit	13,903	—	—	—	13,903
Equity - partners	352,653	777,472	400,810	(1,178,282)	352,653
Equity - noncontrolling interest	—	—	—	100,203	100,203
Total liabilities and partners' equity	$821,046	$1,242,496	$ 408,647	$(1,078,079)	$1,394,110

Condensed Consolidating Balance Sheet

December 31, 2011	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$3,267	$ 3,100	$—	$6,369
Accounts receivable	—	33,972	4,080	—	38,052
Intercompany accounts receivable (payable)	17,745	(17,745)	—	—	—
Prepaid and other current assets	266	2,378	1,085	—	3,729
Total current assets	18,013	21,872	8,265	—	48,150
Properties and equipment, net	—	559,212	401,287	—	960,499
Investment in subsidiaries	960,516	297,008	—	(1,257,524)	—
Transportation agreements, net	—	101,543	—	—	101,543
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	25,302	—	—	25,302
Other assets	1,322	5,882	—	—	7,204
Total assets	$979,851	$1,267,317	$ 409,552	$(1,257,524)	$1,399,196
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$11,307	$ 13,542	$—	$24,849
Accrued interest	7,498	782	—	—	8,280
Deferred revenue	—	4,447	—	—	4,447
Accrued property taxes	—	2,196	—	—	2,196
Other current liabilities	689	1,088	—	—	1,777
Total current liabilities	8,187	19,820	13,542	—	41,549
Long-term debt	332,988	272,900	—	—	605,888
Other long-term liabilities	—	8,653	—	—	8,653
Deferred revenue	—	5,428	—	—	5,428
Equity - partners	638,676	960,516	396,010	(1,356,526)	638,676
Equity - noncontrolling interest	—	—	—	99,002	99,002
Total liabilities and partners' equity	$979,851	$1,267,317	$ 409,552	$(1,257,524)	$1,399,196

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$232,986	$ 13,754	$ (1,158)	$245,582
Third parties	—	41,984	4,994	—	46,978
	—	274,970	18,748	(1,158)	292,560
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	78,766	11,634	(1,158)	89,242
Depreciation and amortization	—	43,147	14,314	—	57,461
General and administrative	3,336	4,258	—	—	7,594
	3,336	126,171	25,948	(1,158)	154,297
Operating income (loss)	(3,336)	148,799	(7,200)	—	138,263
Equity in earnings (loss) of subsidiaries	130,743	(5,400)	—	(125,343)	—
Equity in earnings of SLC Pipeline	—	3,364	—	—	3,364
Interest (expense) income	(31,523)	(15,659)	—	—	(47,182)
Loss on early extinguishment of debt	(2,979)	—	—	—	(2,979)
Other	—	10	—	—	10
	96,241	(17,685)	—	(125,343)	(46,787)
Income (loss) before income taxes	92,905	131,114	(7,200)	(125,343)	91,476
State income tax expense	—	(371)	—	—	(371)
Net income (loss)	92,905	130,743	(7,200)	(125,343)	91,105
Allocation of net loss attributable to Predecessors	4,200	—	—	—	4,200
Allocation of net (income) attributable to noncontrolling interests	(2,953)	—	—	1,800	(1,153)
Net income (loss) attributable to Holly Energy Partners	94,152	130,743	(7,200)	(123,543)	94,152
Other comprehensive (loss)	2,185	—	—	—	2,185
Comprehensive income (loss)	$96,337	$130,743	$ (7,200)	$ (123,543)	$96,337

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2011	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$168,519	$ 313	$ (571)	$168,261
Third parties	—	46,005	2	—	46,007
	—	214,524	315	(571)	214,268
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	63,100	1,992	(571)	64,521
Depreciation and amortization	—	35,200	1,758	—	36,958
General and administrative	3,902	2,674	—	—	6,576
	3,902	100,974	3,750	(571)	108,055
Operating income (loss)	(3,902)	113,550	(3,435)	—	106,213
Equity in earnings (loss) of subsidiaries	101,844	(2,576)	—	(99,268)	—
Equity in earnings of SLC Pipeline	—	2,552	—	—	2,552
Interest (expense) income	(24,494)	(11,465)	—	—	(35,959)
Other	—	17	—	—	17
	77,350	(11,472)	—	(99,268)	(33,390)
Income (loss) before income taxes	73,448	102,078	(3,435)	(99,268)	72,823
State income tax expense	—	(234)	—	—	(234)
Net income (loss)	73,448	101,844	(3,435)	(99,268)	72,589
Allocation of net loss attributable to Predecessors	6,351	—	—	—	6,351
Allocation of net loss attributable to noncontrolling interests	—	—	—	859	859
Net income (loss)attributable to Holly Energy Partners	79,799	101,844	(3,435)	(98,409)	79,799
Other comprehensive income	3,562	—	—	—	3,562
Comprehensive income (loss)	$83,361	$101,844	$ (3,435)	$ (98,409)	$83,361

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2010	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$146,391	$ —	$ (24)	$146,367
Third parties	—	35,762	8	—	35,770
	—	182,153	8	(24)	182,137
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	54,755	215	(24)	54,946
Depreciation and amortization	—	31,476	(113)	—	31,363
General and administrative	5,053	2,666	—	—	7,719
	5,053	88,897	102	(24)	94,028
Operating income (loss)	(5,053)	93,256	(94)	—	88,109
Equity in earnings (loss) of subsidiaries	84,664	(70)	—	(84,594)	—
Equity in earnings of SLC Pipeline	—	2,393	—	—	2,393
Interest (expense) income	(23,358)	(10,636)	—	—	(33,994)
Other	—	17	—	—	17
	61,306	(8,296)	—	(84,594)	(31,584)
Income (loss) before income taxes	56,253	84,960	(94)	(84,594)	56,525
State income tax expense	—	(296)	—	—	(296)
Net income (loss)	56,253	84,664	(94)	(84,594)	56,229
Allocation of net loss attributable to Predecessors	70	—	—	—	70
Allocation of net loss attributable to noncontrolling interests	—	—	—	24	24
Net income (loss) attributable to Holly Energy Partners	56,323	84,664	(94)	(84,570)	56,323
Other comprehensive (loss)	(885)	—	—	—	(885)
Comprehensive income (loss)	$55,438	$84,664	$ (94)	$ (84,570)	$55,438

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$17,432	$142,940	$ 1,039	$—	$161,411
Cash flows from investing activities					
Additions to properties and equipment	—	(28,134)	(14,727)	—	(42,861)
Cash flows from financing activities					
Net borrowings under credit agreement	—	221,000	—	—	221,000
Proceeds from issuance of senior notes	294,750	—	—	—	294,750
Cash distribution to HFC for UNEV acquisition	—	(260,922)	—	—	(260,922)
Repayments of promissory notes	(185,000)	(75,235)	—	—	(260,235)
Contributions from partners	1,748	—	15,000	—	16,748
Distributions to HEP unitholders	(122,777)	—	—	—	(122,777)
Purchase of units for incentive grants	(5,240)	321	—	—	(4,919)
Deferred financing costs	(913)	(2,325)	—	—	(3,238)
Other	—	(89)	—	—	(89)
	(17,432)	(117,250)	15,000	—	(119,682)
Cash and cash equivalents					
Decrease for the period	—	(2,444)	1,312	—	(1,132)
Beginning of period	2	3,267	3,100	—	6,369
End of period	$2	$823	$ 4,412	$—	$5,237

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2011	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$11,666	$85,730	$ 1,646	$—	$99,042
Cash flows from investing activities					
Additions to properties and equipment	—	(43,614)	(162,695)	—	(206,309)
Cash flows from financing activities					
Net borrowings under credit agreement	—	41,000	—	—	41,000
Repayments of promissory notes	—	(77,100)	—	—	(77,100)
Proceeds from issuance of common units	75,815	—	—	—	75,815
Contributions from partners	5,887	—	156,500	—	162,387
Distributions to HEP unitholders	(91,506)	—	—	—	(91,506)
Purchase of units for restricted grants	(1,641)	—	—	—	(1,641)
Deferred financing costs	—	(3,150)	—	—	(3,150)
Other	(221)	—	—	—	(221)
	(11,666)	(39,250)	156,500	—	105,584
Cash and cash equivalents					
Increase for the period	—	2,866	(4,549)	—	(1,683)

Beginning of period	2	401	7,649	—	8,052
End of period	$2	$3,267	$ 3,100	$ —	$6,369

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2010	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(59,916)	$178,213	$(13,561)	$—	$104,736
Cash flows from investing activities					
Acquisition of assets from HFC	—	(35,526)	—	—	(35,526)
Additions to properties and equipment	—	(26,732)	(79,793)	—	(106,525)
	—	(62,258)	(79,793)	—	(142,051)
Cash flows from financing activities					
Net repayments under credit agreement	—	(47,000)	—	—	(47,000)
Repayments of promissory notes	—	—	—	—	—
Proceeds from issuance of senior notes	147,540	—	—	—	147,540
Contributions from partners	—	(13,500)	94,000	—	80,500
Distributions to HEP unitholders	(84,426)	—	—	—	(84,426)
Purchase price in excess of transferred basis in assets acquired from HFC	—	(57,560)	—	—	(57,560)
Purchase of units for restricted grants	(2,704)	—	—	—	(2,704)
Deferred financing costs	(494)	—	—	—	(494)
Other	—	—	—	—	—
	59,916	(118,060)	94,000	—	35,856
Cash and cash equivalents					
Increase for the period	—	(2,105)	646	—	(1,459)
Beginning of period	2	2,506	7,003	—	9,511
End of period	$2	$401	$7,649	$—	$8,052

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

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

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2012 at a reasonable level of assurance.

(b) Changes in internal control over financial reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2012 that would need to be reported on Form 8-K that have not been previously reported.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

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

Certain executive officers of HLS are also officers of HFC. During 2012, Mark Cunningham, Senior Vice President, Operations of HLS, was the only HLS executive officer who spent all of his professional time managing our business and affairs. The rest of HLS's executive officers devoted as much of their professional time as was necessary to oversee the management of our business and affairs. As of January 1, 2013, in addition to Mr. Cunningham, Matthew Clifton, Chairman of the Board and Chief Executive Officer of HLS, and Bruce Shaw, President of HLS, also spend all of their professional time managing our business and affairs and no longer provide services to HFC. The rest of HLS's executive officers continue devote as much of their professional time as is necessary to oversee the management of our business and affairs.

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

Board Leadership Structure

The Board of Directors of HLS (the “Board”) believes that HLS's Chief Executive Officer is best suited to serve as Chairman of the Board because he is the director most familiar with HLS and HEP's business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. The independent directors on the Board bring experience, oversight and expertise from outside HLS, HEP and the industry, while the Chief Executive Officer brings HLS and HEP-specific experience and expertise. The Board believes that the combined role of Chairman of the Board and Chief Executive Officer promotes strategy development and execution and facilitates information flow between management and the Board, all of which are essential to effective governance of HLS and HEP.

Presiding Director

Charles M. Darling, IV was appointed by the non-management directors of HLS to serve as the lead independent director (the “Presiding Director”) of the Board. The Presiding Director has the following responsibilities:

- presiding at all executive sessions of the non-management directors of the Board;
- consulting with management on Board and committee meeting agendas;
- acting as a liaison in appropriate instances between management and the non-management directors, including advising the Chairman of the Board and Chief Executive Officer on the efficiency of the Board meetings; and

- facilitating teamwork and communication between the non-management directors and management.

Persons wishing to communicate with the non-management directors are invited to email the Presiding Director at presiding.director.HEP@hollyenergy.com or write to: Charles M. Darling, IV, Presiding Director, c/o Secretary, Holly Logistic Services, L.L.C., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. The Secretary will review the communication and forward all communication to the appropriate director or directors, other than those communications that are merely solicitations for products or services or relate to matters that are of a type that are clearly improper or irrelevant to the functioning of the Board or the business and affairs of HLS and HEP.

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Risk Management

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

- The Compensation Committee oversees the management of risks relating to HLS's executive compensation plans and arrangements.
- The Audit Committee oversees management of financial reporting and controls risks.
- The Conflicts Committee oversees specific matters that the Board or the Conflicts Committee believes may involve conflicts of interest with HFC.

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

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

Director Qualifications

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

Director Independence

The Board has determined that Messrs. Darling, Gray, Pinkerton, Ridenour and Stengel meet the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange.

Audit Committee. The Audit Committee of HLS is composed of three directors, Messrs. Pinkerton, Ridenour and Darling. The Board has determined that each member of the Audit Committee is “independent” as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Securities Exchange Act of 1934 (the “Exchange Act”).

The Board also determined that Mr. Stengel was “independent” as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Exchange Act during the time he served on the Audit Committee.

Conflicts Committee. The Conflicts Committee of HLS is composed of three directors, Messrs. Stengel, Pinkerton and Gray. The Board has determined that each member of the Conflicts Committee is “independent” as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Exchange Act, as required by the Conflicts Committee Charter. The Board also determined that Mr. Darling was “independent” as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Exchange Act during the time he served on the Conflicts Committee.

Compensation Committee. The Compensation Committee of HLS is composed of five directors, Messrs. Jennings, Darling, Gray, Stengel and Townsend. The Board has determined that each of Messrs. Darling, Gray and Stengel is “independent” as defined by the New York Stock Exchange listing standards. Because we are a master limited partnership, Rule 303A.05 of the

New York Stock Exchange Listed Company Manual, which requires a publicly traded company to have a compensation committee composed entirely of independent directors, does not apply to us. The Board also determined that Mr. Pinkerton was “independent” as defined by the New York Stock Exchange listing standards during the time he served on the Compensation Committee.

Independence Determinations. In making its independence determinations, the Board considered certain transactions, relationships and arrangements. In determining Mr. Ridenour's independence, the Board considered that Mr. Ridenour has not been employed by HFC or HLS since 2008 and has not received compensation in excess of $120,000 since 2009. The Board has determined that these historical relationships do not impair Mr. Ridenour's independence.

Code of Ethics

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

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

The Board, Its Committees and Director Compensation

Directors

The following individuals serve as directors of HLS:

Matthew P. Clifton	Director since July 2004. Age 61.
Principal Occupation:	Chairman of the Board and Chief Executive Officer
Business Experience:	Mr. Clifton was appointed as Chairman of the Board and Chief Executive Officer in March 2004 and was appointed as President in July 2011. Mr. Clifton resigned as President in November 2012. Mr. Clifton joined HFC in 1980 and served as the Executive Chairman of HFC from July 2011 through December 2012. Mr. Clifton previously served as Chief Executive Officer of Holly Corporation from 2006 until the merger in July 2011, as Chairman of the Board of Holly Corporation from April 2007 until the merger in July 2011 and as President of Holly Corporation from 1995 until 2006.
Additional Directorships:	Mr. Clifton served as a director of HFC from 1995 through December 2012.
Qualifications:	Mr. Clifton has extensive knowledge of operations of HLS and HEP, the refining industry and macro-economic conditions, as well as valuable industry relationships throughout the country. Mr. Clifton brings a unique and valuable perspective as well as an understanding of the HLS and HEP's history, culture, vision and strategy to the Board.

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Charles M. Darling, IV Director since July 2004. Age 64.

Principal Occupation: President of DQ Holdings, L.L.C.

Business Experience: Mr. Darling has served as President of DQ Holdings, L.L.C., a venture capital investment and consulting firm focused primarily on opportunities in the energy industry, since August 1998. Mr. Darling was previously the General Manager of Desert Power, LP and of its General Partner, Desert Power, LLC, which was an indirect affiliate of DQ Holdings, LLC. In late 2006, Desert Power, LLC and Desert Power, LP, along with certain of their subsidiaries, filed for bankruptcy in Nevada. In late 2007, the bankruptcy court approved the plan of reorganization, which became final in accordance with its terms in early 2008. Mr. Darling also previously practiced law at the law firm of Baker Botts, L.L.P. for over 20 years.

Qualifications: Mr. Darling has significant experience addressing financial, legal, regulatory and risk matters affecting HLS and HEP due to his 20-year legal practice at a large, national law firm. His service as President and General Counsel of a publicly traded energy company with a publicly traded pipelines master limited partnership and his subsequent endeavors in the energy industry provide him with valuable insight into our industry. Mr. Darling's leadership skills, management and legal experience make him particularly well suited to be our Presiding Director.

William J. Gray Director since April 2008. Age 72.

Principal Occupation: Private Consultant and Member of the New Mexico House of Representatives

Business Experience: Mr. Gray is a private consultant and has served as a member of the New Mexico House of Representatives since November 2006. Mr. Gray has served as a governmental affairs consultant for HFC since January 2003. He also served as a consultant to Holly Corporation from October 1999 through September 2001. Mr. Gray served as a director of Holly Corporation from September 1996 until May 2008. Mr. Gray was employed by Holly Corporation for over 30 years and retired in October 1999 at which time Mr. Gray was Senior Vice President, Marketing and Supply.

Qualifications: Mr. Gray brings to the Board forty years of experience in pipeline, refining, and marketing and supply. Mr. Gray also brings business and management expertise and extensive knowledge of, and a unique perspective on, regulatory matters affecting our industry as a result of his government experience.

Michael C. Jennings Director since October 2011. Age 47.

Principal Occupation: Chief Executive Officer and President of HFC

Business Experience: Mr. Jennings has served as the Chief Executive Officer and President of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011 and as Chairman of the Board of HFC since January 2013. Mr. Jennings previously served as the President and Chief Executive Officer of Frontier Oil Corporation from 2009 until the merger in July 2011 and as the Executive Vice President and Chief Financial Officer of Frontier Oil Corporation from 2005 until 2009.

Additional Directorships: Mr. Jennings currently serves as the Chairman of the Board and a director of HFC and a director of ION Geophysical Corporation. Mr. Jennings served as Chairman of the board of directors of

Frontier Oil Corporation from 2010 until the merger in July 2011 and as a director of Frontier Oil Corporation from 2008 until the merger in July 2011.

Qualifications:	Mr. Jennings provides valuable and extensive industry knowledge and experience. His knowledge of the day-to-day operations of HFC provides a significant resource for the Board and facilitates discussions between the Board and HFC management.

Jerry W. Pinkerton	Director since July 2004. Age 72.

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Principal Occupation: Retired

Business Experience: Mr. Pinkerton retired in December 2003. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp. (now Energy Future Holdings Corp.) and from August 1997 to December 2000, Mr. Pinkerton served as Controller of TXU Corp. and its U.S. subsidiaries. Mr. Pinkerton previously served as the Vice President and Chief Accounting Officer of ENSERCH Corporation and was employed for 26 years as an auditor by Deloitte Haskins & Sells, a predecessor firm of Deloitte & Touche, LLP, including 15 years as an audit partner.

Additional Directorships: Since April 2012, Mr. Pinkerton serves on the board of directors of Southcross Energy Partners GP, LLC, the general partner of Southcross Energy Partners, L.P., and serves as the chair of the audit and conflicts committees of the board of directors of Southcross Energy Partners GP, LLC. Mr. Pinkerton served on the board of directors of Animal Health International, Inc., and served as chair of its audit committee, from May 2008 to June 2011.

Qualifications: Mr. Pinkerton brings to the Board his audit, accounting and financial reporting expertise and a level of financial sophistication that qualifies him as an audit committee financial expert. Due to his executive managerial experience with public companies and public accounting firms, Mr. Pinkerton possesses business and management expertise that provide an invaluable insight into HLS and HEP's business.

P. Dean Ridenour Director since August 2004. Age 71.

Principal Occupation: Retired

Business Experience: Mr. Ridenour retired in February 2010. Mr. Ridenour provided consulting services to Holly Corporation from January 2008 until February 2010, and served as Vice President and Chief Accounting Officer of Holly Corporation and HLS from January 2005 to January 2008. Mr. Ridenour served as Vice President, Special Projects of Holly Corporation from August 2004 to December 2004 and prior to becoming a full-time employee, provided full-time consulting services to Holly Corporation beginning in October 2002. Mr. Ridenour was employed for 34 years by Ernst & Young LLP, including 20 years as an audit partner, prior to retiring from such position in 1997.

Qualifications: Mr. Ridenour's management experience and his accounting and financial reporting expertise qualify him as an audit committee financial expert and make him a valuable member of the Board. In addition, Mr. Ridenour's prior experience at HLS and Holly Corporation provide him with a deep understanding of our business and industry.

William P. Stengel Director since July 2004. Age 64.

Principal Occupation: Retired

Business Experience: Mr. Stengel retired in May 2003. From 1997 to May 2003, Mr. Stengel served as Managing Director of the global energy and mining group at Citigroup/Citibank, N.A.

Qualifications: Mr. Stengel's executive management experience in public companies, banking and financial expertise, and general business and management expertise provides him with significant insight into our operations, management and finance.

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James G. Townsend Director since January 2012. Age 58.

Principal Occupation: Retired

Business Experience:	Mr. Townsend retired from HFC in December 2011. He was employed by Holly Corporation (and HFC) and/or HLS for more than 25 years. From 2008 until his retirement, Mr. Townsend served as Senior Vice President of UNEV Pipeline, LLC, a joint venture between Sinclair Oil Corporation and a subsidiary of HEP. Mr. Townsend served as Vice President, Operations for HLS from 2004 to 2007 and was responsible for all pipeline and terminal operations for Holly Corporation prior to the formation of HEP. Prior to such time, Mr. Townsend served in positions of increasing seniority at Holly Corporation.
Qualifications:	Mr. Townsend brings to the Board his knowledge of the operations of HFC, HLS and their subsidiaries, his 25 years of experience in the industry, and his business expertise.

None of our directors reported any litigation for the period from 2003 to 2013 that is required to be reported in this Annual Report on Form 10-K.

The Board

Under the Company's Governance Guidelines, Board members are expected to prepare for, attend and participate in all meetings of the Board and Board committees on which they serve. During 2012, the Board held eight meetings. Each director attended at least 75% of the total number of meetings of the Board and committees on which he served.

Board Committees

The Board currently has four standing committees:

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

Other than the Executive Committee, each of these committees operates under a written charter adopted by the Board.

During 2012, the Audit Committee held seven meetings, the Conflicts Committee held twenty-one meetings and the Compensation Committee held eight meetings.

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

Name	Executive Committee	Audit Committee	Compensation Committee	Conflicts Committee
Matthew P. Clifton	x(Chair)			
Charles M. Darling, IV		x	x (1)	
William J. Gray			x	x
Michael C. Jennings	x		x (Chair)	
Jerry W. Pinkerton	x	x(Chair)		x
P. Dean Ridenour		x		

William P. Stengel	x	x	x(Chair)
James G. Townsend		x	

(1) Mr. Darling serves as the chairman of the subcommittee of the Compensation Committee.

Audit Committee

The functions of the Audit Committee include the following:

- selecting our independent registered public accounting firm and reviewing the professional services they provide;
- reviewing the scope of the audit performed by the independent registered public accounting firm;
- overseeing matters related to the internal audit function;
- reviewing the audit report issued by the independent auditor;
- reviewing HEP's annual and quarterly financial statements;
- reviewing any material comments contained in the auditor's letters to management;
- reviewing HEP's internal accounting controls; and
- reviewing the type and extent of any non-audit work to be performed by the independent registered public accounting firm and its compatibility with their continued objectivity and independence.

Each member of the Audit Committee has the ability to read and understand fundamental financial statements, and the Board has determined that Mr. Pinkerton and Mr. Ridenour meet the requirements of an “audit committee financial expert” as defined by the rules of the SEC.

Conflicts Committee

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

Compensation Committee

The functions of the Compensation Committee include:

- reviewing, evaluating and approving the agreements, plans, policies and programs of HLS;
- discharging the Board's responsibilities relating to compensation of HLS's officers and directors;
- overseeing the preparation of the Compensation Discussion and Analysis to be included in the Annual Report and preparing the Compensation Committee Report to be included in the Annual Report; and
- administering HEP's equity plan and HLS's annual incentive plan.

The Compensation Committee has appointed a subcommittee comprised of three directors, all of whom are “independent” as defined by the New York Stock Exchange listing standards, for purposes of approving equity awards, including performance goals applicable to such awards, if applicable, and any other matters that are within the responsibilities of the Committee requiring approval solely by independent members of the Board.

Executive Committee

The Executive Committee has such authority as the Board may delegate to it from time to time.

Director Compensation

Members of the Board who also serve as officers or employees of HLS or HFC do not receive additional compensation in their capacity as directors or chairmen of committees.

For the year ended December 31, 2012, directors who were not officers or employees of HLS or HFC ("non-employee directors") were compensated as follows:

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Annual cash retainer (payable in four quarterly installments)	$50,000
Board meeting or committee meeting attended in person (also paid to non-members of committees who are invited to attend by such committee's chairman) (1)	$1,500
Telephonic special board or committee meeting (2)	$1,000
Each attended strategy meeting with HLS management	$1,500
Annual grant of restricted units under the Long-Term Incentive Plan	$75,000
Special cash retainer for chairmen of committees and subcommittees (payable in four quarterly installments)	$10,000

(1) Upon submission of appropriate documentation, non-employee directors also are reimbursed for reasonable out-of-pocket expenses in connection with attending Board or committee meetings.

(2) Prior to August 1, 2012, the fee for telephonic special meetings over 30 minutes was $1,000, and no fee was paid for telephonic special meetings that were 30 minutes or less. Effective August 1, 2012, the Chairman of the Board and the chairman of each committee has authority to exercise his discretion as to whether the topics discussed at a telephonic special meeting of the Board or committee, as applicable, that lasts 30 minutes or less warrants a fee of $1,000. Non-employee directors continue to receive $1,000 for telephonic special meetings that last over 30 minutes.

Equity Awards

Each August 1, non-employee directors receive an annual grant under the Holly Energy Partners, L.P. Long-Term Incentive Plan ("Long-Term Incentive Plan") of restricted units having a fair market value of $75,000 on the date of grant, with the number of restricted units rounded to the nearest whole unit in the case of fractional units. The fair market value of the restricted unit grants is calculated based upon the market closing price of our common units on the day of grant (or the last trading day prior to August 1 if August 1 is not a trading day). The restricted units fully vest one year following the date of grant, subject to the director's continued service on the Board. Accelerated vesting of all unvested units will occur upon a change in control of HFC, HLS, HEP or HEP Logistics. In addition, accelerated vesting of unvested units will occur on a pro-rata basis upon the director's death, total and permanent disability or retirement. Directors are entitled to receive all distributions paid with respect to outstanding restricted units. The distributions are not subject to forfeiture. The directors also have a right to vote with respect to the restricted units.

Non-Qualified Deferred Compensation

In 2012, the non-employee directors of HLS first became eligible to participate in the HollyFrontier Corporation Executive Nonqualified Deferred Compensation Plan, which plan is not tax-qualified under Section 401 of the Internal Revenue Code and allows participants to defer receipt of certain compensation (the "NQDC Plan"). For 2012, the NQDC Plan provided non-employee director participants with the potential to defer up to 50% of their cash retainers and meeting fees for the calendar year. Mr. Pinkerton was the only non-employee director that participated in the NQDC Plan in 2012. Participating directors have full discretion over how their contributions to the NQDC Plan are invested among the offered investment options, and earnings on amounts contributed to the NQDC Plan are calculated in the same manner and at the same rate as earnings on actual investments. Neither HLS nor HFC subsidizes directly or indirectly a participant's earnings under the NQDC Plan. During 2012, earnings on Mr. Pinkerton's account under the NQDC Plan did not exceed 120% of the applicable long-term federal rate (2.63%). As a result, no above market or preferential earnings were paid to Mr. Pinkerton under the NQDC Plan and, therefore, none of the earnings received by Mr. Pinkerton during 2012 are included in the Director Compensation Table below. For additional information on the NQDC Plan, see "Compensation Discussion and Analysis-Overview of 2012 Executive Compensation Components and Decisions-Retirement and Benefit Plans-Deferred Compensation Plan" and the narrative preceding the "Nonqualified Deferred Compensation Table."

Director Compensation Table

The table below sets forth the compensation earned in 2012 by each of the non-employee directors of HLS.

Name (1)	Fees Earned or Paid in Cash	Unit Awards (2)	All Other Compensation	Total
Charles M. Darling, IV	$110,500	$75,025	—	$185,525
William J. Gray	92,500	75,025	32,156 (3)	199,681
Jerry W. Pinkerton	110,500	75,025	—	185,525
P. Dean Ridenour	71,500	75,025	—	146,525
William P. Stengel	110,500	75,025	—	185,525
James G. Townsend	70,500	75,025	—	145,525

(1) Mr. Clifton and Mr. Jennings are not included in this table because they receive no additional compensation for their services as directors of HLS since, during 2012, Mr. Clifton and Mr. Jennings were each an officer of HFC and Mr. Clifton was also an officer of HLS. The compensation paid by us to Mr. Clifton in 2012 is shown under "Summary Compensation Table" below and the compensation paid by HFC to Mr. Clifton and Mr. Jennings in 2012 will be shown in HFC's 2013 Proxy Statement.

(2) Reflects the aggregate grant date fair value of restricted units granted to the non-employee directors on August 1, 2012, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 ("FASB ASC Topic 718"), determined without regard to forfeitures. See Note 7 to our consolidated financial statements for the fiscal year ended December 31, 2012, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards. Each of the non-employee directors received an award of 2,252 restricted units (as adjusted to reflect the two-for-one common unit split that occurred on January 16, 2013) under the Long-Term Incentive Plan on August 1, 2012 that will vest on August 1, 2013. As of December 31, 2012, these are the only restricted units held by our non-employee directors.

(3) Represents fees for consulting services provided by Mr. Gray to HFC during 2012. None of the consulting fees were paid by us.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, executive officers and persons who beneficially own more than 10% of HEP's units to file certain reports with the SEC and New York Stock Exchange concerning their beneficial ownership of HEP's equity securities. Based on a review of these reports, other information available to us and written representations from reporting persons indicating that no other reports were required, all such reports concerning beneficial ownership were filed in a timely manner by reporting persons during the year ended December 31, 2012. In July 2012, the Partnership became aware that, due to administrative errors, (a) a Form 4 was not timely filed for HFC in November 2011 when HFC was issued 7,615,230 common units of HEP (as adjusted for the unit split that occurred on January 16, 2013) as partial consideration for transactions contemplated by a LLC Interest Purchase Agreement, dated November 9, 2011, and (b) a Form 3 was not timely filed for Holly Logistics Limited LLC in December 2010 when HEP Logistics Holdings, L.P. transferred all of the HEP common units it held to Holly Logistics Limited LLC.

Report of the Audit Committee for the Year Ended December 31, 2012

Management of Holly Logistic Services, L.L.C. is responsible for Holly Energy Partners, L.P.'s internal controls and the financial reporting process. The Audit Committee selected, and the Board approved the selection of, Ernst & Young LLP as Holly Energy Partners, L.P.'s independent registered public accounting firm to audit the books, records and accounts of Holly Energy Partners, L.P. for the year ended December 31, 2012. Ernst & Young LLP is responsible for performing an independent audit of Holly Energy Partners, L.P.'s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and to issue a report thereon as well as to issue a report on the effectiveness of Holly Energy Partners, L.P.'s internal control over financial reporting. The Audit Committee monitors and oversees these processes.

The Audit Committee has reviewed and discussed Holly Energy Partners, L.P.'s audited consolidated financial statements with management and Ernst & Young LLP. The Audit Committee has discussed with Ernst & Young LLP the matters required to be

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discussed by Statement on Auditing Standards No. 61, Communications with Audit Committees, as amended, as adopted by the Public Company Accounting Oversight Board in Rule 3200T. The Audit Committee has received the written disclosures and a letter from Ernst & Young LLP pursuant to applicable requirements of the Public Company Accounting Oversight Board regarding Ernst & Young LLP's communications with the Audit Committee concerning independence and has discussed with Ernst & Young LLP that firm's independence.

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

Based on the foregoing review and discussions and such other matters the Audit Committee deemed relevant and appropriate, the Audit Committee recommended to the Board that the audited consolidated financial statements of Holly Energy Partners, L.P. for the year ended December 31, 2012 be included in Holly Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2012 for filing with the SEC.

Members of the Audit Committee:
Jerry W. Pinkerton, Chairman
Charles M. Darling, IV
P. Dean Ridenour

Item 11. Executive Compensation

Executive Officers

The following sets forth information regarding the executive officers of HLS:

Name	Age	Position with HLS
Matthew P. Clifton	61	Chairman of the Board and Chief Executive Officer
Bruce R. Shaw	45	President
Douglas S. Aron	39	Executive Vice President and Chief Financial Officer
Denise C. McWatters	53	Senior Vice President, General Counsel and Secretary
Mark T. Cunningham	53	Senior Vice President, Operations
Scott C. Surplus	53	Vice President and Controller

Information regarding Mr. Clifton is included above under “Directors.”

Bruce R. Shaw was appointed President in November 2012. Mr. Shaw served as Senior Vice President and Chief Financial Officer from December 2011 until November 2012, Senior Vice President, Strategy and Corporate Development from July 2011 until December 2011, Senior Vice President and Chief Financial Officer from January 2008 until July 2011, and Vice President, Corporate Development from August 2004 to January 2007. Mr. Shaw served as Senior Vice President, Strategy and Corporation Development of HFC from July 2011 through December 2012, Senior Vice President and Chief Financial Officer of Holly Corporation from 2008 until the effective time of the merger between Holly Corporation and Frontier Oil Corporation in July 2011, and Vice President, Special Projects for Holly Corporation from September 2007 to December 2007. Mr. Shaw served on the Board of HLS from April 2007 to April 2008. Mr. Shaw briefly left Holly Corporation in June 2007 and served as President of Standard Supply and Distributing Company, Inc. and Bartos Industries, Ltd., two companies that are affiliated with each other in the heating, ventilation, and air conditioning industry. Mr. Shaw previously served Holly Corporation in various positions with increasing seniority from 1997 to 2007. Prior to joining Holly Corporation, Mr. Shaw was a consultant at

McKinsey and Company, a global management consulting firm.

Douglas S. Aron was appointed Executive Vice President and Chief Financial Officer in November 2012. He previously served in such position from July 2011 until December 2011. Mr. Aron currently also serves as Executive Vice President and Chief Financial Officer of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011. Prior to joining HFC, Mr. Aron was Executive Vice President and Chief Financial Officer of Frontier Oil Corporation from 2009 until 2011. Additionally, he served as Vice President-Corporate Finance of Frontier Oil Corporation from 2005 to 2009 and Director-Investor Relations from 2001 to 2005. Prior to joining Frontier Oil Corporation, Mr. Aron was a lending officer for Amegy Bank.

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

Mark T. Cunningham was appointed Senior Vice President, Operations in January 2013. He previously served as Vice President, Operations from July 2007 to January 2013. He served Holly Corporation as Senior Manager of Special Projects from December 2006 through June 2007 and as Senior Manager of Integrity Management and Environmental, Health and Safety from July 2004 through December 2006. Prior to joining Holly Corporation, Mr. Cunningham served Diamond Shamrock/Ultramar Diamond Shamrock for 20 years in several engineering and pipeline operations capacities.

Scott C. Surplus was appointed Vice President and Controller in June 2008. Mr. Surplus also served in a similar capacity for HFC through June 2012. He served Holly Corporation and HLS as Vice President, Risk Management from 2007 to 2008, Vice President, Financial Reporting from 2005 to 2007 and Vice President and Controller from 2004 to 2005. Prior to this, he served in many areas of accounting and finance during his 28 years at Holly Corporation (and HFC), including SEC and financial reporting, tax, treasury, and risk management.

Compensation Discussion and Analysis

This compensation discussion and analysis (“CD&A”) provides information about our compensation objectives and policies for the HLS executive officers who are our “Named Executive Officers” for 2012, to the extent the Compensation Committee of the Board (the “Committee”) determines the compensation of these individuals or such compensation is allocated to us pursuant to SEC rules. In addition, the CD&A is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. Additionally, we describe our policies relating to reimbursement to HFC for compensation expenses.

Overview

We are managed by HLS, the general partner of HEP Logistics, our general partner. HLS is a subsidiary of HFC. The employees providing services to us are employed by HLS or HFC, as we do not have any employees. As of December 31, 2012, HLS had 232 employees that provided general, administrative and operational services to us. Certain executive officers of HLS are also officers of HFC.

For 2012, the “Named Executive Officers” of HLS are as follows:

Matthew P. Clifton, who served as Chief Executive Officer during 2012;

Douglas S. Aron and Bruce R. Shaw, the two individuals who served as Chief Financial Officer during 2012; and

Mark T. Cunningham, who served as Vice President, Operations during 2012 (Mr. Cunningham was promoted to Senior Vice President, Operations in January 2013).

During 2012, Mr. Cunningham was the only Named Executive Officer who spent all of his professional time managing our business and affairs. The other Named Executive Officers split their professional time during 2012 between HFC and us and devoted only as much of their professional time as was necessary to oversee the management of our business and affairs. Mr. Shaw served as Senior Vice President and Chief Financial Officer of HLS from January 1, 2012 until November 1, 2012, when he was appointed as President of HLS. Beginning November 1, 2012, Mr. Aron served as Chief Financial Officer of HLS. Due to his increased responsibilities as President of HLS, Mr. Shaw resigned as Senior Vice President, Strategy and Corporate Development of HFC, effective January 1, 2013. In addition, effective January 1, 2013, Mr. Clifton retired from his position as Executive Chairman of HFC but continues to serve as Chairman and Chief Executive Officer of HLS. For 2013, Mr. Clifton, Mr. Shaw and Mr. Cunningham each allocate 100% of their professional time to us, while Mr. Aron continues to split his professional time between HFC and us.

Under the terms of the Omnibus Agreement, we currently pay an annual administrative fee to HFC of $2,300,000 for the provision of general and administrative services for our benefit, which may be increased or decreased as permitted under the Omnibus Agreement. The administrative services covered by the Omnibus Agreement include, without limitation, the costs of corporate

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services provided to us by HFC such as accounting, tax, information technology, human resources, in-house legal support and outside legal support for general corporate and tax matters; office space, furnishings and equipment; and limited transportation of HLS executive officers and employees on HFC airplanes for business purposes. None of the services covered by the administrative fee is assigned any particular value individually. Although certain Named Executive Officers provide services to both HFC and us, no portion of the administrative fee is specifically allocated to services provided by the Named Executive Officers to us; rather, the administrative fee generally covers services provided to us by HFC and, except as described below, there is no reimbursement by us for the specific costs of such services. See Item 13, “Certain Relationships and Related Transactions, and Director Independence” of this Annual Report on Form 10-K for additional discussion of our relationships and transactions with HFC.

Under the Omnibus Agreement, we also reimburse HFC for certain expenses incurred on our behalf, such as for salaries and employee benefits provided to HLS employees to the extent such individuals perform services for us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us. With respect to equity compensation paid by us to the Named Executive Officers, HLS purchases the units delivered pursuant to awards under our Long-Term Incentive Plan, and we reimburse HLS for the purchase price of the units.

Mr. Cunningham is an employee of HLS, and the Committee makes all decisions regarding his compensation. In 2012, because Mr. Cunningham devoted all of his professional time to our business and affairs, we reimbursed HFC for 100% of the compensation expenses incurred by HFC for salary, bonus, retirement and other benefits provided to Mr. Cunningham. For the same period, we also reimbursed HLS for 100% of the expenses incurred in providing Mr. Cunningham with awards under our Long-Term Incentive Plan. All compensation provided to Mr. Cunningham for 2012 is discussed and reported, in accordance with SEC rules, in the narratives and tables that follow.

As discussed above, the other Named Executive Officers split their professional time between HFC and us during 2012. During 2012, the only compensation Mr. Clifton received for the services he performed for us was in the form of awards of equity-based compensation granted pursuant to the Long-Term Incentive Plan, and we reimbursed HLS for 100% of the expenses incurred in providing Mr. Clifton with awards under our Long-Term Incentive Plan. None of the compensation paid, or other benefits made available to, Mr. Clifton by HFC was allocated to the services he provided to us for 2012. As a result, for Mr. Clifton, only his Long-Term Incentive Plan awards are disclosed in the narratives and tables that follow. The compensation paid by HFC to Mr. Clifton in 2012 will be disclosed in HFC's 2013 Proxy Statement.

At its January 24, 2012 meeting, the Committee determined that, beginning in 2012, the other executive officers of HLS that split their time with HFC, including Mr. Shaw and Mr. Aron, would no longer receive awards of equity-based compensation under the Long-Term Incentive Plan for the services provided to us. Rather, all compensation paid to such executive officers for 2012 was instead paid and determined by HFC, without input from the Committee. In deciding to discontinue awards under the Long-Term Incentive Plan to these executive officers, the Committee determined that, considering Mr. Clifton's focus in 2012 on determining our long-term business goals and policies and the service coverage effected through the Omnibus Agreement, it was appropriate to compensate Mr. Clifton for his services only through long-term equity incentive awards. On the other hand, the types of services provided to us by the other executive officers of HLS that split their time with HFC, including Mr. Shaw and Mr. Aron, were more akin to the services provided by a number of other similarly situated employees that provide services to us under the Omnibus Agreement without receiving equity awards under the Long-Term Incentive Plan.

The compensation paid to Mr. Shaw and Mr. Aron by HFC is covered by the administrative fee under the Omnibus Agreement (and therefore not subject to reimbursement by us); however, in accordance with SEC rules, for purposes of these disclosures, a portion of the compensation paid by HFC to Mr. Shaw and Mr. Aron for 2012 is allocated to the services they performed for us during 2012. The allocation was made based on the assumption that (i) Mr. Shaw spent, in the aggregate, approximately 25% of his professional time in 2012 on our business and affairs, and (ii) Mr.

Aron spent, in the aggregate, approximately 5% of his professional time in 2012 on our business and affairs since he did not perform any services for us during 2012 prior to his appointment as Executive Vice President and Chief Financial Officer of HLS, which was effective November 1, 2012. As a result, for Mr. Shaw and Mr. Aron, only 25% and 5%, respectively, of the total amount of compensation they received from HFC for 2012 is disclosed in the tables that follow. For Mr. Shaw, for years prior to 2012, the Long-Term Incentive Plan awards granted to him are also disclosed herein. Because HFC made all decisions regarding the compensation paid to Mr. Shaw and Mr. Aron in 2012, those decisions are not discussed herein. The total compensation paid by HFC to Mr. Aron in 2012 will be disclosed in HFC's 2013 Proxy Statement.

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

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Objectives of Compensation Program

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

In supporting our objectives, the Committee balances the use of both cash and equity compensation in the total direct compensation package provided to Mr. Cunningham; however, the Committee has not adopted any formal policies for allocating Mr. Cunningham's compensation among his salary, bonus and long-term equity compensation. In January 2012, the Committee, with the assistance of the Chief Executive Officer, reviewed the mix and level of cash and long-term equity incentive compensation for Mr. Cunningham with a goal of providing sufficient current, competitive compensation to retain him, while at the same time providing him incentives to maximize long-term value for us and our unitholders. After reviewing internal evaluations, input by management, and market data provided by the Compensation Consultant, the Committee believes that Mr. Cunningham's 2012 compensation reflects an appropriate allocation of compensation between salary, bonus and equity compensation.

For Mr. Clifton in 2012, the Committee utilized long-term equity incentive compensation to provide Mr. Clifton sufficient current compensation while providing incentive to build value both to us and to our unitholders.

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

The Committee has engaged Frederic W. Cook & Co. (the “Compensation Consultant”), an outside consulting firm specializing in executive compensation, to advise the Committee on matters related to executive and non-employee director compensation and long-term equity incentive awards. The Compensation Consultant provides the Committee with relevant market data, updates on related trends and developments, advice on program design, and input on compensation decisions for executive officers and non-employee directors. The Compensation Consultant is independent, retained directly by the Committee, and provides no other services to HLS or us. No conflicts of interest exist between HLS, us or the Committee, on one hand, and the Compensation Consultant, on the other hand.

The Compensation Consultant does not have authority to determine the ultimate compensation paid to executive officers or non-employee directors, and the Committee is under no obligation to utilize the information provided by the Compensation Consultant when making compensation decisions. The Compensation Consultant provides external context and other input to the Committee prior to the Committee meetings at which salaries and fees are approved, bonuses are awarded and equity compensation or awards are established for the upcoming year.

Review of Market Data

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

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For 2012, our peer group included the following publicly traded master limited partnerships, which are representative of the companies with which we compete for executives:

Atlas Pipeline Partners, L.P.
Buckeye Partners, L.P.
Copano Energy, L.L.C.
Crosstex Energy, L.P.
DCP Midstream Partners L.P.
Genesis Energy, L.P.
Inergy L.P.
Magellan Midstream Partners, L.P.
MarkWest Energy Partners, L.P.
NuStar Energy L.P.
Regency Energy Partners, L.P.
Sunoco Logistics Partners L.P.
Targa Resources Partners, L.P.

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

In 2012, Mr. Cunningham's total direct compensation (including both cash and equity components) was in the middle range of the market. As noted, however, this market analysis is just one of many factors considered when making overall compensation decisions for our executives.

With respect to our other Named Executive Officers, the market range of various compensation elements paid by HFC in 2012 will be discussed in further detail within the "Compensation Discussion and Analysis" section of HFC's 2013 Proxy Statement.

Role of Named Executive Officers in Determining Executive Compensation

In making executive compensation decisions, the Committee reviewed the total compensation provided to each executive in 2011 in determining 2012 compensation and established compensation for 2012 that was consistent with the compensation paid in 2011 after considering overall performance and the other specific factors discussed in this CD&A. The Committee considered recommendations by the Chief Executive Officer (other than as to himself) and other factors in determining the appropriate final compensation factors.

Various members of management facilitate the Committee's consideration of compensation for Named Executive Officers by providing data for the Committee's review. This data includes, but is not limited to, performance evaluations, performance-based compensation provided to the Named Executive Officers in previous years, tax-related considerations and accounting-related considerations. Management provides the Committee with guidance as to how such data impacts performance goals set by the Committee during the previous year. When management considers a discretionary bonus to be appropriate, it will suggest an amount and provide the Committee with management's rationale for such bonus. Given the day-to-day familiarity that management has with the work performed, the Committee values management's recommendations, although no Named Executive Officer has authority to determine or comment on compensation decisions directly related to himself. The Committee makes the final decision as to the compensation as described in this CD&A.

Overview of 2012 Executive Compensation Components and Decisions

The only component of compensation we provided for Mr. Clifton in 2012 was long-term equity incentive compensation.

The components of Mr. Cunningham's compensation in 2012 were:

- base salary;
- annual performance-based cash incentive compensation;
- long-term equity incentive compensation;
- retirement and other post-employment benefits; and
- health and welfare benefits.

Base Salary

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In January 2012, the Committee conducted its annual review of base salaries. In reviewing Mr. Cunningham's base salary, the Committee considered his position, his level of responsibility and his performance in 2011. The Committee also reviewed competitive market data relevant to his position provided by the Compensation Consultant. Following a review of these various factors, the Committee determined that an increase in Mr. Cunningham's base salary was warranted for 2012 and increased his base salary from $211,200 to $240,000, or 14%, effective March 1, 2012.

Annual Incentive Cash Bonus Compensation

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

In January 2012, the Committee established the total bonus pool under the Annual Incentive Plan for all non-hourly personnel of HLS after considering amounts budgeted for the pool, operating results and employee performance. In addition, consistent with historical practice, the Committee determined that the applicable performance period would be the 12-month period beginning January 1, 2012 and ending December 31, 2012, with determination and payment of the cash bonus amounts occurring in the first quarter of 2013. Subsequently, in the fourth quarter of 2012, the Committee determined to make a change to the timing of annual bonus payments going forward. Specifically, the Committee decided that the performance period for cash bonus awards should end on September 30 of the bonus year, so that payment of the bonus awards could be made in the year in which the bonuses were earned. As a result, for 2012 only, the Committee shortened the applicable performance period for the cash bonuses to the first three quarters of 2012. The Committee determined that this change to the performance period did not materially affect the achievement of the applicable performance metrics for the bonuses and hence made no adjustments to those metrics. For 2013, the applicable performance period will begin on October 1, 2012, and end on September 30, 2013, in order to allow for a full 12-month performance period.

Generally, payment with respect to any 2012 cash bonus was contingent upon the satisfaction of the following metrics:

- Actual Distributable Cash Flow vs. Budget: A portion of the bonus is equal to a pre-established percentage of the employee's base salary and is earned based upon our actual distributable cash flow during the performance period compared to the budgeted distributable cash flow for the performance period, adjusted for differences in estimated and actual PPI adjustments and differences in the timing of known acquisitions. The performance metric of distributable cash flow is used because it is a widely accepted financial indicator used to compare partnership performance. We believe that this measure provides an enhanced perspective of the operating performance of our assets and the cash our business is generating, and is therefore a useful criterion in evaluating management's performance and linking the payment of bonuses to our performance.

- Individual Performance: A portion of the bonus is equal to a pre-established percentage of the employee's base salary and is earned based on the employee's individual performance during the performance period. The employee's individual performance is evaluated through a performance review by the employee's immediate supervisor, which is a subjective and discretionary review of each applicable individual. The review includes a written assessment provided by the employee's immediate supervisor. The assessment reviews how well the employee displays each of the following competencies:

- Individual Performance

- Integrity
- Interpersonal Effectiveness

Each one of these performance dimensions has a variety of sub-categories that are separately reviewed. The assessment also evaluates how well the employee performed his or her pre-established individual goals during the performance period.

In addition to the pre-defined performance metrics, the Committee has discretion to approve an increase or a decrease in Mr. Cunningham's bonus. Increases and decreases are determined using the same factors used to establish bonuses, and poor results on the indicated factors could, in the discretion of the Committee, result in a decrease in a bonus. The Committee may consider other factors as well including, for example, environmental, health and safety. The Committee also considers whether conditions outside the control of the executive affected the factors. In cases where the performance metrics described above are achieved, yet the Committee believes additional compensation is warranted to reward an executive for outstanding performance, the

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Committee may increase the executive's bonus amount in its discretion. In making the determination as to whether such discretion should be applied (either to decrease or increase a bonus), the Committee reviews recommendations from management.

The following table shows, for 2012: (i) the pre-established percentage of Mr. Cunningham's annual base salary that is allocable to each performance metric, at target level, (ii) Mr. Cunningham's total target bonus award opportunity, as a percentage of his annual base salary, and (iii) Mr. Cunningham's total maximum bonus award opportunity, as a percentage of his annual base salary. The target bonus award opportunities are determined by the Committee based on total cash compensation, including base salary and annual incentive payments.

	Target Annual Incentive Compensation			
Name	Actual vs. Budgeted DCF	Individual	Target	Maximum
Mark Cunningham	20%	20%	40%	80%

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

For the 2012 performance period, the budgeted distributable cash flow was $103.92 million and actual distributable cash flow during the period (as adjusted as a result of our acquisition of HFC's 75% interest in UNEV Pipeline, LLC in July 2012) was $112.76 million. This resulted in Mr. Cunningham receiving in excess of the target bonus amount with respect to this performance metric. The actual amount paid to Mr. Cunningham for 2012 with respect to this portion of his annual incentive bonus is set forth in the “Non-Equity Incentive Plan Compensation” column of the “Summary Compensation Table.”

With respect to the individual performance portion of the bonus, the Committee determined Mr. Cunningham's bonus amount in recognition of the achievement of his individual performance targets, his impact on our improved financial results in 2012, the achievement of excellent safety results, the decrease in recordable incident rates and excellent system reliability, over a multi-year period, and his continued efforts toward integration of several recent asset acquisitions. This resulted in Mr. Cunningham receiving in excess of the target bonus amount with respect to this performance metric. The actual amount paid to Mr. Cunningham for 2012 with respect to the individual performance portion of his annual incentive bonus is set forth in the “Bonus” column of the “Summary Compensation Table.”

Long-Term Incentive Equity Compensation

The Long-Term Incentive Plan was adopted by the Board in August 2004 with the objective of promoting our interests by providing to management, employees and consultants of HLS and its affiliates who perform services for us and our subsidiaries equity incentive compensation awards. The Long-Term Incentive Plan also is intended to enhance our ability to attract and retain the services of individuals who are essential for our growth and profitability, to encourage those individuals to devote their best efforts to advancing our business, and to align the interests of those individuals with the interests of our unitholders. The Long-Term Incentive Plan was amended and restated effective February 10, 2012.

The Long-Term Incentive Plan provides for the granting of the following awards: unit options, unit appreciation rights, restricted units, phantom units, unit awards and substitute awards. The Committee may approve grants of awards on terms that it determines appropriate, including the period during and the conditions on which the award will vest. Since our inception, we have granted only awards of restricted units, fully vested unit awards, and phantom units with performance vesting (referred to as “performance units”).

In determining the appropriate amount and type of long-term equity incentive awards to be granted to our Named Executive Officers each year, the Committee considers the amount of time devoted by each executive to our business, the executive's position, scope of responsibility and base salary and available compensation information for executives in comparable positions in similar companies. Awards are granted annually during the first quarter of the year. Our goal is to reward the creation of value and high performance with variable compensation dependent on that performance. The Committee believes this analysis verifies that total equity compensation to Mr. Clifton and Mr. Cunningham in 2012 is appropriate for the level of responsibility that each of these officers hold. In 2012, Mr. Cunningham received restricted units and Mr. Clifton received both restricted units and performance units under our Long-Term Incentive Plan.

For purposes of administrative ease, the Committee decided in the fourth quarter of 2012 to change the vesting dates of outstanding restricted unit awards to December 15 of a given year (or the first business day thereafter if December 15 is a Saturday or Sunday) rather than January of the following year. For additional information on the vesting of outstanding equity awards, please see “Outstanding Equity at Fiscal Year End.” Because the performance period for the performance units is based on a period of three-full calendar years, the Committee did not change the vesting dates applicable to those awards.

Restricted Unit Awards

A restricted unit award is an award of common units that are subject to a risk of forfeiture. In 2012, Mr. Clifton and Mr. Cunningham were the only executive officers that were granted restricted units. The following table sets forth the number of restricted units awarded in 2012 to Messrs. Clifton and Cunningham (as adjusted to reflect a two-for-one unit split that occurred on January 16, 2013):

Name	Number of Restricted Units
Matthew P. Clifton	34,308
Mark T. Cunningham	8,170

Restricted unitholders have all the rights of a unitholder with respect to the restricted units, including the right to receive all distributions paid with respect to such restricted units (at the same rate as distributions paid on our common units) and any right to vote with respect to the restricted units, subject to limitations on transfer and disposition of the units during the restricted period. The distributions are not subject to forfeiture. The restricted units granted in 2012 vest in three equal annual installments as noted in the following table and will be fully vested and nonforfeitable after December 15, 2014.

Restricted Unit Vesting Criteria

Vesting Date (1)	Cumulative Amount of Restricted Units Vested
Immediately following December 15, 2012	1/3
Immediately following December 15, 2013	2/3
Immediately following December 15, 2014	All

(1) Vesting will occur on the first business day following December 15 if December 15 falls on a Saturday or a Sunday.

Other than due to a special involuntary termination associated with a defined change-in-control event, death, disability or retirement, if an employee's employment is terminated prior to one of the vesting dates specified above, all unvested restricted units will be forfeited. In the event of the employee's death, total and permanent disability or retirement, the employee will vest with respect to a pro rata number of units attributable to the period of service completed during the vesting period and will forfeit any unvested units. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. In the event of a special involuntary termination, all restricted units will automatically become fully vested. The termination and change-in-control provisions applicable to these awards are described in greater detail below in the section titled “Potential Payments upon Termination or Change in Control.”

Performance Unit Awards

A performance unit is a notational phantom unit subject to certain performance conditions that entitles the grantee to receive a common unit upon the vesting of the unit. In 2012, Mr. Clifton was the only executive officer that received performance units.

For 2012, Mr. Clifton was granted a target number of performance units equal to 11,436 common units (as adjusted to reflect a two-for-one unit split that occurred on January 16, 2013). The target number of performance units is determined by dividing a specified target dollar amount by the closing price of our common units on the date of grant of the award.

Performance units are settled only upon the attainment of pre-established performance targets, which may include the achievement of specified financial objectives determined by the Committee. The Committee also approves the period over which the performance targets must be attained in order for performance units to vest. Prior to vesting, distributions are paid on each outstanding performance unit, based on the target number of performance units subject to the award, at the same rate as distributions paid on our common units. The distributions are not subject to forfeiture.

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The Committee determined that the increase in distributable cash flow per common unit during the performance period should be used as the performance objective for the performance unit awards granted in 2012. The performance period for the awards began on January 1, 2012 and ends on December 31, 2014. Under the terms of the performance units granted to Mr. Clifton in 2012, Mr. Clifton may earn from 50% to 150% of the target number of performance units. Following the completion of the performance period, Mr. Clifton is entitled to payment of a number of common units equal to the result of multiplying his target number of performance units by the performance percentage set forth below, depending on the actual distributable cash flow per common unit for the three years ended December 31, 2014 (as adjusted to reflect a two-for-one unit split that occurred on January 16, 2013):

Performance Unit Vesting Criteria

3-Year Total Increase in Distributable Cash Flow per Common Unit above $7.553	Performance Percentage (%) to be Multiplied by Performance Units
$0.00	50%
$0.621	100%
$1.274 or more	150%

In order to receive more than 50% of the units subject to this award, the distributable cash flow per common unit for the three years ended December 31, 2014 must total greater than $7.553 per unit. In order to receive 100% of the units subject to this award, the distributable cash flow per common unit in the three years ended December 31, 2014 must total $8.174 per unit. In order to receive 150% of the units subject to this award, the distributable cash flow per common unit for the three years ended December 31, 2014 must total $8.827 per unit. The percentages are interpolated between points.

In the event that the Mr. Clifton's services to us terminate prior to January 1, 2015, other than due to a special involuntary termination associated with a defined change-in-control event, an involuntary termination, death, total and permanent disability or retirement, he will forfeit his award. In the event of Mr. Clifton's involuntary termination, death, total and permanent disability or retirement, Mr. Clifton will remain eligible to vest with respect to a pro rata number of units attributable to the period of service completed during the performance period (rounded up to include the month of termination) and will forfeit any unvested units. Any units that are not forfeited will become vested and payable based upon actual performance as of the end of the specified performance period. In its sole discretion, the Committee may make a payment assuming the maximum level of performance is achieved. In the event of a special involuntary termination, 150% of the performance units will be deemed earned and will become immediately vested and payable. The termination and change-in-control provisions of this award are described in greater detail below under the section titled “Potential Payments upon Termination or Change in Control.”

Acquisition of Common Units for Long-Term Incentive Plan Awards

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

Retirement and Benefit Plans

The cost of retirement and welfare benefits for our Named Executive Officers who are employees of HLS are charged monthly to us in accordance with the terms of the Omnibus Agreement. The terms of these benefit arrangements are generally described below. Our Named Executive Officers who split their professional time between us and HFC generally participate in the same retirement and welfare benefit arrangements, and information regarding their participation in these arrangements will generally be described in HFC's 2013 Proxy Statement.

Health and Welfare Benefits

All full-time employees of HLS, including our executive officers employed by HLS, are eligible to participate in various health and welfare benefit plans, including medical, dental, life insurance, and disability programs. Mr. Cunningham was the only Named Executive Officer whose health and welfare benefits were charged to us in 2012 pursuant to the Omnibus Agreement.

Defined Contribution Plan

For 2012, all employees of HLS were eligible to participate in the HollyFrontier Corporation 401(k) Retirement Savings Plan, a tax qualified defined contribution plan (the “401(k) Plan”). Employees may contribute amounts from 0% up to a maximum of 75% of their eligible compensation to the 401(k) Plan. Employee contributions that were made on a tax-deferred basis were generally limited to $17,000 for 2012, with employees 50 years of age or over able to make additional tax-deferred contributions of $5,500.

In 2012, employees not covered by collective bargaining agreements with labor unions received employer matching contributions of their employee contributions to the 401(k) Plan equal to 100% of the first 6% of the employee's eligible compensation. These employer matching contributions vest immediately. In addition, for 2012, all non-union employees received an employer retirement contribution to the 401(k) Plan ranging from 3% to 8% of the participating employee's eligible compensation, subject to applicable Internal Revenue Code limits, based on years of service. Employer retirement contributions are subject to a three-year cliff-vesting period.

Mr. Cunningham was the only Named Executive Officer whose 401(k) Plan benefits were charged to us in 2012 pursuant to the Omnibus Agreement.

Deferred Compensation Plan

In 2012, certain employees of HLS and HFC, including the Named Executive Officers, first became eligible to participate in the NQDC Plan. The NQDC Plan was previously named the Frontier Deferred Compensation Plan and was assumed by HFC in connection with its merger with Frontier Oil Corporation in 2011. Beginning in 2012, HFC determined to expand participation in the NQDC to certain management and other highly compensated employees of HFC and HLS to provide them an opportunity to defer compensation in excess of qualified retirement plan limitations on a pre-tax basis and accumulate tax-deferred earnings to achieve their financial goals.

Eligible employees may contribute between 1% and 50% of their eligible earnings, which includes base salary and bonuses, to the NQDC Plan. Participants in the NQDC Plan may also receive certain employer-provided contributions, including matching restoration contributions, retirement restoration contributions, transition benefit contributions (pursuant to the Transition Benefit Plan described below), and nonqualified nonelective contributions. Matching restoration contributions and retirement restoration contributions represent contribution amounts that could not be made under the 40 1(k) Plan due to Internal Revenue Code limitations on tax-qualified plans. See the narrative preceding the “Nonqualified Deferred Compensation Table” for additional information regarding these contributions and the other terms and conditions of the NQDC Plan.

Mr. Cunningham was the only Named Executive Officer whose NQDC Plan benefits were charged to us in 2012 pursuant to the Omnibus Agreement.

Retirement Pension Plans

HFC traditionally maintained the Holly Retirement Plan, a tax-qualified defined benefit retirement plan (the “Retirement Plan”), and the Holly Retirement Restoration Plan, an unfunded plan that provides additional payments to participating executives whose Retirement Plan benefits were subject to certain Internal Revenue Code limitations (the “Restoration Plan”). No additional benefits accrued under the Retirement Plan and Restoration Plan for any participants effective May 1, 2012, and the retirement benefits offered to employees going forward are solely provided through defined contribution retirement plans.

Employees hired prior to 2007 and not subject to a collective bargaining agreement, were, until January 1, 2012, eligible to participate in and accrue benefits under the Retirement Plan. Employees participating in the Retirement Plan were also eligible to participate in the 401(k) Plan, but were generally not eligible to receive a retirement contribution under the 401(k) Plan for years prior to 2012. As of January 1, 2012, participants in the Retirement Plan and the Restoration Plan who are not subject to a collective bargaining agreement were no longer accruing additional benefits under these plans, and as of May 1, 2012, all participants in these plans ceased accruing additional benefits.

HFC has begun the process to liquidate the Retirement Plan and the Restoration Plan.

In connection with the cessation of benefit accruals under the Retirement Plan and the Restoration Plan, HFC adopted a Transition Benefit Plan pursuant to which eligible participants in the Retirement Plan are provided a transition benefit for each of 2012, 2013, and 2014. The amount of the transition benefit for each year is equal to the participant's eligible compensation as of December 31 of that year, multiplied by a transition benefit percentage determined based on the participant's eligible years of service as of January 1, 2012 (in the case of salaried employees). The participant must be employed on the last day of the year (subject to certain exceptions for death or disability) in order to earn a transition benefit for that year. For executive officers, the transition benefit is paid in the form of a transition benefit contribution to the NQDC Plan. For additional information regarding these transition benefit contributions, see the narrative preceding the “Nonqualified Deferred Compensation Plan Table.”

Mr. Cunningham was the only Named Executive Officer whose Retirement Plan and Transition Benefit Plan benefits were charged to us in 2012 pursuant to the Omnibus Agreement. Mr. Cunningham ceased accruing benefits under the Retirement Plan at the end of 2011, and is not a participant in the Restoration Plan.

Change in Control Agreements

As of the date of this Annual Report on Form 10-K, neither we nor HLS has entered into any employment agreements with any of the Named Executive Officers. On February 14, 2011, the Board adopted the Holly Energy Partners, L.P. Change in Control Policy (the "Change in Control Policy") and the related form of Change in Control Agreement for certain officers of HLS. The material terms of, and the quantification of, the potential amounts payable under the Change in Control Agreements currently in effect with our Named Executive Officers are described below in the section titled "Potential Payments upon Termination or Change in Control." The Change in Control Agreements contain "double-trigger" payment provisions that require not only a change in control of HFC, HLS or HEP, but also a qualifying termination of the executive within a specified period of time following the change in control in order for an officer to be entitled to benefits. We believe the Change in Control Agreements provide for management continuity in the event of a change in control and provide competitive benefits for the recruitment and retention of executives.

We entered into a Change in Control Agreement with Mr. Cunningham, effective as of February 14, 2011, in accordance with the Change in Control Policy. We bear all costs and expenses associated with this agreement.

HFC has a Change in Control Policy and Change in Control Agreements between HFC and Mr. Clifton, Mr. Shaw and Mr. Aron, the costs of which are fully borne by HFC and which were in effect during 2012. The HFC Change in Control Agreements are triggered only upon a change in control of HFC, and the terms of the HFC Change in Control Agreements will be described in HFC's 2013 Proxy Statement.

Tax and Accounting Implications

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

Recoupment of Compensation

To date, the Board has not adopted a formal clawback policy to recoup incentive based compensation upon the occurrence of a financial restatement, misconduct, or other specified events. However, equity awards granted to Named Executive Officers are subject to the terms of the Long-Term Incentive Plan, which states that such awards may be canceled, repurchased and/or recouped to the extent required by applicable law or any clawback policy that we adopt. The Committee will evaluate the practical, administrative and other implications of adopting, implementing and enforcing a clawback policy.

2013 Compensation Decisions

As a result of Mr. Clifton's retirement from HFC effective January 1, 2013 and Mr. Shaw's resignation from HFC effective January 1, 2013, the Committee determined that 100% of Mr. Clifton's and Mr. Shaw's compensation would be determined by the Committee and paid by HLS beginning in 2013. In addition, the Committee determined that all the equity awards granted to Mr. Clifton and Mr. Shaw in 2013 would be granted by us under the Long-Term Incentive Plan. Beginning in 2013, the cost of retirement and welfare benefits for Mr. Clifton and Mr. Shaw are charged monthly to us in accordance with the terms of the Omnibus Agreement.

Compensation Committee Report

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

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Members of the Compensation Committee:
Michael C. Jennings, Chairman
Charles M. Darling, IV
William J. Gray
William P. Stengel
James G. Townsend

Executive Compensation Tables

The following executive compensation tables and related information are intended to be read together with the more detailed disclosure regarding our executive compensation program presented under the caption "Compensation Discussion and Analysis." All unit and per unit amounts in the following tables have been adjusted to reflect the two-for-one unit split that occurred on January 16, 2013.

Summary Compensation Table

The table below summarizes the total compensation paid or earned by each of the Named Executive Officers in 2012, 2011 and 2010, to the extent such compensation is allocable to us pursuant to SEC rules.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	Non-Equity Incentive Plan Compensation (3)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings(4)	All Other Compensation (5)	Total
Matthew P. Clifton	2012	—	—	$1,434,995	—	—	—	$1,434,995
Chairman of the Board and Chief	2011	—	—	588,501	—	—	—	588,501
Executive Officer (6)	2010	—	—	844,057	—	—	—	844,057
Douglas S. Aron Executive Vice	2012	$261,350	—	—	—	—	—	$261,350
President and Chief Financial Officer (7)	2011	—	—	—	—	—	—	—
Bruce R. Shaw President (8)	2012	$400,707	—	—	—	—	—	$400,707
	2011	—	—	93,770	—	—	—	93,770
	2010	—	—	93,783	—	—	—	93,783
Mark T.	2012	$236,160(9)	$47,920	$250,043	$52,080	$31,211	$97,280	$714,694
Cunningham Senior Vice	2011	210,344	71,250	180,024	58,750	64,673	12,600	597,641
President - Operations	2010	201,780	20,500	150,002	82,000	39,620	8,491	502,393

(1) Amounts in this column reflect the discretionary bonus amount, if any, paid pursuant to the individual performance metric under our Annual Incentive Plan and any other bonus paid outside our Annual Incentive Plan. Other

payments made under our Annual Incentive Plan are included in the “Non-Equity Incentive Plan Compensation” column.

(2) Represents the aggregate grant date fair value of awards of restricted units and performance units made in the year indicated computed in accordance with FASB ASC Topic 718, determined without regard to forfeitures, and does not reflect the actual value that may be recognized by the executive. See Notes 6, 7 and 7 to our consolidated financial statements for the fiscal years ended December 31, 2010, 2011 and 2012, respectively, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards.

With respect to performance units awarded in 2012, the amounts in the table above were based on a probable payout percentage of 110%. If it is assumed that the performance units granted in 2012 would be paid out at the maximum payout level of 150%, the grant date fair value of Mr. Clifton's performance units would be $524,998.

The terms of the 2012 performance unit awards and the 2012 restricted unit awards are described above under “Compensation Discussion and Analysis - Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive

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Equity Compensation." For additional information on outstanding restricted unit and performance unit awards, see below under "Outstanding Equity Awards at Fiscal Year End." No forfeitures of equity awards held by the Named Executive Officers occurred in 2012.

(3) Amounts in this column reflect the bonus amount, if any, paid under our Annual Incentive Plan, other than with respect to the individual performance metric (which amounts are reported in the "Bonus" column). The 2012 bonus amounts under our Annual Incentive Plan are described above in greater detail under "Compensation Discussion and Analysis-Overview of 2012 Executive Compensation Components and Decisions-Annual Incentive Cash Bonus Compensation."

(4) Represents the aggregate change in the actuarial present value of a Named Executive Officer's accumulated benefits under all defined benefit pension plans in which he participates. During 2012, earnings on Mr. Cunningham's account under the NQDC Plan did not exceed 120% of the applicable long-term federal rate (2.63%). As a result, no above market or preferential earnings were paid to Mr. Cunningham and, therefore, none of the earnings received by Mr. Cunningham during 2012 are included in this table. The aggregate change in the actuarial present value of Mr. Cunningham's accumulated benefits under the Retirement Plan are based on the following assumptions:

	December 31, 2010	December 31, 2011	December 31, 2012
Discount Rate:	5.65%	4.6%	3.95%
Mortality Table:	RP2000 White Collar Projected to 2020 (50% Male/ 50% Female)	2011 IRS Prescribed Mortality - Static Annuitant, male and female	2012 IRS Prescribed Mortality - Static Annuitant, male and female
Retirement Age:	the later of current age or age 62	the later of current age or age 62	the later of current age or age 62

See "Pension Benefits Table" for additional information.

(5) For 2012, includes the compensation as described under "All Other Compensation" below.

(6) Mr. Clifton also served as President of HLS until November 2012. During 2012, Mr. Clifton split his professional time between HFC and us, and the only compensation he received for the services he performed for us was in the form of awards of restricted units and performance units under our Long-Term Incentive Plan. Nome of the compensation paid, or other benefits made available to Mr. Clifton by HFC was allocated to the services he provided to us for 2012. As a result, only the grant date fair value of his 2012 Long-Term Incentive Plan awards are disclosed as 2012 compensation in this table. Information regarding the compensation paid to Mr. Clifton as consideration for the services he performed for HFC during 2012 will be reported in HFC's 2013 Proxy Statement.

(7) Mr. Aron served as Executive Vice President and Chief Financial Officer of HLS from July 1, 2011 until December 31, 2011, when he was replaced by Mr. Shaw, and began serving as Executive Vice President and Chief Financial Officer of HLS again on November 1, 2012, when Mr. Shaw was appointed as President of HLS. During 2012, Mr. Aron split his professional time between HFC and us, and all compensation paid to him for 2012 was determined and paid by HFC. In accordance with SEC rules, a portion of the total compensation paid by HFC to Mr. Aron for 2012 is allocated to the services he performed for us during 2012. Because Mr. Aron served as Executive Vice President and Chief Financial Officer of HLS for only two months during 2012, the allocation was made based on the assumption that Mr. Aron spent, in the aggregate, approximately 5% of his professional time in 2012 on our business and affairs. As a result, for Mr. Aron, only 5% of the total amount of compensation he received from HFC for 2012 has been reported in this table and the allocated amount has been solely attributed to Mr. Aron's base salary in the table above since his HFC bonus and equity awards are tied to HFC performance.

(8) This amount represents the aggregate dollar value of total compensation paid to Mr. Aron by HFC (including base salary, non-equity incentive compensation, equity awards and other compensation) calculated pursuant to SEC rules and multiplied by 5%. The total compensation paid by HFC to Mr. Aron in 2012 (including the portion of his salary reported in this table) will be disclosed in HFC's 2013 Proxy Statement.

Mr. Shaw served as Senior Vice President and Chief Financial Officer until November 2012, when he was appointed as President of HLS. During 2012, Mr. Shaw split his professional time between HFC and us, and all compensation paid to him for 2012 was determined and paid by HFC. In accordance with SEC rules, a portion of the total compensation paid by HFC to Mr. Shaw for 2012 is allocated to the services he performed for us during 2012. The allocation was made based on the assumption that Mr. Shaw spent, in the aggregate, approximately 25% of his professional time in 2012 on our business and affairs. As a result, for Mr. Shaw, only 25% of the total amount of compensation he received from HFC for 2012 has been reported in this table and the allocated amount has been solely attributed to Mr. Shaw's base salary in the table above since his HFC bonus and equity awards are tied to HFC performance. This amount represents the aggregate dollar value of total compensation paid to Mr. Shaw by HFC (as set forth in the following sentence), calculated pursuant to SEC rules, and multiplied by 25%. Because Mr. Shaw is not a “named executive officer” of HFC, his total compensation in 2012 is not required to be disclosed in our or HFC's public filings; however, for 2012, Mr. Shaw generally received the following total compensation from HFC: (a) $415,000 in base salary (including the portion of his salary reported in this table), (b) $418,000 in discretionary and non-equity incentive bonus compensation, (c) $597,277 in grant date fair value of HFC restricted stock and performance share units, and (d) $172,551 in other compensation, including a change in value of defined benefit pension plan benefits and contributions under defined contribution plans. Mr. Shaw ceased accruing benefits under the Retirement Plan in May 2007 and, as of December 31, 2012, he had 8.25 years of credited service under the Retirement Plan and the Restoration Plan and the present value of his accumulated benefits was $182,932 under the Retirement Plan and $9,386 under the Restoration Plan. HFC's compensation policies and programs for its executive officers will be described in HFC's 2013 Proxy Statement.

(9) As of January 1, 2012, Mr. Cunningham's annual salary was $211,200. His annual salary was increased to $240,000 effective March 1, 2012. His actual payroll payments in 2012 for the 2012 fiscal year were $230,622 due to our bi-weekly payroll system (the December 24, 2012 through December 31, 2012 payroll payment was made on January 15, 2013). Similar adjustments were made for other mid-period pay adjustments in prior periods.

All Other Compensation

The table below describes the components of Mr. Cunningham's compensation included in the “All Other Compensation” column for 2012 in the Summary Compensation Table above.

Component	Amount
401(k) Plan Retirement Contribution	$10,000
401(k) Plan Company Matching Contribution	$15,000
NQDC Plan Retirement Contribution	$8,912
NQDC Plan Company Matching Contributions	$13,368
Transition Benefit Contribution	$50,000

We reimbursed these amounts pursuant to the Omnibus Agreement.

Grants of Plan-Based Awards

The following table sets forth, for Mr. Clifton and Mr. Cunningham, information about plan-based awards under our equity and non-equity incentive plans made during the year ending December 31, 2012. In this table, awards are abbreviated as “AICP” for the annual incentive cash awards under our Annual Incentive Plan, as “RUA” for restricted unit awards, and as “PUA” for performance unit awards. The 2012 awards of performance units and restricted units were issued under our Long-Term Incentive Plan. Mr. Aron and Mr. Shaw did not receive any plan-based awards from us during 2012.

Name	Type	Committee Action Date	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All other Equity Awards (3)	Grant Date Fair Value (4)
				Threshold	Target	Maximum	Threshold	Target	Maximum		
Matthew P.	PUA	2/27/2012	3/1/2012	—	—	—	5,718	11,436	17,154	—	$384,999
Clifton	RUA	2/27/2012	3/1/2012	—	—	—	—	—	—	34,308	1,049,996
Douglas S. Aron	—	—	—	—	—	—	—	—	—	—	—
Bruce R. Shaw	—	—	—	—	—	—	—	—	—	—	—

Mark T.	RUA	1/24/2012	3/1/2012	—	—	—	—	—	—	8,170	250,043
Cunningham	AICP	—	—	—	$48,000	$96,000	—	—	—	—	—

(1) Represents the potential payout for the award to Mr. Cunningham under our Annual Incentive Plan. The award was subject to the achievement of certain performance metrics. The performance metrics and awards are described under "Compensation Discussion and Analysis - Overview of 2012 Executive Compensation Components and Decisions - Annual Incentive Cash

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Bonus Compensation.” Amounts reported do not include amounts potentially payable pursuant to the individual performance portion of the award. The amount actually paid with respect to the individual performance portion of the award is reported in the “Bonus” column of the “Summary Compensation Table” for 2012, and the amount actually paid with respect to the portion of the award reported in this table is reported in the “Non-Equity Incentive Compensation” column of the “Summary Compensation Table” for 2012.

(2) Represents the potential number of performance units payable under the Long-Term Incentive Plan. The number of units paid at the end of the performance period may vary from the target amount, based on our achievement of specified performance measures. The terms of the performance unit awards are described above under “Compensation Discussion and Analysis - Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive Equity Compensation - Performance Unit Awards.”

(3) Represents awards of restricted units. The terms of the restricted unit awards are described above under “Compensation Discussion and Analysis - Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive Equity Compensation - Restricted Unit Awards.”

(4) Represents the grant date fair value determined pursuant to FASB ACS Topic 718, based on a closing price of our common units of $30.61 on March 1, 2012, the date of grant. The value of performance units was calculated using the $30.61 price based on the probable payout percentage of 110%.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth, for Mr. Clifton, Mr. Shaw and Mr. Cunningham, information regarding outstanding restricted units and performance units that were held by each Named Executive Officer as of December 31, 2012, including awards that were granted prior to 2012. The value of these awards was calculated based on a price of $32.89 per unit, the closing price of our common units on December 31, 2012. Mr. Aron does not hold any outstanding equity awards under our Long-Term Incentive Plan.

As described in greater detail above under “Overview of 2012 Executive Compensation Components and Decisions -Long-Term Incentive Equity Compensation,” the Committee decided at its last meeting in 2012, for administrative ease, to change the vesting dates of outstanding restricted unit awards. As a result, restricted unit awards that would otherwise have vested in January of a specified year, instead vest on December 15 of the preceding year (or the first business day thereafter if December 15 is a Saturday or a Sunday). The original vesting dates of outstanding performance unit awards have not been modified.

	Equity Awards (1)			
Name	Number of Units That Have Not Vested	Market Value of Units That Have Not Vested	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested
Matthew P. Clifton	22,872	$752,260	81,747 (2)	$2,688,659
Douglas S. Aron	—	—	—	—
Bruce R. Shaw	1,048	34,469	—	—
Mark T. Cunningham	7,458	245,294	—	—

(1) All awards are more particularly described in the narrative that immediately follows this chart.

(2) Under SEC rules, the number and value of performance units reported is based on the number of units payable at the end of the performance period assuming the maximum level of performance is achieved. The target number of

performance units held by Mr. Clifton at December 31, 2012 equaled 54,498. For purposes of this table, the performance units reported reflect 150% of the target number of performance units, which is the maximum performance percentage applicable to the awards.

The following chart sets forth by year of grant the number of restricted units and performance units awarded to Mr. Clifton, Mr. Shaw and Mr. Cunningham that remained outstanding as of December 31, 2012, and that are reported in the immediately preceding chart. For performance unit awards, the target number of performance units is listed in the chart below.

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Name	2010 Performance Units (1)	2011 Restricted Units (2)	2011 Performance Units (3)	2012 Restricted Units (4)	2012 Performance Units (5)	Total
Matthew P. Clifton	25,124	—	17,938	22,872	11,436	77,370
Douglas S. Aron						
Bruce R. Shaw	—	1,048	—	—	—	1,048
Mark T. Cunningham	—	2,012	—	5,446	—	7,458

(1) Mr. Clifton received an award of a target number of 25,124 performance units in March 2010. Under the terms of the grant, Mr. Clifton may earn from 50% to 150% of the target number of performance units, based on the total increase in our distributable cash flow per common unit for the performance period. The performance period for the award began on January 1, 2010 and ends on December 31, 2012. Following the completion of the performance period, Mr. Clifton shall be entitled to payment of a number of common units equal to the result of multiplying the target number of performance units by the performance percentage set forth below:

Performance Unit Vesting Criteria

3-Year Total Increase in Distributable Cash Flow Per Common Unit above $6.246 [(1)]	Performance Percentage (%) to be Multiplied by Performance Units
$0.00	50%
$0.513	100%
$1.054 or more	150%

(1) $6.246 represents a 3-year cumulative distributable cash flow per common unit of $2.082 per annum, $2.082 being the annual distributable cash flow per common unit rate in effect at the start of the performance period.

In order to receive more than 50% of the units subject to this award, the distributable cash flow per common unit for the three years ended December 31, 2012 must total greater than $6.246 per unit. In order to receive 100%, the distributable cash flow per common unit for the three years ended December 31, 2012 must total $6.759 per unit. In order to receive 150%, the distributable cash flow per common unit for the three years ended December 31, 2012 must total $7.300 per unit. The percentages are interpolated between points.

In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150%. The termination and change-in-control provisions of this award are described below under the section titled “Potential Payments upon Termination or Change in Control.” On February 5, 2013, the Committee determined that the performance percentage applicable to these performance units was 120%, and Mr. Clifton was paid 30,149 common units in accordance with such determination.

(2) In March 2011, Mr. Shaw received 3,144 restricted units and Mr. Cunningham received 6,036 restricted units. Under the terms of the grants, except in the case of early termination, the restricted units vest in accordance with the following schedule:

Restricted Unit Vesting Criteria

Vesting Date	Cumulative Amount of Restricted Units Vested
Immediately following December 31, 2011	1/3
Immediately following December 15, 2012	2/3
Immediately following December 15, 2013	All

The termination and change-in-control provisions of this award are described below in the section titled “Potential Payments upon Termination or Change in Control.”

(3) Mr. Clifton received an award of a target number of 17,938 performance units in March 2011. Under the terms of the grant, Mr. Clifton may earn from 50% to 150% of the target number of performance units, based on the total increase in our distributable cash flow per common unit for the performance period. The performance period for the award began on January 1, 2011 and ends on December 31, 2013. Following the completion of the performance period, Mr. Clifton shall be entitled to payment of a number of common units equal to the result of multiplying the target number of performance units by the

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performance percentage set forth below:
Performance Unit Vesting Criteria

3-Year Total Increase in Distributable Cash Flow per Common Unit above $6.432[(1)]	Performance Percentage (%) to be Multiplied by Performance Units
$0.00	50%
$0.529	100%
$1.085 or more	150%

(1) $6.432 represents a 3-year cumulative distributable cash flow per common unit of $2.144 per annum, $2.144 being the annual distributable cash flow per common unit rate in effect at the start of the performance period.

In order to receive more than 50% of the units subject to this award, the distributable cash flow per common unit for the three years ended December 31, 2013 must total greater than $6.432 per unit. In order to receive 100% of the units subject to this award, the distributable cash flow per common unit in the three years ended December 31, 2013 must total $6.961 per unit. In order to receive 150%, the distributable cash flow per common unit for the three years ended December 31, 2013 must total $7.517 per unit. The percentages are interpolated between points.

In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150%. The termination and change-in-control provisions of this award are described below under the section titled "Potential Payments upon Termination or Change in Control."

(4) In March 2012, Mr. Clifton received 34,308 restricted units and Mr. Cunningham received 8,170 restricted units. The vesting dates for the restricted units granted in March 2012 are described in the section titled "Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive Equity Compensation - Restricted Unit Awards."

(5) Mr. Clifton received an award of a target number of 11,436 performance units in March 2012. The vesting dates and conditions for this award are described in the section titled "Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive Equity Compensation - Performance Unit Awards."

Option Exercises and Units Vested

The following table provides information regarding the vesting in 2012 of restricted unit and performance unit awards held by Mr. Clifton, Mr. Shaw, and Mr. Cunningham. To date, we have not granted any unit options.

As described in greater detail above under "Overview of 2012 Executive Compensation Components and Decisions -Long-Term Incentive Equity Compensation," the Committee decided at its last meeting in 2012, for administrative ease, to change the vesting dates of outstanding restricted unit awards. As a result, restricted unit awards that would otherwise have vested in January of a specified year, instead vest on December 15 of the preceding year (or the first business day thereafter if December 15 is a Saturday or a Sunday).

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

Named Executive Officer	Unit Awards Number of Units Acquired on Vesting	Value Realized on Vesting
Matthew P. Clifton [(1)]	58,218	$1,625,645

Douglas S. Aron	—	—
Bruce R. Shaw	7,250	$206,388
Mark T. Cunningham	13,446	$393,760

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(1) Includes 46,782 performance units that became payable to Mr. Clifton on January 25, 2012 upon the Committee's determination that the performance percentage applicable to the target number of 42,920 performance units granted to Mr. Clifton in March 2009 was 109%.

Pension Benefits Table

Certain of our Named Executive Officers are participants in the Retirement Plan and the Restoration Plan. As of January 1, 2012, participants in the Retirement Plan and the Restoration Plan who are not subject to a collective bargaining agreement, including Named Executive Officers, ceased accruing additional benefits under the plans, and as of May 1, 2012, all participants in these plans ceased accruing additional benefits. In connection with the cessation of benefit accruals under the Retirement Plan and the Restoration Plan, HFC adopted a Transition Benefit Plan pursuant to which eligible participants in the Retirement Plan are provided a transition benefit for each of 2012, 2013, and 2014. For executive officers, the transition benefit is paid in the form of a transition benefit contribution to the NQDC Plan. For additional information regarding these transition benefit contributions, see the narrative preceding the “Nonqualified Deferred Compensation Table.” HFC has begun the process to liquidate the Retirement Plan and the Restoration Plan.

Mr. Cunningham was the only Named Executive Officer whose Retirement Plan benefits were charged to us in 2012 pursuant to the Omnibus Agreement. The table below sets forth an estimate of the retirement benefits payable to Mr. Cunningham at normal retirement age under the Retirement Plan. Mr. Cunningham does not participate in the Restoration Plan. Even though Mr. Clifton and Mr. Shaw are also participants in the Retirement Plan and/or the Restoration Plan, we have not provided any disclosure with respect to their potential retirement benefits since those benefits are paid for by HFC. Additional information regarding the Retirement Plan and the Restoration Plan will be provided in HFC's 2013 Proxy Statement.

Pension Benefits

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
Matthew P. Clifton	—	—	—	—
Douglas S. Aron	—	—	—	—
Bruce R. Shaw	—	—	—	—
Mark T. Cunningham [1]	Retirement Plan	7.5	$209,169	—

(1) Mr. Cunningham is not eligible to commence receiving any benefit under the Retirement Plan as of December 31, 2012.

The actuarial present value of the accumulated benefits reflected in the above chart was determined using the same assumptions as used for financial reporting purposes (which are discussed further in Note 18 to HFC's consolidated financial statements for the fiscal year ended December 31, 2012), except the payment date was assumed to be age 62 rather than age 65. The earliest age at which a benefit can be paid with no benefit reduction under the Retirement Plan is age 62. In addition, the material assumptions used for these calculations include the following:

Discount Rate	3.95%
Mortality Table	2012 IRS Prescribed Mortality - Static Annuitant, male and female

The amount of benefits accrued under the Retirement Plan is based upon a participant's compensation, age and length of service. The compensation taken into account under the Retirement Plan is a participant's average monthly compensation, which is based on an individual's base salary or base pay and any quarterly bonuses during the highest consecutive 36-month period of employment. No quarterly bonuses were provided to executives in 2012, but quarterly bonuses were paid to some non-executive union employees.

The Retirement Plan provides for benefits upon normal retirement, early retirement, and late retirement, as well as providing accelerated deferred vested benefits, disability benefits, and death benefits. The normal retirement benefit under the plan may commence after an employee retires following his or her attainment of age 65. The normal form of payment is a monthly pension for the participant's life in an amount equal to (a) 1.6% of the participant's average monthly compensation multiplied by his or her total years of credited benefit service, minus (b) 1.5% of the participant's primary social security benefit multiplied by his or her total years of credited benefit service, such amount not to exceed 45% of the participant's primary social security benefit. Accrued benefits under the Retirement Plan were frozen based on pay and service as of the close of business on December 31, 2011. In addition, a participant who (i) has attained age 50 and completed at least 10 years of service, or (ii) has attained age 55 and completed at least 3 years of service may elect to terminate employment and begin receiving benefits under the Retirement Plan.

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An employee's benefit service is not deemed interrupted if the employee performed services for HFC and is later transitioned to work as an HLS employee. Instead of the normal form of payment, participants may also elect to receive their accrued benefits in the form of a life annuity with a period certain, a contingent annuity, or a lump sum.

Benefits up to limits set by the Internal Revenue Code are funded by HFC's contributions to the Retirement Plan, with the amounts determined on an actuarial basis. In 2012, the Internal Revenue Code limited benefits that could be covered by the Retirement Plan's assets to $200,000 per year (subject to increases for future years based on price level changes) and limited the compensation that could be taken into account in computing such benefits to $250,000 per year (subject to certain upward adjustments for future years).

Nonqualified Deferred Compensation

In 2012, all of our Named Executive Officers participated in the NQDC Plan. The NQDC Plan functions as a spill-over plan, allowing key employees to defer tax on income in excess of Internal Revenue Code limits that apply under the 401(k) Plan. For 2012, the annual deferral contribution limit under the 401(k) Plan was $17,000, and the annual compensation limit was $250,000. Deferral elections made by eligible employees under the NQDC Plan apply to the total amount of eligible earnings the employees want to contribute across both the 401(k) Plan and the NQDC Plan. Once eligible employees reach the Internal Revenue Code limits on contributions under the 401(k) Plan, contributions automatically begin being contributed to the NQDC Plan. Federal and state income taxes are generally not payable on income deferred under the NQDC Plan until funds are withdrawn.

Eligible employees may make salary deferral contributions between 1% and 50% of eligible earnings to the NQDC Plan. Eligible earnings include base pay, bonuses and overtime, but exclude extraordinary pay such as severance, accrued vacation, equity compensation, and certain other items. Eligible employees who are age 50 or older are required to make catch-up contributions to the 401(k) Plan before any contributions will be deposited into the NQDC Plan. For 2012, the catch-up contribution limit was $5,500. Deferral elections are irrevocable for an entire plan year and must be made prior to December 31 immediately preceding the plan year. Elections will carry over to the next plan year unless changed or otherwise revoked.

Participants in the NQDC Plan are eligible to receive a matching restoration contribution with respect to their elective deferrals made up to 6% of the participant's eligible earnings for the plan year in excess of the limits under Section 401(k) of the Internal Revenue Code. These matching restoration contributions are fully vested at all times. In addition, participants are eligible for a retirement restoration contribution ranging from 3% to 8% of the participant's eligible earnings for the plan year in excess of the limits under Section 401(k) of the Internal Revenue Code, based on years of service. Retirement restoration contributions are subject to a three-year cliff vesting period and will become fully vested in the event of the participant's death or a change in control. In order to receive a retirement restoration contribution, an eligible employee must be an active participant in the NQDC Plan on the last day of the calendar year (subject to certain exceptions for death, disability or retirement). Participants may also receive nonqualified nonelective contributions under the NQDC Plan, which contributions may be subject to a vesting schedule determined at the time the contributions are made.

Participants in the Retirement Plan whose benefit accruals ceased as of December 31, 2011 are also eligible to receive a transition benefit contribution under the NQDC Plan for plan years 2012, 2013 and 2014. The amount of the transition benefit contribution for each year is equal to the participant's eligible compensation (determined in accordance with the Transition Benefit Plan) as of December 31 of that year, multiplied by a transition benefit percentage determined based on the participant's eligible years of service as of January 1, 2012 (in the case of salaried employees) in accordance with the following table:

Years of Services	Transition Benefit

	(as percentage of eligible compensation)
Less than 5 years	10%
5 to 15 years	20%
15 to 20 years	25%
20 years and over	35%

The participant must be employed on the last day of the year (subject to certain exceptions for death or disability) in order to earn a transition benefit contribution for that year. Transition benefit contributions are fully vested immediately. Eligible compensation used to calculate the transition benefit contribution is subject to applicable Internal Revenue Code limits ($250,000 in 2012), except that if an employee participated in the Restoration Plan, all of his or her eligible compensation will be taken into consideration in determining the transition benefit contribution.

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Participating employees have full discretion over how their contributions to the NQDC Plan are invested among the offered investment options, and earnings on amounts contributed to the NQDC Plan are calculated in the same manner and at the same rate as earnings on actual investments. Neither HLS nor HFC subsidizes directly or indirectly a participant's earnings under the NQDC Plan. During 2012, the investment options offered under the NQDC Plan were the same as the investment options available to participants in the tax-qualified 401(k) Plan, except that the tax-qualified 401(k) Plan offers the Principal Stable Value Fund and the NQDC Plan instead offers the Principal Money Market Fund. Earnings for 2012 with respect to NQDC Plan amounts invested in the Principal Money Market Fund did not exceed 120% of the applicable long-term federal rate (2.63%) and, as a result, no above market or preferential earnings were paid under the NQDC Plan for 2012. The following table lists the investment options for the NQDC Plan in 2012 with the annual rate of return for each fund:

Investment Funds	Rate of Return
Allianz NFJ Small Cap Value I Fund	10.79%
Buffalo Small Cap Fund	19.93%
Columbia Acorn International Z Fund	21.6%
Columbia Acorn Z Fund	17.93%
Fidelity Contrafund Fund	16.26%
Fidelity Low-Priced Stock Fund	18.5%
Harbor Capital Appreciation Instl Fund	15.69%
LargeCap S&P 500 Index Instl Fund	15.73%
Madcap S&P 400 Index Instl Fund	17.65%
Money Market Instl Fund	—%
Perkins Mid Cap Value T Fund	10.32%
PIMCO Total Return Instl Fund	10.36%
PIMCO All Asset All Authority Instl Fund	17.66%
RS Emerging Markets A Fund	13.26%
SmallCap S&P 600 Index Instl Fund	16.1%
T. Rowe Price Retirement Income Fund	10.05%
T. Rowe Price Retirement 2005 Fund	11.35%
T. Rowe Price Retirement 2010 Fund	12.44%
T. Rowe Price Retirement 2015 Fund	13.81%
T. Rowe Price Retirement 2020 Fund	15.01%
T. Rowe Price Retirement 2025 Fund	16%
T. Rowe Price Retirement 2030 Fund	16.82%
T. Rowe Price Retirement 2035 Fund	17.35%
T. Rowe Price Retirement 2040 Fund	17.55%
T. Rowe Price Retirement 2045 Fund	17.62%
T. Rowe Price Retirement 2050 Fund	17.55%
T. Rowe Price Retirement 2055 Fund	17.6%
Thornburg International Value R5 Fund	15.74%
Vanguard Equity-Income Adm. Fund	13.58%
Vanguard Total Bond Market Index Signal Fund	4.15%
Vanguard Total International Stock Index Signal Fund	18.21%

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

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Non-Qualified Deferred Compensation Table

Mr. Cunningham was the only Named Executive Officer whose NQDC Plan benefits were charged to us in 2012 pursuant to the Omnibus Agreement. The following table provides information regarding contributions to, and the year-end balance of, Mr. Cunningham's NQDC Plan account for 2012. Even though Mr. Clifton, Mr. Aron and Mr. Shaw are also participants in the NQDC Plan, we have not provided any disclosure with respect to their NQDC Plan benefits since those benefits were paid for by HFC in 2012. Additional information regarding the NQDC Plan will be provided in HFC's 2013 Proxy Statement.

Name	Executive Contributions (1)	Company Contributions (2)	Aggregate Earnings (3)	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2012 (4)
Matthew P. Clifton	—	—	—	—	—
Douglas S. Aron	—	—	—	—	—
Bruce R. Shaw	—	—	—	—	—
Mark T. Cunningham	$43,840	$72,280	$1,315	—	$117,435

(1) The amount reported was deferred at the election of Mr. Cunningham and is also included in the amounts reported in the “Salary,” “Bonus” and/or “Non-Equity Incentive Plan Compensation” columns of the Summary Compensation Table for 2012.

(2) The amount reported is also included in the “All Other Compensation” column of the “Summary Compensation Table” for 2012.

(3) The amount reported represents the aggregate earnings on the investments made in the NQDC Plan that accrued during 2012 on amounts of eligible compensation deferred at the election of Mr. Cunningham and the employer-provided contributions made on his behalf.

(4) The aggregate balance for Mr. Cunningham reflects the cumulative value, as of December 31, 2012, of the employee and employer-provided contributions to the NQDC Plan for Mr. Cunningham's account, and any earnings on these amounts, since Mr. Cunningham began participating in the NQDC Plan in 2012.

Potential Payments upon Termination or Change In Control

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

Change in Control Agreements

During 2012, the only Named Executive Officer who had entered into a Change in Control Agreement with us was Mr. Cunningham. We entered to a Change in Control Agreement with Mr. Cunningham, effective as of February 14, 2011, in accordance with our Change in Control Policy. We bear all costs and expenses associated with this agreement.

HFC has a Change in Control Policy and Change in Control Agreements between HFC and Mr. Clifton, Mr. Shaw and Mr. Aron, which were in effect during 2012. The HFC Change in Control Agreements trigger only upon a change in control of HFC. The terms of the HFC Change in Control Agreements, and a quantification of potential benefits under the Change in Control Agreements with HFC and certain of its named executive officers, will be disclosed in HFC's 2013 Proxy Statement.

The Change in Control Agreements terminate on January 31, 2014, and thereafter automatically renew for successive one year terms (on each anniversary date thereafter) unless a cancellation notice is given by us 60 days prior to the automatic extension date. The Change in Control Agreements provide that if, in connection with or within two years after a “Change in Control” of HFC, HLS or HEP (1) the executive is terminated without “Cause,” leaves voluntarily for “Good Reason,” or is terminated as a condition of the occurrence of the transaction constituting the “Change in Control,” and (2) the executive is not offered employment with HFC, HLS, HEP, HEP Logistics or any of their affiliates on substantially the same terms in the aggregate as his previous employment with HLS within 30 days after the termination, then the executive will receive the following cash severance amounts paid by us:

- a cash payment equal to his accrued and unpaid salary, unreimbursed expenses and accrued vacation pay,

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

- continued participation by the executive and his or her dependents in medical and dental benefits for the number of years equal to the executive's designated multiplier.

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

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries or HLS, HEP, HEP Logistics or any of their subsidiaries) becomes the beneficial owner of more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics or more than 50% of the outstanding common stock or membership interests, as applicable or HFC or HLS;
- a majority of HFC's Board of Directors is replaced during a 12-month period by directors who were not endorsed by a majority of the previous board members;
- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 50% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;
- the holders of voting securities of HFC or HEP approve a plan of complete liquidation or dissolution of HFC or HEP, as applicable; or
- the holders of voting securities of HFC or HEP approve the sale or disposition of all or substantially all of the assets of HFC or HEP, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

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

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

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

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

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

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

Long-Term Equity Incentive Awards

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

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

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

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

- Restricted Units: The executive will vest with respect to a pro rata number of units attributable to the period of service completed during the applicable vesting period and will forfeit any unvested units.
- Performance Units: The executive will remain eligible to vest with respect to a pro rata number of units attributable to the period of service completed during the applicable performance period (rounded up to include the month of termination) and will forfeit any unvested units. The Committee will determine the number of remaining performance units earned and the amount to be paid to the executive as soon as administratively possible after the end of the performance period based upon the performance actually attained for the entire performance period. The foregoing also applies if the executive separates from employment for any other reason other than a voluntary separation, Special Involuntary Separation or for "Cause."

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

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries or HLS, HEP, HEP Logistics or any of their subsidiaries) becomes the beneficial owner of more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics;
- a majority of HFC's Board of Directors is replaced during a 12-month period by directors who were not endorsed by two-thirds of the previous board members;
- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 60% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP, or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;
- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve a plan of complete liquidation or dissolution of HFC, HLS, HEP or HEP Logistics, as applicable; or
- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve the sale or disposition of all or substantially all of the assets of HFC, HLS, HEP or HEP Logistics, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

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

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

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

- a change in the executive's principal office of employment of more than 25 miles from the executive's work address at the time of grant of the award;
- a material increase (without adequate consideration) or material reduction in the duties to be performed by the executive; or
- a material reduction in the executive's base compensation (other than bonuses and other discretionary items of compensation or a general reduction applicable generally to executives).

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

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

The following table summarizes the compensation and other benefits that would have been payable to the Named Executive Officers under the arrangements described above assuming their employment terminated under various scenarios, including in connection with a change in control, on December 31, 2012. For these purposes, our common unit price was assumed to be $32.89, which was the closing price per unit on December 31, 2012 (as adjusted to reflect the two-for-one common unit split that occurred on January 16, 2013).

In reviewing the tables, please note the following:

- Accrued vacation for a specific year is not allowed to be carried over to a subsequent year, so we assumed all accrued vacation for the 2012 year was taken prior to December 31, 2012.

- Because vesting of the performance units upon a termination due to death, disability, retirement, or other separation (other than a voluntary separation, a for "Cause" separation or a Special Involuntary Termination) remains contingent upon the attainment of performance goals at the end of the applicable performance periods, no amounts associated with accelerated vesting of performance units under those circumstances have been included in the table below. Due to the change in vesting dates of outstanding restricted unit awards to December 15 of a given year, no amounts are reported for accelerated vesting of restricted unit awards upon termination due to death, disability or retirement because units attributable to fiscal year 2012 vested on December 15, 2012.

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

- In calculating whether any tax reimbursements were owed to the Named Executive Officers, we used the following assumptions: (a) the excise tax rate under Section 4999 of the Tax Code is 20%, the federal income tax rate is 35%, the Medicare rate is 1.45%, the adjustment to reflect the phase-out of itemized deductions is 1.05%, and there are no state or local income taxes, (b) no amounts will be discounted as attributable to reasonable compensation, (c) all cash severance payments are contingent upon a change in control, and (d) the presumption required under applicable regulations that the equity awards granted in 2012 were contingent upon a change in control could be rebutted.

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Named Executive Officer	Cash Payments	Value of Welfare Benefits	Vesting of Equity Awards	Tax Reimbursement	Total
Matthew P. Clifton					
Termination in connection with or following a Change in Control	—	—	$3,440,919	—	$3,440,919
Termination due to Death, Disability or Retirement	—	—	—	—	—
Douglas S. Aron					
Termination in connection with or following a Change in Control	—	—	—	—	—
Termination due to Death, Disability or Retirement	—	—	—	—	—
Bruce R. Shaw					
Termination in connection with or following a Change in Control	—	—	$34,469	—	$34,469
Termination due to Death, Disability or Retirement	—	—	—	—	—
Mark T. Cunningham					
Termination in connection with or following a Change in Control	$364,295	$20,334	$245,294	—	$629,923
Termination due to Death, Disability or Retirement	—	—	—	—	—

Compensation Practices as They Relate To Risk Management

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

While annual cash-based incentive bonus awards play an appropriate role in the executive compensation program, the Committee believes that payment should be determined based on an evaluation of our performance on a wide variety of measures, as compared to our past performance and the performance of our peers, which mitigates excessive risk-taking that could produce unsustainable gains in one area of performance at the expense of our overall long-term interests. In addition, we set performance goals that we believe are reasonable in light of our past performance and market conditions. For Named Executive Officers performing all or a majority of their services for us, an appropriate part of total compensation is fixed, while another portion is variable and linked to performance. A portion of the variable compensation we provide is comprised of long-term incentives. A portion of the long-term incentives we provide is in the form of restricted units subject to time-based vesting conditions, which retains value even in a depressed market, so executives are less likely to take unreasonable risks. With respect to our performance-based equity incentives, assuming achievement of at least a minimum level of performance, payouts result in some compensation at levels below full target achievement, in lieu of an “all or nothing” approach. Further, our unit ownership guidelines require certain of our executives to hold certain levels of units (in addition to unvested and unsettled equity-based awards), which aligns an appropriate portion of their personal wealth to our long-term performance and the interests of our unitholders.

Guidelines for Unit Ownership for Outside Directors

Pursuant to the unit ownership guidelines approved by the Board in 2009, each outside director is expected to maintain an ownership level of our common units with a market value of $125,000. To the extent an outside director does not meet these guidelines, he will be expected to retain 25% of the units received upon settlement of restricted units awarded to him, until the unit ownership requirement is met. Units owned from any source count toward meeting the guideline, but unvested restricted units do not count. As of December 31, 2012, each of our outside directors complied with the unit ownership guidelines.

Guidelines for Unit Ownership for Executives

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Pursuant to the unit ownership guidelines approved by the Board in 2009, each Named Executive Officer specified below is expected to maintain an ownership level of our common units with the market value set forth next to his name:

Executive	Value of Units
Matthew P. Clifton	$500,000
Bruce R. Shaw	$250,000

To the extent each of the Named Executive Officers listed above does not meet these guidelines, he will be expected to retain 25% of the after-tax units received upon settlement of restricted unit and performance unit awards.

Units owned from any source count toward meeting the guideline, but units relating to unvested restricted units and/or performance units do not count. As of December 31, 2012, each of the Named Executive Officers listed above complied with the unit ownership guidelines.

Anti-Hedging and Anti-Pledging Policy

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

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

The following table sets forth as of February 15, 2013 the beneficial ownership of common units of HEP held by:

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

The percentage of common units noted below is based on 56,782,048 common units outstanding as of February 15, 2013. All unit amounts have been adjusted to reflect a two-for-one unit split that occurred on January 16, 2013. Unless otherwise indicated, the address for each unitholder shall be c/o Holly Energy Partners, L.P., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

Name of Beneficial Owner	Common Units	Percentage of Outstanding Common Units
HollyFrontier Corporation (1)	24,255,030	44%
Tortoise Capital Advisors, L.L.C. (2)	4,533,374	8%
SteelPath Fund Advisors, LLC (3)	3,040,290	5.4%
Matthew P. Clifton (4)	250,957	*
Bruce R. Shaw (4)	19,240	*
Douglas S. Aron (5)	2,840	*
Mark T. Cunningham (4)	26,322	*
Michael C. Jennings	6,000	*
P. Dean Ridenour (6)	66,140	*
Charles M. Darling, IV (6)(7)	42,772	*

William J. Gray (6)	18,570	*
Jerry W. Pinkerton (6)	21,772	*
William P. Stengel (6)(8)	17,556	*
James G. Townsend (6)	15,756	*
All directors and executive officers as group (13 persons) (9)	508,787	*

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* Less than 1%

(1) HollyFrontier Corporation directly holds 145,006 common units over which it has sole voting and dispositive power and 24,110,024 common units over which it has shared voting and dispositive power. The 24,110,024 common units over which HollyFrontier Corporation has shared voting and dispositive power are held as follows: Holly Logistics Limited LLC directly holds 21,615,230 common units; HollyFrontier Holdings LLC directly holds 2,059,800 common units; Navajo Pipeline Co., L.P. directly holds 254,880 common units; and other wholly-owned subsidiaries of HollyFrontier Corporation directly own 180,114 common units. HollyFrontier Corporation is the ultimate parent company of each such entity and may therefore be deemed to beneficially own the units held by each such entity. HollyFrontier Corporation files information with or furnishes information to, the Securities and Exchange Commission pursuant to the information requirements of the Exchange Act. The percentage of outstanding common units owned includes a 2% general partner interest held by HEP Logistics Holdings, L.P. which is HEP's general partner and an indirect wholly-owned subsidiary of HollyFrontier Corporation. The address of HollyFrontier Corporation is 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

(2) Tortoise Capital Advisors, L.L.C. filed with the SEC a Schedule 13G/A on February 12, 2013. Based on this Schedule 13G/A, Tortoise Capital Advisors, L.L.C. reported that as of December 31, 2012, it had sole voting power and sole dispositive power with respect to zero units, shared voting power with respect to 2,190,661 units, shared dispositive power with respect to 2,266,687 units and that the aggregate amount of units it beneficially owns equals 8% of our common units outstanding. We believe that the unit totals included in this Schedule 13G/A have not been adjusted to reflect our two-for-one unit split that occurred on January 16, 2013, which we have given effect to in the table above. The address of Tortoise Capital Advisors, L.L.C. is 11550 Ash St., Suite 300, Leawood, KS 66211.

(3) SteelPath Fund Advisors, LLC filed with the SEC a Schedule 13G, dated February 13, 2012. Based on this Schedule 13G, SteelPath Fund Advisors, LLC has shared voting power and shared dispositive power with respect to 1,520,145 units. The units reported in the table above for SteelPath Fund Advisors, LLC give effect to our two-for-one unit split that occurred on January 16, 2013. The address of SteelPath Fund Advisors, LLC is 2100 McKinney Ave., Suite 1401, Dallas, TX 75201.

(4) The number reported includes restricted units for which the executive has sole voting power but no dispositive power, as follows: Mr. Clifton (22,872 units), Mr. Shaw (1,048 units), and Mr. Cunningham (7,458 units). The number does not include performance units held by Mr. Clifton.

(5) Includes 420 common units held by Mr. Aron as custodian for his son in an account under the Uniform Transfer to Minors Act and 420 common units held by Mr. Aron as custodian for his daughter in an account under the Uniform Transfer to Minors Act. Mr. Aron disclaims beneficial ownership of these common units.

(6) The number reported includes 2,252 restricted units for which the non-management director has sole voting power but no dispositive power.

(7) Mr. Darling is an owner and general manager of DQ Holdings, L.L.C. The number reported includes 22,400 common units owned by DQ Holdings, L.L.C. for which Mr. Darling has shared voting and dispositive power. Mr. Darling disclaims beneficial ownership as to the common units held by DQ Holdings, L.L.C. except to the extent of his pecuniary interest therein.

(8) The number reported includes 1,000 common units owned by Mr. Stengel's spouse for which Mr. Stengel shares voting and disposition power. Mr. Stengel disclaims beneficial ownership as to the common units owned by his spouse.

(9) The number reported includes 32,382 restricted units held by executive officers for which they have sole voting power but no dispositive power and 13,512 restricted units held by non-management directors for which they have sole voting power but no dispositive power. The number reported also includes 22,400 common units as to which Mr. Darling disclaims beneficial ownership, except to the extent of his pecuniary interest therein, 1,000 common

units for which Mr. Stengel disclaims beneficial ownership, 840 common units for which Mr. Aron disclaims beneficial ownership, and 4,000 common units for which Ms. Denise McWatters, an executive officer of HLS, disclaims beneficial ownership.

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Equity Compensation Plan Table

The following table summarizes information about our equity compensation plans as of December 31, 2012:

Plan Category (1)	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders (2)	81,747 (3)	—	1,833,024
Total	81,747		1,833,024

(1) All stock-based compensation plans are described in Note 7 to our consolidated financial statements for the fiscal year ended December 31, 2012.

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

(3) Represents units subject to performance units granted to Mr. Clifton under the Long-Term Incentive Plan in 2010, 2011 and 2012 assuming a maximum payout level of 150% at the time of vesting. If the performance units granted to Mr. Clifton in 2010, 2011 and 2012 are paid at the threshold payout level of 100%, 54,498 units would be issued upon the vesting of such performance units.

For more information about our Long-Term Incentive Plan, which did not, at the time of its initial adoption, require approval by our limited partners, refer to Item 11, “Executive Compensation - Overview of 2012 Executive Compensation Components and Decisions - Long-Term Incentive Equity Compensation.”

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

Our general partner and its affiliates own 24,255,030 of our common units representing a 42% limited partner interest in us. In addition, the general partner owns a 2% general partner interest in us. Transactions with our general partner are discussed later in this section.

DISTRIBUTIONS AND PAYMENTS TO THE GENERAL PARTNER AND ITS AFFILIATES

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

Operational stage

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Distributions of available cash to our general partner and its affiliates	We generally make cash distributions 98% to the unitholders, including our general partner and its affiliates as the holders of an aggregate of 24,255,030 of the common units and 2% to the general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner is entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.
Payments to our general partner and its affiliates	We pay HFC or its affiliates an administrative fee, currently $2.3 million per year, for the provision of various general and administrative services for our benefit. The administrative fee may increase if we make an acquisition that requires an increase in the level of general and administrative services that we receive from HFC or its affiliates. In addition, the general partner is entitled to reimbursement for all expenses it incurs on our behalf, including other general and administrative expenses. These reimbursable expenses include the salaries and the cost of employee benefits of employees of HLS who provide services to us. Please read “Omnibus Agreement” below. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

OMNIBUS AGREEMENT

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

- our obligation to pay HFC an annual administrative fee, currently in the amount of $2.3 million, for the provision by HFC of certain general and administrative services;
- HFC’s and its affiliates’ agreement not to compete with us under certain circumstances and our right to notice of, and right of first offer to purchase, certain logistics assets constructed by HFC and acquired as part of an acquisition by HFC of refining assets;
- an indemnity by HFC for certain potential environmental liabilities;
- our obligation to indemnify HFC for environmental liabilities related to our assets existing on the date of our initial public offering to the extent HFC is not required to indemnify us; and
- HFC’s right of first refusal to purchase our assets that serve HFC’s refineries.

Payment of general and administrative services fee

Under the Omnibus Agreement we pay HFC an annual administrative fee, currently in the amount of $2.3 million, for the provision of various general and administrative services for our benefit. Our general partner may agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses.

The $2.3 million fee includes expenses incurred by HFC and its affiliates to perform centralized corporate functions, such as legal, accounting, treasury, information technology and other corporate services, including the administration of employee benefit plans. The fee does not include salaries of pipeline and terminal personnel or other employees of HLS who perform services for us or the cost of their employee benefits, such as 401(k), pension, and health insurance benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct general and administrative expenses they incur on our behalf.

Noncompetition

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

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

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

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

Indemnification

Under the Omnibus Agreement, certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC and occurring or existing prior to the date of such transfers. The Omnibus Agreement provides environmental indemnification with respect to certain transferred assets of up to $15 million through 2021, plus additional indemnification of $2.5 million through 2015 and up to $7.5 million through 2023. HFC's indemnification obligations under the Omnibus Agreement do not apply to (i) the Tulsa west loading racks acquired in August 2009, (ii) the 16-inch intermediate pipeline acquired in June 2009, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, (v) the logistics and storage assets acquired from Sinclair in December 2009, (vi) the Tulsa east storage tanks and loading racks acquired in March 2010 or (vii) the UNEV Pipeline. For the Tulsa loading racks acquired from HFC in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009, HFC agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of these assets. Additionally, HFC agreed to indemnify us for any liabilities arising from its operation of our loading racks located at HFC's Tulsa refinery west facility.

We have indemnified HFC and its affiliates against environmental liabilities related to events that occur on our assets after the date we acquired such asset.

Right of first refusal to purchase our assets

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

PIPELINE AND TERMINAL, TANKAGE AND THROUGHPUT AGREEMENTS

We serve HFC’s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 2019 to 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (“PPI”) or the Federal Energy Regulatory Commission (“FERC”) index. Additionally, such agreements require HFC to reimburse us for certain costs. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 million.

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

SUMMARY OF TRANSACTIONS WITH HFC

- UNEV Pipeline Interest Acquisition - On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units. As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest).

- Legacy Frontier Tankage and Terminal Transaction – On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC’s El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of Promissory Notes with an aggregate principal amount of $150 million and 7,615,230 of our common units. We repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. We repaid the remaining $72.9 million balance in March 2012.

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- Tulsa East / Lovington Storage Asset Transaction - On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million located at HFC's Tulsa refinery east facility and an asphalt loading rack facility located at HFC's Navajo refinery Lovington facility.

- See "2012 Acquisition," "2011 Acquisition" and "2010 Acquisitions" under Item 1, "Business" of this Annual Report on Form 10-K for additional information on these acquisitions from HFC.

- Revenues received from HFC were $245.6 million, $168.3 million and $146.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

- HFC charged us for general and administrative services under the Omnibus Agreement of $2.3 million for each of the years ended December 31, 2012, 2011 and 2010, respectively.

- We reimbursed HFC for costs of employees supporting our operations of $31.1 million, $21.4 million and $18.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

- HFC reimbursed us $13.4 million, $11.9 million and $3.7 million for certain reimbursable costs and capital projects for the years ended December 31, 2012, 2011 and 2010, respectively.

- We distributed $64.0 million, $40.6 million and $35.9 million for the years ended December 31, 2012, 2011 and 2010, respectively, to HFC as regular distributions on its common units, subordinated units and general partner interest, including general partner incentive distributions.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

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

There are no transactions disclosed in this Item 13 entered into since January 1, 2012 that were not required to be reviewed, ratified or approved pursuant to our Code of Business Conduct and Ethics or with respect to which our policies and procedures with respect to conflicts of interest were not followed.

See Item 10 for a discussion of "Director Independence."

Item 14. Principal Accounting Fees and Services

The audit committee of the board of directors of HLS selected Ernst & Young LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of the HEP for the 2012 calendar year.
Fees paid to Ernst & Young LLP for 2012 and 2011 are as follows:

	2012	2011
Audit Fees [1]	$762,000	$662,000
Tax Fees	117,000	176,000
Total	$879,000	$838,000

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

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

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

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

(3) Exhibits
See Index to Exhibits on pages 132 to 138.

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HOLLY ENERGY PARTNERS, L.P.
SIGNATURES

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

HOLLY ENERGY PARTNERS, L.P.
(Registrant)

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

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

Date: February 27, 2013	/s/ Matthew P. Clifton Matthew P. Clifton Chairman of the Board of Directors and Chief Executive Officer

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

Date: February 27, 2013	/s/ Matthew P. Clifton Matthew P. Clifton Chief Executive Officer (Principal Executive Officer)
Date: February 27, 2013	/s/ Bruce R. Shaw Bruce R. Shaw President
Date: February 27, 2013	/s/ Douglas S. Aron Douglas S. Aron Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 27, 2013	/s/ Scott C. Surplus Scott C. Surplus Vice President and Controller (Principal Accounting Officer)
Date: February 27, 2013	/s/ Charles M. Darling, IV Charles M. Darling, IV Director
Date: February 27, 2013	/s/ William J. Gray William J. Gray Director

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Date: February 27, 2013	/s/ Michael C. Jennings Michael C. Jennings Director
Date: February 27, 2013	/s/ Jerry W. Pinkerton Jerry W. Pinkerton Director
Date: February 27, 2013	/s/ P. Dean Ridenour P. Dean Ridenour Director
Date: February 27, 2013	/s/ William P. Stengel William P. Stengel Director
Date: February 27, 2013	/s/ James G. Townsend James G. Townsend Director

Exhibit Index

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated February 25, 2008, between Holly Corporation, Navajo Pipeline Co., L.P., Navajo Refining Company, L.L.C., Woods Cross Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C. and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 2.1 of Registrant's Form 8-K Current Report dated February 27, 2008, File No. 001-32225).
2.2	Asset Sale and Purchase Agreement, dated October 19, 2009, between Holly Refining & Marketing - Tulsa LLC, HEP Tulsa LLC and Sinclair Tulsa Refining Company (incorporated by reference to Exhibit 2.1 of Registrant's Form 8-K Current Report dated October 21, 2009, File No. 001-32225).
3.1	First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 001-32225).
3.2	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated February 28, 2005 (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K Current Report dated February 28, 2005, File No. 001-32225).
3.3	Amendment No. 2 to the First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated July 6, 2005 (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K Current Report dated July 6, 2005, File No. 001-32225).
3.4	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated April 11, 2008 (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K Current Report dated April 15, 2008, File No. 001-32225).
3.5	Limited Partial Waiver of Incentive Distribution Rights under the First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated July 12, 2012 (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K Current Report dated July 12, 2012, File No. 001-32225).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated January 16, 2013 (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K Current Report dated January 16, 2013, File No. 001-32225).
3.7	First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners - Operating Company, L.P. (incorporated by reference to Exhibit 3.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 001-32225).
3.8	First Amended and Restated Agreement of Limited Partnership of HEP Logistics Holdings, L.P. (incorporated by reference to Exhibit 3.4 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 001-32225).
3.9	First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 3.5 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 001-32225).
3.10	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C., dated April 27, 2011 (incorporated by reference to Exhibit 3.1 of Registrant's Form 8-K Current Report dated May 3, 2011, File No. 001-32225).
3.11	First Amended and Restated Limited Liability Company Agreement of HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 3.6 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 001-32225).
4.1	Indenture, dated February 28, 2005, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the Guarantors and U.S. Bank National Association, providing for the issuance of 6.25% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K Current Report dated February 28, 2005, File No. 001-32225).

4.2	Form of 6.25% Senior Note Due 2015 (included as Exhibit A to the Indenture filed as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.2 of Registrant's Form 8-K Current Report dated February 28, 2005, File No. 001-32225).
4.3	Form of Notation of Guarantee (included as Exhibit E to the Indenture filed as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.3 of Registrant's Form 8-K Current Report dated February 28, 2005, File No. 001-32225).
4.4	First Supplemental Indenture, dated March 10, 2005, among HEP Fin-Tex/Trust-River, L.P., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended March 31, 2005, File No. 001-32225).
4.5	Second Supplemental Indenture, dated April 27, 2005, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended March 31, 2005, File No. 001-32225).

4.6	Third Supplemental Indenture, dated June 11, 2009, among Lovington-Artesia, L.L.C., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 001-32225).
4.7	Fourth Supplemental Indenture, dated June 29, 2009, among HEP SLC, LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 001-32225).
4.8	Fifth Supplemental Indenture, dated July 13, 2009, among HEP Tulsa LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 001-32225).
4.9	Sixth Supplemental Indenture, dated December 15, 2009, among Roadrunner Pipeline, L.L.C., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2009, File No. 001-32225).
4.10	Seventh Supplemental Indenture, dated April 14, 2010, among Holly Energy Storage- Tulsa LLC, Holly Energy Storage-Lovington LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).
4.11	Eighth Supplemental Indenture, dated June 4, 2010, among HEP Operations LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).
4.12	Ninth Supplemental Indenture, dated December 29, 2011, among Cheyenne Logistics LLC, El Dorado Logistics LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.12 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2011, File No. 001-32225).
4.13	Tenth Supplemental Indenture, dated March 12, 2012, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant's Form 8-K Current Report dated March 12, 2012, File No. 001-32225).
4.14	Indenture, dated March 10, 2010, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association, providing for the issuance of 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K Current Report dated March 11, 2010, File No. 001-32225).
4.15	First Supplemental Indenture, dated April 14, 2010, among Holly Energy Storage-Tulsa LLC, Holly Energy Storage-Lovington LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).
4.16	Second Supplemental Indenture, dated June 4, 2010, among HEP Operations LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).
4.17	Third Supplemental Indenture, dated December 29, 2011, among Cheyenne Logistics LLC, El Dorado Logistics LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.16 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2011, File No. 001-32225)
4.18	Fourth Supplemental Indenture, dated August 6, 2012, among HEP UNEV Holdings LLC, HEP UNEV Pipeline LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S.

	Bank National Association (incorporated by reference to Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2012, File No. 001-32225).
4.19	Indenture, dated March 12, 2012, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association, providing for the issuance of 6.50% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K Current Report dated March 12, 2012, File No. 001-32225).
4.20	First Supplemental Indenture, dated August 6, 2012, among HEP UNEV Holdings LLC, HEP UNEV Pipeline LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2012, File No. 001-32225).
10.1	Option Agreement, dated January 31, 2008, among Holly Corporation, Holly Energy Partners, L.P. and certain of their respective subsidiaries (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated February 5, 2008, File No. 001-32225).
10.2	First Amendment to Option Agreement, dated February 11, 2010, among Holly Corporation, Holly Energy Partners, L.P. and certain of their respective subsidiaries (incorporated by reference to Exhibit 10.2 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).

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10.3	Termination of Option Agreement, dated July 12, 2012, between HollyFrontier Corporation (as successor-in-interest to Holly Corporation), Holly Energy Partners, L.P. and certain of their respective subsidiaries (incorporated by reference to Exhibit 10.8 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, File No. 001-32225).
10.4	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.5	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.3 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.6	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.4 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.7	Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.5 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.8	Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.6 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.9	Fee and Leasehold Deed of Trust, dated February 29, 2008, by HEP Woods Cross, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.7 of Registrant's Form 8-K Current Report dated March 6, 2008, File No. 001-32225).
10.10	Second Amended and Second Amended and Restated Credit Agreement, dated February 14, 2011, among Holly Energy Partners - Operating, L.P., Wells Fargo Bank, N.A., as administrative agent and issuing bank, Union Bank, N.A., as syndication agent, BBVA Compass Bank and U.S. Bank N.A., as co-documentation agents and certain other lenders (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated February 18, 2011, File No. 001-32225).
10.11	Agreement and Amendment No. 1 to Second Amended and Restated Credit Agreement, dated February 3, 2012, among Holly Energy Partners - Operating, L.P., certain of its subsidiaries acting as guarantors, Wells Fargo Bank, N.A., as administrative agent, an issuing bank and a lender and certain other lenders party thereto (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated February 9, 2012, File No. 001-32225).
10.12	Agreement and Amendment No. 2 to Second Amended and Restated Credit Agreement, dated June 29, 2012, among Holly Energy Partners - Operating, L.P., certain of its subsidiaries acting as guarantors, Wells Fargo Bank, N.A., as administrative agent, an issuing bank and lender and certain other lenders party thereto (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated June 29, 2012, File No. 001-32225).
10.13	Pipelines and Terminals Agreement, dated February 28, 2005, among the Holly Energy Partners, L.P. and Alon USA, LP (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated February 28, 2005, File No. 001-32225).
10.14	First Amendment of Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.4 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).
10.15	Second Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated March 1, 2011 (incorporated by reference to Exhibit 10.5 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).
10.16	Third Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 6, 2011 (incorporated by reference to Exhibit 10.6 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).

10.17	First Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated January 25, 2005 (incorporated by reference to Exhibit 10.1 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).
10.18	Second Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 29, 2007 (incorporated by reference to Exhibit 10.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).
10.19	Third Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated April 1, 2011 (incorporated by reference to Exhibit 10.3 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 00001-32225).
10.20	Corrected Version dated October 10, 2007 of Amendment and Supplement to Pipeline Lease Agreement effective August 31, 2007 between HEP Pipeline Assets, Limited Partnership and Alon USA, LP (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated October 16, 2007, File No. 001-32225)

10.21	LLC Interest Purchase Agreement, dated June 1, 2009, among Holly Corporation, Navajo Pipeline Co., L.P. and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated June 5, 2009, File No. 001-32225).
10.22	Amended and Restated Intermediate Pipelines Agreement, dated June 1, 2009, among Holly Corporation, Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C., Lovington-Artesia, L.L.C., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C. and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated June 5, 2009, File No. 001-32225).
10.23	Amendment to Amended and Restated Intermediate Pipelines Agreement, dated December 9, 2010, among Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C., Lovington-Artesia, L.L.C., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C. and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.23 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.24	Assignment and Assumption Agreement (Amended and Restated Intermediate Pipelines Agreement), effective January 1, 2011, between Navajo Refining Company, L.L.C. and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.24 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.25	Mortgage, Line of Credit Mortgage and Deed of Trust, dated June 1, 2009, by Lovington-Artesia, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.4 of Registrant's Form 8-K Current Report dated June 5, 2009, File No. 001-32225).
10.26	Asset Purchase Agreement, dated August 1, 2009, between Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated August 6, 2009, File No. 001-32225).
10.27	Tulsa Equipment and Throughput Agreement, dated August 1, 2009, between Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.3 of Registrant's Form 8-K Current Report dated August 6, 2009, File No. 001-32225).
10.28	Amendment to Tulsa Equipment and Throughput Agreement, dated December 9, 2010, among Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.28 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.29	Assignment and Assumption Agreement (Tulsa Equipment and Throughput Agreement), effective January 1, 2011, between Holly Refining & Marketing - Tulsa, LLC and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.29 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.30	Tulsa Purchase Option Agreement, dated August 1, 2009, between Holly Refining & Marketing - Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.4 of Registrant's Form 8-K Current Report dated August 6, 2009, File No. 001-32225).
10.31	LLC Interest Purchase Agreement, dated December 1, 2009, among Holly Corporation, Navajo Pipeline Co., L.P. and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.32	Asset Purchase Agreement, dated December 1, 2009, between Holly Corporation, Navajo Pipeline Co., L.P. and HEP Pipeline, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.33	Pipeline Throughput Agreement, dated December 1, 2009, between Navajo Refining Company, L.L.C. and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.4 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.34	Assignment and Assumption Agreement (Pipeline Throughput Agreement (Roadrunner)), effective January 1, 2011, between Navajo Refining Company, L.L.C. and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.34 of Registrant's Annual Report on Form 10-K for its fiscal year

	ended December 31, 2010, File No. 001-32225).
10.35	Form of Mortgage, Line of Credit Mortgage and Deed of Trust, to be entered into by HEP Pipeline L.L.C. and Holly Energy Partners, L.P. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.5 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.36	Form of Mortgage and Deed of Trust, to be entered into by Roadrunner Pipeline, L.L.C for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.6 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.37	Form of Mortgage, Line of Credit Mortgage and Deed of Trust, to be entered into by Roadrunner Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.7 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).

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10.38	Amended and Restated Crude Pipelines and Tankage Agreement, entered into on December 1, 2009, effective January 1, 2009, among Navajo Refining Company, L.L.C., Holly Refining & Marketing Company - Woods Cross, Holly Refining & Marketing Company, Holly Energy Partners - Operating, L.P., HEP Pipeline, LLC and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 10.8 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.39	Letter Agreement, dated October 14, 2011, regarding the Amended and Restated Crude Pipelines and Tankage Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.3 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2011, File No. 001-32225)
10.40	Amended and Restated Refined Product Pipelines and Terminals Agreement, entered into on December 1, 2009, effective February 1, 2009, among Navajo Refining Company, L.L.C., Holly Refining & Marketing Company - Woods Cross, Holly Energy Partners - Operating, L.P., HEP Pipeline Assets, Limited Partnership, HEP Pipeline, LLC, HEP Refining Assets, L.P., HEP Refining, L.L.C., HEP Mountain Home, L.L.C. and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 10.9 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.41	Assignment and Assumption Agreement (Amended and Restated Refined Product Pipelines and Terminals Agreement), effective January 1, 2011, among Navajo Refining Company, L.L.C., Holly Refining & Marketing-Woods Cross and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.40 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.42	Indemnification Proceeds and Payments Allocation Agreement, dated December 1, 2009, between Holly Refining & Marketing - Tulsa, LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated December 7, 2009, File No. 001-32225).
10.43	LLC Interest Purchase Agreement, dated March 31, 2010, among Holly Corporation, Holly Refining & Marketing-Tulsa, LLC, Lea Refining Company, HEP Tulsa LLC and HEP Refining, L.L.C. (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated April 6, 2010, File No. 001-32225).
10.44	Second Amended and Restated Pipelines, Tankage and Loading Rack Throughput Agreement, dated August 31, 2011, between Holly Refining and Marketing-Tulsa LLC, HEP Tulsa LLC and Holly Energy Storage - Tulsa LLC (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated September 1, 2011, File No. 001-32225).
10.45	Amendment to First Amended and Restated Pipelines, Tankage and Loading Rack Throughput Agreement (Tulsa East), dated June 11, 2010, between Holly Refining & Marketing-Tulsa LLC, HEP Tulsa LLC and Holly Energy Storage-Tulsa LLC (incorporated by reference to Exhibit 10.1 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).
10.46	Assignment and Assumption Agreement (First Amended and Restated Pipelines, Tankage and Loading Rack Throughput Agreement (Tulsa East)), effective January 1, 2011, between Holly Refining & Marketing-Tulsa, LLC and Holly Refining & Marketing Company LLC (incorporated by reference to Exhibit 10.45 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 001-32225).
10.47	Loading Rack Throughput Agreement (Lovington), dated March 31, 2010, between Navajo Refining Company, L.L.C. and Holly Energy Storage-Lovington LLC (incorporated by reference to Exhibit 10.3 of Registrant's Form 8-K Current Report dated April 6, 2010, File No. 001-32225).
10.48	First Amended and Restated Lease and Access Agreement (East Tulsa), dated March 31, 2010, between Holly Refining & Marketing-Tulsa, LLC, HEP Tulsa LLC and Holly Energy Storage-Tulsa LLC (incorporated by reference to Exhibit 10.5 of Registrant's Form 8-K Current Report dated April 6, 2010, File No. 001-32225).
10.49	Pipeline Systems Operating Agreement, dated February 8, 2010, among Navajo Refining Company, L.L.C., Lea Refining Company, Woods Cross Refining Company, L.L.C., Holly Refining & Marketing - Tulsa LLC and Holly Energy Partners-Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant's

	Form 8-K Current Report dated February 9, 2010, File No. 001-32225).
10.50	First Amendment to Pipeline Systems Operating Agreement, dated March 31, 2010, among Navajo Refining Company, L.L.C., Lea Refining Company, Woods Cross Refining Company, L.L.C., Holly Refining & Marketing-Tulsa, LLC and Holly Energy Partners-Operating, L.P. (incorporated by reference to Exhibit 10.6 of Registrant's Form 8-K Current Report dated April 6, 2010, File No. 001-32225).
10.51	Tulsa Refinery Interconnects Term Sheet dated August 9, 2010 (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated August 11, 2010, File No. 001-32225).
10.52	Amendment to Tulsa Refinery Interconnects Term Sheet dated December 31, 2010 (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated January 6, 2011, File No. 001-32225).
10.53	Second Amendment to Tulsa Refinery Interconnects Term Sheet dated March 31, 2011 (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated March 31, 2011, File No. 001-32225).
10.54	LLC Interest Purchase Agreement, dated November 9, 2011, among HollyFrontier Corporation, Frontier Refining LLC, Frontier El Dorado Refining LLC, Holly Energy Partners - Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated November 10, 2011, File No. 001-32225).

10.55	First Amended and Restated Tankage, Loading Rack and Crude Oil Receiving Throughput Agreement (Cheyenne), dated January 11, 2012,effective November 1, 2011, between Frontier Refining LLC and Cheyenne Logistics LLC (incorporated by reference to exhibit 10.54 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2011, File No. 001-32225).
10.56	First Amended and Restated Pipeline Delivery, Tankage and Loading Rack Throughput Agreement (El Dorado), dated January 11, 2012 effective November 1, 2011, between Frontier El Dorado Refining LLC and El Dorado Logistics LLC (incorporated by reference to Exhibit 10.55 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2011, File No. 001-32225).
10.57	Seventh Amended and Restated Omnibus Agreement, dated July 12, 2012, among HollyFrontier Corporation, Holly Energy Partners, L.P. and certain of their respective subsidiaries (incorporated by reference to Exhibit 10.6 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2012, File No. 001-32225).
10.58	Lease and Access Agreement (Cheyenne), dated November 9, 2011, between Frontier Refining LLC and Cheyenne Logistics LLC (incorporated by reference to Exhibit 10.5 of Registrant's Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.59	Lease and Access Agreement (El Dorado), dated November 9, 2011, between Frontier El Dorado Refining LLC and El Dorado Logistics LLC (incorporated by reference to Exhibit 10.6 of Registrant's Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.60	Form of Senior Unsecured Note in favor of Frontier Refining LLC (incorporated by reference to Exhibit 10.7 of Registrant's Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.61	Form of Senior Unsecured Note in favor of Frontier El Dorado Refining LLC (incorporated by reference to Exhibit 10.8 of Registrant's Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.62	Mortgage, dated January 31, 2012, by Cheyenne Logistics LLC for the benefit of HollyFrontier Corporation (incorporated by reference to Exhibit 10.61 of Registrant's Annual Report on Form 10-K for its fiscal year ended December 31, 2011, File No. 001-32225).
10.63	Mortgage and Deed of Trust, dated January 31, 2012, by El Dorado Logistics LLC for the benefit of HollyFrontier Corporation (incorporated by reference to Exhibit 10.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended March 31, 2012, File No. 001-32225).
10.64	Purchase Agreement, dated February 28, 2012, among Holly Energy Partners, L.P., Holly Energy Finance Corp., each of the guarantors party thereto and Citigroup Global Markets, Inc., UBS Securities LLC and Wells Fargo Securities, LLC, as representatives of the initial purchasers named therein (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated March 5, 2012, File No. 001-32225).
10.65	LLC Interest Purchase Agreement, dated July 12, 2012, among HollyFrontier Corporation, Holly Energy Partners, L.P and HEP UNEV Holdings LLC (incorporated by reference to Exhibit 10.5 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, File No. 001-32225).
10.66	Amended and Restated Limited Liability Company Agreement of HEP UNEV Holdings LLC, dated July 12, 2012, among HEP UNEV Holdings LLC, Holly Energy Partners, L.P. and HollyFrontier Holdings LLC (incorporated by reference to Exhibit 10.7 of Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, File No. 001-32225).
10.67+	Holly Energy Partners, L.P. Long-Term Incentive Plan (as amended and restated effective February 10, 2012) (incorporated by reference to Exhibit 10.1 of Registrant's Form 8-K Current Report dated April 30, 2012, File No. 001-32225).
10.68+*	First Amendment to the Holly Energy Partners, L.P. Long-Term Incentive Plan, effective January 16, 2013.
10.69+	Form of Director Restricted Unit Agreement (incorporated by reference to Exhibit 10.1 of Registrant's Current Report on Form 8-K dated November 15, 2004, File No. 001-32225).
10.70+	Form of Employee Restricted Unit Agreement (incorporated by reference to Exhibit 10.2 of Registrant's Current Report on Form 8-K dated November 15, 2004, File No. 001-32225).
10.71+	

	Form of Restricted Unit Agreement (without Performance Vesting) (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated August 4, 2005, File No. 001-32225).
10.72+	Form of Holly Energy Partners, L.P. Indemnification Agreement to be entered into with officers and directors of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant's Form 8-K Current Report dated February 18, 2011, File No. 001-32225).
10.73+*	HollyFrontier Corporation Executive Nonqualified Deferred Compensation Plan.
10.74+	Holly Energy Partners, L.P. Change in Control Agreement Policy (incorporated by reference to Exhibit 10.3 of Registrant's Form 8-K Current Report dated February 18, 2011, File No. 001-32225).
10.75+	Form of Change in Control Agreement (incorporated by reference to Exhibit 10.4 of Registrant's Form 8-K Current Report dated February 18, 2011, File No. 001-32225).
10.76+	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.2 of Registrant's Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 001-32225).

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10.77+*	Amended and Restated Annual Incentive Plan.
21.1*	Subsidiaries of Registrant.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
101++	The following financial information from Holly Energy Partners, L.P.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2012, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Comprehensive Income, (iv) Consolidated Statements of Cash Flows, (v) Consolidated Statement of Partners' Equity, and (vi) Notes to Consolidated Financial Statements.

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