HOLLY ENERGY PARTNERS LP
Form 10-K
February 15, 2008

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007
Commission File Number 1-32225
HOLLY ENERGY PARTNERS, L.P.
Formed under the laws of the State of Delaware
I.R.S. Employer Identification No. 20-0833098
100 Crescent Court, Suite 1600
Dallas, Texas 75201-6915
Telephone Number: (214) 871-3555
Securities registered pursuant to Section 12(b) of the Act:
Common Limited Partner Units
Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes o No þ

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 o No þ

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 þ No o

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 the Form 10-K or any amendments to the Form 10-K. þ

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller Reporting Company o

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $412 million on June 30, 2007, based on the last sales price as quoted on the New York Stock Exchange.

The number of the registrant s outstanding common limited partners units at February 13, 2008 was 8,170,000.

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 an Analysis of Financial Condition and Results of Operations in Item 7, are forward-looking statements. These statements are based on management s belief and assumptions 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 believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that our expectations will prove to be correct. Therefore, actual outcomes and results could differ materially from what is expressed, implied or forecast in these statements. Any differences could be caused by a number of factors including, but not limited to:

- Risks and uncertainties with respect to the actual quantities of petroleum products shipped on our pipelines and/or terminalled in our terminals;
- The economic viability of Holly 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 pending or contemplated acquisitions;
- The availability and cost of our 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, operations 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, in conjunction with the forward-looking statements included in the Form 10-K that are referred to above. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements set forth in this Form 10-K under Risk Factors in Item 1A. All forward-looking statements included in this Form 10-K and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INDEX TO DEFINED TERMS AND NAMES

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

Terms used in the financial statements and footnotes are as defined therein.

Item 1. Business

OVERVIEW

Holly Energy Partners, L.P. (HEP) is a Delaware limited partnership formed by Holly Corporation and is the successor to Navajo Pipeline Co., L.P. (Predecessor) (NPL). We operate a system of refined product pipelines and distribution terminals primarily in west Texas, New Mexico, Utah and Arizona. We maintain our principal corporate offices at 100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915. 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. Additionally available on our website are copies of our Corporate 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. Holly refers to Holly Corporation and its subsidiaries, other than HEP and its subsidiaries and other than Holly Logistic Services, L.L.C. (HLS), a subsidiary of Holly Corporation that is the general partner of the general partner of HEP and manages HEP.

HEP acquired substantially all of the refined product pipeline and terminalling assets that support Holly s refining and marketing operations in west Texas, New Mexico, Utah and Arizona and a 70% interest in Rio Grande Pipeline Company (Rio Grande) upon the closing of its initial public offering in July 2004.

On February 28, 2005, we acquired from Alon USA, Inc. and several of its wholly-owned subsidiaries (collectively, Alon) four refined products pipelines, an associated tank farm and two refined products terminals located primarily in Texas. On July 8, 2005, we acquired Holly s two 65-mile parallel intermediate feedstock pipelines (the Intermediate Pipelines) which connect its Lovington, New Mexico and Artesia, New Mexico refining facilities (collectively, the Navajo Refinery).

We generate revenues by charging tariffs for transporting petroleum products through our pipelines and by charging fees for terminalling refined products and other hydrocarbons, and storing and providing other services at our terminals. We do not take ownership of products that we transport or terminal; therefore, we are not directly exposed to changes in commodity prices. We serve Holly s refineries in New Mexico and Utah under two 15-year pipeline and terminal agreements with Holly. One of these agreements relates to the pipelines and terminals contributed by Holly to us at the time of our initial public offering and expires in 2019 (Holly PTA). Our other agreement with Holly relates to the Intermediate Pipelines acquired from Holly in July 2005 and expires in 2020 (Holly IPA). We also serve Alon s Big Spring, Texas refinery (Big Spring Refinery) under the Alon Pipelines and Terminals Agreement expiring 2020 (Alon PTA). The substantial majority of our business is devoted to providing transportation and terminalling services to Holly. We operate our business as one business segment. Our assets include:

Pipelines:

- approximately 780 miles of refined product pipelines, including 340 miles of leased pipelines, that transport gasoline, diesel, and jet fuel principally from Holly s Navajo Refinery in New Mexico to its customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Colorado, 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;

- two parallel 65-mile pipelines that transport intermediate feedstocks and crude oil from Holly s Lovington, New Mexico refinery facilities to Holly s Artesia, New Mexico refinery facilities; and

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a 70% interest in Rio Grande, a joint venture that owns a 249-mile refined product pipeline that transports liquid petroleum gases (LPG) from west Texas to the Texas/Mexico border near El Paso for further transport into northern Mexico.

Refined Product Terminals:

four refined product terminals (one of which is 50% owned), located in El Paso, Texas; Moriarty and Bloomfield, New Mexico; and Tucson, Arizona, with an aggregate capacity of approximately 900,000 barrels, that are integrated with our refined product pipeline system that serves Holly 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 480,000 barrels, that are integrated with our refined product pipelines that serve Alon s Big Spring Refinery; and

two refined product truck loading racks, one located within Holly s Navajo Refinery that is permitted to load over 40,000 barrels per day (bpd) of light refined products, and one located within Holly s Woods Cross Refinery near Salt Lake City, Utah, that is permitted to load over 25,000 bpd of light refined products.

Agreements with Holly

Under the 15-year Holly PTA, Holly pays us fees to transport on our refined product pipelines or throughput in our terminals a volume of refined products that will produce a minimum level of revenue. This minimum revenue commitment will increase each year at a rate equal to the percentage change in the producer price index (PPI), but will not decrease as a result of a decrease in the PPI. Following the July 1, 2007 PPI adjustment, the volume commitments by Holly under the Holly PTA will produce a minimum of $39.6 million of revenue for the twelve months ending June 30, 2008. Holly pays the published tariff rates on the refined product pipelines and contractually agreed upon fees at the terminals. The tariffs adjust annually at a rate equal to the percentage change in the PPI. The terminal fees adjust annually based upon an index comprised of comparable fees posted by third parties. Holly s minimum revenue commitment applies only to the initial assets we acquired from Holly and may not be spread among assets we subsequently acquire. If Holly fails to meet its minimum revenue commitment in any quarter, it is required to pay us in cash the amount of any shortfall by the last day of the month following the end of the quarter. A shortfall payment may be applied as a credit in the following four quarters after Holly s minimum obligations are met.

In October 2007, we entered into an agreement with Holly that amends the Holly PTA under which we have agreed to expand our refined products pipeline system between Artesia, New Mexico and El Paso, Texas (the South System). The expansion of the South System will include replacing 85 miles of 8-inch pipe with 12-inch pipe, adding 150,000 barrels of refined product storage at our El Paso Terminal, improving existing pumps, adding a tie-in to the Kinder Morgan L.P. (Kinder Morgan) pipeline to Tucson and Phoenix, Arizona, and making related modifications. The cost of this project is estimated to be $48.3 million. Currently, we are expecting to complete this project by January 2009. The agreement also provides for a tariff increase, expected to be effective May 1, 2008, on Holly shipments on our refined product pipelines.

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

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right after we have made efforts to mitigate their effects to negotiate a monthly surcharge on Holly for the use of the terminals or to file for an increased tariff rate for use of the pipelines to cover Holly s pro rata portion of the cost of complying with these laws or regulations. In such instances, we will negotiate in good faith with Holly to agree on the level of the monthly surcharge or increased tariff rate.

Holly s obligations under this agreement may be proportionately reduced or suspended if Holly shuts down or materially reconfigures one of its refineries. Holly will be required to give at least twelve months advance notice of any long-term shutdown or material reconfiguration. Holly s obligations may also be temporarily suspended or terminated in certain circumstances.

Under certain provisions of an omnibus agreement that we entered with Holly in July 2004 and expires in 2019 (the Omnibus Agreement), we pay Holly an annual administrative fee for the provision by Holly or its affiliates of various general and administrative services to us. Initially, this fee was $2.0 million for each of the three years following the closing of our initial public offering. Effective July 1, 2007, the annual fee increased to $2.1 million in accordance with provisions under the agreement. This fee includes expenses incurred by Holly 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 pipeline and terminal personnel or other employees of HLS or the cost of their employee benefits, such as 401(k), pension and health insurance benefits, which are separately charged to us by Holly. We also reimburse Holly and its affiliates for direct expenses they incur on our behalf. In addition, we also pay for our own direct general and administrative costs, including costs relating to operating as a separate publicly held entity, such as costs for preparation of partners K-1 tax information, SEC filings, investor relations, directors compensation, directors and officers insurance and registrar and transfer agent fees. Under the Omnibus Agreement, Holly also agreed to indemnify us in an aggregate amount not to exceed $15.0 million for ten years after the closing of our initial public offering for any environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing prior to the closing date of our initial public offering.

Alon Transaction

On February 28, 2005, we acquired from Alon four refined products pipelines, an associated tank farm and two refined products terminals. These pipelines and terminals are located primarily in Texas and transport and terminal light refined products for Alon s refinery in Big Spring, Texas.

The total consideration paid for these pipeline and terminal assets was $120.0 million in cash and 937,500 of our Class B subordinated units which, subject to certain conditions, will convert into an equal number of common units on February 28, 2010. We financed the Alon transaction with a portion of the proceeds of our private offering of $150.0 million principal amount of 6.25% senior notes due 2015 (the Senior Notes). In connection with the Alon transaction, we entered into the Alon PTA. Under this agreement, Alon agreed to transport on our pipelines and throughput in our terminals a volume of refined products that would result in minimum revenue levels each year that will change annually based on changes in the PPI, but will not decrease below the initial $20.2 million annual amount. Following the March 1, 2007 PPI rate adjustment, Alon s total minimum commitment for the twelve months ending February 29, 2008 is $20.9 million. The agreed upon tariffs increase or decrease each year at a rate equal to the percentage change in the PPI, but not below the initial tariffs. Alon s minimum volume commitment was calculated based on 90% of Alon s then recent usage of these pipelines and terminals taking into account an expansion of Alon s Big Spring Refinery completed in February 2005. At revenue levels above 105% of the base revenue amount, as adjusted each year for changes in the PPI, Alon will receive an annual 50% discount on incremental revenues. Alon s obligations under the Alon PTA may be reduced or suspended under certain circumstances. We granted Alon a second mortgage on the pipelines and terminals acquired from Alon to secure certain of Alon s rights under the Alon PTA. Alon has a right of first refusal to purchase the pipelines and terminals if we decide to sell them in the future. Additionally, we entered into an environmental agreement expiring in 2015 with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon, whereby Alon will indemnify us subject to a $100,000 deductible and a $20.0 million maximum liability cap.

The consideration for the Alon pipeline and terminal assets was allocated to the individual assets acquired based on their estimated fair values. Fair values of the assets acquired were estimated using the cost, market and income approach methodologies. Under the cost approach, management determined the fair value of acquired tangible pipeline and terminal assets based on the estimated replacement cost of assets using current costs, adjusted for the effects of physical depreciation and physical deterioration. The fair value of acquired rights of way was determined using the market approach based on publicly available market data. The value of the transportation agreement was determined using the income approach, under which management estimated the net present value of the after-tax earnings attributable to the Alon PTA over a 30-year life (the 15-year initial term plus the expected 15 years of extension periods), plus the value of the tax benefit of amortization.

Holly Intermediate Pipelines Transaction

On July 8, 2005, we acquired pursuant to a definitive purchase agreement (the Purchase Agreement) Holly s Intermediate Pipelines which connect its Lovington, New Mexico and Artesia, New Mexico refining facilities. The total consideration was $81.5 million, which consisted of $77.7 million in cash, 70,000 common units of HEP and a capital account credit of $1.0 million to maintain Holly s existing general partner interest in the Partnership. We financed the cash portion of the consideration for the Intermediate Pipelines with the proceeds raised from (a) the private sale of 1,100,000 of our common units for $45.1 million to a limited number of institutional investors which closed simultaneously with the acquisition and (b) an additional $35.0 million in principal amount of our 6.25% senior notes due 2015. This acquisition was made pursuant to an option to purchase these pipelines granted by Holly to us at the time of our initial public offering in July 2004.

In connection with this transaction, we entered into an agreement with Holly to transport volumes of intermediate products on the Intermediate Pipelines that expires in 2020. Under the Holly IPA, Holly agreed to transport volumes of product that would result in initial minimum funds to us of $11.8 million each year that will change annually based on changes in the PPI but will not decrease as a result of a decrease in the PPI. Following the July 1, 2007 PPI adjustment, the volume commitments by Holly under the Holly IPA will result in minimum funds to us of $12.8 million for the twelve months ending June 30, 2008. Holly s minimum revenue commitment applies only to the Intermediate Pipelines, and Holly is not able to spread its minimum revenue commitment among pipeline assets HEP already owns or subsequently acquires. If Holly fails to meet its minimum revenue commitment in any quarter, it is required to pay us in cash the amount of any shortfall by the last day of the month following the end of the quarter. A shortfall payment may be applied as a credit in the following four quarters after Holly s minimum obligations are met. The Holly IPA may be extended by the mutual agreement of the parties.

If new laws or regulations are enacted that require us to make substantial and unanticipated capital expenditures with regard to the Intermediate Pipelines, we have the right to amend the tariff rates to recover our costs of complying with these new laws or regulations (including a reasonable rate of return). Under certain circumstances, either party may temporarily suspend its obligations under the Holly IPA. We granted Holly a second mortgage on the Intermediate Pipelines to secure certain of Holly s rights under the Holly IPA. Holly agreed to provide $2.5 million of additional indemnification above the initial $15.0 million of indemnification under the Omnibus Agreement that previously provided for environmental noncompliance and remediation liabilities occurring or existing before the closing date of the Purchase Agreement, bringing the total indemnification, expiring in 2020, provided to us from Holly to $17.5 million. Of this total, indemnification above $15.0 million relates solely to the Intermediate Pipelines.

As this transaction was among entities under common control, we recorded the acquired assets at Holly s historic book value of $6.8 million. The $71.9 million excess of the purchase price over the historic book value is recorded as a reduction to partners equity for financial accounting purposes.

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

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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, and 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, special projects may be approved. The funds allocated to 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.

In October 2007, we entered into an agreement with Holly that amends the Holly PTA under which we have agreed to expand our South System between Artesia, New Mexico and El Paso, Texas. The expansion of the South System will include replacing 85 miles of 8-inch pipe with 12-inch pipe, adding 150,000 barrels of refined product storage at our El Paso Terminal, improving existing pumps, adding a tie-in to the Kinder Morgan pipeline to Tucson and Phoenix, Arizona, and making related modifications. The cost of this project is estimated to be $48.3 million. Currently, we are expecting to complete this project by January 2009. The agreement also provides for a tariff increase, expected to be effective May 1, 2008, on Holly shipments on our refined product pipelines.

In November 2007, we announced an agreement in principle for the acquisition of certain pipeline and tankage assets from Holly for approximately $180.0 million. The consideration is expected to consist of $171.0 million in cash and our common units valued at approximately $9.0 million. The assets include 136 miles of crude oil trunk lines that deliver crude to Holly s Navajo Refinery in southeast New Mexico, approximately 725 miles of gathering and connection pipelines located in west Texas and New Mexico, on-site crude tankage having a combined 600,000 barrels of storage capacity located within the Navajo and Woods Cross refinery complexes, a jet fuel products pipeline and terminal (terminal leased through September 2011) between Artesia and Roswell, New Mexico, and 10 miles of crude oil and product pipelines that support Holly s Woods Cross Refinery. In connection with the closing of this proposed transaction, we intend to enter into a 15-year pipelines and tankage agreement with Holly that will contain a minimum annual revenue commitment to us from Holly. Both the HLS and Holly boards of directors have approved this proposed transaction, which we expect to close in the first quarter of 2008.

In November 2007, we executed a definitive agreement with Plains All American Pipeline, L.P. (Plains) to acquire a 25% joint venture interest in a new 95-mile intrastate pipeline system now under construction by Plains, for the shipment of up to 120,000 bpd of crude oil into the Salt Lake City area (the SLC Pipeline). Under the agreement, the SLC Pipeline will be owned by a joint venture company which will be owned 75% by Plains and 25% by us. Subject to the actual cost of the SLC Pipeline, we will purchase our 25% interest in the joint venture for an amount between $22.0 and $25.5 million in the second quarter of 2008, when the SLC Pipeline is expected to become fully operational. The SLC Pipeline will allow various refiners in the Salt Lake City area, including Holly s Woods Cross refinery, to ship crude oil into the Salt Lake City area from the Utah terminus of the Frontier Pipeline as well as crude oil from Wyoming and Utah, which is currently flowing on Plains Rocky Mountain Pipeline.

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On January 31, 2008, we entered into an option agreement with Holly, granting us an option to purchase all of Holly s equity interests in a joint venture pipeline currently under construction. The pipeline will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada (the UNEV Pipeline). Holly currently owns 75% of the equity interests in the UNEV Pipeline. Under this agreement, we have an option to purchase Holly s equity interests in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to Holly s investment in the joint venture pipeline, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The total cost of the pipeline project including terminals is expected to be $300.0 million. Holly s share of this cost is $225.0 million. Construction of this project is currently expected to be completed and operational in mid 2009.

We are also studying several other projects, which are in various stages of analysis.

We expect that our currently planned expenditures for sustaining and maintenance capital as well as expenditures for capital development projects such as the UNEV Pipeline, SLC Pipeline and South System expansion projects described above will be funded with existing cash balances, cash generated by operations, the sale of additional limited partner units and advances under our $100 million senior secured revolving credit agreement maturing August 2011 (the Credit Agreement).

Additionally, we plan to upsize our Credit Agreement to fund the cash portion of the consideration for our announced purchase of certain pipeline and tankage assets from Holly described above.

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.

We started our smart pigging program in 1988, prior to Department of Transportation (DOT) regulations requiring the program. Beginning in 2002, the DOT required smart pigging or other integrity testing of all DOT-regulated crude oil and refined product pipelines. This requirement is being phased in over a five-year period. As of December 31, 2007 we were in compliance with DOT 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. They also 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 and 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 are also protected by foam systems that are activated in case of fire. All of our terminals are subject to participation in a comprehensive environmental management program to assure compliance with applicable air, solid waste, and wastewater regulations.

COMPETITION

As a result of our physical integration with Holly s Navajo Refinery, our contractual relationship with Holly under the Omnibus Agreement and the two Holly pipelines and terminals agreements, we believe that we will not face significant competition for barrels of refined products transported from Holly s Navajo Refinery, particularly during the term of our Holly PTA and Holly IPA expiring in 2019 and 2020, respectively. Additionally, with our contractual relationship with Alon under the Alon PTA, we believe that we will not face significant competition for those barrels of refined products we transport from Alon s Big Spring Refinery, particularly during the term of our Alon PTA expiring in 2020.

However, we do face competition from other pipelines that may be able to supply the end-user markets of Holly or Alon with refined products on a more competitive basis. Additionally, If Holly 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 Holly s competitors are some of the world s largest integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems. Holly 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 Holly, 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. Under the terms of the Holly PTA, we continue to receive a significant portion of the throughput at our terminal facilities from Holly.

Our ten refined product terminals compete with other independent terminal operators as well as integrated oil companies on the basis of 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 Federal Energy Regulatory Commission (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 proposed new or changed rates by protest, and challenges to rates that are already on file and in effect by complaint. Upon the appropriate showing, a successful complainant may obtain damages or reparations for generally up to two years prior to the filing of a complaint. The FERC generally has not investigated interstate rates on its own initiative when those rates, like ours, have not been the subject of a protest or a complaint by a shipper. However, the FERC could investigate any new interstate rates we might file if those rates were protested by a third party and the third party were able to show that it had a substantial economic interest in our tariff rate level. The FERC could also investigate any of our existing interstate rates if a complaint were filed against the rate.

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, 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 have generally 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.

We inspect our pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

Holly agreed to indemnify us in an aggregate amount not to exceed $15.0 million for ten years after the closing of our initial public offering on July 13, 2004 for environmental noncompliance and remediation liabilities associated with the assets initially transferred to us and occurring or existing before that date. When the Intermediate Pipelines were purchased in July 2005, Holly agreed to provide $2.5 million of additional indemnification, bringing the total indemnification provided to us from Holly to $17.5 million. Of this total, indemnification above $15.0 million relates solely to the Intermediate Pipelines. Additionally, we entered into an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon, under which Alon, for a ten year term expiring in 2015, will indemnify us subject to a $100,000 deductible and a $20.0 million maximum liability cap.

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.

An environmental remediation project is in progress currently at our El Paso terminal, the remaining costs of which are projected to be $2.0 million over the next four years. Other parties are undertaking remediation projects at our Boise, Burley and Albuquerque terminals, and we are obligated to pay a portion of these costs at the Albuquerque terminal, but not at the Boise or Burley terminals. As of

December 31, 2007, we estimate the total remaining remediation cost for the Albuquerque terminal to be insignificant. A remediation project is also under way in New Mexico concerning a leak at a point along our refined product pipeline from Artesia, New Mexico to Orla, Texas. As of At December 31, 2007, we estimate the remaining cost on this project to be $0.3 million, half of which will be incurred in 2008. Holly has agreed, subject to a $15.0 million limit, to indemnify us for environmental liabilities related to the assets transferred to us by Holly to the extent such liabilities existed or arose from operation of these assets prior to the closing of our initial public offering on July 13, 2004 and are asserted within 10 years after that date. The Holly indemnification will cover the costs associated with the remediation projects mentioned above, including assessment, monitoring, and remediation programs.

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.

EMPLOYEES

To carry out our operations, HLS employs 106 people who provide direct support to our operations, of which 6 are covered by collective bargaining agreements that expire in March 2009. Holly Logistic Services, L.L.C. considers its employee relations to be good. Neither we nor our general partner have employees. We reimburse Holly for direct expenses that Holly or its affiliates incurs on our behalf for the employees of HLS.

Item 1A. Risk Factors

Investing in us involves a degree of risk, including the risks described below. You should carefully consider the following risk factors 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.

We depend upon Holly and particularly its Navajo Refinery for a majority of our revenues; if those revenues were reduced or if Holly s financial condition materially deteriorated, there would be a material adverse effect on our results of operations.

For the year ended December 31, 2007, Holly accounted for 58% of the revenues of our petroleum products pipelines and 67% of the revenues of our terminals and truck loading racks. We expect to continue to derive a majority of our revenues from Holly for the foreseeable future. If Holly satisfies only its minimum obligations under the Holly PTA and Holly IPA or is unable to meet its minimum revenue commitment for any reason, including due to prolonged downtime or a shutdown at the Navajo Refinery or the Woods Cross Refinery, our revenues 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, 2007, production from the Navajo Refinery accounted for 55% of the throughput volumes transported by our refined product pipelines. The Navajo Refinery also received 100% of the petroleum products shipped on our Intermediate Pipelines. Operations at the Navajo Refinery could be partially or completely shut down, temporarily or permanently, as the result of:

- competition from other refineries and pipelines that may be able to supply the refinery s end-user markets on a more cost-effective basis;

operational problems such as catastrophic events at the refinery, labor difficulties 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 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;

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 prices, 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 Holly may take in response to a shutdown. Holly makes all decisions at the Navajo Refinery 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 and capital expenditures; is responsible for all related costs; and is under no contractual obligation to us to maintain operations at the Navajo Refinery.

Furthermore, Holly s obligations under the Holly PTA and Holly IPA would be temporarily suspended during the occurrence of a *force majeure* 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 Holly 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, 2007, Alon accounted for 27% of the combined revenues of our petroleum products 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 materially reduce the volume of refined products we transport and terminal for Alon. 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 would depend 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

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responsible for all costs at the Big Spring Refinery concerning levels of production, regulatory compliance, refinery turnarounds, labor relations, environmental remediation and capital expenditures.

In addition, under the Alon PTA, 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 beyond the control of either of us, 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.

We are exposed to the credit risks of our key customers.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. As stated above, we receive substantial revenues from both Holly and Alon under their respective pipelines and terminals agreements. In addition, a subsidiary of BP Plc (BP) is the only shipper on the Rio Grande Pipeline, a joint venture in which we own a 70% interest and from which we derived 9% of our revenues for the year ended December 31, 2007.

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.

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 competitively supply our shippers end-user markets with refined products. The Longhorn Pipeline is a 72,000 bpd common carrier pipeline that delivers refined products utilizing a direct route from the Texas Gulf Coast to El Paso and, through interconnections with third-party common carrier pipelines, into the Arizona market. Deliveries of refined products shipped on the Longhorn Pipeline increased significantly during 2007, and we believe is currently operating at or near full capacity. Longhorn Partners Pipeline, L.P., owner of the Longhorn Pipeline, has also announced a planned expansion of its pipeline from 72,000 bpd to 125,000 bpd. Also in 2007, Kinder Morgan completed an expansion of its El Paso, Texas to Tucson and Phoenix, Arizona pipeline, increasing its capacity to 200,000 bpd. Increased supplies of refined product delivered by the Longhorn Pipeline and 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 Holly and/or Alon. Such eventuality could reduce our opportunity to earn revenues from Holly and Alon in excess of their minimum volume commitment obligations.

An additional factor that could affect some of Holly 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 Holly and Alon to these markets.

A material decrease in the supply, or a material increase in the price, of crude oil available to Holly s and Alon s refineries, could materially reduce our revenues.

The volume of refined products we transport in our refined products pipelines depends on the level of production of refined products from Holly 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, 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 value of the products produced by the refineries, either temporary or permanent, which caused 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.

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. Alon s obligations to lease capacity on the Artesia-Orla-El Paso pipeline have remaining terms ranging from four to twelve years. BP s agreement to ship on the Rio Grande Pipeline expires in April 2008. Our pipelines and terminals agreements with Holly and Alon expire in 2019 and 2020, respectively.

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

Our pipelines and terminal operations are subject to increasingly strict environmental and safety laws and regulations. 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 have also 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.

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, injury, or extensive property damage, as well as an interruption in our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies could increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of

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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.

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.

Holly, 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. For example, the common carrier pipelines used by Holly to serve the Arizona and Albuquerque markets are currently operated at or near capacity and are subject to proration. As a result, the volumes of refined product that Holly and other shippers have been able to deliver to these markets have been limited. The flow of additional products into El Paso for shipment to Arizona could further exacerbate such constraints on deliveries to Arizona. Any reduction in volumes transported in our pipelines or through our terminals could adversely affect our revenues and cash flows.

If our assumptions concerning population growth are inaccurate or if Holly 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 and Rocky Mountain regions of the United States will experience population growth that is higher than the national average; and

- the willingness and ability of Holly to capture a share of this additional demand in its existing markets and to identify and penetrate new markets in the Southwestern and Rocky Mountain regions of the United States.

If our assumptions about growth in market demand prove incorrect, Holly 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, Holly is under no obligation to pursue a growth strategy. If Holly chooses not to gain, or is unable to gain additional customers in new or existing markets in the Southwestern and Rocky Mountain regions of the United States, our growth strategy would be adversely affected. Moreover, Holly 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. Finally, Holly also will be subject to integration risks with respect to any new acquisitions it chooses to make.

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.

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Rate regulation may not allow us to recover the full amount of increases in our costs.

The primary rate-making methodology of the FERC is price indexing. We use this methodology in all of our interstate markets. The indexing method allows a pipeline to increase its rates based on a percentage change in the 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 our interstate or intrastate tariff rates are successfully challenged, we could be required to reduce our tariff rates, which would reduce our revenues.

Under the FERC indexing methodology, 18 CFR 342-3, our interstate pipeline tariff rates are deemed just and reasonable. If a party with an economic interest were to file either a protest or a complaint against our tariff rates, then our existing rates could be subject to detailed review. If our rates were found to be in excess of levels justified by our cost of service, the FERC could order us to reduce our rates. In addition, a state commission could also 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 would result in lower revenues and cash flows.

Holly 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.

Potential changes to current petroleum pipeline rate-making methods and procedures may impact the federal and state regulations under which we will operate in the future.

If the FERC s petroleum pipeline rate-making methodology changes, the new methodology could result in tariffs that generate lower revenues and cash flow.

Terrorist attacks, and the threat of terrorist attacks or domestic vandalism, have resulted in increased costs to our business. Continued hostilities in the Middle East 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 hostilities in the Middle East 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.

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, 2007, the principal amount of our total outstanding long-term debt was $185.0 million. Various limitations in our Credit Agreement and the indenture for our Senior Notes may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage could have important consequences. We will 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 materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We cannot assure you that we would be able to refinance our existing indebtedness 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 contribution agreements with Alon and with Holly with respect to the Intermediate Pipelines restrict us from selling the pipelines and terminals acquired from Alon or Holly, as applicable, and from prepaying more than $30.0 million of the Senior Notes until 2015, subject to certain limited exceptions. Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize 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 may also 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.

Our growth through acquisitions may be limited by future market considerations.

Future business or asset acquisitions may be dependent upon financial market conditions. Increases in our average cost of capital resulting from increases in interest rates or changes in our bond rating or from increased cost of equity capital may prevent us from making accretive acquisitions and thus limit our growth opportunities.

Risks to Common Unitholders

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

Currently, Holly indirectly owns the 2% general partner interest and a 43% limited partner interest in us and owns and controls our general partner, HEP Logistics Holdings, L.P. Conflicts of interest may arise between Holly 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 affiliates over our interests. These conflicts include, among others, the following situations:

Holly, 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 Holly 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. Holly s directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of Holly;

our general partner is allowed to take into account the interests of parties other than us, such as Holly, in resolving conflicts of interest;

our general partner determines which costs incurred by Holly 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 Holly.

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

Under our partnership agreement, we are currently obligated to pay Holly an administrative fee of $2.1 million per year for the provision by Holly or its affiliates 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 Holly or its affiliates. Our general partner will determine the amount of general and administrative expenses that will be properly 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. 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.

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.

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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. Also, if the general partner is removed without cause during the subordination period and units held by the general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on the common units will be extinguished. A removal of the general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholders dissatisfaction with the general partner s performance in managing our partnership will most likely result in the termination of the subordination period.

Furthermore, 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. 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.

During the subordination period, our general partner, without the approval of our unitholders, may cause us to issue up to 3,500,000 additional common units. Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in connection with acquisitions or capital improvements that increase cash flow from operations per unit on an estimated pro forma basis;
- issuances of common units to repay indebtedness, the cost of which to service is greater than the distribution obligations associated with the units issued in connection with the repayment of the indebtedness;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances;
- in the event of a combination or subdivision of common units;

- issuances of common units under our employee benefit plans; or
- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal or removal of our general partner.

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.

After the end of the subordination period, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of 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.

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

Holly and its affiliates may engage in limited competition with us. Pursuant to the omnibus agreement among us, Holly and our general partner, Holly 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 Holly or any of its subsidiaries at the closing of our initial public offering;
- any crude oil pipeline or gathering system acquired or constructed by Holly or any of its subsidiaries that is physically interconnected to Holly s refining facilities;
- any business or asset that Holly or any of it subsidiaries acquires or constructs that has a fair market value or construction cost of less than $5.0 million; and
- any business or asset that Holly or any of its subsidiaries acquires or constructs that has a fair market value or construction cost of $5.0 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 with the concurrence of our conflicts committee.

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In the event that Holly or its affiliates no longer control our partnership or there is a change of control of Holly, 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 Holly 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 a distribution on the subordinated units, to make incentive distributions, or to hasten the expiration of the subordination period.

Our general partner has a limited call right that may require a holder of units 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, 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 an undesirable time or price and may not receive any return on its investment. A common unitholder may also incur a tax liability upon a sale of its units.

A unitholder may not have limited liability if a court finds that unitholder actions constitute control of our business.

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 of the Delaware Revised Uniform Limited Partnership Act (the Delaware 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.

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 entity-level taxation by states. If the IRS were to treat us as a corporation or if we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the current maximum corporate tax rate of 35%. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits 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. Thus, 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 the common units.

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Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced. The 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, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will be borne by our unitholders and our general partner.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other tax matter affecting us. The IRS may adopt positions that differ from the positions we have taken or may take on tax matters. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

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

Unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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

If a unitholder sells common units, it will recognize gain or loss equal to the difference between the amount realized and its tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income it was allocated for a common unit, which decreased its tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than its tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income.

Tax-exempt entities, regulated investment companies or foreign persons may have adverse tax consequences from owning common units.

Investment in common units by tax-exempt entities, regulated investment companies or mutual funds and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

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

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

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

In addition to federal income taxes, unitholders will likely 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. Unitholders will likely 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. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in New Mexico, Arizona, Texas, Washington, Utah, Oklahoma and Idaho. Of those states, only Texas and Washington do not currently impose a state income tax. 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 and local tax returns.

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 is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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 Holly 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, Colorado, Utah, Oklahoma and northern Mexico. 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 of two parallel pipelines that originate at Holly s Lovington, New Mexico refining facilities and terminate at Holly s Artesia, New Mexico refining facilities. These pipelines transport intermediate feedstocks and crude oil for Holly s refining operations in New Mexico.

Our pipelines are regularly inspected, are well maintained and we believe, are in good repair. Generally, other than as provided in the pipelines and terminal agreements with Holly and Alon, 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.

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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 Holly and for third parties.

	Years Ended December 31,				
	2007	**2006**	**2005**[(1)]	**2004**	**2003**
Refined products transported for (bpd):					
Holly	142,447	126,929	94,473	65,525	51,456
Third parties [(2)]	62,720	62,655	65,053	29,967	23,469
Total	205,167	189,584	159,526	95,492	74,925
Total barrels in thousands (mbbls)	74,886	69,198	58,227	34,950	27,348

(1) Includes volumes transported on the pipelines acquired from Alon on February 28, 2005, and volumes transported on the Intermediate Pipelines acquired on July 8, 2005.

(2) Includes Rio Grande Pipeline volumes beginning June 30, 2003, when we increased our ownership from 25% to 70% and began consolidating the results of Rio Grande Pipeline.

The following table sets forth certain operating data for each of our petroleum product pipelines. Except as shown below, we own 100% of our refined product 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 20,000 barrels of refined product per day. Effective September 1, 2008, the leased capacity shall decrease to 17,500 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.

Origin and Destination	Diameter (inches)	Approximate Length (miles)	Capacity (bpd)
Refined Product Pipelines:			
Artesia, NM to El Paso, TX	6	156	24,000
Artesia, NM to Orla, TX to El Paso, TX	8/12/8	215	70,000(1)
Artesia, NM to Moriarty, NM(2)	12/8	215	45,000(3)
Moriarty, NM to Bloomfield, NM(2)	8	191	(3)
Big Spring, TX to Abilene, TX(4)	6/8	105	20,000
Big Spring, TX to Wichita Falls, TX(4)	6/8	227	23,000
Wichita Falls, TX to Duncan, OK(4)	6	47	21,000
Midland, TX to Orla, TX(4)	8/10	135	25,000
Intermediate Product Pipelines:			
Lovington, NM to Artesia, NM(5)	8	65	48,000
Lovington, NM to Artesia, NM(5)	10	65	72,000
Rio Grande Pipeline Company:			
Rio Grande Pipeline(6)	8	249	27,000

(1) *Includes 20,000 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) *Acquired from Alon on February 28, 2005.*

(5) *Acquired from Holly on July 8, 2005.*

(6) *We have a 70% joint venture interest in the entity that owns this pipeline that runs from Midland, TX to El Paso, TX. Capacity reflects a 100% interest.*

Holly shipped an aggregate of 55% of the petroleum products transported on our refined product pipelines and 100% of the petroleum products transported on our Intermediate Pipelines in 2007. These pipelines transported approximately 96% of the light refined products produced by Holly s Navajo Refinery in 2007.

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 for the shipment of refined products produced at Holly s Navajo Refinery to our El Paso terminal, where we deliver 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. Holly is the only shipper on this pipeline. The refined products shipped on this pipeline represented 17% of the total light refined products produced at Holly s Navajo Refinery during 2007. Refined products produced at Holly s 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, 67-mile and a 12-inch, 14-mile segment from the Navajo Refinery to Orla, Texas, constructed in 1981;
- a 12-inch, 99-mile segment from Orla to outside El Paso, Texas, constructed in 1996; and
- an 8-inch, 35-mile segment from outside El Paso to our El Paso terminal, constructed in the mid 1950 s

There are two shippers on this pipeline, Holly and Alon. In 2007, this pipeline transported to our El Paso terminal 55% of the light refined products produced at Holly s Navajo Refinery. As mentioned above, refined products destined to the 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.

At Orla, our pipeline also receives volumes of gasoline and diesel via a tie-in to our pipeline from Alon s Big Spring, Texas refinery.

Artesia, New Mexico to Moriarty, New Mexico

The Artesia to Moriarty refined product pipeline consists of a 60-mile, 12-inch pipeline from Holly s Artesia facility to White Lakes Junction, New Mexico that was constructed in 1999, and approximately 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). Holly is the only shipper on this pipeline. We currently pay a monthly fee (which is subject to adjustments based on changes in the PPI) of $488,000 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). Holly 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 Alon s 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 Alon s 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 Alon s Big Spring Refinery from Midland to our tank farm at Orla. Alon is the only shipper on this pipeline.

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 Holly s Lovington facility to its Artesia facility.

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 Holly s Lovington facility to its Artesia facility. Holly is the only shipper on this pipeline.

Rio Grande Pipeline

We own a 70% interest in Rio Grande, a joint venture that owns a 249-mile, 8-inch common carrier LPG pipeline regulated by the FERC. The other owner of Rio Grande is a subsidiary of BP. The pipeline originates from a connection with an Enterprise pipeline in west Texas at Lawson Junction which serves as its primary receipt point, although there is an additional receipt point near Midland, Texas. The pipeline terminates at the Mexico border near San Elizario, Texas. The pipeline transports LPGs for ultimate use by Petróleos Mexicanos (PEMEX, the government-owned energy company of Mexico.) Rio Grande does not own any facilities or pipelines in Mexico. The pipeline has a current capacity of approximately 27,000 bpd. This pipeline was originally constructed in the mid 1950 s, was first reconditioned in 1988, and subsequently reconditioned in 1996 and 2003. Approximately 75 miles of this pipeline has been replaced with new pipe, and an additional 50 miles has been recoated.

Rio Grande was formed in 1996, at which time we contributed nearly 220 miles of pipeline from near Odessa, Texas to outside El Paso, Texas in exchange for a 25% interest in the joint venture. Rio Grande Pipeline began operations in 1997. In June 2003, we acquired an additional 45% interest in the joint venture for $28.7 million. Currently, only LPG s are transported on this pipeline, and BP is the only shipper. BP s contract expires in April 2008. The contract provides that BP will ship a minimum average of 16,500 bpd during the term of the agreement. The tariff rates and shipping regulations are regulated by the FERC.

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In January 2005, Rio Grande appointed us as operator of the pipeline system effective April 1, 2005 through January 31, 2010. We paid $745,000 to the then-current operator as an inducement to and consideration for its early resignation. As operator, we receive a management fee of $1.1 million per year, adjusted annually for any changes in the PPI.

An officer of HLS is one of the two members of Rio Grande s management committee.

REFINED PRODUCT TERMINALS AND TRUCK RACKS

Our refined product terminals receive products from pipelines, Holly s Navajo and Woods Cross refineries and Alon s Big Spring Refinery. We then distribute them to Holly 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 Holly s and Alon s marketing activities. 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.

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. Holly 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,				
	2007	**2006**	**2005(1)**	**2004**	**2003**
Refined products terminalled for (bpd):					
Holly	119,910	118,202	120,795	114,991	86,780
Third parties	45,457	43,285	42,334	24,821	19,956
Total	165,367	161,487	163,129	139,812	106,736
Total (mbbls)	60,359	58,943	59,542	51,171	38,959

(1) Includes volumes for the terminals and tank farm acquired from Alon February 28,

2005.

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

Terminal Location[(1)]	Storage Capacity (barrels)	Number of Tanks	Supply Source	Mode of Delivery
El Paso, TX	507,000	16	Pipeline/ rail	Truck/Pipeline
Moriarty, NM	189,000	9	Pipeline	Truck
Bloomfield, NM	193,000	7	Pipeline	Truck
Tucson, AZ[(2)]	176,000	9	Pipeline	Truck
Mountain Home, ID[(3)]	120,000	3	Pipeline	Pipeline
Boise, ID[(4)]	111,000	9	Pipeline	Pipeline
Burley, ID[(4)]	70,000	7	Pipeline	Truck
Spokane, WA	333,000	32	Pipeline/Rail	Truck
Abilene, TX[(5)]	127,000	5	Pipeline	Truck/Pipeline
Wichita Falls, TX[(5)]	220,000	11	Pipeline	Truck/Pipeline
Orla tank farm[(5)]	135,000	5	Pipeline	Pipeline
Artesia facility truck rack	N/A	N/A	Refinery	Truck
Woods Cross facility truck rack	N/A	N/A	Refinery	Truck/Pipeline
Total	2,181,000			

(1) We closed our Albuquerque terminal in the fourth quarter of 2007.

(2) The Tucson terminal consists of two parcels. The underlying ground on both parcels is leased.

(3) Handles only jet fuel.

(4) 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.

(5) *Acquired from Alon on February 28, 2005.*

El Paso Terminal

We receive light refined products at this terminal from Holly s Artesia facility through our Artesia to El Paso and Artesia to Orla to El Paso pipelines and by rail that account for approximately 68% of the volumes at this terminal. We also receive product from Alon s Big Spring Refinery that accounted for 32% of the volumes at this terminal in 2007. Refined products received at this terminal are sold locally via the truck rack or transported to our Tucson terminal 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. and a terminal connected to the Longhorn Pipeline.

Moriarty Terminal

We receive light refined products at this terminal from Holly s Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack; Holly 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 Holly s Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack; Holly is our only customer at this terminal. Competition in this market includes a refinery and truck loading rack owned by Western Refining, Inc.

Tucson Terminal

The Tucson terminal consists of two parcels. On one parcel, we lease the underlying ground as a 50% co-tenant with a division of NuStar pursuant to which we own 50% of the improvements on that parcel. On the other parcel, our joint venture with NuStar leases the underlying ground and owns the improvements. This joint venture agreement gives us rights to 100% of the terminal capacity (for both parcels), which is operated by NuStar for a fee. We receive light refined products at this terminal from Kinder Morgan s East System pipeline, which transports refined products from Holly s 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 and CalJet.

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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 Transportation Company (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 Holly 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. Holly 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 Holly 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. Holly 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. Shell and Chevron are the 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 2007. 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 Alon s Big Spring Refinery, which accounted for all of its volumes in 2007. 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 to NuStar s Southlake pipeline. Alon is the only customer at this terminal.

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 2007. 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 Holly s Artesia facility loads light refined products, produced at the facility, onto tanker trucks for delivery to markets in the surrounding area. Holly is the only customer of this truck rack.

Woods Cross Facility Truck Rack

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

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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. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of security holders during the fourth quarter of 2007.

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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 to common unitholders and the trading volume of common units for the period indicated.

Years Ended December 31,	High	Low	Cash Distributions	Trading Volume
2007				
Fourth Quarter	$48.09	$42.04	$ 0.715	1,065,300
Third Quarter	$57.24	$43.10	$ 0.705	1,273,100
Second Quarter	$56.69	$46.55	$ 0.690	1,231,600
First Quarter	$49.97	$39.50	$ 0.675	948,900
2006				
Fourth Quarter	$41.10	$37.90	$ 0.665	876,800
Third Quarter	$40.44	$35.80	$ 0.655	957,700
Second Quarter	$42.58	$38.15	$ 0.640	704,100
First Quarter	$42.75	$37.00	$ 0.625	1,165,000

A distribution for the quarter ended December 31, 2007 of $0.725 per unit was paid on February 14, 2008.

As of February 7, 2008, we had approximately 4,620 common unitholders, including beneficial owners of common units held in street name.

We consider 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. Our revolving credit facility prohibits us from making cash distributions if any potential default or event of default, as defined in the Credit Agreement, occurs or would result from the cash distribution. The indenture relating to our Senior Notes prohibits us from making cash distributions under certain circumstances.

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 law, 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. Working capital borrowings are generally borrowings that are made under our revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Upon the closing of our initial public offering, Holly received 7,000,000 subordinated units. During the subordination period, the common units have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.50 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will extend until the first day of any quarter beginning after June 30, 2009 that each of the following tests are met: distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three

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consecutive, non-overlapping four-quarter periods immediately preceding that date; the adjusted operating surplus (as defined in our partnership agreement) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and there are no arrearages in payment of the minimum quarterly distribution on the common units. If the unitholders remove the general partner without cause, the subordination period may end before June 30, 2009.

We issued 937,500 of our Class B subordinated units in connection with the Alon transaction in 2005. The Class B subordinated units issued to Alon vote as a single class and rank equally with our existing subordinated units. There is a subordination period with respect to the Class B subordinated units with generally similar provisions to the subordinated units held by Holly, except that the subordination period will end on the last day of any quarter ending on or after March 31, 2010 if Alon has not defaulted on its minimum volume commitment payment obligations for the three consecutive, non-overlapping four quarter periods immediately preceding that date, subject to certain grace periods. If Holly is removed as the general partner without cause, the subordination period for the Class B subordinated units may end before March 31, 2010.

We make distributions of available cash from operating surplus for any quarter during any subordination period in the following manner: first, 98% to the 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; second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

The general partner, HEP Logistics Holdings, L.P., is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount	**Marginal Percentage Interest in Distributions**	
		Unitholders	**General Partner**
Minimum Quarterly Distribution	$0.50	98%	2%
First Target Distribution	Up to $0.55	98%	2%
Second Target Distribution	above $0.55 up to $0.625	85%	15%
Third Target distribution	above $0.625 up to $0.75	75%	25%
Thereafter	Above $0.75	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. See Historical Results of Operations below for a description of factors affecting the comparability of our financial information for years prior to 2005.

				Combined	2004 Successor	Predecessor	
	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004[1]	July 13, 2004 Through December 31, 2004	January 1, 2004 Through July 12, 2004	Year Ended December 31, 2003
	(In thousands, except per unit data)						
Statement Of Income Data:							
Revenue	$ 105,407	$ 89,194	$ 80,120	$ 67,766	$ 28,182	$ 39,584	$ 30,800
Operating costs and expenses							
Operations	32,911	28,630	25,332	23,641	10,104	13,537	24,193
Depreciation and amortization	14,382	15,330	14,201	7,224	3,241	3,983	6,453
General and administrative	5,043	4,854	4,047	1,860	1,859	1	
	52,336	48,814	43,580	32,725	15,204	17,521	30,646
Operating income	53,071	40,380	36,540	35,041	12,978	22,063	154
Interest income	533	899	649	144	65	79	291
Interest expense	(13,289)	(13,056)	(9,633)	(697)	(697)		
Gain on sale of assets	298						
Equity in earnings of Rio Grande Pipeline Company							894
	(12,458)	(12,157)	(8,984)	(553)	(632)	79	1,185
Income before minority interest	40,613	28,223	27,556	34,488	12,346	22,142	1,339

Minority interest in Rio Grande Pipeline Company	(1,067)	(680)	(740)	(1,994)	(956)	(1,038)	(758)
Income before income taxes	39,546	27,543	26,816	32,494	11,390	21,104	581
State income tax	(275)						
Net income	39,271	27,543	26,816	32,494	11,390	21,104	581
Less:							
Net income attributable to Predecessor				21,104		21,104	581
General partner interest in net income	2,932	1,710	721	228	228		
Limited partners interest in net income	$ 36,339	$ 25,833	$ 26,095	$ 11,162	$ 11,162	$	$
Net income per limited partner unit basic and diluted	$ 2.26	$ 1.60	$ 1.70		$ 0.80		
Cash distributions declared per unit applicable to limited partners	$ 2.785	$ 2.585	$ 2.225		$ 0.435		
Other Financial Data:							
EBITDA [2]	$ 66,684	$ 55,030	$ 50,001	$ 40,271	$ 15,263	$ 25,008	$ 6,743
Cash flows from operating activities	$ 59,056	$ 45,853	$ 42,628	$ 15,867	$ 15,371	$ 496	$ 5,909
Cash flows from investing activities	$ (9,632)	$ (9,107)	$ (131,795)	$ (2,977)	$ (305)	$ (2,672)	$ (27,947)
Cash flows from financing activities	$ (50,658)	$ (45,774)	$ 90,646	$ (480)	$ 1,770	$ (2,250)	$ 28,372
	$ 1,863	$ 1,095	$ 364	$ 1,197	$ 305	$ 892	$ 1,934

Maintenance capital expenditures (3)							
Expansion capital expenditures	8,094	8,012	3,519	1,780		1,780	4,837
Total capital expenditures	$ 9,957	$ 9,107	$ 3,883	$ 2,977	$ 305	$ 2,672	$ 6,771
Balance Sheet Data (at period end):							
Net property, plant and equipment	$ 158,600	$ 160,484	$ 162,298	$ 74,626	$ 74,626	$ 95,337	$ 95,826
Total assets	$ 238,904	$ 245,771	$ 254,775	$ 103,758	$ 103,758	$ 156,373	$ 140,425
Long-term debt	$ 181,435	$ 180,660	$ 180,737	$ 25,000	$ 25,000	$	$
Total liabilities	$ 200,348	$ 198,582	$ 190,962	$ 28,998	$ 28,998	$ 53,146	$ 57,089
Net partners equity (4)	$ 27,816	$ 36,226	$ 52,060	$ 61,528	$ 61,528	$ 89,964	$ 68,860

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(1) Combined results for the year ended December 31, 2004 is not a calculation based upon U.S. generally accepted accounting principles (GAAP), and is presented here to provide the investor with additional information for comparing year-over-year information.

(2) Earnings before interest, taxes, depreciation and amortization (EBITDA) are calculated as net income plus (a) interest expense net of interest income and (b) depreciation and amortization. EBITDA is a non-GAAP measure. However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements.

EBITDA should not be considered as an alternative to net income 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 enhances an investor s understanding of our ability to satisfy principal and interest obligations with respect to our indebtedness and to use cash for other purposes, including capital expenditures. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants. Our reconciliation of EBITDA to net income is presented below.

				Combined	2004 Successor	Predecessor	
	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004	July 13, 2004 Through December 31, 2004	January 1, 2004 Through July 12, 2004	Year Ended December 31, 2003
				(In thousands)			
Net income	$ 39,271	$ 27,543	$ 26,816	$ 32,494	$ 11,390	$ 21,104	$ 581
Add depreciation and amortization	14,382	15,330	14,201	7,224	3,241	3,983	6,453
Add state income tax	275						
Add interest expense	13,289	13,056	9,633	697	697		
Subtract interest income	(533)	(899)	(649)	(144)	(65)	(79)	(291)
EBITDA	$ 66,684	$ 55,030	$ 50,001	$ 40,271	$ 15,263	$ 25,008	$ 6,743

(3) 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, and safety and to address environmental regulations.

(4) As a master limited partnership, we distribute our available cash, which exceeds 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.

Historical Results of Operations

In reviewing the historical results of operations that are presented above, you should be aware of the following:

Until January 1, 2004, our historical revenues included only actual amounts received from:

- third parties who utilized our pipelines and terminals;
- Holly for use of our FERC-regulated refined product pipeline; and
- Holly for use of the Lovington crude oil pipelines, which were not contributed to our partnership.

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Until January 1, 2004, we did not record revenue for:

- transporting products for Holly on our intrastate refined product pipelines;
- providing terminalling services to Holly; and
- transporting crude oil and feedstocks on the Intermediate Pipelines that connect Holly s Artesia and Lovington facilities, which were not contributed to our partnership.

Commencing January 1, 2004, we began charging Holly fees for the use of all of our pipelines and terminals at the rates set forth in the Holly PTA.

Furthermore, the historical financial data do not reflect any general and administrative expenses prior to July 13, 2004 as Holly did not historically allocate any of its general and administrative expenses to its pipelines and terminals. Our historical results of operations prior to July 13, 2004 include costs associated with crude oil and intermediate product pipelines, which were not contributed to our partnership.

For periods after commencement of operations by HEP on July 13, 2004, our financial statements reflect:

- net proceeds from our initial public offering which closed on July 13, 2004
- the transfer of certain of our predecessor s operations to HEP, which
  - includes our predecessor s refined product pipeline and terminal assets and short-term debt due to Holly (which was repaid upon the closing of our initial public offering), and
  - excludes our predecessor s crude oil systems, intermediate product pipelines, accounts receivable from or payable to affiliates, and other miscellaneous assets and liabilities;
- the execution of the Holly PTA and the recognition of revenues derived therefrom; and
- the execution of the Omnibus Agreement with Holly and several of its subsidiaries and the recognition of allocated general and administrative expenses in addition to direct general and administrative expense related to our operation as a publicly owned entity.

NPL constitutes HEP s predecessor. The transfer of ownership of assets from NPL to HEP on July 13, 2004 represented a reorganization of entities under common control and was recorded at NPL s historical cost. Accordingly, our financial statements include the historical results of operations of NPL prior to the transfer to HEP.

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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. In this document, the words we , our , ours a 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 formed by Holly and is the successor to NPL. We own and operate substantially all of the refined product pipeline and terminalling assets that support Holly s refining and marketing operations in west Texas, New Mexico, Utah, Idaho and Arizona and a 70% interest in Rio Grande. HEP is currently 45% owned by Holly.

We operate a system of petroleum product pipelines in Texas, New Mexico and Oklahoma, and distribution terminals in Texas, New Mexico, Arizona, Utah, Idaho, and Washington. We generate revenues by charging tariffs for transporting petroleum products through our pipelines and by charging fees for terminalling refined products and other hydrocarbons, and storing and providing other services at our terminals. We do not take ownership of products that we transport or terminal; therefore, we are not directly exposed to changes in commodity prices.

On February 28, 2005, we acquired from Alon four refined products pipelines, an associated tank farm and two refined products terminals located primarily in Texas that serve Alon s Big Spring, Texas refinery. Please read Alon Transaction under Liquidity and Capital Resources below for additional information.

On July 8, 2005, we acquired Holly s Intermediate Pipelines which connect its Lovington, New Mexico and Artesia, New Mexico refining facilities. Please read Holly Intermediate Pipelines Transaction under Liquidity and Capital Resources below for additional information.

Agreements with Holly

We serve Holly s refineries in New Mexico and Utah under two 15-year pipeline and terminal agreements. The Holly PTA relates to the pipelines and terminals contributed by Holly to us at the time of our initial public offering and expires in 2019. The Holly IPA relates to the Intermediate Pipelines acquired from Holly in July 2005 and expires in 2020. The substantial majority of our business is devoted to providing transportation and terminalling services to Holly. Following the July 1, 2007 rate adjustment for the PPI, the volume commitment by Holly under the Holly PTA will produce at least $39.6 million of revenue for the twelve months ending June 30, 2008. Under the Holly IPA, Holly agreed to transport volumes of intermediate products on the intermediate pipelines that following the July 1, 2007 PPI adjustment will result in minimum funds to us of $12.8 million for the twelve months ended June 30, 2008. If Holly fails to meet its minimum volume commitments 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. A shortfall payment may be applied as a credit in the following four quarters after Holly s minimum obligations are met.

In October 2007, we entered into an agreement with Holly that amends the Holly PTA under which we have agreed to expand our South System between Artesia, New Mexico and El Paso, Texas. The expansion of the South System will include replacing 85 miles of 8-inch pipe with 12-inch pipe, adding 150,000 barrels of refined product storage at our El Paso Terminal, improving existing pumps, adding a tie-in to the Kinder Morgan pipeline to Tucson and Phoenix, Arizona, and making related modifications. The cost of this project is estimated to be $48.3 million. Currently, we are expecting to complete this project by January 2009. The agreement also provides for a tariff increase, expected to be effective May 1, 2008, on Holly shipments on our refined product pipelines.

Under the Omnibus Agreement, we pay Holly an annual administrative fee, initially $2.0 million for each of the three years following the closing of our initial public offering, for the provision by Holly or its affiliates of various general and administrative services to us. Effective July 1, 2007, the annual fee increased to $2.1 million in accordance with provisions under the agreement. This fee does not include the salaries of pipeline and terminal personnel or the cost of their employee benefits, such as 401(k), pension and health insurance benefits, which are separately charged to us by Holly. We also reimburse Holly and its affiliates for direct expenses they incur on our behalf.

Please read Agreements with Holly under Item 1, Business for additional information on these agreements with Holly.

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RESULTS OF OPERATIONS

The following tables present our operating income, volume information, and cash flow summary information for the years ended December 31, 2007, 2006 and 2005.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Change from 2006
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 36,281	$ 31,723	$ 4,558
Third parties refined product pipelines	36,271	31,685	4,586
	72,552	63,408	9,144
Affiliates intermediate pipelines	13,731	10,733	2,998
	86,283	74,141	12,142
Terminals and truck loading racks:			
Affiliates	10,949	10,422	527
Third parties	5,427	4,631	796
	16,376	15,053	1,323
Other affiliates	2,748		2,748
Total revenues	105,407	89,194	16,213
Operating costs and expenses			
Operations	32,911	28,630	4,281
Depreciation and amortization	14,382	15,330	(948)
General and administrative	5,043	4,854	189
	52,336	48,814	3,522
Operating income	53,071	40,380	12,691
Interest income	533	899	(366)
Interest expense, including amortization	(13,289)	(13,056)	(233)
Gain on sale of assets	298		298
Minority interest in Rio Grande Pipeline Company	(1,067)	(680)	(387)
	(13,525)	(12,837)	(688)
Income before income taxes	39,546	27,543	12,003

State income tax	(275)		(275)
Net income	39,271	27,543	11,728
Less general partner interest in net income, including incentive distributions [1]	2,932	1,710	1,222
Limited partners interest in net income	$ 36,339	$ 25,833	$ 10,506
Net income per unit applicable to limited partners [1]	$ 2.26	$ 1.60	$ 0.66
Weighted average limited partners units outstanding	16,108	16,108	
EBITDA[2]	$ 66,684	$ 55,030	$ 11,654
Distributable cash flow [3]	$ 51,012	$ 47,219	$ 3,793
Volumes (bpd)[4]			
Pipelines:			
Affiliates refined product pipelines	77,441	69,271	8,170
Third parties refined product pipelines	62,720	62,655	65
	140,161	131,926	8,235
Affiliates intermediate pipelines	65,006	57,658	7,348
	205,167	189,584	15,583
Terminals and truck loading racks:			
Affiliates	119,910	118,202	1,708
Third parties	45,457	43,285	2,172
	165,367	161,487	3,880
Total for petroleum pipelines and terminal assets (bpd)	370,534	351,071	19,463

	Year Ended December 31, 2006	Year Ended December 31, 2005	Change from 2005
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 31,723	$ 29,288	$ 2,435
Third parties refined product pipelines	31,685	31,447	238
	63,408	60,735	2,673
Affiliates intermediate pipelines	10,733	4,643	6,090
	74,141	65,378	8,763
Terminals and truck loading racks:			
Affiliates	10,422	10,253	169
Third parties	4,631	4,489	142
	15,053	14,742	311
Total revenues	89,194	80,120	9,074
Operating costs and expenses			
Operations	28,630	25,332	3,298
Depreciation and amortization	15,330	14,201	1,129
General and administrative	4,854	4,047	807
	48,814	43,580	5,234
Operating income	40,380	36,540	3,840
Interest income	899	649	250
Interest expense, including amortization	(13,056)	(9,633)	(3,423)
Minority interest in Rio Grande Pipeline Company	(680)	(740)	60
	(12,837)	(9,724)	(3,113)
Net income	27,543	26,816	727
Less general partner interest in net income, including incentive distributions [(1)]	1,710	721	989
Limited partners interest in net income	$ 25,833	$ 26,095	$ (262)

Net income per unit applicable to limited partners [(1)]	$ 1.60	$ 1.70	$ (0.10)
Weighted average limited partners units outstanding	16,108	15,356	752
EBITDA[(2)]	$ 55,030	$ 50,001	$ 5,029
Distributable cash flow [(3)]	$ 47,219	$ 41,438	$ 5,781
Volumes (bpd)[(4)]			
Pipelines:			
Affiliates refined product pipelines	69,271	66,206	3,065
Third parties refined product pipelines	62,655	65,053	(2,398)
	131,926	131,259	667
Affiliates intermediate pipelines	57,658	28,267	29,391
	189,584	159,526	30,058
Terminals and truck loading racks:			
Affiliates	118,202	120,795	(2,593)
Third parties	43,285	42,334	951
	161,487	163,129	(1,642)
Total for petroleum pipelines and terminal assets (bpd)	351,071	322,655	28,416

(1) 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 any incentive distributions

declared in the period. The limited partners interest in net income is divided by the weighted average limited partner units outstanding in computing the net income per unit applicable to limited partners.

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(2) EBITDA is calculated as net income plus (a) interest expense net of interest income and (b) depreciation and amortization. EBITDA is a non-GAAP measure. However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income 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 accepted

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,		
	2007	**2006**	**2005**
		(In thousands)	
Net income	$ 39,271	$ 27,543	$ 26,816
Add interest expense	12,281	12,088	8,848
Add amortization of discount and deferred debt issuance costs	1,008	968	785
Subtract interest income	(533)	(899)	(649)
Add state income tax	275		
Add depreciation and amortization	14,382	15,330	14,201
EBITDA	$ 66,684	$ 55,030	$ 50,001

(3) Distributable cash flow is not a calculation based upon U.S. GAAP. However, the amounts included in the calculation are derived from amounts separately presented in our consolidated financial statements, with the exception of maintenance capital expenditures.

Distributable cash flow should not be considered in isolation or as an alternative to net income or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating.

Set forth below is our calculation of distributable cash flow.

Years Ended December 31,

	2007	2006	2005
		(In thousands)	
Net income	$ 39,271	$ 27,543	$ 26,816
Add depreciation and amortization	14,382	15,330	14,201
Add amortization of discount and deferred debt issuance costs	1,008	968	785
Add (subtract) increase (decrease) in deferred revenue	(1,786)	4,473	
Subtract maintenance capital expenditures*	(1,863)	(1,095)	(364)
Distributable cash flow	$ 51,012	$ 47,219	$ 41,438

* 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.

(4) The amounts reported include volumes from the assets acquired from Alon starting in March 2005 and the Intermediate Pipelines acquired from Holly starting in July 2005. The amounts reported in the 2005 periods include volumes on the acquired assets subsequent to the respective acquisition dates averaged over the full reported periods.

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Results of Operations Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Summary

Net income was $39.3 million for the year ended December 31, 2007, an increase of $11.8 million from $27.5 million for the year ended December 31, 2006. The increase in overall earnings was principally due to an increase in volumes transported on our pipeline systems, the effects of the annual tariff increases on product shipments, the realization of certain previously deferred revenue and revenue related to the sale of inventory of accumulated terminal overages of refined product to Holly, partially offset by an increase in our operating costs and expenses. Revenues of $3.7 million relating to deficiency payments associated with certain guaranteed shipping contracts was deferred during the year ended December 31, 2007. Such revenue will be recognized in future periods either as payment for shipments in excess of guaranteed levels or when shipping rights expire unused after a twelve-month period.

Revenues

Revenues of $105.4 million for the year ended December 31, 2007 were $16.2 million greater than the $89.2 million for the comparable period of 2006. This increase in revenue was principally due to an increase in volumes transported on our pipeline systems, the effects of annual tariff increases on product shipments, an increase in previously deferred revenue realized and revenue related to the sale of inventory of accumulated terminal overages of refined product to Holly.

The increase in volumes transported on our pipeline systems for the year ended December 31, 2007 as compared to 2006 was principally due to significant downtime at all of the refineries served by our product distribution network in the second quarter of 2006. Refiners were generally required to start producing ultra low sulfur diesel fuel (ULSD) by June 2006. To meet this requirement, many refiners, including Holly s Navajo Refinery and Alon s Big Spring Refinery, required downtime at their refineries so that ULSD-associated projects could be brought on line. Additionally, Holly completed an expansion of the Navajo Refinery during this period of downtime which resulted in increased refinery production and has contributed to increased volume shipments on our pipeline systems.

Revenues from refined product pipelines increased by $9.2 million from $63.4 million for the year ended December 31, 2006 to $72.6 million for the year ended December 31, 2007. This increase in refined product pipeline revenue was principally due to an increase in volumes shipped on our refined product pipelines, the effect of the annual tariff increase on refined product shipments, and the realization of $3.1 million of previously deferred revenue. Shipments on our refined product pipelines averaged 140.2 thousand barrels per day (mbpd) for the year ended December 31, 2007 as compared to 131.9 mbpd for the year ended December 31, 2006.

Revenues from the intermediate pipelines increased by $3.0 million from $10.7 million for the year ended December 31, 2006 to $13.7 million for the year ended December 31, 2007. This increase in intermediate pipeline revenue was principally due to an increase in volumes shipped on our intermediate pipelines, the effect of the annual tariff increase on intermediate pipeline shipments and an increase in previously deferred revenue realized. Intermediate pipeline revenue for the year ended December 31, 2007 included $2.4 million, as compared to $1.0 million for the year ended December 31, 2006, of previously deferred revenue. Shipments on the Intermediate Pipelines averaged 65.0 mbpd for the year ended December 31, 2007 as compared to 57.7 mbpd for the year ended December 31, 2006.

Revenues from terminal and truck loading rack service fees increased by $1.3 million from $15.1 million for the year ended December 31, 2006 to $16.4 million for the year ended December 31, 2007. This increase was principally due to an increase in refined products terminalled in our facilities. Refined products terminalled in our facilities averaged 165.4 mbpd for the year ended December 31, 2007 as compared to 161.5 mbpd for the year ended December 31, 2006.

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Other revenues for the year ended December 31, 2007 consisted of $2.7 million related to the sale of inventory of accumulated terminal overages of refined product to Holly. These overages arose from net product gains at our terminals from the beginning of 2005 through the third quarter of 2007. We have negotiated an amendment to our pipelines and terminals agreement with Holly that provides that such terminal overages of refined product shall belong to Holly in the future. There were no other revenues for the year ended December 31, 2006.

Operations Expense

Operations expense increased $4.3 million from the year ended December 31, 2006 to the year ended December 31, 2007. This increase in expense was principally due to higher throughput volumes, an increase in pipeline and terminal maintenance expense and an increase in the cost of employees who perform services for us, including the addition of two new senior level executives.

Depreciation and Amortization

Depreciation and amortization decreased by $0.9 million from the year ended December 31, 2006 to the year ended December 31, 2007, due principally to a reduction in amortization expense, as a transportation agreement became fully amortized in April 2007.

General and Administrative

General and administrative costs increased by $0.2 million from the year ended December 31, 2006 to the year ended December 31, 2007, due principally to an increase in equity-based incentive compensation expense.

Interest Expense

Interest expense for the year ended December 31, 2007 totaled $13.3 million, an increase of $0.2 million from $13.1 million for the year ended December 31, 2006. For the year ended December 31, 2007, interest expense consisted of: $11.9 million of interest on the outstanding debt, net of the impact of the interest rate swap; $0.4 million of commitment fees on the unused portion of the Credit Agreement; and $1.0 million of amortization of the discount on the Senior Notes and deferred debt issuance costs. For the year ended December 31, 2006, interest expense consisted of: $11.6 million of interest on the outstanding debt, net of the impact of the interest rate swap; $0.5 million of commitment fees on the unused portion of the Credit Agreement; and $1.0 million of amortization of the discount on the Senior Notes and deferred debt issuance costs.

Minority Interest in Earnings of Rio Grande

The minority interest related to the 30% of Rio Grande that we do not own reduced our income by $1.1 for the year ended December 31, 2007 as compared to $0.7 million for the year ended December 31, 2006.

State Income Tax

In May 2006, the State of Texas enacted a bill that replaced the existing franchise tax with a margin tax. Effective January 1, 2007, the margin tax applies to legal entities conducting business in Texas, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The margin tax 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. As a result, we recorded $0.3 million in state income tax for the year ended December 31, 2007 that is solely attributable to the Texas margin tax. There was no comparable state income tax for the year ended December 31, 2006.

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Results of Operations Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Summary

Net income was $27.5 million for the year ended December 31, 2006, an increase of $0.7 million from $26.8 million for the year ended December 31, 2005. The increase in overall earnings was principally due to the earnings generated from the Intermediate Pipelines acquired from Holly on July 8, 2005, for which we realized earnings for only six months in 2005, and increases in volumes transported by affiliates on our intermediate and refined product pipeline systems following Holly s completion in June 2006 of an expansion of the Navajo Refinery. Also favorably impacting earnings in 2006 were the effects of the annual tariff increases on our pipelines and the recognition of certain previously deferred revenue. Partially offsetting these positive factors was a reduction of volumes transported and terminalled in the second quarter of 2006 due to significant refinery downtime experienced by all of the refineries utilizing our refined product distribution network (described below) and higher interest expense principally related to the senior notes issued in connection with the pipeline and terminal assets acquired from Alon in early 2005 and the Intermediate Pipelines acquired from Holly in July 2005.

Revenues

Revenues of $89.2 million for the year ended December 31, 2006 were $9.1 million greater than the $80.1 million for the comparable period of 2005. This increase was principally due to an increase in volumes transported on the pipeline and terminal assets acquired from Alon in early 2005 and the Intermediate Pipelines acquired from Holly in July 2005, for which we realized revenues for only ten and six of the twelve months of 2005, respectively. Additionally, favorably impacting revenues for the year ended December 31, 2006 was the recognition of certain previously deferred revenue, an increase in volumes transported by affiliates following the Navajo Refinery expansion, and the effects of the annual tariff increases on our pipelines. Partially offsetting these increases, was a reduction of volumes transported and terminalled in the second quarter of 2006 due to significant refinery downtime experienced by all of the refineries utilizing our refined product distribution network as discussed below. Also impacting revenue for the year ended December 31, 2006, BP completed its obligation to pay the border crossing fee under BP s Rio Grande Pipeline contract in 2005. We did not have border crossing fee revenues for the year ended December 31, 2006, due to the fulfillment of this contract.

Refineries served by our product distribution network incurred significant downtime during the second quarter of 2006. Refiners were generally required to start producing ULSD fuel by June 2006. To meet this requirement, many refiners, including Holly s Navajo Refinery and Alon s Big Spring Refinery, required downtime at their refineries so that ULSD-associated projects could be brought on line. Additionally, Holly completed an expansion of the Navajo Refinery during this period of downtime which resulted in additional unit downtime. The tie-in of these new projects coming on line, combined with other refinery maintenance, much of which was timed in conjunction with the capital projects, resulted in reduced refinery production, which was the principal factor contributing to a significant volume decrease during the second quarter of 2006.

Revenues from refined product pipelines increased by $2.7 million from $60.7 million for the year ended December 31, 2005 to $63.4 million for the year ended December 31, 2006. Shipments on our refined product pipelines averaged 131.9 mbpd for the year ended December 31, 2006 as compared to 131.3 mbpd for the year ended December 31, 2005. Refined product pipeline revenues for the year ended December 31, 2006 were negatively impacted due to BP s completion of its border crossing fee obligations under BP s Rio Grande Pipeline contract in early 2005. We had no border crossing fee revenues for the year ended December 31, 2006 as compared to $0.8 million in 2005 due to the fulfillment of this contract.

Revenues from the intermediate pipelines increased by $6.1 million from $4.6 million for the year ended December 31, 2005 to $10.7 million for the year ended December 31, 2006. This increase includes $1.0 million attributable to the recognition of previously deferred revenue as the contractual period for us to provide certain pipeline services had expired. Shipments on the Intermediate Pipelines averaged 57.7 mbpd for the year ended December 31, 2006 as compared to 28.3 mbpd for the year ended December 31, 2005. The increase was principally due to realizing revenues for a full twelve months of volumes during the year ended December 31, 2006, while we realized revenues for only six months during the year ended December 31, 2005.

Revenues from terminal and truck loading rack service fees increased by $0.4 million from $14.7 million for the year ended December 31, 2005 to $15.1 million for the year ended December 31, 2006, principally due to rates increases in terminal fees charged to our affiliates. Refined products terminalled in our facilities for the comparable periods decreased to 161.5 mbpd in the year ended December 31, 2006 from 163.1 mbpd in the year ended December 31, 2005.

Operations Expense

Operations expense increased $3.3 million from the year ended December 31, 2005 to the year ended December 31, 2006. This increase in expense was principally due to $2.2 million of increased direct operating costs relating to the assets acquired from Alon and direct operating costs of $0.7 million for the Intermediate Pipelines that were acquired in July 2005. Additionally impacting operations expense were other year-over-year increases in pipeline and terminal maintenance expense and direct operating costs relating to the personnel who support our operations.

Depreciation and Amortization

Depreciation and amortization was $1.1 million higher in the year ended December 31, 2006 than in the year ended December 31, 2005, due principally to the increase in depreciation from the pipeline and terminal assets acquired from Alon in 2005.

General and Administrative

General and administrative costs were $4.9 million for the year ended December 31, 2006, an increase of $0.9 million from $4.0 million for the year ended December 31, 2005 due mainly to equity-based compensation expense and business development costs.

Interest Expense

Interest expense for the year ended December 31, 2006 totaled $13.1 million, an increase of $3.5 million from $9.6 million for the year ended December 31, 2005. The increase is due to the debt issued in connection with the Alon and Intermediate Pipelines acquisitions. In the year ended December 31, 2006, interest expense consisted of: $11.6 million of interest on the outstanding debt, net of the impact of the interest rate swap; $0.5 million of commitment fees on the unused portion of the Credit Agreement; and $1.0 million of amortization of the discount on the Senior Notes and deferred debt issuance costs. In the year ended December 31, 2005, interest expense consisted of: $8.4 million of interest on the outstanding debt, net of the impact of the interest rate swap; $0.4 million of commitment fees on the unused portion of the Credit Agreement; and $0.8 million of amortization of the discount on the Senior Notes and deferred debt issuance costs.

Minority Interest in Earnings of Rio Grande

The minority interest related to the 30% of Rio Grande that we do not own for the year ended December 31, 2006 was comparable to the year ended December 31, 2005. The minority interest in Rio Grande reduced our income by $0.7 million for the years ended December 31, 2006 and 2005.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

In August 2007, we entered into an amended and restated four-year, $100.0 million senior secured revolving Credit Agreement expiring in August 2011 that amends and restates our previous senior credit agreement in its entirety. Union Bank of California, N.A. is one of the lenders and serves as administrative agent under this agreement. The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. As of December 31, 2007 and December 31, 2006, we had no amounts outstanding under the Credit Agreement.

We financed the $120.0 million cash portion of the consideration for the Alon transaction through our private offering on February 28, 2005 of $150.0 million of 6.25% Senior Notes due 2015. We used the balance to repay $30.0 million of outstanding indebtedness under our Credit Agreement, including $5.0 million drawn shortly before the closing of the Alon transaction. We financed a portion of the cash consideration for the Intermediate Pipelines transaction with the private offering in June 2005 of an additional $35.0 million in principal amount of the Senior Notes. On July 28, 2005, we filed a registration statement to allow the holders of the Senior Notes to exchange the Senior Notes for exchange notes registered with the SEC with substantially identical terms, which exchange was completed in October 2005.

We financed a portion of the cash consideration paid for the Intermediate Pipelines with $45.1 million of proceeds raised from the private sale of 1,100,000 of our common units to a limited number of institutional investors which closed simultaneously with the closing of the acquisition of the Intermediate Pipelines on July 8, 2005. On September 2, 2005, we filed a registration statement with the SEC using a shelf registration process which allows the institutional investors to freely transfer their units. Additionally under this shelf process, we may offer from time to time up to $800.0 million of our 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 our Credit Agreement will provide sufficient resources to meet our working capital liquidity needs for the foreseeable future. In February, May, August and November 2007, we paid regular quarterly cash distributions of $0.675, $0.69, $0.705 and $0.715, respectively, on all units, an aggregate amount of $48.0 million. Included in these distributions was an aggregate of $2.2 million paid to the general partner as incentive distributions, as the quarterly distributions per unit exceeded the target distribution amount of $0.55.

Cash and cash equivalents decreased by $1.2 million during the year ended December 31, 2007. The cash flows used for financing activities of $50.7 million and cash flows used for investing activities of $9.6 million, exceeded cash flows generated from operating activities of $59.1 million. Working capital decreased by $4.0 million to $5.4 million during the year ended December 31, 2007.

Cash Flows Operating Activities

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Cash flows from operating activities increased by $13.2 million from $45.9 million for the year ended December 31, 2006 to $59.1 million for the year ended December 31, 2007. This increase is principally due to $14.8 million in additional cash collections from our major customers, resulting principally from increased revenues and shortfall billings, partially offset by miscellaneous year-over-year changes in collections and payments.

As discussed above, our major shippers are obligated to make deficiency payments to us if we do not receive certain minimum revenue payments. Certain of these shippers then have the right to recapture these amounts if future volumes exceed minimum levels. For the year ended December 31, 2007, we received cash payments of $4.6 million under these commitments. We billed $5.5 million during the year ended December 31, 2006 related to shortfalls that occurred in 2006, of which $5.5 million expired without recapture and was recognized as revenue in the year ended December 31, 2007. Another $0.4 million is included in our accounts receivable at December 31, 2007 related to shortfalls that occurred in the fourth quarter of 2007.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Cash flows from operating activities increased by $3.3 million from $42.6 million for the year ended December 31, 2005 to $45.9 million for the year ended December 31, 2006. This increase is principally due to $13.5 million additional cash collections from customers on the Alon assets and Intermediate Pipelines purchased in 2005. This increase of cash collections is partially offset by increased operations expense of $2.8 million on these new assets and increased cash payments for interest of $7.1 million, principally on the debt issued for these acquisitions. The remaining decrease in cash flows from operating activities is due to miscellaneous year-over-year changes in collections and payments, offset by lower pre-payments in 2006.

For the year ended December 31, 2006, we received cash payments of $5.6 million under minimum revenue commitments, of which $0.9 million was recaptured in 2006. We billed $1.0 million during the year ended December 31, 2005 related to shortfalls that occurred in 2005, which expired without recapture and was recognized as revenue in the year ended December 31, 2006. Another $1.3 million is included in our accounts receivable at December 31, 2006 related to shortfalls that occurred in the fourth quarter of 2006.

Cash Flows Investing Activities

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Cash flows used for investing activities increased by $0.5 million from $9.1 million for the year ended December 31, 2006 to $9.6 million for the year ended December 31, 2007. Additions to properties and equipment for the year ended December 31, 2007 was $10.0 million, an increase of $0.9 million from $9.1 million for the year ended December 31, 2006. During the year ended December 31, 2007, we also received cash proceeds of $0.3 million related to the sale of certain assets.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Cash flows used for investing activities decreased by $122.7 million from $131.8 million for the year ended December 31, 2005 to $9.1 million for the year ended December 31, 2006. On February 28, 2005, we closed on the Alon transaction which required $120.0 million in cash plus transaction costs of $2.0 million. Additionally, we issued 937,500 Class B subordinated units valued at $24.7 million to Alon as part of the consideration. See Alon Transaction below for additional information. On July 8, 2005, we closed on the acquisition of the Holly Intermediate Pipelines for $81.5 million, which consisted of $77.7 million in cash, 70,000 common units of HEP and a capital account credit of $1.0 million to maintain Holly s existing general partner interest in the Partnership. As this was a transaction between entities under common control, we recorded the acquired assets at Holly s historic book value. This resulted in payment to Holly of a purchase price of $71.9 million in excess of the basis of the assets received, which is included in cash flows from financing activities. See Holly Intermediate Pipelines Transaction below for additional information. Additions to properties and equipment for the year ended December 31, 2006 was $9.1 million, an increase of $5.2 million from $3.9 million for the year ended December 31, 2005.

Cash Flows Financing Activities

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Cash flows used for financing activities increased by $4.9 million from $45.8 million for the year ended December 31, 2006 to $50.7 million for the ended December 31, 2007. During the year ended December 31, 2007, we paid cash distributions on all units and the general partner interest in the aggregate amount of $48.0 million, an increase of $4.3 million from $43.7 million in distributions paid during the year ended December 31, 2006. Cash distributions paid to the minority interest owner in Rio Grande was $1.3 million for the year ended December 31, 2007, a decrease of $0.2 million from $1.5 million in distributions paid for the year ended December 31, 2006. Cash paid for the purchase of our common units for restricted grants was $1.1 million for the year ended December 31, 2007, an increase of $0.5 million from $0.6 million for the year ended December 31, 2006. Also for the year ended December 31, 2007, we paid $0.3 million in deferred financing costs that were attributable to the amendment to our Credit Agreement.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Cash flows used for financing activities increased by $136.4 million to $45.8 million for the year ended December 31, 2006. This compared to cash flows provided by financing activities of $90.6 million for the year ended December 31, 2005. In February 2005, we received proceeds of $147.4 million from the issuance of Senior Notes in connection with the Alon asset acquisition. Additionally, we used proceeds from the original Senior Note offering to repay $30.0 million of outstanding indebtedness under our Credit Agreement, including $5.0 million drawn shortly before the closing of the Alon transaction. In June 2005, in anticipation of the July Holly Intermediate Pipelines transaction, we received additional proceeds from Senior Notes issued of $33.8 million. See Senior Notes Due 2015 below for additional information. We financed a portion of the cash consideration paid for the Intermediate Pipelines with $45.1 million of proceeds raised from the private sale of 1,100,000 of our common units to a limited number of institutional investors which closed simultaneously with the closing of the acquisition of the Intermediate Pipelines on July 8, 2005. During the year ended December 31, 2006, we paid cash distributions on all units and the general partner interest in the aggregate amount of $43.7 million, an increase of $8.7 million from $35.0 million in distributions paid during the year ended December 31, 2005. Cash distributions paid to the minority interest owner in Rio Grande was $1.5 million for the year ended December 31, 2006, a decrease of $0.7 million from $2.2 million for the year months ended December 31, 2005. Cash paid for the purchase of our common units for restricted grants was $0.6 million for each of the years ended December 31, 2006 and 2005. Also for the year ended December 31, 2005, we received an additional $0.6 million capital contribution from our general partner and paid $1.2 million in deferred debt issuance costs.

Capital Requirements

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of, and are expected to continue to consist of, maintenance capital expenditures and expansion capital expenditures. Maintenance capital expenditures represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity of existing assets. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, and 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, special projects may be approved. The funds allocated to 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.

In October 2007, we entered into an agreement with Holly that amends the Holly PTA under which we have agreed to expand our South System between Artesia, New Mexico and El Paso, Texas. The expansion of the South System will include replacing 85 miles of 8-inch pipe with 12-inch pipe, adding 150,000 barrels of refined product storage at our El Paso Terminal, improving existing pumps, adding a tie-in to the Kinder Morgan pipeline to Tucson and Phoenix, Arizona, and making related modifications.

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The cost of this project is estimated to be $48.3 million. Currently, we are expecting to complete this project by January 2009. The agreement also provides for a tariff increase, expected to be effective May 1, 2008, on Holly shipments on our refined product pipelines.

In November 2007, we announced an agreement in principle for the acquisition of certain pipeline and tankage assets from Holly for approximately $180.0 million. The consideration is expected to consist of $171.0 million in cash and our common units valued at approximately $9.0 million. The assets include 136 miles of crude oil trunk lines that deliver crude to Holly s Navajo Refinery in southeast New Mexico, approximately 725 miles of gathering and connection pipelines located in west Texas and New Mexico, on-site crude tankage having a combined 600,000 barrels of storage capacity located within the Navajo and Woods Cross refinery complexes, a jet fuel products pipeline and terminal (terminal leased through September 2011) between Artesia and Roswell, New Mexico, and 10 miles of crude oil and product pipelines that support Holly s Woods Cross Refinery. In connection with the closing of this proposed transaction, we intend to enter into a 15-year pipelines and tankage agreement with Holly that will contain a minimum annual revenue commitment to us from Holly. Both the HLS and Holly boards of directors have approved this proposed transaction, which we expect to close in the first quarter of 2008.

In November 2007, we executed a definitive agreement with Plains to acquire a 25% joint venture interest in a new 95-mile intrastate pipeline system now under construction by Plains, for the shipment of up to 120,000 bpd of crude oil into the Salt Lake City area. Under the agreement, the SLC Pipeline will be owned by a joint venture company which will be owned 75% by Plains and 25% by us. Subject to the actual cost of the SLC Pipeline, we will purchase our 25% interest in the joint venture for an amount between $22.0 and $25.5 million in the second quarter of 2008, when the SLC Pipeline is expected to become fully operational. The SLC Pipeline will allow various refiners in the Salt Lake City area, including Holly s Woods Cross refinery, to ship crude oil into the Salt Lake City area from the Utah terminus of the Frontier Pipeline as well as crude oil from Wyoming and Utah, which is currently flowing on Plains Rocky Mountain Pipeline.

On January 31, 2008, we entered into an option agreement with Holly, granting us an option to purchase all of Holly s equity interests in a joint venture pipeline currently under construction. The pipeline will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada. Holly currently owns 75% of the equity interests in the UNEV Pipeline. Under this agreement, we have an option to purchase Holly s equity interests in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to Holly s investment in the joint venture pipeline, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The total cost of the pipeline project including terminals is expected to be $300.0 million. Holly s share of this cost is $225.0 million. Construction of this project is currently expected to be completed and operational in mid 2009.

We are also studying several other projects, which are in various stages of analysis.

We expect that our currently planned expenditures for sustaining and maintenance capital as well as expenditures for capital development projects such as the UNEV Pipeline, SLC Pipeline and South System expansion projects described above will be funded with existing cash balances, cash generated by operations, the sale of additional limited partner units and advances under our Credit Agreement.

Additionally, we plan to upsize our Credit Agreement to fund the cash portion of the consideration for our announced purchase of certain pipeline and tankage assets from Holly described above.

Credit Agreement

In August 2007, we entered into an amended and restated four-year, $100.0 million senior secured revolving credit agreement expiring in August 2011 that amends and restates our previous senior credit agreement in its entirety. Union Bank of California, N.A. is a lender and serves as administrative agent under this agreement. The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. Advances under the Credit Agreement that are designated for working capital are short-term liabilities. Other advances under the Credit Agreement are classified as long-term liabilities. In addition, the Credit Agreement is available to fund letters of credit up to a $50.0 million sub-limit. Up to $20.0 million is available to fund distributions to unitholders. As of December 31, 2007, we had no amounts outstanding under the Credit Agreement.

We have the right to request an increase in the maximum amount of the Credit Agreement, up to $200.0 million. Such request will become effective if (a) certain conditions specified in the Credit Agreement are met and (b) existing lenders under the Credit Agreement or other financial institutions reasonably acceptable to the administrative agent commit to lend such increased amounts under the agreement.

Our obligations under the Credit Agreement are secured by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to our general partner and guaranteed by our wholly-owned subsidiaries.

We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs. We are required to reduce all working capital borrowings under the Credit Agreement to zero for a period of at least 15 consecutive days once each twelve-month period prior to the maturity date of the agreement.

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 0.25% to 1.50%) or (b) at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin (ranging from 1.00% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the 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 a rate ranging from 0.20% or 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters. The agreement matures in August 2011. At that time, the agreement will terminate and all outstanding amounts thereunder will be due and payable.

The Credit Agreement imposes certain requirements, 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 and debt to EBITDA ratio. If an event of default exists under the agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes Due 2015

Our Senior Notes mature on March 1, 2015 and bear interest at 6.25%. The Senior Notes are unsecured and impose certain restrictive covenants, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. 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.

The $185.0 million principal amount of Senior Notes is recorded at $181.4 million on our accompanying consolidated balance sheet at December 31, 2007. The difference of $3.6 million is due to the $2.7 million unamortized discount and $0.9 million relating to the fair value of the interest rate swap contract as further discussed under Risk Management.

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The following table presents our long-term contractual obligations as of December 31, 2007.

The pipeline operating lease amounts below reflect the exercise of the first of three 10-year extensions, effective July 2007, 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 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 below include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2007. 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 below.

In consideration for Holly s assistance in obtaining our joint venture opportunity in the SLC Pipeline discussed under Capital Requirements , we will pay Holly a $2.5 million finder s fee upon the closing of our investment in the joint venture with Plains.

		Payments Due by Period			
	Total	Less than 1 Year	2-3 Years	4-5 Years	Over 5 Years
			(In thousands)		
Long-term debt principal	$ 185,000	$	$	$	$ 185,000
Long-term debt interest	86,719	11,563	23,125	23,125	28,906
Pipeline operating lease	55,625	5,855	11,711	11,711	26,348
Right of way leases	1,646	497	161	82	906
Other	23,724	5,066	4,841	4,367	9,450
Total	$ 352,714	$ 22,981	$ 39,838	$ 39,285	$ 250,610

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2007, 2006 and 2005.

A substantial majority of our revenues are generated under long-term contracts that include the right to increase our rates and minimum revenue guarantees annually for increases in the PPI. Historically, the PPI has increased an average of 3.7% annually over the past 5 calendar years.

Environmental Matters

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. For additional discussion on environmental matter, please see Environmental Regulation and Remediation under Item 1, Business .

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.

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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 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 receives the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- we determine a high likelihood that we will not be required to provide services within the allowed period.

We recognize shortfall billings as revenue prior to the expiration of the contractual term period to provide services only when we determine with a high likelihood that we will not be required to provide services within the allowed period. We determine this when based on current and projected shipping levels, that 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 and the customer acknowledges that its anticipated shipment levels will not permit it to utilize such a shortfall credit within the respective contractual make up period. To date, we have not recognized any shortfall billings as revenue prior to the expiration of the contractual term period.

Long-Lived Assets

We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. We evaluate long-lived 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. Estimates of future discounted cash flows and fair value of assets require subjective assumptions with regard to future operating results, and actual results could differ from those estimates. No impairments of long-lived assets were recorded during the years ended December 31, 2007, 2006 and 2005.

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.

Recent Accounting Pronouncements

Interpretation No. 48 Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We adopted this standard effective January 1, 2007. The adoption of this standard did not have a material impact on our financial condition, results of operations and cash flows.

Statement of Financial Accounting Standards (SFAS) No. 157 Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

SFAS No. 133 Implementation Issue No. E23 Issues Involving the Application of the Shortcut Method under Paragraph 68

In January 2008, the FASB posted SFAS No. 133 Implementation Issue No. E23, Issues Involving the Application of the Shortcut Method under Paragraph 68. This standard addresses issues pertaining to the application of the shortcut method in accounting for hedges when the settlement of a hedged item occurs subsequent to the interest rate swap trade date. It also addresses hedging relationships when the transaction price of an interest rate swap is zero. This standard is effective for hedging relationships designated on or after January 1, 2008 and requires the reassessment of preexisting hedges utilizing the shortcut method under this new guidance. While we are currently evaluating this standard, we do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

RISK MANAGEMENT

We have entered into an interest rate swap contract to effectively convert the interest expense associated with $60.0 million of our 6.25% Senior Notes from a fixed rate to variable rates. Under the swap agreement, we receive 6.25% fixed rate on the notional amount and pay a variable rate equal to three month LIBOR plus an applicable margin of 1.1575%. The variable rate being paid on the notional amount at December 31, 2007 was 6.281%, including the applicable margin. The maturity of the swap contract is March 1, 2015, matching the maturity of the Senior Notes. This interest rate swap has been designated as a fair value hedge as defined by SFAS No. 133. Our interest rate swap meets the conditions required to assume no ineffectiveness under SFAS No. 133 and, therefore, we have used the shortcut method of accounting prescribed for fair value hedges by SFAS No. 133. Accordingly, we adjust the carrying value of the swap to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swaps.

The fair value of the interest rate swap agreement of $0.9 million is included in Other long-term liabilities in our accompanying consolidated balance sheet at December 31, 2007. The offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged is recognized as a reduction of Long-term debt on our accompanying consolidated balance sheet at December 31, 2007.

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

At December 31, 2007, we had an outstanding principal balance on our Senior Notes of $185.0 million. By means of our interest rate swap contract, we have effectively converted $60.0 million of the Senior Notes from a fixed rate to variable rate. For the fixed rate debt portion of $125.0 million, changes in interest rates would generally affect the fair value of the debt, but not our earnings or cash flows. Conversely, for the variable rate debt portion of $60.0 million, changes in interest rates would generally not impact the fair value of the debt, but may affect our future earnings and cash flows. We estimate a hypothetical 10% change in the yield-to-maturity applicable to our fixed rate debt portion of $125.0 million as of December 31, 2007 would result in a change of approximately $4.9 million in the fair value of the debt. A hypothetical 10% change in the interest rate applicable to our variable rate debt portion of $60.0 million would not have a material effect on our earnings or cash flows.

At December 31, 2007, our cash and cash equivalents included highly liquid investments with a maturity of three months or less at the time of purchase. Due to the short-term nature of our cash and cash equivalents, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our operating results or cash flows to be materially affected to any significant degree by the effect of a sudden change in market interest rates on our investment portfolio.

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.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. See Risk Management under Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of market risk exposures that we have with respect to our cash and cash equivalents and 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 market risks associated with commodity prices.

Item 8. Financial Statements and Supplementary Data

MANAGEMENT S REPORT ON ITS ASSESSMENT OF THE COMPANY 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, 2007 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 believes that, as of December 31, 2007, 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, 2007. That report appears on page 57.

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 (the Partnership) internal control over financial reporting as of December 31 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Partnership s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management s report. Our responsibility is to express an opinion on the effectiveness of 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, 2007, 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, 2007 and 2006, and the related consolidated statements of income, partners equity (deficit), and cash flows for each of the three years in the period ended December 31, 2007 of Holly Energy Partners, L.P. and our report dated February 14, 2008, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 14, 2008

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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, 2007 and 2006, and the related consolidated statements of income, partners equity (deficit), and cash flows for each of the three years in the period ended December 31, 2007. 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Holly Energy Partners, L.P. at December 31, 2007 and 2006, and the related consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2007 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, 2007, 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 14, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 14, 2008

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Holly Energy Partners, L.P.
Consolidated Balance Sheets

	December 31, 2007	December 31, 2006
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,321	$ 11,555
Accounts receivable:		
Trade	6,611	7,339
Affiliates	5,700	5,716
	12,311	13,055
Prepaid and other current assets	546	1,212
Total current assets	23,178	25,822
Properties and equipment, net	158,600	160,484
Transportation agreements, net	54,273	56,821
Other assets	2,853	2,644
Total assets	$ 238,904	$ 245,771
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable	$ 3,011	$ 3,781
Accounts payable affiliates	6,021	2,198
Accrued interest	2,996	2,941
Deferred revenue	3,700	5,486
Accrued property taxes	1,177	868
Other current liabilities	827	1,098
Total current liabilities	17,732	16,372
Commitments and contingencies		
Long-term debt	181,435	180,660
Other long-term liabilities	1,181	1,550
Minority interest	10,740	10,963
Partners equity (deficit):		
Common unitholders (8,170,000 units issued and outstanding at December 31, 2007 and 2006)	172,807	176,844
Subordinated unitholders (7,000,000 units issued and outstanding at December 31, 2007 and 2006)	(73,725)	(70,022)

Class B subordinated unitholders (937,500 units issued and outstanding at December 31, 2007 and 2006)	22,973	23,469
General partner interest (2% interest)	(94,239)	(94,065)
Total partners equity	27,816	36,226
Total liabilities and partners equity	$ 238,904	$ 245,771

See accompanying notes.

Holly Energy Partners, L.P.
Consolidated Statements of Income

	Years Ended December 31,		
	2007	2006	2005
	(In thousands, except per unit data)		
Revenues:			
Affiliates	$ 60,961	$ 52,878	$ 44,184
Third parties	41,698	36,316	35,936
	102,659	89,194	80,120
Affiliates other	2,748		
	105,407	89,194	80,120
Operating costs and expenses:			
Operations	32,911	28,630	25,332
Depreciation and amortization	14,382	15,330	14,201
General and administrative	5,043	4,854	4,047
	52,336	48,814	43,580
Operating income	53,071	40,380	36,540
Other income (expense):			
Interest income	533	899	649
Interest expense	(13,289)	(13,056)	(9,633)
Gain on sale of assets	298		
	(12,458)	(12,157)	(8,984)
Income before minority interest	40,613	28,223	27,556
Minority interest in Rio Grande Pipeline Company	(1,067)	(680)	(740)
Income before income taxes	39,546	27,543	26,816
State income tax	(275)		
Net income	39,271	27,543	26,816
Less general partner interest in net income	2,932	1,710	721

Limited partners interest in net income	$ 36,339	$ 25,833	$ 26,095
Net income per limited partners unit - basic and diluted	$ 2.26	$ 1.60	$ 1.70
Weighted average limited partners units outstanding	16,108	16,108	15,356

See accompanying notes.

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Holly Energy Partners, L.P.
Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flows from operating activities			
Net income	$ 39,271	$ 27,543	$ 26,816
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	14,382	15,330	14,201
Minority interest in Rio Grande Pipeline Company	1,067	680	740
Amortization of restricted and performance units	1,375	927	207
Gain on sale of assets	(298)		
(Increase) decrease in current assets:			
Accounts receivable	728	(4,263)	(2,338)
Accounts receivable affiliates	16	(637)	(1,758)
Prepaid and other current assets	666	115	(1,499)
Increase (decrease) in current liabilities:			
Accounts payable	(770)	761	1,305
Accounts payable affiliates	3,823	764	164
Accrued interest	55	49	2,840
Deferred revenue	(1,786)	4,473	1,013
Accrued property taxes	309	(144)	700
Other current liabilities	(271)	(215)	(20)
Other, net	489	470	257
Net cash provided by operating activities	59,056	45,853	42,628
Cash flows from investing activities			
Additions to properties and equipment	(9,957)	(9,107)	(3,883)
Cash proceeds from sale of assets	325		
Acquisitions of pipeline and terminal assets			(127,912)
Net cash used for investing activities	(9,632)	(9,107)	(131,795)
Cash flows from financing activities			
Proceeds from issuance of senior notes, net of discounts			181,238
Proceeds from issuance of common units, net of underwriter discount			45,100
Excess purchase price over contributed basis of intermediate pipelines			(71,850)
Distributions to partners	(47,974)	(43,670)	(35,022)
Repayment of revolving credit agreement			(25,000)
Costs of issuing common units			(349)
Deferred debt issuance costs			(1,228)

Cash distributions to minority interest	(1,290)	(1,470)	(2,220)
Cash contribution from general partner			612
Purchase of units for restricted grants	(1,082)	(634)	(635)
Deferred financing costs	(296)		
Other	(16)		
Net cash provided by (used for) financing activities	(50,658)	(45,774)	90,646
Cash and cash equivalents			
Increase (decrease) for the period	(1,234)	(9,028)	1,479
Beginning of period	11,555	20,583	19,104
End of period	$ 10,321	$ 11,555	$ 20,583

See accompanying notes.

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Holly Energy Partners, L.P.
Consolidated Statements of Partners Equity (Deficit)

	Common Units	Subordinated Units	Class B Subordinated Units	General Partner Interest	Total
			(In thousands)		
Balance December 31, 2004	$ 144,318	$ (59,470)	$	$ (23,320)	$ 61,528
Issuance of common units	45,100				45,100
Cost of issuing common units	(349)				(349)
Issuance of Class B subordinated units			24,674		24,674
Capital contribution				1,591	1,591
Distributions to partners	(16,945)	(15,575)	(1,617)	(885)	(35,022)
Excess purchase price over contributed basis of intermediate pipelines				(71,850)	(71,850)
Purchase of units for restricted grants	(635)				(635)
Amortization of restricted units	207				207
Net income	12,872	11,892	1,331	721	26,816
Balance December 31, 2005	184,568	(63,153)	24,388	(93,743)	52,060
Distributions to partners	(21,120)	(18,095)	(2,423)	(2,032)	(43,670)
Purchase of units for restricted grants	(634)				(634)
Amortization of restricted units	927				927
Net income	13,103	11,226	1,504	1,710	27,543
Balance December 31, 2006	176,844	(70,022)	23,469	(94,065)	36,226
Distributions to partners	(22,762)	(19,495)	(2,611)	(3,106)	(47,974)
Purchase of units for restricted grants	(1,082)				(1,082)
Amortization of restricted and performance units	1,375				1,375
Net income	18,432	15,792	2,115	2,932	39,271
Balance December 31, 2007	$ 172,807	$ (73,725)	$ 22,973	$ (94,239)	$ 27,816

See accompanying notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2007

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

Description of Business

Holly Energy Partners, L.P. (HEP) together with its consolidated subsidiaries, is a publicly held master limited partnership, currently 45% owned by Holly Corporation (Holly). 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 u refer to HEP unless the context otherwise indicates.

We operate in one business segment the operation of petroleum pipelines and terminal facilities.

One of Holly s wholly-owned subsidiaries owns a refinery in Artesia, New Mexico, which Holly operates in conjunction with crude, vacuum distillation and other facilities situated in Lovington, New Mexico (collectively, the Navajo Refinery). In July 2005, we acquired the two parallel intermediate feedstock pipelines (the Intermediate Pipelines), which connect the New Mexico refining facilities. The Navajo Refinery produces high-value refined products such as gasoline, diesel fuel and jet fuel and serves markets in the southwestern United States and northern Mexico. In conjunction with Holly s operation of the Navajo Refinery, we operate refined product pipelines as part of the product distribution network of the Navajo Refinery. Our terminal operations serving the Navajo Refinery include a truck rack at the Navajo Refinery and four integrated refined product terminals located in New Mexico, Texas and Arizona.

Another of Holly s wholly-owned subsidiaries owns a refinery located near Salt Lake City, Utah (the Woods Cross Refinery). Our operations serving the Woods Cross Refinery include a truck rack at the Woods Cross Refinery, a refined product terminal in Spokane, Washington and a 50% non-operating interest in product terminals in Boise and Burley, Idaho.

In February 2005, we acquired from Alon USA, Inc. and several of its wholly-owned subsidiaries (collectively, Alon) four refined products pipelines, an associated tank farm and two refined products terminals. These pipelines and terminals are located primarily in Texas and transport light refined products for Alon s refinery in Big Spring, Texas. Additionally, we own a refined product terminal in Mountain Home, Idaho, and a 70% interest in Rio Grande Pipeline Company (Rio Grande), which provides pipeline transportation of liquid petroleum gases to northern Mexico.

Principles of Consolidation

The consolidated financial statements include our accounts and those of our subsidiaries and Rio Grande. All significant inter-company transactions and balances have been eliminated. The pipeline and terminal assets that were contributed to us from Holly concurrently with the completion of our initial public offering in 2004, as well as the intermediate pipeline assets that were purchased from Holly in July 2005 were accounted for as transactions among entities under common control. Accordingly, these assets were recorded on our balance sheets at Holly s basis instead of the purchase price or fair value.

If the assets acquired from Holly upon our formation and if the intermediate pipelines transaction had been acquired from third parties, the cash payment upon formation of $125.6 million and the excess of the intermediate pipeline purchase price over its basis of $71.9 million would have been recorded as properties or intangible assets instead of reductions of partners equity. Also, the subordinated units issued to Holly would have been recorded at fair value instead of the carryover basis of the contributed assets.

Use of Estimates

The preparation of financial statements in accordance with U.S. generally accepted accounting principles 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.

Reclassifications

In the December 31, 2006 consolidated balance sheet, we have reclassified a $2.2 million liability that was previously netted against our accounts receivable affiliates balance to conform to our 2007 presentation. This liability is now presented as accounts payable affiliates.

Cash and Cash Equivalents

For purposes of the statements of cash flows, we consider all highly liquid investments with maturity of three months or less at the time of purchase to be cash equivalents. The carrying amounts reported on the balance sheet 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 Holly, 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. Depreciation is provided by the straight-line method over the estimated useful lives of the assets; primarily 10 to 16 years for pipeline and terminal facilities, 23 to 33 years for regulated pipelines and 3 to 10 years for corporate and other assets. Maintenance, repairs and major replacements are generally expensed as incurred. Costs of replacements constituting improvement are capitalized.

Transportation Agreements

The transportation agreement assets are stated at cost and are being amortized over the periods of the agreements using the straight-line method.

Long-Lived Assets

We evaluate long-lived assets, including 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. No impairments of long-lived assets were recorded during the periods included in these financial statements.

Asset Retirement Obligations

We record legal obligations associated with the retirement of 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. If a reasonable estimate cannot be made at the time the liability is incurred, we record the liability when sufficient information is available to estimate the liability s fair value.

We have asset retirement obligations with respect to certain of our assets due to legal obligations to clean and/or dispose of various component parts at the time they are retired. At December 31, 2007, an asset retirement obligation of $0.3 million is included in Other long-term liabilities in our consolidated balance sheets.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals. Billings to customers for 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 receives the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- we determine a high likelihood that we will not be required to provide services within the allowed period.

We recognize shortfall billings as revenue prior to the expiration of the contractual term period to provide services only when we determine with a high likelihood that we will not be required to provide services within the allowed period. We determine this when based on current and projected shipping levels, that 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 and the customer acknowledges that its anticipated shipment levels will not permit it to utilize such a shortfall credit within the respective contractual make up period. To date, we have not recognized any shortfall billings as revenue prior to the expiration of the contractual term period.

Additional pipeline transportation revenues result from an operating lease to a third party of an interest in the capacity of one of our pipelines.

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. Environmental costs recoverable through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable.

State Income Tax

In May 2006, the State of Texas enacted a bill that replaced the existing franchise tax with a margin tax. Effective January 1, 2007, the margin tax applies to legal entities conducting business in Texas, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The margin tax 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. As a result, we recorded $0.3 million in state income tax for the year ended December 31, 2007 that is solely attributable to the Texas margin tax.

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

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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. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder s tax accounting, which is partially dependent upon the unitholder s tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder s tax attributes in our partnership is not available to us.

Net Income per Limited Partners Unit

We have identified the general partner interest and the subordinated units as participating securities and 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 (including subordinated units and Class B subordinated units) is computed by dividing limited partners interest in net income, after deducting the general partner s 2% interest and incentive distributions, by the weighted-average number of outstanding common and subordinated units.

Recent Accounting Pronouncements

Interpretation No. 48 Accounting for Uncertainty in Income Taxes"

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We adopted this standard effective January 1, 2007. The adoption of this standard did not have a material impact on our financial condition, results of operations and cash flows.

Statement of Financial Accounting Standards (SFAS) No. 157 Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

SFAS No. 133 Implementation Issue No. E23 Issues Involving the Application of the Shortcut Method under Paragraph 68"

In January 2008, the FASB posted SFAS No. 133 Implementation Issue No. E23, Issues Involving the Application of the Shortcut Method under Paragraph 68. This standard addresses issues pertaining to the application of the shortcut method in accounting for hedges when the settlement of a hedged item occurs subsequent to the interest rate swap trade date. It also addresses hedging relationships when the transaction price of an interest rate swap is zero. This standard is effective for hedging relationships designated on or after January 1, 2008 and requires the reassessment of preexisting hedges utilizing the shortcut method under this new guidance. While we are currently evaluating this standard, we do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

Note 2: Acquisitions

Alon Transaction

On February 28, 2005, we acquired from Alon four refined products pipelines, an associated tank farm and two refined products terminals. These pipelines and terminals are located primarily in Texas and transport and terminal light refined products for Alon s refinery in Big Spring, Texas.

The total consideration paid for these pipeline and terminal assets was $120.0 million in cash and 937,500 of our Class B subordinated units which, subject to certain conditions, will convert into an equal number of common units on February 28, 2010. We financed the Alon transaction with a portion of the proceeds of our private offering of $150.0 million principal amount of 6.25% Senior Notes due 2015 (see Note 6 for further information on the Senior Notes). In connection with the Alon transaction, we entered into a 15-year pipelines and terminals agreement with Alon expiring 2020 (the Alon PTA). Under this agreement, Alon agreed to transport on our pipelines and throughput in our terminals a volume of refined products that would result in minimum revenue levels each year that will change annually based on changes in the PPI, but will not decrease below the initial $20.2 million annual amount. Following the March 1, 2007 PPI rate adjustment, Alon s total minimum commitment for the twelve months ending February 29, 2008 is $20.9 million. The agreed upon tariffs will increase or decrease each year at a rate equal to the percentage change in the PPI, but not below the initial tariffs. Alon s minimum volume commitment was calculated based on 90% of Alon s then recent usage of these pipelines and terminals taking into account an expansion of Alon s Big Spring, Texas refinery (Big Spring Refinery) completed in February 2005. At revenue levels above 105% of the base revenue amount, as adjusted each year for changes in the PPI, Alon will receive an annual 50% discount on incremental revenues. Alon s obligations under the Alon PTA may be reduced or suspended under certain circumstances. We granted Alon a second mortgage on the pipelines and terminals acquired from Alon to secure certain of Alon s rights under the Alon PTA. Alon has a right of first refusal to purchase the pipelines and terminals if we decide to sell them in the future. Additionally, we entered into an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon, under which Alon, for a ten year term expiring in 2015, will indemnify us subject to a $100,000 deductible and a $20.0 million maximum liability cap.

The consideration for the Alon pipeline and terminal assets was allocated to the individual assets acquired based on their estimated fair values. The aggregate consideration amounted to $146.7 million, which consisted of $24.7 million fair value of our Class B subordinated units, $120.0 million in cash and $2.0 million of transaction costs. In accounting for this acquisition, we recorded pipeline and terminal assets of $86.7 million and an intangible asset of $60.0 million, representing the allocated value of the 15-year Alon PTA. This intangible asset is included in Transportation agreements, net in our consolidated balance sheets.

Holly Intermediate Pipelines Transaction

On July 8, 2005, we acquired pursuant to a definitive purchase agreement (the Purchase Agreement) Holly s Intermediate Pipelines which connect its Lovington, New Mexico and Artesia, New Mexico refining facilities. The total consideration was $81.5 million, which consisted of $77.7 million in cash, 70,000 common units of HEP and a capital account credit of $1.0 million to maintain Holly s existing general partner interest in the Partnership. We financed the cash portion of the consideration for the Intermediate Pipelines with the proceeds raised from (a) the private sale of 1,100,000 of our common units for $45.1 million to a limited number of institutional investors which closed simultaneously with the acquisition and (b) an additional $35.0 million in principal amount of our 6.25% Senior Notes due 2015. This acquisition was made pursuant to an option to purchase these pipelines granted by Holly to us at the time of our initial public offering in July 2004.

In connection with this transaction, we entered into a 15-year pipelines agreement with Holly (the Holly IPA) which expires in 2020. Under this agreement, Holly agreed to transport volumes of intermediate products on the Intermediate Pipelines that would result in initial minimum funds to us of $11.8 million each year that will change annually based on changes in the PPI. Following the July 1, 2007 PPI adjustment, the volume commitments by Holly under the Holly IPA will result in minimum funds to us of $12.8 million annually. The agreed upon tariff is adjusted each year at a rate equal to the percentage change in the PPI, but the minimum commitment will not decrease as a result of a decrease in the PPI. Holly s minimum revenue commitment applies only to the Intermediate Pipelines, and Holly will not be able to spread its minimum revenue commitment among pipeline assets HEP already owns or subsequently acquires. If Holly fails to meet its minimum revenue commitment 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. A shortfall payment may be applied as a credit in the following four quarters after Holly s minimum obligations are met. The Holly IPA may be extended by the mutual agreement of the parties.

If new laws or regulations are enacted that require us to make substantial and unanticipated capital expenditures with regard to the Intermediate Pipelines, we have the right to amend the tariff rates to recover our costs of complying with these new laws or regulations (including a reasonable rate of return). Under certain circumstances, either party may temporarily suspend its obligations under the Holly IPA. We granted Holly a second mortgage on the Intermediate Pipelines to secure certain of Holly s rights under the Holly IPA. Holly has agreed to provide $2.5 million of additional indemnification above the initial $15.0 million of indemnification under certain provisions of an omnibus agreement that we entered with Holly in July 2004 (the Omnibus Agreement) that previously provided for environmental noncompliance and remediation liabilities occurring or existing before the closing date of the Purchase Agreement, bringing the total indemnification provided to us from Holly to $17.5 million. Of this total, indemnification above $15.0 million relates solely to the Intermediate Pipelines.

As this transaction was among entities under common control, we recorded the acquired assets at Holly s historic book value of $6.8 million. The $71.9 million excess of the purchase price over the historic book value is recorded as a reduction to partners equity for financial accounting purposes.

Note 3: Properties and Equipment

	December 31, 2007	December 31, 2006
	(In thousands)	
Pipelines and terminals	$ 196,800	$ 195,688
Land and right of way	22,825	22,486
Other	5,706	5,267
Construction in progress	9,103	1,539
	234,434	224,980
Less accumulated depreciation	75,834	64,496
	$ 158,600	$ 160,484

During the years ended December 31, 2007 and 2006, we did not capitalize any interest related to major construction projects.

Note 4: Transportation Agreements

Our transportation agreements consist of the following:

The Alon transportation agreement represents a portion of the total purchase price of the Alon assets that was allocated based on an estimated fair value derived under the income approach. This asset is being amortized over 30 years ending 2035, the 15-year initial term of the Alon PTA plus the expected 15-year extension period.

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The Rio Grande transportation agreement represented costs incurred by Rio Grande in constructing certain pipeline and terminal facilities located in Mexico, which were then contributed to an affiliate of Pemex, the national oil company of Mexico. In exchange, Rio Grande received a 10-year transportation agreement from BP plc (BP). The initial 10-year term of this agreement expired in April 2007. The agreement was extended for an additional year and expires in April 2008. The carrying amount of this asset was fully amortized and retired in April 2007.

The carrying amounts of the transportation agreements are as follows:

	December 31,	
	2007	2006
	(In thousands)	
Alon transportation agreement	$ 59,933	$ 59,933
Rio Grande transportation agreement		20,836
	59,933	80,769
Less accumulated amortization	5,660	23,948
	$ 54,273	$ 56,821

Note 5: Employees, Retirement and Benefit Plans

Employees who provide direct services to us are employed by Holly Logistic Services, L.L.C. (HLS), a Holly subsidiary. Their costs, including salaries, bonuses, payroll taxes, benefits, and other direct costs, are charged to us monthly in accordance with the Omnibus Agreement.

These employees participate in the retirement and benefit plans of Holly. Our share of retirement and benefit plan costs for the years ended December 31, 2007, 2006 and 2005 was $1.3 million, $1.4 million and $0.9 million, respectively. Included in these amounts are retirement costs of $0.6 million, $0.5 million and $0.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

We have adopted a Long-Term Incentive Plan for employees, consultants and 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.

On December 31, 2007, we had two types of equity-based compensation, which are described below. The compensation cost charged against income for these plans was $1.3 million, $0.9 million and $0.2 million for the years ended December 31, 2007, 2006 and 2005, respectively. It is currently our policy to purchase units in the open market instead of issuing new units for settlement of restricted unit grants. At December 31, 2007, 350,000 units were authorized to be granted under the equity-based compensation plans, of which 260,115 had not yet been granted.

We elected early adoption of SFAS No. 123 (revised) on July 1, 2005, based on modified prospective application. The effect of this change in accounting principle was immaterial to our financial condition and results of operations.

Restricted Units

Under our Long-Term Incentive Plan, we grant restricted units to selected employees, consultants and directors who perform services for us, with vesting generally over a period of one to five years. Certain restricted units granted to our directors vest quarterly. 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 vesting for certain key executives is contingent upon certain earnings per unit targets being realized. The fair value of each unit of restricted unit awards was measured at the market price as of the date of grant and is being amortized over the vesting period, including the units issued to the key executives, as we expect those units to fully vest.

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A summary of restricted unit activity and changes during the year ended December 31, 2007 is presented below:

Restricted Units	Grants	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2007 (not vested)	36,597	$ 40.21		
Granted	23,523	47.10		
Forfeited	(1,555)	44.17		
Vesting and transfer of full ownership to recipients	(13,854)	36.74		
Outstanding at December 31, 2007 (not vested)	44,711	$ 44.77	1.2 years	$ 1,956

During the year ended December 31, 2007, 13,854 restricted units having an intrinsic value of $0.6 million and a fair value of $0.5 million were vested and transferred to recipients of our restricted unit grants. There were no restricted units vested or transferred to recipients during the years ended December 31, 2006 and 2005. As of December 31, 2007, there was $0.7 million of total unrecognized compensation costs related to nonvested restricted unit grants. That cost is expected to be recognized over a weighted-average period of 1.2 years.

In 2007, we paid $1.1 million for the purchase of 23,523 of our common units in the open market for the recipients of all 2007 restricted unit grants.

Performance Units

Under our Long-Term Incentive Plan, we grant performance units to selected executives and employees who perform services for us. These performance units are payable upon meeting the performance criteria over a service period, and generally vest over a period of three years. The amount payable under the initial performance grant of 1,514 units in 2005 is based upon our unit price and upon our total unitholder return during the requisite period as compared to the total unitholder return of a selected peer group of partnerships. The amount payable under all other performance unit grants is based upon the growth in distributions per limited partner unit during the requisite period.

We granted 12,321 performance units to certain officers in February 2007. These units will vest over a three-year performance period ending December 31, 2009, and are payable in HEP common units. The number of units actually earned will be based on the growth of distributions to limited partners over the performance period, and can range from 50% to 150% of the number of performance units issued. The fair value of these performance units is based on the grant date closing unit price of $46.12 and will apply to the number of units ultimately awarded.

A summary of performance unit activity and changes during the year ended December 31, 2007 is presented below:

Performance Units	Payable In Units
Outstanding at January 1, 2007 (not vested)	14,016
Vesting and payment of units to recipients	
Granted	12,321
Forfeited	(2,189)
Outstanding at December 31, 2007 (not vested)	24,148

There were no payments or units issued for performance units vesting during the years ended December 31, 2007, 2006 and 2005. Based on the weighted average fair value at December 31, 2007 of $46.43, there was $0.7 million of total unrecognized compensation cost related to nonvested performance units. That cost is expected to be recognized over a weighted-average period of 1.5 years.

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Note 6: Debt

Credit Agreement

In August 2007, we entered into an amended and restated four-year, $100.0 million senior secured revolving credit agreement expiring in August 2011 (the Credit Agreement) that amends and restates our previous senior credit agreement in its entirety. Union Bank of California, N.A. is one of the lenders and serves as administrative agent under this agreement. As of December 31, 2007 and December 31, 2006, we had no amounts outstanding under the Credit Agreement.

The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. Advances under the Credit Agreement that are designated for working capital are short-term liabilities. Other advances under the Credit Agreement are classified as long-term liabilities. In addition, the Credit Agreement is available to fund letters of credit up to a $50.0 million sub-limit. Up to $20.0 million is available to fund distributions to unitholders.

We have the right to request an increase in the maximum amount of the Credit Agreement, up to $200.0 million. Such request will become effective if (a) certain conditions specified in the Credit Agreement are met and (b) existing lenders under the Credit Agreement or other financial institutions reasonably acceptable to the administrative agent commit to lend such increased amounts under the agreement.

Our obligations under the Credit Agreement are secured by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries.

We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs. We are required to reduce all working capital borrowings under the Credit Agreement to zero for a period of at least 15 consecutive days once each twelve-month period prior to the maturity date of the agreement.

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 0.25% to 1.50%) or (b) at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin (ranging from 1.00% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the 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 a rate ranging from 0.20% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters. At December 31, 2007, we are subject to the 0.25% rate on the $100.0 million of the unused commitment on the Credit Agreement. The agreement matures in August 2011. At that time, the agreement will terminate and all outstanding amounts thereunder will be due and payable.

The Credit Agreement imposes certain requirements, 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 and debt to EBITDA ratio. If an event of default exists under the agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes Due 2015

Our Senior Notes maturing March 1, 2015 are registered with the U.S. Securities and Exchange Commission (SEC) and bear interest at 6.25% (Senior Notes). The Senior Notes are unsecured and impose certain restrictive covenants, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. 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.

The $185.0 million principal amount of Senior Notes is recorded at $181.4 million in our consolidated balance sheets at December 31, 2007. The difference of $3.6 million is due to $2.7 million of unamortized discount and $0.9 million relating to the fair value of the interest rate swap contract discussed below.

Interest Rate Risk Management

We have entered into an interest rate swap contract to effectively convert the interest expense associated with $60.0 million of our 6.25% Senior Notes from a fixed rate to variable rates. The interest rate on the $60.0 million notional amount is equal to three month LIBOR plus an applicable margin of 1.1575%. The variable rate being paid on the notional amount at December 31, 2007 was 6.281%, including the applicable margin. The maturity of the swap contract is March 1, 2015, matching the maturity of the Senior Notes.

This interest rate swap has been designated as a fair value hedge as defined by SFAS No. 133. Our interest rate swap meets the conditions required to assume no ineffectiveness under SFAS No. 133 and, therefore, we have used the shortcut method of accounting prescribed for fair value hedges by SFAS No. 133. Accordingly, we adjust the carrying value of the swap to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swap.

The fair value of our interest rate swap of $0.9 million and $1.2 million is included in Other long-term liabilities in our consolidated balance sheets at December 31, 2007 and 2006, respectively. The offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged is recognized as a reduction of Long-term debt in our consolidated balance sheets at December 31, 2007 and 2006.

Other Debt Information

	Years Ended December 31,		
	2007	**2006**	**2005**
		(In thousands)	
Interest on outstanding debt:			
Senior Notes, net of interest rate swap	$ 11,867	$ 11,588	$ 8,245
Credit Agreement			164
Amortization of discount and deferred issuance costs	1,008	968	785
Commitment fees	414	500	439
Net interest expense	$ 13,289	$ 13,056	$ 9,633
Cash paid for interest [1]	$ 12,316	$ 11,912	$ 6,793

(1) Net of cash received under our interest rate swap agreement of $3.8 million, $3.8 million and $1.7 million for the years ended December 31,

2007, 2006 and
2005,
respectively.

The estimated fair value of our Senior Notes was $169.3 million at December 31, 2007.

Note 7: Commitments and Contingencies

We lease certain facilities, pipelines and rights of way under operating leases, most of which contain renewal options. In 2007, we exercised the first of three 10-year lease extensions under our lease agreement for the refined products pipeline between White Lakes Junction and Kutz Station in New Mexico. The right of way agreements have various termination dates through 2053.

As of December 31, 2007, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year are as follows:

Year Ending December 31,	$000 s
2008	$ 6,352
2009	5,973
2010	5,899
2011	5,902
2012	5,891
Thereafter	27,254
Total	$ 57,271

Rental expense charged to operations was $6.1 million, $5.9 million and $5.6 million for the years ended December 31, 2007, 2006 and 2005, 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 8: Significant Customers

All revenues are domestic revenues, of which over 90% are currently generated from our three largest customers: Holly, Alon and BP. The major concentration of our petroleum products pipeline system s revenues is derived from activities conducted in the southwest United States. The following table presents the percentage of total revenues generated by each of these three customers:

	Years Ended December 31,		
	2007	2006	2005
Holly	60%	59%	55%
Alon	27%	28%	30%
BP	9%	9%	11%

Note 9: Related Party Transactions

Holly

We serve Holly s refineries in New Mexico and Utah under two 15-year pipeline and terminal agreements. One of these agreements relates to the pipelines and terminals contributed by Holly to us at the time of our initial public offering and expires in 2019 (Holly PTA). The Holly IPA relates to the Intermediate Pipelines acquired from Holly in July 2005 and expires in 2020. The substantial majority of our business is devoted to providing transportation and terminalling services to Holly. The minimum revenue commitments under the Holly PTA and the Holly IPA increase each year at a rate equal to the percentage change in the producer price index (PPI), but will not decrease as a result of a decrease in the PPI.

Following the July 1, 2007 PPI rate adjustment, the volume commitment by Holly under the Holly PTA will produce at least $39.6 million of revenue for the twelve months ending June 30, 2008. Under the Holly IPA, Holly agreed to transport volumes of intermediate products on the Intermediate Pipelines that following the July 1, 2007 PPI rate adjustment, will result in minimum funds to us of $12.8 million for the twelve months ending June 30, 2008.

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

In October 2007, we entered into an agreement with Holly that amends the Holly PTA under which we have agreed to expand our refined products pipeline system between Artesia, New Mexico and El Paso, Texas (the South System). The expansion of the South System will include replacing 85 miles of 8-inch pipe with 12-inch pipe, adding 150,000 barrels of refined product storage at our El Paso Terminal, improving existing pumps, adding a tie-in to the Kinder Morgan pipeline to Tucson and Phoenix, Arizona, and making related modifications. The cost of this project is estimated to be $48.3 million. Currently, we are expecting to complete this project by January 2009. The agreement also provides for a tariff increase, expected to be effective May 1, 2008, on Holly shipments on our refined product pipelines.

Under certain provisions of the Omnibus Agreement that we entered with Holly in July 2004 and expires in 2019, we pay Holly an annual administrative fee, initially $2.0 million for each of the three years following the closing of our initial public offering, for the provision by Holly or its affiliates of various general and administrative services to us. Effective July 1, 2007, the annual fee increased to $2.1 million in accordance with provisions under the agreement. This fee does not include the salaries of pipeline and terminal personnel or the cost of their employee benefits, such as 401(k), pension and health insurance benefits, which are separately charged to us by Holly. We also reimburse Holly and its affiliates for direct expenses they incur on our behalf.

In consideration for Holly s assistance in obtaining our joint venture opportunity in a new 95-mile intrastate pipeline system (the SLC Pipeline) now under construction by Plains All American Pipeline, L.P. (Plains), we will pay Holly a $2.5 million finder s fee upon the closing of our investment in the joint venture with Plains. See Note 13 for further information on this proposed joint venture.

Pipeline and terminal revenues received from Holly were $61.0 million, $52.9 million and $44.2 million for the years ended December 31, 2007, 2006 and 2005, respectively. These amounts include the revenues received under the Holly PTA and Holly IPA.

Other revenues for the year ended December 31, 2007 were $2.7 million related to our sale of inventory of accumulated terminal overages of refined product. These overages arose from net product gains at our terminals from the beginning of 2005 through the third quarter of 2007. We have negotiated an amendment to our pipelines and terminals agreement with Holly that provides that such terminal overages of refined product shall belong to Holly in the future.

Holly charged general and administrative services under the Omnibus Agreement of $2.0 million for each of the years ended December 31, 2007, 2006 and 2005.

We reimbursed Holly for costs of employees supporting our operations of $8.5 million, $7.7 million and $6.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Holly reimbursed us $0.3 million for the year ended December 31, 2007 and $0.2 million for each of the years ended December 31, 2006 and 2005 for certain costs paid on their behalf.

We distributed $22.8 million, $20.3 million and $16.5 million for the years ended December 31, 2007, 2006 and 2005, respectively, to Holly as regular distributions on its subordinated units, common units and general partner interest.

We acquired the Intermediate Pipelines from Holly in July 2005, which resulted in payment to Holly of a purchase price of $71.9 million in excess of the basis of the assets received. See Note 2 for further information on the Intermediate Pipelines transaction.

Our accounts receivable from Holly was $5.7 million at December 31, 2007 and 2006.

Our accounts payable to Holly were $6.0 million and $2.2 million at December 31, 2007 and 2006, respectively.

Holly failed to meet its minimum volume commitment for each of the first nine quarters of the Holly IPA. Through December 31, 2007, we have charged Holly $4.5 million for these shortfalls of which zero and $0.2 million is included in affiliate accounts receivable at December 31, 2007 and 2006 respectively.

Our revenues for the years ended December 31, 2007 and 2006 included shortfalls billed under the Holly IPA of $2.4 million in 2006 and $1.0 million in 2005, respectively, as Holly did not exceed its minimum volume commitment in any of the subsequent four quarters in 2007 and 2006. Deferred revenue in the consolidated balance sheets at December 31, 2007 and 2006, includes $1.1 million and $2.4 million, respectively, relating to the Holly IPA. It is possible that Holly may not exceed its minimum obligations under the Holly IPA to allow Holly to receive credit for any of the $1.1 million deferred at December 31, 2007.

BP

We have a 70% ownership interest in Rio Grande and BP owns the other 30%. Due to the ownership interest and resulting consolidation, BP is a related party to us.

BP is the sole customer of Rio Grande. BP s agreement to ship on the Rio Grande pipeline expires in April 2008. We recorded revenues from them of $9.2 million, $8.4 million and $8.8 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Rio Grande paid distributions to BP of $1.3 million, $1.5 million and $2.2 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Included in our accounts receivable trade at December 31, 2007 and 2006 were $1.5 million and $2.1 million, respectively, which represented the receivable balance of Rio Grande from BP.

Alon

We have a 15-year 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 results in a minimum level of annual revenue. The agreed upon tariffs are increased or decreased annually at a rate equal to the percentage change in PPI, but not below the initial tariff rate. Following the March 1, 2007 PPI rate adjustment, Alon s total minimum commitment for the twelve months ending February 29, 2008 is $20.9 million.

Alon became a related party when it acquired all of our Class B subordinated units in connection with our acquisition of assets from them on February 28, 2005.

We recognized $21.8 million, $18.0 million and $17.6 million of revenues for pipeline transportation and terminalling services under the Alon PTA and $7.1 million, $6.9 million and $5.6 million under a pipeline capacity lease for the years ended December 31, 2007, 2006 and 2005, respectively. The pipeline lease agreement with Alon was amended effective August 31, 2007 to extend two capacity leases for 10 years to August 31, 2018 and July 31, 2020, respectively, to reduce the total leased capacity from 20,000 to 17,500 barrels per day (bpd) effective September 1, 2008, and to allow Alon an option, effective from September 1, 2008, to increase the leased capacity by 2,500 bpd for a term of 10 years.

We paid $2.6 million, $2.4 million and $1.6 million to Alon for distributions on our Class B subordinated units for the years ended December 31, 2007, 2006 and 2005, respectively.

Included in our accounts receivable trade at December 31, 2007 and 2006 were $3.5 million and $5.0 million, respectively, which represented our receivable balance from Alon.

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Our revenues for the year ended December 31, 2007 included $3.1 million of shortfalls billed under the Alon PTA in 2006 as Alon did not exceed its minimum revenue obligation in any of the subsequent four quarters. Deferred revenue in the consolidated balance sheets at December 31, 2007 and 2006 includes $2.6 million and $3.1 million, respectively, relating to the Alon PTA. It is possible that Alon may not exceed its minimum obligations under the Alon PTA to allow Alon to receive credit for any of the $2.6 million deferred at December 31, 2007.

Note 10: Partners Equity, Allocations and Cash Distributions

Issuances of units

Upon the closing of our initial public offering on July 13, 2004, Holly received 7,000,000 subordinated units, which constituted 49% ownership of us at that time, and a 2% general partner interest. During the subordination period, the common units have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.50 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will extend until the first day of any quarter beginning after June 30, 2009 that each of the following tests are met: distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; the adjusted operating surplus (as defined in its partnership agreement) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and there are no arrearages in payment of the minimum quarterly distribution on the common units. If the unitholders remove the general partner without cause, the subordination period may end before June 30, 2009.

The Holly subordinated units may convert to common units on a one-for-one basis when certain conditions are met. The partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders, subordinated unitholders and general partner will receive.

As partial consideration in the Alon transaction in the first quarter of 2005, we issued 937,500 of our Class B subordinated units at a fair value of $24.7 million. Additionally, our general partner contributed $0.6 million as an additional capital contribution to maintain its 2% general partner interest.

We financed a portion of the cash consideration paid for the Intermediate Pipelines with $45.1 million of proceeds raised from the private sale of 1,100,000 of our common units to a limited number of institutional investors which closed on July 8, 2005. On September 2, 2005, we filed a registration statement with the SEC using a shelf registration process which allows the institutional investors to freely transfer their units. Additionally under this shelf process, we may offer from time to time up to $800.0 million of our 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.

In connection with the Intermediate Pipelines transaction, we issued 70,000 common units to Holly. We also received a portion of the Intermediate Pipeline assets with $1.0 million book value as a capital contribution from HEP Logistics Holdings, L.P. in order to maintain their 2% general partner interest. As a result of these transactions, Holly s total ownership interest was reduced from 51% at the time of our initial public offering to 45% in July 2005 following the Intermediate Pipelines transaction.

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Allocations of Net Income

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 any incentive distributions declared in the period. After the amount of incentive distributions is allocated to the general partner, the remaining net income for the period is generally allocated to the partners based on their weighted average ownership percentage during the period.

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. Our Credit Agreement prohibits us from making cash distributions if any potential default or event of default, as defined in the Credit Agreement, occurs or would result from the cash distribution.

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 law, 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. Working capital borrowings are generally borrowings that are made under our revolving Credit Agreement and in all cases are used solely for working capital purposes or to pay distributions to partners.

We make distributions of available cash from operating surplus for any quarter during any subordination period in the following manner: firstly, 98% to the 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; secondly, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; thirdly, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

The general partner, HEP Logistics Holdings, L.P., is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.50	98%	2%
First Target Distribution	Up to $0.55	98%	2%
Second Target Distribution	above $0.55 up to $0.625	85%	15%
Third Target distribution	above $0.625 up to $0.75	75%	25%
Thereafter	Above $0.75	50%	50%

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The following table presents the allocation of our regular quarterly cash distributions to the general and limited partners for each period in which declared.

	2007	2006	2005
	(in thousands, except per unit data)		
General partner interest	$ 915	$ 850	$ 697
General partner incentive distribution	2,191	1,182	188
Total general partner distribution	3,106	2,032	885
Limited partner distribution	44,868	41,638	34,137
Total regular quarterly cash distribution	$ 47,974	$ 43,670	$ 35,022
Cash distribution per unit applicable to limited partners	$ 2.785	$ 2.585	$ 2.225

On January 29, 2008, we announced a cash distribution for the fourth quarter of 2007 of $0.725 per unit. The distribution is payable on all common, subordinated, and general partner units and was paid February 14, 2008 to all unitholders of record on February 7, 2008. The aggregate amount of the distribution was $12.6 million, including $0.7 million paid to the general partner as an incentive distribution.

As a master limited partnership, we distribute our available cash, which exceeds 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.

Note 11: 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, 2007					
Revenues	$ 23,872	$ 27,131	$ 27,213	$ 27,191	$ 105,407
Operating income	$ 10,796	$ 14,450	$ 14,274	$ 13,551	$ 53,071
Net income	$ 7,434	$ 11,006	$ 10,690	$ 10,141	$ 39,271
Limited partners interest in net income	$ 6,854	$ 10,280	$ 9,896	$ 9,309	$ 36,339
Net income per limited partner unit basic and diluted	$ 0.43	$ 0.64	$ 0.61	$ 0.58	$ 2.26
Distributions declared per limited partner unit	$ 0.675	$ 0.690	$ 0.705	$ 0.715	$ 2.785
Year ended December 31, 2006					
Revenues	$ 22,438	$ 18,527	$ 22,899	$ 25,330	$ 89,194
Operating income	$ 10,312	$ 6,028	$ 10,801	$ 13,239	$ 40,380
Net income	$ 7,135	$ 2,998	$ 7,751	$ 9,659	$ 27,543
Limited partners interest in net income	$ 6,808	$ 2,679	$ 7,263	$ 9,083	$ 25,833
Net income per limited partner unit basic and diluted	$ 0.42	$ 0.17	$ 0.45	$ 0.56	$ 1.60
	$ 0.625	$ 0.640	$ 0.655	$ 0.665	$ 2.585

Distributions declared per limited partner unit

Note 12: Supplemental Guarantor/Non-Guarantor Financial Information

Obligations of Holly Energy Partners, L.P. (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. Rio Grande (Non-Guarantor), in which we have a 70% ownership interest, is the only subsidiary which has not guaranteed these obligations.

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

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Condensed Consolidating Balance Sheet

December 31, 2007	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 2	$ 8,060	$ 2,259	$	$ 10,321
Accounts receivable		10,820	1,491		12,311
Intercompany accounts receivable (payable)	(141,175)	141,553	(378)		
Prepaid and other current assets	183	363			546
Total current assets	(140,990)	160,796	3,372		23,178
Properties and equipment, net		125,383	33,217		158,600
Investment in subsidiaries	353,235	25,059		(378,294)	
Transportation agreements, net		54,273			54,273
Other assets	1,302	1,551			2,853
Total assets	$ 213,547	$ 367,062	$ 36,589	$ (378,294)	$ 238,904
LIABILITIES AND PARTNERS EQUITY					
Current liabilities:					
Accounts payable	$	$ 8,499	$ 533	$	$ 9,032
Accrued interest	(2,932)	5,928			2,996
Deferred revenue		3,700			3,700
Accrued property taxes		1,021	156		1,177
Other current liabilities	6,387	(5,661)	101		827
Total current liabilities	3,455	13,487	790		17,732
Long-term debt	181,435				181,435
Other long-term liabilities	841	340			1,181
Minority interest				10,740	10,740
Partners equity	27,816	353,235	35,799	(389,034)	27,816
Total liabilities and partners equity	$ 213,547	$ 367,062	$ 36,589	$ (378,294)	$ 238,904

Condensed Consolidating Balance Sheet

December 31, 2006	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 2	$ 9,819	$ 1,734	$	$ 11,555
Accounts receivable		10,970	2,085		13,055
Intercompany accounts receivable (payable)	(78,952)	79,144	(192)		

Prepaid and other current assets	203	1,009			1,212
Total current assets	(78,747)	100,942	3,627		25,822
Properties and equipment, net		127,357	33,127		160,484
Investment in subsidiaries	298,872	25,581		(324,453)	
Transportation agreements, net		56,271	550		56,821
Other assets	1,453	1,191			2,644
Total assets	$ 221,578	$ 311,342	$ 37,304	$ (324,453)	$ 245,771
LIABILITIES AND PARTNERS EQUITY					
Current liabilities:					
Accounts payable	$	$ 5,554	$ 425	$	$ 5,979
Accrued interest	2,941				2,941
Deferred revenue		5,486			5,486
Accrued property taxes		726	142		868
Other current liabilities	516	389	193		1,098
Total current liabilities	3,457	12,155	760		16,372
Long-term debt	180,660				180,660
Other long-term liabilities	1,235	315			1,550
Minority interest				10,963	10,963
Partners equity	36,226	298,872	36,544	(335,416)	36,226
Total liabilities and partners equity	$ 221,578	$ 311,342	$ 37,304	$ (324,453)	$ 245,771

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Condensed Consolidating Statement of Income

Year ended December 31, 2007	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Revenues:					
Affiliates	$	$ 60,961	$	$	$ 60,961
Third parties		33,720	9,217	(1,239)	41,698
		94,681	9,217	(1,239)	102,659
Affiliates other		2,748			2,748
		97,429	9,217	(1,239)	105,407
Operating costs and expenses:					
Operations		30,523	3,627	(1,239)	32,911
Depreciation and amortization		12,520	1,862		14,382
General and administrative	2,730	2,135	178		5,043
	2,730	45,178	5,667	(1,239)	52,336
Operating income (loss)	(2,730)	52,251	3,550		53,071
Equity in earnings of subsidiaries	54,362	2,487		(56,849)	
Interest income (expense)	(12,361)	(474)	79		(12,756)
Gain on sale of assets		298			298
Minority interest				(1,067)	(1,067)
	42,001	2,311	79	(57,916)	(13,525)
Income before income taxes	39,271	54,562	3,629	(57,916)	39,546
State income tax		(200)	(75)		(275)
Net income	$ 39,271	$ 54,362	$ 3,554	$ (57,916)	$ 39,271

Condensed Consolidating Statement of Income

Year ended December 31, 2006	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Revenues:					
Affiliates	$	$ 52,878	$	$	$ 52,878
Third parties		29,119	8,400	(1,203)	36,316
		81,997	8,400	(1,203)	89,194
Operating costs and expenses:					
Operations		27,009	2,824	(1,203)	28,630
Depreciation and amortization		11,933	3,397		15,330
General and administrative	2,794	2,055	5		4,854
	2,794	40,997	6,226	(1,203)	48,814

Operating income (loss)	(2,794)	41,000	2,174		40,380
Equity in earnings of subsidiaries	42,456	1,588		(44,044)	
Interest income (expense)	(12,119)	(132)	94		(12,157)
Minority interest				(680)	(680)
Net income	$ 27,543	$ 42,456	$ 2,268	$ (44,724)	$ 27,543

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Condensed Consolidating Statement of Income

Year ended December 31, 2005	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Revenues:					
Affiliates	$	$ 44,184	$	$	$ 44,184
Third parties		28,000	8,770	(834)	35,936
		72,184	8,770	(834)	80,120
Operating costs and expenses:					
Operations		23,270	2,896	(834)	25,332
Depreciation and amortization		10,824	3,377		14,201
General and administrative	1,966	2,064	17		4,047
	1,966	36,158	6,290	(834)	43,580
Operating income (loss)	(1,966)	36,026	2,480		36,540
Equity in earnings of subsidiaries	37,410	1,728		(39,138)	
Interest expense	(8,628)	(344)	(12)		(8,984)
Minority interest				(740)	(740)
Net income	$ 26,816	$ 37,410	$ 2,468	$ (39,878)	$ 26,816

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2007	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities	$ 49,056	$ 6,784	$ 6,226	$ (3,010)	$ 59,056
Cash flows from investing activities					
Additions to properties and equipment		(8,556)	(1,401)		(9,957)
Proceeds from sale of assets		325			325
		(8,231)	(1,401)		(9,632)
Cash flows from financing activities					
Distributions to partners	(47,974)		(4,300)	4,300	(47,974)
Cash distributions to minority interest				(1,290)	(1,290)
Purchase of units for restricted unit grants	(1,082)				(1,082)
Deferred financing costs		(296)			(296)
Other		(16)			(16)
	(49,056)	(312)	(4,300)	3,010	(50,658)
Cash and cash equivalents					
Increase (decrease) for the year		(1,759)	525		(1,234)
Beginning of year	2	9,819	1,734		11,555

End of year	$ 2	$ 8,060	$ 2,259	$	$ 10,321

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2006	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor**	**Eliminations**	**Consolidated**
			(In thousands)		
Cash flows from operating activities	$ 44,304	$ 930	$ 4,049	$ (3,430)	$ 45,853
Cash flows from investing activities additions to properties and equipment		(8,881)	(226)		(9,107)
Cash flows from financing activities					
Distributions to partners	(43,670)		(4,900)	4,900	(43,670)
Cash distributions to minority interest				(1,470)	(1,470)
Purchase of units for restricted unit grants	(634)				(634)
	(44,304)		(4,900)	3,430	(45,774)
Cash and cash equivalents					
Decrease for the year		(7,951)	(1,077)		(9,028)
Beginning of year	2	17,770	2,811		20,583
End of year	$ 2	$ 9,819	$ 1,734	$	$ 11,555

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Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2005	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities	$ 7,566	$ 33,945	$ 6,297	$ (5,180)	$ 42,628
Cash flows from investing activities					
Acquisitions of pipeline and terminal assets	(125,801)	(2,111)			(127,912)
Additions to properties and equipment		(3,838)	(45)		(3,883)
Investments in subsidiaries, net	(1)			1	
	(125,802)	(5,949)	(45)	1	(131,795)
Cash flows from financing activities					
Proceeds from issuance of senior notes, net of discounts	181,238				181,238
Proceeds from issuance of common units, net of underwriter discount	45,100				45,100
Excess purchase price over contributed basis of intermediate pipelines	(71,850)				(71,850)
Contributions from (distributions to) partners	(34,410)	1	(7,400)	7,399	(34,410)
Repayment of revolving credit agreement		(25,000)			(25,000)
Cash distributions to minority interest				(2,220)	(2,220)
Other financing activities, net	(1,842)	(370)			(2,212)
	118,236	(25,369)	(7,400)	5,179	90,646
Cash and cash equivalents					
Increase (decrease) for the year		2,627	(1,148)		1,479
Beginning of year	2	15,143	3,959		19,104
End of year	$ 2	$ 17,770	$ 2,811	$	$ 20,583

Note 13: Proposed Joint Ventures and Acquisitions

In November 2007, we executed a definitive agreement with Plains All American Pipeline, L.P. to acquire a 25% joint venture interest in a new 95-mile intrastate pipeline system now under construction by Plains, for the shipment of up to 120,000 bpd of crude oil into the Salt Lake City area. Under the agreement, the SLC Pipeline will be owned by a joint venture company which will be owned 75% by Plains and 25% by us. Subject to the actual cost of the SLC Pipeline, we will purchase our 25% interest in the joint venture for an amount between $22.0 and $25.5 million in the second quarter of 2008, when the SLC Pipeline is expected to become fully operational.

In November 2007, we announced an agreement in principle for the acquisition of certain pipeline and tankage assets from Holly for approximately $180.0 million. The consideration is expected to consist of $171.0 million in cash and our common units valued at approximately $9.0 million. The assets include crude oil trunk lines that deliver crude to Holly s Navajo Refinery in southeast New Mexico, gathering and connection pipelines located in west Texas and New Mexico, on-site crude tankage located within the Navajo and Woods Cross refinery complexes, a jet fuel products pipeline and terminal (terminal leased through September 2011) between Artesia and Roswell, New Mexico, and crude oil and product pipelines that support Holly s Woods Cross Refinery. In connection with the closing of this proposed transaction, we intend to enter into a 15-year pipelines and tankage agreement with Holly that will contain a minimum annual revenue commitment to us from Holly. The HLS board of directors has approved this proposed transaction, which we expect to close in the first quarter of 2008.

On January 31, 2008, we entered into an option agreement with Holly, granting us an option to purchase all of Holly s equity interests in a joint venture pipeline currently under construction. The pipeline will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada (the UNEV Pipeline). Holly currently owns 75% of the equity interests in the UNEV Pipeline. Under this agreement, we have an option to purchase Holly s equity interests in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to Holly s investment in the joint venture pipeline, plus interest at 7% per annum.

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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 Exchange Act Rule 13a-15(e)) as of the end of the period covered by this annual report on Form 10-K. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of our disclosure controls and procedures are effective in ensuring that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

(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 Company s Internal Control Over Financial Reporting and Report of the Registered Public Accounting Firm.

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2007 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., as the general partner of HEP Logistics Holdings, L.P., our general partner, manages our operations and activities on our behalf. Our general partner is not elected by our unitholders. Unitholders are not entitled to elect the directors of HLS or directly or indirectly participate in our management or operation. The sole member of HLS, which is a subsidiary of Holly, elects our directors to serve until their death, resignation or removal. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations that are non-recourse.

Three members of the board of directors of HLS serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of HLS or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the New York Stock Exchange and the Exchange Act to serve on the audit committee of a board of directors. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, we have an audit committee of three independent directors that reviews our external financial reporting, selects our independent registered public accounting firm, and reviews procedures for internal auditing and the adequacy of our internal accounting controls. We also have a compensation committee of the three independent directors which oversees compensation decisions for the officers of HLS, as well as the compensation plans described below. In addition, we have an executive committee of the board consisting of one independent director and two directors employed by Holly.

The board of directors of HLS has determined that Messrs. Darling, Pinkerton and Stengel meet the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange and under the Exchange Act. These directors serve as the only members of our audit, conflicts and compensation committees.

Mr. Darling has been selected to preside at regularly scheduled meetings of non-management directors. Persons wishing to communicate with the non-management directors are invited to email the Presiding Director at presiding.director@hollyenergypartners.com or write to: Charles M. Darling, IV, Presiding Director, c/o Secretary, Holly Logistic Services, L.L.C., 100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915.

The board of directors of HLS held ten meetings during 2007, with the audit committee, conflicts committee and compensation committee holding seven, sixteen and seven meetings, respectively. All board members attended each board meeting. All committee members attended each committee meeting for the committees on which they serve.

We are managed and operated by the directors and officers of HLS on behalf of our general partner. Most of our operational personnel are employees of HLS.

Mr. Clifton spends approximately 25% of his time overseeing the management of our business and affairs. Mr. Blair spends all of his time in the management of our business. The rest of our officers devote approximately one-quarter of their time to us. Our non-management directors devote as much time as is necessary to prepare for and attend board of directors and committee meetings.

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The following table shows information for the current directors and executive officers of HLS.

Name	Age	Position with HLS
Matthew P. Clifton	56	Chairman of the Board and Chief Executive Officer[1]
Bruce R. Shaw	40	Director, Senior Vice President and Chief Financial Officer
W. John Glancy	65	Vice President, General Counsel
David G. Blair	49	Senior Vice President
Mark T. Cunningham	48	Vice President, Operations
P. Dean Ridenour	66	Director[1]
Charles M. Darling, IV	59	Director[234]
Jerry W. Pinkerton	67	Director[1234]
William P. Stengel	59	Director[234]

1 Member of the Executive Committee

2 Member of the Conflicts Committee

3 Member of the Audit Committee

4 Member of the Compensation Committee

Matthew P. Clifton was elected Chairman of our Board, and Chief Executive Officer in March 2004. He has been employed by Holly for over twenty years. Mr. Clifton served as Holly s Vice President of Economics, Engineering and Legal Affairs from 1988 to 1991, Senior Vice President of Holly Corporation from 1991 to 1995, President of Navajo Pipeline Company, a wholly owned subsidiary of Holly Corporation, since its inception in 1981, President of Holly Corporation from 1995 to 2005, and has served as Chief Executive Officer of Holly Corporation since January 1, 2006. Mr. Clifton has also served as a director of Holly Corporation since 1995.

Bruce R. Shaw was elected to our Board of Directors in April 2007 and to the position of Senior Vice President, Chief Financial Officer in January 2008. Mr. Shaw served as Vice President, Special Projects for Holly from September 2007 to December 2007. Prior to September 2007, Mr. Shaw briefly left Holly 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 including Vice President of Corporate Development from February 2006 to May 2007, Vice President of Crude Purchasing and Corporate Development from February 2005 to February 2006, Vice President of Corporate Development from March 2004 to February 2005, Vice President of Marketing and Corporate Development from November 2003 to March 2004, Vice President of Corporate Development from October 2001 to November 2003 and Director of Corporate Development from June 1997 to January 2000. Mr. Shaw also served as Vice President, Corporate Development for HLS from August 2004 to January 2007.

W. John Glancy was elected Vice President and General Counsel in August 2004, and served as Secretary from August 2004 to April 2005. Mr. Glancy has served as Senior Vice President and General Counsel of Holly Corporation since September 1999. From December 1998 to September 1999, he was Senior Vice President Legal of Holly Corporation and held the office of Secretary of Holly Corporation from April 1999 until February 2005. From

1997 through March 1999, he practiced law in the Law Offices of W. John Glancy in Dallas. From 1972 through 1996, he was in private law practice with several different law firms in Dallas. He also was a director of Holly Corporation from 1975 to 1995, and for part of that period was Secretary of Holly Corporation.

David G. Blair was elected Senior Vice President in January 2007. He has been employed by Holly for over 25 years. Mr. Blair served as Holly s Vice President responsible for Holly Asphalt Company from February 2005 to December 2006. Mr. Blair was General Manager of the NK Asphalt Partnership between Koch Materials Company and Navajo Refining Company from July 2000 to February 2005. Mr. Blair was named Vice President, Marketing, Asphalt & Specialty Products in October 1994. Mr. Blair served in various positions within Holly in crude oil supply, wholesale product marketing, and supply and trading from 1981 to 1991.

Mark T. Cunningham was elected Vice President of Operations in July of 2007. He has served Holly as Senior Manager of Special Projects from December 2006 through June 2007 and as Senior Manager of Integrity Management and EH&S from July 2004 through December 2006. Prior to joining Holly, Mr. Cunningham served Diamond Shamrock / Ultramar Diamond Shamrock for 20 years in several engineering and pipeline operations capacities. He began his time with Diamond Shamrock in 1983 and served various positions including Senior Design Engineer, Superintendent of Special Projects, Regional Manager and General Manager of Operations and Director of Operations through April 2003.

P. Dean Ridenour was elected to our Board of Directors in August 2004 and served as Vice President and Chief Accounting Officer 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. From April 2001 until October 2002, Mr. Ridenour was temporarily retired. From July 1999 through April 2001, Mr. Ridenour served as Chief Financial Officer and director of GeoUtilities, Inc., an internet-based superstore for energy, telecom and other utility services, which was purchased by AES Corporation in March 2000. Mr. Ridenour was employed for 34 years by Ernst & Young LLP, including 20 years as an audit partner, retiring in 1997. Mr. Ridenour is no longer an officer of HEP.

Charles M. Darling, IV was elected to our Board of Directors in July 2004. 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. From 1997 to 1998, Mr. Darling was the President and General Counsel, and was a Director from 1993 to 1998, of DeepTech International, which was acquired by El Paso Energy Corp. in August 1998. Mr. Darling was also a Director at Leviathan Gas Pipeline Company from 1993 through 1998. Prior to joining DeepTech in 1997, Mr. Darling practiced law at the law firm of Baker Botts, L.L.P., for over 20 years.

Jerry W. Pinkerton was elected to our Board of Directors in July 2004. Since December 2003, Mr. Pinkerton has been retired. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp., an energy services company, with respect to accounting-related projects principally involving financial reporting. From August 1997 to December 2000, Mr. Pinkerton served as Controller of TXU and its U.S. subsidiaries. From August 1988 until its merger with TXU in August 1997, Mr. Pinkerton served as the Vice President and Chief Accounting Officer of ENSERCH Corporation/Lone Star Gas Company, a diversified energy company. Prior to joining ENSERCH, Mr. Pinkerton 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.

William P. Stengel was elected to our Board of Directors in July 2004. Mr. Stengel has been retired since 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. and was responsible for Citigroup s global relationships with U.S. multinational oil and gas companies headquartered in the United States. From 1973 to 1997, Mr. Stengel served in various other capacities with Citigroup/Citibank, N.A.

Compliance With Section 16(a) of the Securities Exchange Act of 1934

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than 10% of Holly Energy Partners, L.P. s units to file certain reports with the SEC and New York Stock Exchange concerning their beneficial ownership of Holly Energy Partners, L.P. s equity securities. Holly Energy Partners, L.P. believes that during the year ended December 31, 2007, its officers, directors and 10% unitholders were in compliance with applicable requirements of Section 16(a).

Audit Committee

HLS s audit committee is composed of three directors who are not officers or employees of HEP or any of its subsidiaries or Holly Corporation or any of its subsidiaries. The board of directors of HLS has adopted a written charter for the audit committee. The board of directors of HLS has determined that a member of the audit committee, namely Jerry W. Pinkerton, is an audit committee financial expert (as defined by the SEC) and has designated Mr. Pinkerton as the audit committee financial expert.

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The audit committee selects our independent registered public accounting firm and reviews the professional services they provide. It reviews the scope of the audit performed by the independent registered public accounting firm, the audit report issued by the independent auditor, HEP s annual and quarterly financial statements, any material comments contained in the auditor s letters to management, HEP s internal accounting controls and such other matters relating to accounting, auditing and financial reporting as it deems appropriate. In addition, the audit committee reviews the type and extent of any non-audit work to be performed by the independent auditor and its compatibility with their continued objectivity and independence.

Report of the Audit Committee for the Year Ended December 31, 2007

Management of Holly Logistic Services, L.L.C. is responsible for Holly Energy Partners, L.P. s internal controls and the financial reporting process. Ernst & Young LLP, Holly Energy Partners, L.P. s Independent Registered Public Accounting Firm for the year ended December 31, 2007, 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 selects Holly Energy Partners, L.P. s independent registered public accounting firm.

The audit committee has reviewed and discussed Holly Energy Partners, L.P. s audited consolidated financial statements with management and the independent registered public accounting firm. The audit committee has discussed with Ernst & Young LLP the matters required to be discussed by Statement on Auditing Standards No. 61, *Communications with Audit Committees.* The audit committee has received the written disclosures and the letter from Ernst & Young LLP required by Independence Standards Board Standard No. 1, *Independence Discussions with Audit Committees,* and has discussed with Ernst & Young LLP that firm s independence. The audit committee selected Ernst & Young LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of the Partnership for the 2007 calendar year.

The board of directors of our general partner, upon recommendation by the audit committee, has adopted an audit committee charter, which 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 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.

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 of directors that the audited consolidated financial statements of Holly Energy Partners, L.P. be included in Holly Energy Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2007.

Members of the Audit Committee:

Jerry W. Pinkerton, Chairman

Charles M. Darling, IV

William P. Stengel

Code of Ethics

HEP has adopted a Code of Business Conduct and Ethics that applies to all officers, directors and employees, including the company s principal executive officer, principal financial officer, and principal accounting officer. Available on our website at www.hollyenergy.com are copies of our Corporate Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics, all of which also will be provided in print without charge upon written request to the Vice President, Investor Relations at: Holly Energy Partners, L.P., 100 Crescent Court, Suite 1600, Dallas, TX, 75201-6915. The Partnership intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its Code of Business Conduct and Ethics with respect to its principal financial officers by posting such information on this website.

New York Stock Exchange Certification

In 2007, Mr. Clifton, as the Company s Chief Executive Officer, provided to the New York Stock Exchange the annual CEO certification regarding the Company s compliance with the New York Stock Exchange s corporate governance listing standards.

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Item 11. Executive Compensation

DIRECTOR COMPENSATION

Directors who also serve as officers or employees of HLS or Holly do not receive additional compensation in their capacity as directors. The only officers of HLS or Holly who also served as directors during 2007 were Messrs. Clifton, Ridenour and Shaw. Mr. Shaw was an employee of Holly during 2007 except between June 1 and September 16, 2007; he is now Senior Vice President and Chief Financial Officer of Holly and HLS effective as of January 7, 2008, replacing Stephen J. McDonnell. Although Mr. Ridenour is still an employee, he no longer serves as an officer of HLS. In July 2007, the Board of Directors implemented changes to the cash and equity components of the compensation of non-employee directors. As of December 31, 2007, the compensation for non-employee directors was: (a) a $50,000 annual cash retainer, payable in four quarterly installments (adjusted August 1, 2007 from $30,000 in 2006); (b) $1,500 for attendance at each in-person meeting of the Board of Directors or a Board committee, a $1,000 meeting fee for attendance at each telephonic meeting of the Board of Directors or a Board committee that lasts more than thirty minutes (adjusted August 1, 2007 from a $1,500 meeting fee for telephonic meetings lasting over two hours and a $750 meeting fee for telephonic meetings lasting from 30 minutes to two hours in 2006), and a fee of $1,500 per day for each day that a non-employee director attends a strategy meeting with the HLS management; (c) an annual grant under the Holly Energy Partners, L.P. Long-Term Incentive Plan (Long-Term Incentive Plan) of restricted HEP units equal in value to $50,000 on the date of grant, with vesting in 25% increments every three months over the following 12 months (adjusted August 1, 2007 from $40,000 with a vesting period of 12 months in 2006). The Long-Term Incentive Plan grants are effective on the date they are approved by the Board of Directors and this date varies each year. A restricted HEP unit is a common unit subject to forfeiture until the award vests. In addition, the directors who serve as chairpersons of the committees of the Board of Directors each receive an annual retainer of $10,000, payable in four quarterly installments (adjusted August 1, 2007 from $7,500 for the chairpersons of the Audit and Conflicts Committees and $5,000 for the chairperson of the Compensation Committee in 2006). In addition, each director is reimbursed for out-of-pocket expenses in connection with attending board or committee meetings. Each director is fully indemnified by HLS for actions associated with being a director to the extent permitted under Delaware law.

During the calendar year ending December 31, 2007, compensation was made to directors of HLS as set forth below:

	Fees Earned or Paid in Cash	Stock Awards(1)	Total
Charles M. Darling, IV	$ 86,917	$75,304	$162,221
Jerry W. Pinkerton	$ 88,375	$75,304	$163,679
William P. Stengel	$ 88,375	$75,304	$163,679
Bruce R. Shaw (2)	$ 12,333	$20,937	$ 33,270

(1) Reflects the amount recognized in the year ended December 31, 2007 in accordance with Statement of Financial Accounting Standards (SFAS) No. 123(R), Share

Based Payments, and includes amounts for awards granted prior to 2007. In 2007, each of the outside directors received an award of 959 restricted HEP units on August 1, 2007 with a grant date fair value of $50,000. 240 of the 959 units vested on November 1, 2007. The remaining restricted HEP units will vest quarterly on February 1, 2008, May 1, 2008 and August 1, 2008. The fair market value of each restricted unit grant is measured on the grant date and is amortized over the vesting period. As of December 31, 2007, Messrs. Darling, Pinkerton and Stengel each held 1,620 unvested restricted units.

(2) Mr. Shaw was compensated as a non-employee director between June 1, 2007 and September 16,

2007. As of December 31, 2007, Mr. Shaw held 719 unvested restricted units.

COMPENSATION DISCUSSION AND ANALYSIS

This compensation discussion and analysis (CD&A) provides information about our compensation objectives and policies for our principal executive officer, our principal financial officer and our other most highly compensated executive officers and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. We provide a general description of our compensation program and specific information about its various components. Additionally, we describe our policies relating to reimbursement to Holly for compensation expenses. We also provide information about HLS executive officer changes that became effective in January 2008. Immediately following this CD&A is our Compensation Committee Report (the Committee Report).

Overview

HEP is managed by HLS, the general partner of HEP s general partner. HLS is a subsidiary of Holly. The employees providing services to HEP are employed by HLS; HEP itself has no employees. As of December 31, 2007, HLS had 106 employees that provide general, administrative and operational services to HEP. Throughout this discussion, the following individuals are referred to as the Named Executive Officers and are included in the Summary Compensation Table on page 100:

Matthew P. Clifton, HLS s Chairman of the Board and Chief Executive Officer;

Stephen J. McDonnell, HLS s Vice President and Chief Financial Officer (Mr. McDonnell was replaced by Bruce R. Shaw, who became Senior Vice President and Chief Financial Officer effective January 7, 2008);

P. Dean Ridenour served as HLS s Vice President and Chief Accounting Officer until January 7, 2008. Although Mr. Ridenour is still an employee, he no longer serves as an officer of HLS.

David G. Blair, HLS s Senior Vice President;

Mark T. Cunningham, HLS s Vice President, Operations beginning July 1, 2007 and an HLS employee throughout 2007; and

James G. Townsend, Vice President, Pipeline Operations until August 7, 2007, when he became an employee of Holly.

Of the five Named Executive Officers of HEP, only Messrs. Blair and Cunningham are current employees of HLS. Mr. Townsend was an employee of HLS until August 7, 2007 but also performed duties for Holly throughout 2007.

Under the terms of the Omnibus Agreement, the annual administrative fee we pay to Holly increased to $2,100,000 as of July 1, 2007 and is for the provision of general and administrative services for our benefit, which may be increased as permitted under the Omnibus Agreement. Additionally, we reimburse Holly for expenses incurred on our behalf. The administrative services covered by the Omnibus Agreement include, without limitation, the costs of corporate services provided to HEP by Holly such as accounting, information technology, human resources and in-house legal support; office space, furnishings and equipment; and transportation of HEP executive officers on Holly airplanes for business purposes. The partnership agreement provides that our general partner will determine the expenses that are allocable to HEP. See Item 13, Certain Relationships and Related Transactions of this Form 10-K Annual Report for additional discussion of our relationships and transactions with Holly. None of the services covered by the administrative fee are assigned any particular value individually. Although certain Named Executive Officers provide services to both Holly and HEP, no portion of the administrative fee is specifically allocated to services provided by the Named Executive Officers to HEP; rather, the administrative fee generally covers services provided to HEP by Holly and HLS employees and, except as described below, there is no reimbursement by HEP of cash compensation expenses paid by Holly or HLS to the Named Executive Officers. With respect to equity compensation paid by HEP to the Named Executive Officers, HLS purchases the units, and HEP reimburses HLS for the purchase price.

With respect to Mr. Townsend, we reimbursed Holly for 58% of the expenses incurred by Holly for Mr. Townsend s salary, bonus, retirement and other benefits through August 31, 2007 when Mr. Townsend s compensation was allocated 100% to Holly. As Mr. Townsend also provided services to Holly s subsidiary, Navajo Pipeline Co., L.P. (Navajo Pipeline) through August 31, 2007, 42% of his cash compensation and benefits for this period were charged to Navajo Pipeline. We reimbursed Holly (or in the case of equity compensation, HLS purchased units and HEP reimbursed HLS for the cost of the units) for 58% of the expenses incurred in providing Mr. Townsend with long-term incentive equity compensation for the period from January 1, 2007 through August 31, 2007. Notwithstanding that 42% of the costs associated with compensating Mr. Townsend were borne by Holly and not HEP during such period, all 2007 compensation paid to Mr. Townsend by Holly, HLS and HEP is disclosed in the tabular disclosure following this compensation discussion and analysis.

With respect to Messrs. Blair and Cunningham, we reimbursed Holly for 100% of the compensation expenses incurred by Holly for salary, bonus, retirement and other benefits for 2007 for Messrs. Blair and Cunningham. We reimbursed HLS for 100% of the expenses incurred in providing Messrs. Blair and Cunningham with long-term incentive equity compensation. All compensation paid to them is fully disclosed in the tabular disclosure following this compensation discussion and analysis.

Messrs. Clifton, McDonnell and Ridenour were compensated by HLS for the services they perform for HLS through awards of equity-based compensation granted pursuant to the Long-Term Incentive Plan. None of the cash compensation paid to or other benefits made available to Messrs. Clifton, McDonnell and Ridenour by Holly was allocated to the services they provide to HLS and, therefore, only the Long-Term Incentive Plan awards granted to them are disclosed herein.

Objectives of Compensation Program

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

The HLS Compensation Committee (the Committee), comprised entirely of independent directors, administers the Long-Term Incentive Plan for certain HLS employees and reviewed and confirmed in February 2007 the recommendations of the Holly Compensation Committee with regard to the total compensation of Messrs. Clifton, McDonnell and Ridenour. The Committee determined and approved the long-term incentive compensation to be paid to the Named Executive Officers and the compensation in addition to the long-term incentive compensation to be paid to Mr. Blair and, during his tenure with HEP, to Mr. Townsend.

As to Mr. Blair and during his tenure with HEP, Mr. Townsend, the Committee has not adopted any formal policies for allocating compensation among salaries, bonuses and long-term incentive compensation. The Committee attempts to balance the use of both cash and equity compensation in the total compensation package provided to Messrs. Blair and Townsend and as to our other Named Executive officers, attempts to utilize long-term incentive compensation to build value to both HEP and its unitholders. The Committee considers recommendations by management and many other factors in deciding on the final compensation factors for which it has responsibility for each Named Executive Officer. The Committee does not review or approve pension benefits for Named Executive officers and all are provided the same pension benefits that are provided to Holly employees.

In February 2007, the Committee, with the assistance of management, sought to designate an appropriate mix of cash and long-term equity incentive compensation for Messrs. Townsend and Blair with a goal to provide sufficient current compensation to retain them, while at the same time providing incentives to maximize long-term value for HEP and its unit holders. The Committee, with the assistance of management, annually performs an internal review of each of the Named Executive Officers long-term incentive compensation to determine whether the executives are being provided with equity awards that are effective in motivating the Named Executive Officers to create long-term value for HEP. The Committee also compares the Named Executive Officers compensation to that of similarly situated executives in other comparable businesses. These long-term equity incentives are designed to retain the executives during the period of time during which their performance is expected to impact our business and reward them in accordance with the success of those long-term goals and policies.

As part of its consideration, the Committee reviewed and discussed market data and recommendations provided by an established, independent consulting firm specializing in executive compensation issues. Except with respect to his own compensation, the Committee solicited the recommendations of our Chairman of the Board and Chief Executive Officer, which the Committee considers in making its determinations. The Committee also reviewed the total compensation provided in the previous year in determining compensation to be paid in 2007.

Mr. Cunningham s compensation is established by Messrs. Clifton and Blair with the assistance of the Vice President of Human Resources based upon all of the same factors used by the Committee and

described in this subsection. Mr. Cunningham s salary is a grade that does not require Committee approval, so his compensation package is reviewed and approved by management instead of the Committee. The Committee was provided with an overview of Mr. Cunningham s compensation with opportunity for discussion.

Overview of 2007 Executive Compensation Components

For Mr. Townsend (whose compensation was for the period from January 1, 2007 through August 31, 2007) and Messrs. Blair and Cunningham (whose compensation was for the entire year), the components of compensation in 2007 were:

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

In 2007, the only component of compensation we provided for the other Named Executive Officers was long-term equity incentive compensation. Because Messrs. Clifton, McDonnell, and Ridenour commit less than half of their business time to HEP, during which time they are primarily involved in determining the long-term business goals and policies of HEP, the Committee believes that it is appropriate to compensate them only through long-term equity incentives. All Named Executive Officers receiving equity awards received restricted HEP units with the exception of Mr. Clifton, who only received an award of HEP performance units, and Mr. Blair, who received an award of both restricted HEP units and HEP performance units. The nature of each of these types of awards is more fully described below.

Base Salary

The base salary for Mr. Blair was approved at the time of his promotion in late 2006 and was not changed for 2007. The base salary for Mr. Townsend was approved in February 2007 to be effective as of March 1, 2007. The Committee approved these salaries based on their respective positions and levels of responsibility, individual performance, HLS s salary range for executives at their respective levels and market practices. The Committee also reviewed competitive market data provided by Frederick W. Cook & Associates, an independent consultant (Consultant) retained by the Committee, relevant to the two positions.

Mr. Cunningham s salary is not established by the Committee and was established by Messrs. Blair and Clifton and the Vice President of Human Resources in the amount set forth in the Summary Compensation Table.

Annual Incentive Cash Bonus Compensation

The Holly Logistic Services Annual Incentive Plan (the Annual Incentive Plan) was adopted by the HLS Board of Directors in August 2004 with the objective of motivating management and the employees of HLS and its affiliates who perform services for HLS and HEP to collectively produce outstanding results, encourage superior performance, increase productivity, contribute to the health and safety goals of the Company 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 it are subject to final determination by the Committee that the performance goals for the applicable periods have been achieved.

These performance criteria can include both HEP and Holly factors, given the scope of responsibilities of our Named Executive Officers. The total bonus pool for all executives and employees of HLS is typically determined by the Committee after the end of each year or designated performance period, calculated pursuant to the achievement of the objective pre-established performance criteria described above. Awards for a given year are paid in cash in the first quarter of the following year.

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Payment with respect to any cash bonus is contingent upon the satisfaction of the following pre-established 2007 performance criteria:

A portion of the bonus is equal to a pre-established percentage of the employee s base salary and is earned only if Holly achieves its 2007 pre-tax net income (PTNI) goal of $256,000,000. This component is subject to being adjusted to a minimum amount of 0% and a maximum amount of two times the employee s pre-established percentage. If the PTNI goal is met, the Committee uses discretion in determining the percentage paid. Subject to the requirement that the PTNI goal is met, the adjustment of up to two times the employee s pre-established percentage may vary from year to year in the Committee s discretion.

A portion of the bonus is equal to a pre-established percentage of the employee s base salary, and is earned only if Holly s stock price performance for the year outperforms that of our peers. This component is subject to being adjusted to a minimum amount of 0% and a maximum amount of two times the employee s pre-established percentage. If the goal is met, the Committee uses discretion in determining the percentage paid. Subject to the requirement that this goal is met, the adjustment of up to two times the employee s pre-established percentage may vary from year to year in the Committee s discretion.

A portion of the bonus is equal to a pre-established percentage of the employee s base salary, based on the performance of the employee s business unit versus the unit s budgeted goal for 2007. Subject to the requirement that this goal is met, the adjustment of up to two times the employee s pre-established percentage may vary from year to year in the Committee s discretion.

A portion of the bonus equal to a pre-established percentage of the employee s base salary, based on the employee s individual performance over the year. This component is subject to being adjusted to a minimum amount of 0% and a maximum amount of two times the employee s pre-established percentage. The employee s individual performance for 2007 is evaluated through an annual performance review completed in February 2008. 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 their individual goals for 2007.

The 2008 performance goals have not yet been established. The Committee does not believe that the 2008 goals are material in understanding the 2007 compensation.

In addition to the pre-defined performance criteria, the Committee has discretion to approve an increase or decrease in a Named Executive Officer s bonus. Increases and decreases are determined using the same factors that are 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 also considers whether conditions outside the control of the executives affected the factors. In cases where the performance objectives described above are achieved, yet the Committee believes additional compensation is warranted to reward an executive for outstanding performance, the Committee may award additional bonuses in its discretion. In making the determination as to whether such discretion should be applied (either to decrease a bonus or award additional bonuses), the Committee reviews recommendations from management. For 2007, as in 2006, the Committee approved a discretionary increase in some bonuses as shown in footnote 1 to the Summary Compensation Table. All bonuses will be paid in March 2008.

The Committee also utilized the analysis of the Consultant to determine how the compensation of Messrs. Blair, Cunningham and Townsend, including bonus payments, compared to our peers and a market average (see the paragraph below titled Review of Market Data for further discussion). The annual

incentive targets were assessed on the basis of total cash, including base salary and annual incentive payments. The Committee believes this analysis verifies that total cash compensation to Messrs. Blair, Cunningham and Townsend is appropriate.

The target and actual annual incentive cash bonus compensation awarded (and subsequently earned and payable) is described in the narrative to the section titled 2007 Grants of Plan-Based Awards .

Long-Term Incentive Equity Compensation

The Long-Term Incentive Plan was adopted by the HLS Board of Directors in August 2004 with the objective of promoting the interests of HEP by providing to management, employees and consultants of HLS and its affiliates who perform services for HLS and HEP and its subsidiaries incentive compensation awards that are based on units of HEP. The Long-Term Incentive Plan is also contemplated to enhance our ability to attract and retain the services of individuals who are essential for the growth and profitability of HEP, to encourage them to devote their best efforts to advancing our business strategically, and to align their interests with those of our unit holders. The Long-Term Incentive Plan is reviewed and approved by the Committee.

The Long-Term Incentive Plan contemplates four potential types of awards: restricted units, performance units, unit options and unit appreciation rights. Since the inception of HEP, we have awarded only restricted units and performance unit awards.

With respect to the Named Executive Officers, in determining the appropriate amount and type of long-term incentive awards to be made, the Committee considers the amount of time devoted by each executive to our business, the executive s position and scope of responsibility, base salary and available compensation information for executives in comparable positions in similar companies. The awards are granted annually during the first quarter of the year, typically in February.

Our goal is to reward the creation of value and high performance with variable compensation dependent on that performance, thus the peer data is used subjectively (and not as an objective factor) to confirm that our executives are paid consistently with other similar companies. The peer data allows the Committee to verify that the compensation paid to executives is appropriate. The total compensation may be adjusted if the Committee observes material variation of the market date (no specific formula is used to benchmark this data).

Restricted Units

A restricted unit is a common unit subject to forfeiture upon termination of employment prior to the vesting of the award. The Committee may approve grants on the terms that it determines, including the period during which the award will vest. Under the Long-Term Incentive Plan, the Committee may condition vesting upon the achievement of specified financial objectives. The restricted units will vest upon a change of control of HEP, our general partner, HLS or Holly, unless provided otherwise by the Committee. Restricted unit holders have all the rights of a unitholder with respect to such restricted units, including the right to receive all distributions paid with respect to such restricted 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.

In 2007, the Named Executive Officers who were granted awards of restricted units were Messrs. McDonnell, Ridenour, Blair, Cunningham and Townsend. One-third of these restricted unit awards became fully vested and nonforfeitable on January 1, 2008. After December 31, 2008, two-thirds of the restricted units will be fully vested and nonforfeitable, and all the restricted units will be fully vested and nonforfeitable after December 31, 2009.

Performance Units

A performance unit is a notational phantom unit that entitles the grantee to receive a common unit upon the vesting of the unit or, as may be provided in the applicable agreement between the grantee and HLS, the cash equivalent to the value of a common unit. Performance units will only be settled upon the attainment of pre-established performance targets. The Committee may approve grants on such terms as the Committee shall determine. The Committee approves the period over which performance units will vest, and the Committee may base its determination upon the achievement of specified financial objectives. As with restricted units, performance units will vest upon a change of control of HEP, our general partner, HLS or Holly, unless provided otherwise by the Committee. Performance units are also subject to forfeiture in the event that the executive s employment or service relationship terminates for any reason, unless and to the extent that the Committee provides otherwise.

In 2007, the only Named Executive Officers who received an award of performance units were Messrs. Clifton and Blair. Performance units were awarded to Messrs. Clifton and Blair given their responsibilities to HEP with respect to long-term strategy. The performance period for such award is from January 1, 2007 through December 31, 2009. Messrs. Clifton and Blair may earn no less than 50% and no more than 150% of the performance units subject to their awards over the course of the performance period as described more fully in the narrative accompanying the Grant of Plan Based Awards Table. The performance units may be settled only in common units of HEP.

Acquisition of Common Units for Long-Term Incentive Equity Awards

Common units to be delivered in connection with the grant of performance unit 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 do not currently hold treasury units. HLS is entitled to reimbursement by us for the cost of acquiring the common units.

Review of Market Data

Market pay levels are one of many factors we consider in setting compensation for the Named Executive Officers and we regularly compare our compensation program with market information in regard to salary and annual incentive levels, long-term incentive award levels, and short- and long-term incentive practices. The purpose of this analysis is to provide a frame of reference in evaluating the reasonableness and competitiveness of compensation with the energy industry, and to ensure that our compensation is generally comparable to companies of similar size and scope of operations.

Market pay levels are obtained from various sources including published compensation surveys and information taken from the SEC filings for two groups of publicly traded organizations, as compiled by our independent compensation consultant. One benchmark group includes a number of publicly traded master limited partnerships (MLPs) that included in 2007: Kinder Morgan Energy Partners, L.P., Enbridge Energy Partners, L.P., TEPPCO Partners, L.P., NuStar Energy L.P. (formerly Valero L.P.), Magellan Midstream Partners, L.P., Buckeye Energy Partners, L.P., Sunoco Logistics Partners L.P., Inergy L.P., Crosstex Energy, LP, TC Pipelines, LP, Mark-West Energy Partners, L.P., Atlas Pipeline Partners, L.P. and Hiland Partners, LP. Information for a broader group of energy companies, including Holly, is also reviewed in developing our salary and incentive structures as well as in the development of long-term equity incentive award guidelines.

Our objective is to position pay levels approximating the middle range of market practice. As noted, however, market pay levels are only one factor considered, with pay decisions ultimately reflecting a discretionary evaluation of individual contribution and value to HEP.

The Consultant does not have approval authority for the ultimate compensation that is provided to employees. Instead, the Consultant provides recommendations to management by identifying areas that do not appear to be consistent with the general practice of our peers (without setting specific benchmarks and using a discretionary standard). The Consultant provides recommendations regarding compensation to management and to the Committee prior to the late February or March meetings when salaries are approved, bonuses are awarded and equity compensation is established.

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Role of Named Executive Officers in Determining Executive Compensation

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 HEP s annual budget as approved by HLS s Board of Directors, HEP s financial performance over the course of the year versus that of its peers, performance evaluations of Named Executive Officers, 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 pre-determined performance goals set by the Committee during the previous year. When management considers a discretionary bonus to be appropriate for a Named Executive Officer, 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 by the Named Executive Officers, the Committee values management s recommendations. However, the Committee makes the final decision as to the compensation of HLS s Named Executive Officers. For 2007, and after consideration of management s recommendations regarding discretionary increases in the bonuses and discussion regarding such increases, the Committee approved discretionary increases in some bonuses as shown in footnote 1 to the Summary Compensation Table.

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 SFAS 123(R), 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. As HLS is a subsidiary of Holly, a publicly-traded corporation, the Committee is mindful of the impact that Section 162(m) of the Internal Revenue Code (the Code) may have on compensatory deductions passed through to HLS s parent and the Committee considers this impact when it approves compensation for the Named Executive Officers. To the extent Section 162(m) of the Code may impact the deductibility of compensation expenses, the Committee intends generally to structure arrangements, where feasible, to minimize or eliminate the impact of the limitations of Section 162(m) of the Code. Nevertheless, to the extent that, in the opinion of the Committee, structuring compensatory arrangements to fully maximize a corporate deduction is not in the best interest of HEP, either due to the need to attract or retain top talent or for any other legitimate business reason, the Committee may approve compensation arrangements that are not deductible.

Retirement and Benefit Plans

The cost of retirement and welfare benefits for employees of HLS are charged monthly to us by Holly in accordance with the terms of the Omnibus Agreement. These employees participate in Holly s Retirement Plan (a tax qualified defined benefit plan) and Holly s Thrift Plan (a tax qualified defined contribution plan). Holly s Retirement Plan is described below in the narrative accompanying the Pension Benefits Table.

The Thrift Plan is offered to all employees of HLS. Employees may, at their election, contribute to the Thrift Plan 0% up to a maximum of 50% of their compensation. In 2006, employees had the option to participate in both the Retirement Plan and the Thrift Plan. Effective January 1, 2007, the Retirement Plan was frozen for new employees not covered by collective bargaining agreements with labor unions, and these new employees were required to participate in the new Automatic Thrift Plan Contribution feature under the Thrift Plan (as shown on summary compensation table). To the extent an employee was hired prior to January 1, 2007, and elected to begin receiving the Automatic Thrift Plan Contribution under the Thrift Plan, their participation in future benefits under the Retirement Plan was frozen. The Automatic Thrift Plan Contribution is up to 5% of base pay subject to applicable IRS limits and it is paid in addition to employee deferrals and employer matching contributions under the Thrift Plan.

In 2007, for employees not covered by collective bargaining agreements with labor unions, Holly matched employee contributions to the Thrift Plan up to 6% of their compensation. Employee contributions that were made on a tax-deferred basis were generally limited to $15,500 per year with employees over 50 years of age able to make additional tax-deferred contributions of $5,000. Prior to 2007, Holly s contributions in the Thrift Plan did not vest until the earlier of three years of credited service or termination of employment due to retirement, disability or death. On and after January 1, 2007, all contributions for employees not covered by collective bargaining agreements with labor unions are immediately vested with no waiting period.

None of Messrs. Blair, Cunningham or Townsend elected to receive the Automatic Thrift Plan Contribution under the Thrift Plan and all remained in the Holly Retirement Plan that is discussed below in the section titled Pension Benefits Table. Messrs. Townsend, Cunningham and Blair are the only Named Executive Officers whose Retirement Plan and Thrift Plan benefits are charged to us by Holly. The cost of Mr. Townsend s benefits was allocated 58% to us for the period from January 1, 2007 through August 31, 2007 and the remainder of the cost was paid by Holly.

Change-in-Control Agreements

Holly has entered into Change-In-Control Agreements with Messrs. Blair, Cunningham and Townsend. The material terms of, and the quantification of, the potential amounts payable under the Change-in-Control Agreements are described below in the section titled Potential Payments upon Termination or Change-in-Control. Holly provides these agreements to Messrs. Blair and Cunningham to provide for management continuity in the event of a change of control, and to assist in the recruitment and retention of executives. Neither we nor HLS has entered into any employment agreements or severance agreements with any of the Named Executive Officers, other than the change-in-control agreements described below.

Compensation Committee Report

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

Members of the Compensation Committee:

Charles M. Darling, IV, Chairman

Jerry W. Pinkerton

William P. Stengel

Summary Compensation Table

The table below summarizes the total compensation paid or earned by each of the Named Executive Officers in 2007. As previously noted, the cash compensation and benefits for Named Executive Officers other than Messrs. Townsend, Cunningham and Blair were not paid by us, but rather by Holly, and were not allocated to the services those Named Executive Officers performed for us in 2007. Information regarding the compensation paid to Messrs. Clifton, McDonnell, and Ridenour as consideration for the services they perform for Holly will be reported in Holly s annual proxy statement.

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Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus (1)	Stock Awards (2)	Option Awards	Non-Equity Incentive Plan Compensation (3)	Change in Pension Value (4)	All Other Compensation (5)	Total
Matthew P. Clifton, Chairman of the Board and Chief	2007	$	$	$386,086	$	$	$	$	$386,086
Executive Officer	2006	$	$	$286,522	$	$	$	$	$286,522
Stephen J. McDonnell, Vice President and	2007	$	$	$ 75,219	$	$	$	$	$ 75,219
Chief Financial Officer	2006	$	$	$ 35,086	$	$	$	$	$ 35,086
P. Dean Ridenour, Vice President and	2007	$	$	$184,240	$	$	$	$	$184,240
Chief Accounting Officer	2006	$	$	$135,406	$	$	$	$	$135,406
David G. Blair, Senior Vice President	2007	$260,004	$117,000	$133,904	$	$208,000	$26,177	$13,500	$758,585
Mark T. Cunningham, Vice President - Operations	2007	$147,148 (6)	$ 71,000	$ 28,539	$	$ 72,000	$10,194	$ 8,793	$337,674
James G. Townsend, Vice President	2007	$199,508 (7)	$ 40,000	$136,952	$	$160,000	$51,111	$11,970	$599,541
Pipeline Operations	2006	$203,940	$ 30,000	$ 71,132	$	$143,000	$38,555	$ 7,471	$494,098

(1) This reflects the discretionary bonus that is in excess of the pre-established maximum amount potentially payable pursuant to our annual incentive bonus

arrangement. For 2007, Mr. Townsend s bonus was reimbursed by us in the manner set forth in footnote 7 to this chart.

(2) Amounts listed represent the amount of expense recognized for financial reporting purposes in 2006 and 2007 for restricted unit and performance unit awards in accordance with SFAS No. 123(R) and includes amounts from awards granted prior to 2007. Following SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. See note 6 to our consolidated financial statements for a discussion of the assumptions used in determining the SFAS 123(R) compensation

cost of these awards. The amount for Mr. Clifton and Mr. Blair is based on an estimated payment of 125% of the performance units. No forfeitures of equity awards to the named executive officers occurred in 2007.

(3) See the narrative to the section titled 2007 Grant of Plan-Based Awards for further information on the performance targets used to determine the amounts attributable to amounts earned in 2007 under our Annual Incentive Plan.

(4) The amounts reflect the following assumptions:

	December 31, 2006	**December 31, 2007**
Discount Rate:	6.00%	6.40%
Mortality Table:	RP2000 White Collar	RP2000 White Collar
Reserving Table:	(50% Male/ 50% Female)	(50% Male/ 50% Female)
Retirement Age:	the later of current age or age 62	the later of current age or age 62

(5) This reflects matching contributions

made to the Thrift Plan by HLS, which were reimbursed by HEP. Since all Named Executive Officers elected to remain in the Holly Retirement Plan, the only contributions are employer matching of employee contributions, subject to the limits described in the section Retirement and Benefit Plans.

(6) Mr. Cunningham s annual salary was $132,636 effective January 1, 2007, $138,612 effective March 1, 2007 and $159,408 effective July 15, 2007.

(7) Mr. Townsend s annual salary was adjusted to $201,408 effective March 1, 2007 from his previous salary of $190,000. For the period from January 1, 2007 through August 31, 2007, 42% of Mr. Townsend s salary was charged to Navajo Pipeline

for services provided in 2007 by Mr. Townsend to Navajo Pipeline and, therefore, was not reimbursed by us and 58% of this amount was paid by HLS. However, because Mr. Townsend is not a Named Executive Officer of Holly and, hence, the total compensation received by him (for services to both Holly and us) will not otherwise be disclosed. We believe it is appropriate to include his full salary notwithstanding the fact that only 58% of this amount is borne by us. From September 1, 2007 through December 31, 2007, Mr. Townsend s salary was charged 100% to Holly Corporation and was not reimbursed by us. Mr. Townsend s salary for 2006 includes a retroactive salary adjustment for 2005 that was paid in 2006.

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2007 Grants of Plan-Based Awards

The amounts reflected in the table below represent three elements of compensation that we provide to our Named Executive Officers: performance units and restricted units granted pursuant to the Long-Term Incentive Plan, and cash bonuses awarded pursuant to the Annual Incentive Plan.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)				(j)	
(a) Name	(b) Grant Date	(c) Thresh-old	(d) Target	(e) Maximum	(f) Thresh-old	(g) Target	(h) Maximum (#)	(i) All other Equity Awards (3)	Base Price of Awards ($/Unit)	(k) Grant Date Fair Value (4)
Matthew P. Clifton Performance Units	2/28/07	$	$	$	4,368	8,736	13,104		$	$381,064
Stephen J. McDonnell Restricted Units	2/28/07	$	$	$				2,033	$	$ 88,679
P. Dean Ridenour Restricted Units	2/28/07	$	$	$				4,066	$	$177,359
David G. Blair Performance Units	2/28/07	$	$	$	1,525	3,049	4,574		$	$132,997
Restricted Units	2/28/07	$	$	$				3,049	$	$132,997
Cash Incentives		n/a	$130,002	$260,004					$	$
Mark T. Cunningham Restricted Units		$	$	$				549		$ 23,947
Cash Incentives		n/a	$ 47,822	$ 95,644					$	$
James G. Townsend (5) Restricted Units	2/28/07	$	$	$				2,857	$	$124,622
Cash Incentives		n/a	$ 80,563	$161,126					$	$

(1) This reflects a target and

maximum bonus award amounts for each Named Executive Officer equal to the target percentages set forth above in the section titled Annual Incentive Compensation. The maximum reflects that the employee may receive up to 200% of the target bonus award amount.

(2) The Committee approved a grant of 8,736 performance units to Mr. Clifton and 3,049 performance units to Mr. Blair, the vesting schedules of which are described in the narrative below.

(3) The Committee approved a grant of 3,049 restricted units to Mr. Blair, 549 restricted units to Mr. Cunningham, 2033 restricted units to Mr. McDonnell, 4,066 restricted units to Mr. Ridenour and 2,857 to Mr. Townsend, the vesting schedules of which are described in the narrative below.

(4) This reflects the price of $43.62, the closing price at the close of business on February 27, 2007, the day immediately preceding the date of grant.

(5) Mr. Townsend performed work for HEP from January 1, 2007 through August 7, 2007. As discussed in the footnotes to the Summary Compensation Table above, 58% of Mr. Townsend s costs were allocated to HEP for the period from January 1, 2007 through August 31, 2007.

Performance Units

Under the terms of the grant of performance units to Messrs. Clifton and Blair, each of the executives may earn from 50% to 150% of the performance units, based on the increase in HEP s cash distributions on the common units of HEP. The performance period for the award began on January 1, 2007 and ends on December 31, 2009. Following the completion of the performance period, Messrs. Clifton and Blair shall be entitled to a payment of a number of common units equal to the result of multiplying their respective original grant amounts by the performance percentage set forth below:

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3-Year Total Increase in Cash Distributions Per Common Unit above $8.10 (1)	*Performance Percentage (%) to be Multiplied by Performance Units*
$0.00 or less	*50%*
$0.328 or less	*75%*
$0.665 or less	*100%*
$1.011 or less	*125%*
$1.367 or more	*150%*

(1) $8.10 represents a 3-year cumulative distribution of $2.70 per annum, $2.70 being the distribution rate in effect at the start of the performance period.

In order to receive 75% of the units subject to this award, the cash distributions per unit declared and paid in the three years ended December 31, 2009 must total $8.43 per unit. In order to receive 100%, the distributions per unit declared and paid for the three years ended December 31, 2009 must total $8.77 per unit. In order to receive 125%, the distributions per unit declared and paid for the three years ended December 31, 2009 must total $9.11 per unit. In order to receive 150%, the distributions per unit declared and paid in the three years ended December 31, 2009 must total $9.47 per unit. The percentages are interpolated between points.

In the event that the employment of either Mr. Clifton or Mr. Blair terminates prior to January 1, 2010, other than due to a defined change-in-control event, death, disability or retirement, the applicable employee will forfeit his award. The change-in-control provisions of this award are described below under the section titled Severance and Change-in-Control Arrangements. In the event of the death or total and permanent disability of either Mr. Clifton or Mr. Blair, as determined by the Committee in its sole discretion, or upon either of the employee s retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, the applicable employee shall forfeit a number of units equal to the percentage that the number of full months following the date of separation, death, disability or retirement to the end of the performance period bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150% instead of the prorated number. As shown in the table above, the amount shown in column (f) reflects the minimum payment amount of 50%, the amount shown in column (g) reflects the target amount of 100% and the amount shown in column (h) reflects the maximum payment level of 150%.

Restricted Units

Under the terms of the grants of restricted units, one-third of the restricted units will be fully vested and nonforfeitable after December 31, 2007, two-thirds will be fully vested and nonforfeitable after December 31, 2008, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2009. Other than due to a defined change-in-control event, death, disability or retirement, the employee shall forfeit two-thirds of the units if his employment is terminated after December 31, 2007 and before January 1, 2008, and one-third of the units if his employment is terminated after December 31, 2009 and before January 1, 2010. The change-in-control provisions of this award are described below under the section titled Severance and Change-in-Control Arrangements. In the event of the employee s death, total and permanent disability as determined by the Committee in its sole discretion, or upon either of the employee s retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, the employee shall forfeit a number of units equal to (i) the total award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2009 bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Each listed employee is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

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Annual Incentive Cash Bonus Compensation

The cash bonuses that are available to the Named Executive Officers under the Annual Incentive Plan are based upon pre-set percentages of salary, achieved by reaching certain performance levels. A description of the pre-established performance criteria utilized in 2007 can be found above in the CD&A under the section titled Annual Incentive Cash Bonus Compensation. The following chart reflects the target percentages that were set for Messrs. Blair, Cunningham and Townsend for 2007 (Messrs. Clifton, McDonnell and Ridenour do not receive Non-Equity Incentive Plan Compensation) and the actual percentages awarded to each individual:

Name and Principal Position	% based on Holly PTNI	% based upon Holly stock price	Business Unit Performance	Individual Performance (1)	Total Possible Incentive Compensation (2)
David G. Blair, Senior Vice	10%	10%	20%	10%	50%
President	Actual: 20%	Actual: 20%	Actual: 20%	Actual: 20%	Actual: 80%
James G. Townsend, Vice President	5%	5%	20%	10%	40%
Pipeline Operations	Actual: 10%	Actual: 10%	Actual: 20%	Actual: 20%	Actual: 60%
Mark T. Cunningham,	2.5%	2.5%	15%	10%	30%
Vice President	Actual: 5%	Actual: 5%	Actual: 15%	Actual: 20%	Actual: 45%

(1) This performance criteria was not exceeded and was awarded at the target level instead of an increased level.

(2) The percentages in the first four columns for each individual are added together and then multiplied by the base salary for each individual. The target and maximum awards are reflected above in the chart in the 2007 Grants of Plan Based Awards section. Each of the listed employees

received the maximum awards.

Outstanding Equity Awards at Fiscal Year End

	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, Units or Other Rights That Have Not Vested [2]**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Units, Units or Other Rights That Have Not Vested**
Matthew P. Clifton	n/a	n/a	33,563	$ 1,468,381
Stephen J. McDonnell	3,371	$ 147,461	n/a	n/a
P. Dean Ridenour[3]	7,829[4]	$ 342,519	n/a	n/a
David G. Blair	3,049	$ 133,394	4,573	$ 200,069
Mark T. Cunningham	1,040	$ 45,500	n/a	n/a
James G. Townsend[5]	5,255	$ 229,906	n/a	n/a

(1) The values are based upon the closing market price of $43.75 on December 31, 2007.

(2) For purposes of this disclosure only, all performance units have been calculated assuming the maximum threshold is reached.

(3)

Mr. Ridenour was no longer the Vice President and Chief Accounting Officer as of January 7, 2008 and provides services to Holly as a consultant. It is expected that in April 2008 Mr. Ridenour will cease to be a Holly employee but will continue as a non-employee consultant to Holly under a two-year consulting contract. The Compensation Committee has determined that, solely for purposes of the Award Grants, Mr. Ridenour s work as a consultant under the consulting agreement will be treated as continuing employment with the Partnership and Mr. Ridenour s non-vested restricted units will not be forfeited because of the change from employee to consultant status.

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

(5) Because of his work as Project Manager of the UNEV project, the Committee determined that Mr. Townsend s unvested units will continue to vest in accordance with the vesting schedule so long as he continues to be a Holly employee.

Mr. Clifton s Equity Incentive Plan Awards are reflected in the combined total of A, B and C below:

A. Mr. Clifton received an award of 7,802 restricted units made in February 2005. Except in the case of early termination, after December 31, 2007 (i) one third of the restricted units will vest if HEP s quarterly adjusted net income per diluted unit is at least $0.56 for any quarter between October 1, 2007 and December 31, 2010; (ii) an additional one third of the restricted units will vest if HEP s quarterly adjusted net income per diluted unit is at least $0.56 for any quarter between October 1, 2008 and December 31, 2010; and (iii) an additional one third of the restricted units will vest if HEP s quarterly adjusted net income per diluted unit is at least $0.56 for any quarter between October 1, 2009 and December 31, 2010. All units may vest as late as December 31, 2010, but the indicated number of units may vest sooner if the required adjusted net income per diluted unit is obtained sooner.

   Other than due to a defined change-in-control event, death, disability or retirement, Mr. Clifton shall forfeit two-thirds of the units if his employment is terminated after December 31, 2007 and before January 1, 2009, and one-third of the units if his employment is terminated after December 31, 2008 and before January 1, 2010. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Clifton s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Clifton shall forfeit a number of units equal to (i) the total number of units initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2009 bears to 60. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. Clifton is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

B. An award of 8,438 performance units was made to Mr. Clifton in February 2006. Under the terms of the grant, Mr. Clifton may earn from 50% to 150% of the performance units, based on the increase in HEP s cash distributions on the common units of HEP. The performance period for the award began on January 1, 2006 and ends on December 31, 2008. Following the completion of the performance period, Mr. Clifton shall be entitled to a payment of a number of common units equal to the result of multiplying the original grant amount of 8,438 by the performance percentage set forth below:

3-Year Total Increase in Cash Distributions Per Common Unit above $7.50 (beginning with base of $2.50)	*Performance Percentage (%) to be Multiplied by Performance Units*
$0.00 or less	*50%*
$0.62	*100%*
$1.27 or more	*150%*

In order to receive 100% of the units subject to this award, the cash distributions per unit declared and paid in the three years ended December 31, 2008 must total $8.12 per unit. In order to receive 125%, the distributions per unit declared and paid for the three years ended December 31, 2008 must total $8.44 per unit. In order to receive 150%, the distributions per unit declared and paid in the three years ended December 31, 2008 must total $8.77 per unit. The percentages shall be interpolated between points.

In the event that Mr. Clifton s employment terminates prior to January 1, 2009, other than due to a defined change-in-control event, death, disability or retirement, he will forfeit his award. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Clifton s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Clifton shall forfeit a number of units equal to the percentage that the number of full months following the date of separation, death, disability or retirement to the end of the performance period bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150% instead of the prorated number.

C. Mr. Clifton received an award of 8,736 performance units in February 2007**.** The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Performance Units.

Mr. McDonnell s awards are reflected in the combined total of A, B and C below:

A. An award of 505 restricted units was made to Mr. McDonnell in February 2005. Under the terms of the grant, except in the case of early termination, one-third of the restricted units were fully vested and nonforfeitable after December 31, 2007, two-thirds will be fully vested and nonforfeitable after December 31, 2008, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2009.

Other than due to a defined change-in-control event, death, disability or retirement, Mr. McDonnell shall forfeit two-thirds of the units if his employment is terminated after December 31, 2007 and before January 1, 2009, and one-third of the units if his employment is terminated after December 31, 2008 and before January 1, 2010. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. McDonnell s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. McDonnell shall forfeit a number of units equal to (i) the total number of units initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2009 bears to 60. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. McDonnell is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

B. An award of 1,250 restricted units was made to Mr. McDonnell in February 2006. Under the terms of the grant, one-third of the units vested on January 1, 2007, one-third vested on January 1, 2008, and all of the restricted units will be fully vested and nonforfeitable on January 1, 2009. Other than due to a defined change-in-control event, death, disability or retirement, Mr. McDonnell shall forfeit one-third of the units if his employment is terminated after December 31, 2007 and before January 1, 2009. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. McDonnell s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. McDonnell shall forfeit a number of units equal to (i) the total number of units initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2008 bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. McDonnell is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

C. An award of 2,033 restricted units was made To Mr. McDonnell in February 2007. The vesting dates for this aware are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Restricted Units, one-third of which vested after December 31, 2007.

Mr. Ridenour s awards are reflected in the combined total of A, B and C below:

A. An award of 846 restricted units was made to Mr. Ridenour in February 2005. Under the terms of the grant, except in the case of early termination, one-third of the restricted units were fully vested and nonforfeitable after December 31, 2007, two-thirds will be fully vested and nonforfeitable after December 31, 2008, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2009.

Other than due to a defined change-in-control event, death, disability or retirement, Mr. Ridenour shall forfeit two-thirds of the units if his employment is terminated after December 31, 2007 and before January 1, 2009, and one-third of the units if his employment is terminated after December 31, 2008 and before January 1, 2010. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Ridenour s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Ridenour shall forfeit a number of units equal to (i) the total number of shares initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2009 bears to 60. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. Ridenour is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

B. An award of 4,375 restricted units was made to Mr. Ridenour in February 2006. Under the terms of the grant, one-third of the units vested on January 1, 2007, one-third of the units were fully vested and nonforfeitable on January 1, 2008, and all of the restricted units will be fully vested and nonforfeitable on January 1, 2009. Other than due to a defined change-in-control event, death, disability or retirement, Mr. Ridenour shall forfeit the one-third of the units if his employment is terminated after December 31, 2007 and before January 1, 2009. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Ridenour s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Ridenour shall forfeit a number of units equal to (i) the total number of shares initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2008 bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. Ridenour is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

C. An award of 4,066 restricted units was made to Mr. Ridenour in February 2007. The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Restricted Units, one-third of which vested after December 31, 2007.

Mr. Blair s restricted awards are reflected in the following:

An award of 3,049 restricted units was made to Mr. Blair in February 2007. The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Restricted Units, one-third of which vested after December 31, 2007.

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Mr. Blair s Equity Incentive Plan Awards are reflected in the following:

An award of 3,049 performance units was made to Mr. Blair in February 2007. The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Performance Units.

Mr. Cunningham s restricted awards are reflected in combined total of A, B and C below:

A. An award of 208 restricted units was made to Mr. Cunningham in February 2005. Under the terms of the grant, except in the case of early termination, one-third of the restricted units were fully vested and nonforfeitable after December 31, 2007, two-thirds will be fully vested and nonforfeitable after December 31, 2008, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2009.

B. An award of 425 restricted units was made to Mr. Cunningham in February 2006. Under the terms of the grant, two-thirds of the restricted units were fully vested and nonforfeitable after December 31, 2007, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2008. Other than due to a defined change-in-control event, death, disability or retirement, Mr. Cunningham shall forfeit the remaining units if his employment is terminated after December 31, 2007 and before January 1, 2009. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Cunningham s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Cunningham s shall forfeit a number of units equal to (i) the total number of shares initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2008 bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number.
Mr. Cunningham is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

C. An award of 549 restricted units was made to Mr. Cunningham in February 2007. The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Restricted Units.

Mr. Townsend s restricted awards are reflected in combined total of A, B and C below:

A. An award of 731 restricted units was made to Mr. Townsend in February 2005. Under the terms of the grant, except in the case of early termination, one-third of the restricted units were fully vested and nonforfeitable after December 31, 2007, two-thirds will be fully vested and nonforfeitable after December 31, 2008, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2009.

B. An award of 2,500 restricted units was made to Mr. Townsend in February 2006. Under the terms of the grant, two-thirds of the restricted units were fully vested and nonforfeitable after December 31, 2007, and all of the restricted units will be fully vested and nonforfeitable after December 31, 2008. Other than due to a defined change-in-control event, death, disability or retirement, Mr. Townsend shall forfeit the remaining units if his employment is terminated after December 31, 2007 and before January 1, 2009. The change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change-in-Control. In the event of Mr. Townsend s death, total and permanent disability as determined by the Committee in its sole discretion or retirement after attaining age 62 or retirement after attaining an earlier retirement age approved by the Committee in its sole discretion, Mr. Townsend shall forfeit a number of units equal to (i) the total number of shares initially subject to the award times (ii) the percentage that the period of full months beginning on the first calendar month following the date of death, disability or retirement and ending on December 31, 2008

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bears to 36. Any remaining units that are not vested will become vested. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Mr. Townsend is a unitholder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units.

C. An award of 2,857 restricted units was made to Mr. Townsend in February 2007. The vesting dates for this award are described in the narrative disclosures in the section titled 2007 Grants of Plan-Based Awards under the heading Restricted Units, one-third of which vested after December 31, 2007.

OPTION EXERCISES AND STOCK VESTED

The following table presents stock options exercised by, and stock awards vested for, our Named Executive Officers during 2007:

	Stock Awards	
Named Executive Officer	Number of Shares Acquired on Vesting (1)	Value Realized on Vesting (2)
Matthew P. Clifton		
Stephen J. McDonnell	417	$ 16,784
P. Dean Ridenour	3,333	$ 151,047
David G. Blair		
Mark T. Cunningham	142	$ 5,716
James G. Townsend	833	$ 33,528

(1) All units were granted on February 16, 2006 and vested on January 1, 2007 except for 1,875 units for Mr. Ridenour that were granted on November 4, 2004 and vested on August 4, 2007.

(2) Calculated as the aggregate market value of the shares vesting on the vesting dates.

Pension Benefits Table

Our Named Executive Officers participate in Holly s Retirement Plan, which generally provides a defined benefit to participants following their retirement. The table below sets forth an estimate of the retirement benefits payable to Messrs. Townsend, Blair and Cunningham at normal retirement age under Holly s Retirement Plan. Messrs. Clifton, McDonnell and Ridenour also participate in Holly s Retirement Plan; however, since we do not reimburse HLS for their pension benefits, which are instead paid for by Holly, we have not provided any disclosure with respect to their potential retirement benefits. The costs of the pension benefits for Messrs. Blair, Cunningham and Townsend are reimbursed on a current basis.

Pension Benefits

Name [1] (a)	Plan Name (b)	Number of Years Credited Service (c)	Present Value of Accumulated Benefit (d)	Payments During Last Fiscal Year (e)
Matthew P. Clifton	n/a	n/a	n/a	n/a
Stephen J. McDonnell	n/a	n/a	n/a	n/a
P. Dean Ridenour	n/a	n/a	n/a	n/a
David G. Blair	Retirement Plan	26.8	$ 446,333	$
Mark T. Cunningham	Retirement Plan	3.5	$ 29,563	$
James G. Townsend	Retirement Plan	23.2	$ 396,636	$

(1) We do not reimburse HLS for pension benefits for Messrs. Clifton, McDonnell or Ridenour. Their retirement benefits are paid for by Holly.

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The actuarial present value of the accumulated benefits is determined using the same assumptions as used for financial reporting purposes except the payment date is assumed to be age 62 for Holly s Retirement Plan rather than age 65. Age 62 is the earliest date a benefit can be paid with no benefit reduction under Holly s Retirement Plan. In addition, the material assumptions used for these calculations include the following:

Discount Rate	6.40%
Mortality Table	RP2000 White Collar Projected to 2020 (50% male/ 50% 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 2007, but quarterly bonuses were paid to some non-executive union employees.

Holly s 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. An employee s benefit service is not deemed interrupted if the employee performed services for Holly and is later transitioned to work as an HLS employee for us. 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 Code are funded by Holly s contributions to the Retirement Plan, with the amounts determined on an actuarial basis. In 2007, the Code limited benefits that could be covered by the Retirement Plan s assets to $180,000 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 $225,000 per year (subject to certain upward adjustments for future years).

Since Mr. Townsend is over age 50 and has more than 10 years of service, he is eligible for early retirement benefits under the Holly Retirement Plan as of December 31, 2007. If Mr. Townsend began receiving early retirement benefits prior to his attainment of age 60, his accrued benefit will be reduced by (a) 1/12 of 2.5% for each full month from the date he will attain age 60 until the date he will attain age 62, and (b) 1/12 of 5% for each full month by which the commencement of his benefits precedes his attainment of age 65. Mr. Townsend s early retirement benefit payable beginning January 1, 2008 is estimated to be $2,998.44 per month payable for his lifetime, or $558,400 payable as a lump sum.

Nonqualified Deferred Compensation Table

Our Named Executive Officers do not participate in any nonqualified deferred compensation plans.

Potential Payments Upon Termination or Change-in-Control

There are no employment agreements currently in effect between us and any Named Executive Officer, and the Named Executive Officers are not covered under any general severance plan of Holly, HLS or HEP. Holly has entered into Change-In-Control Agreements with Messrs. Blair, Cunningham and Townsend. The expenses associated with the Change-in-Control Agreements are borne by Holly and are not reimbursable by us. Holly has also entered into similar agreements with Messrs. Clifton, McDonnell and Ridenour, the costs of which are also borne by Holly. Because Messrs. Clifton, McDonnell and

Ridenour do not perform services solely on behalf of HEP, a quantification of their potential benefits under the Change-In-Control Agreement is not provided below but will be disclosed in Holly s annual proxy statement.
Mr. Ridenour s Change-in-Control Agreement will terminate on March 31, 2008, when his employment ends and he becomes an independent contractor consultant.
The Change-In-Control Agreements are subject to an initial three year term, with an automatic one year extension on the second anniversary of the effective date (and on each anniversary date thereafter) unless a cancellation notice is given 60 days prior to the second anniversary of the effective date (or any anniversary date thereafter, as applicable).
The Change-In-Control Agreements provide that if, in connection with or within two years after a Change-in-Control of Holly, 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 Holly or its related entities on substantially the same terms as his previous employment with HLS within 30 days after the termination, then the executive will receive the following cash severance amounts paid by Holly as outlined in the table below: (i) a cash payment, paid within 10 days following the executive s termination, equal to his accrued and unpaid salary, unreimbursed expenses and accrued vacation pay, and (ii) a lump sum amount, paid within 15 days following the executive s termination, equal to a multiple specified in the table below for such executive times (A) his annual base salary as of his date of termination or the date immediately prior to the Change-in-Control, whichever is greater, and (B) his annual bonus amount, calculated as the average annual bonus paid to him for the prior three years. In addition, the executive (and his dependents, as applicable) will receive a continuation of their medical and dental benefits for the number of years indicated in the table below for such executive.

Named Executive Officer	Cash Severance Multiple	Years for Continuation of Medical and Dental Benefits
David G. Blair	2 times	2
James G. Townsend [(1)]	1 times	1
Mark T. Cunningham	1 times	1

(1) For 2007, Mr. Townsend worked for HEP from January 1 through August 31 only.

For purposes of the Change-In-Control Agreements, the following terms have been given the meanings set forth below:

(a) Cause means an executive s (i) engagement in any act of willful gross negligence or willful misconduct on a matter that is not inconsequential, as reasonably determined by Holly s board of directors in good faith, or (ii) conviction of a felony.

(b) Change-in-Control means, subject to certain specific exceptions set forth in the Change-In-Control Agreements: (i) a person or group of persons becomes the beneficial owner of more than 50% of the combined voting power of the then outstanding securities of Holly, HLS or HEP or of the then outstanding common stock or membership interests, as applicable, of Holly or HLS, (ii) a majority of the members of Holly s board of directors is replaced during a 12 month period by directors who were not endorsed by a majority of the board members prior to their appointment, (iii) the consummation of a merger of consolidation of Holly, HLS, HEP or any subsidiary of any of the foregoing other than (A) a merger or consolidation resulting in the voting securities of Holly, HLS, or HEP, as applicable, outstanding immediately prior to the transaction continuing to represent at least 50% of the combined voting power of the voting securities of Holly, HLS, HEP or the surviving entity, as applicable, outstanding immediately after the transaction, or (B) a merger of consolidation effected to implement a recapitalization of Holly, HLS, or HEP in which no person or group becomes the beneficial owner of securities of Holly, HLS, or HEP representing more than 50% of the combined voting power of the then outstanding securities of Holly, HLS or HEP, or (iv) the stockholders or unit holders, as applicable, of Holly or HEP approve a plan of complete liquidation or dissolution of Holly or HEP or an agreement for the sale or disposition of all or substantially all of the assets of Holly or HEP.

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(c) Good Reason means, without the express written consent of the executive: (i) a material reduction in the executive s (or his supervisor s) authority, duties or responsibilities, (ii) a material reduction in the executive s base compensation, or (iii) 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. The executive must provide notice to Holly of the alleged Good Reason event within 90 days of its occurrence and Holly, HLS and HEP will be have an opportunity to remedy the alleged Good Reason event within 30 days from receipt of the notice of the allegation.

All payments and benefits due under the Change-In-Control Agreements will be conditioned on the execution and nonrevocation by the executive of a release of claims for the benefit of Holly, HLS and HEP 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 Holly, HLS or HEP. Violation of the confidentiality provisions entitles Holly, HLS or HEP 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 Holly, HLS or HEP as a result of a change in ownership or control) (collectively, the Payments) exceed the amount allowed under section 280G of the Code for such executive by 10% or more, Holly will pay the executive a tax gross up (a Gross Up) in an amount necessary to allow the executive to retain (after all regular income and Code Section 280G taxes) a net amount equal to the total present value of the Payments on the date they are to be paid (after all regular income taxes but without reduction for Code Section 290G taxes). Conversely, the Payments will be reduced if they exceed the Code Section 280G limit for the executive by less than 10% (a Cut Back).

In addition, under the terms of the long-term incentive equity awards described above, if, in the event of a Change-in-Control , (i) a Named Executive Officer s employment is terminated, other than for cause, or (ii) he resigns after an Adverse Change has occurred, then all restrictions on the award will lapse, the units will become vested and the vested units will be delivered to the Named Executive Officer as soon as practicable. For the 2006 and 2007 long-term incentive equity awards, the units will vest at 150% in the event of a Change in Control.

For purposes of the long-term equity incentive awards, the following terms have been given the meanings set forth below:

(a) Adverse Change means, (i) a change in the city the executive is required to work, (ii) a substantial increase in the travel requirements of employment, (iii) a substantial reduction in the duties performed by the executive, or (iv) a significant reduction in non-discretionary compensation or benefits of the executives (other than a general reduction applicable generally to executives).

(b) Cause means (i) an act of dishonesty constituting a felony or serious misdemeanor and resulting (or intended to result in) personal gain or enrichment to the executive at the expense of HLS, (ii) gross or willful and wanton negligence in the performance of the executive s material duties, or (ii) conviction of a felony involving moral turpitude.

(c) Change-in-Control means, subject to certain specific exceptions set forth in the long-term equity incentive awards: (i) a person or group of persons becomes the beneficial owner of more than 40% of the combined voting power of the then outstanding securities of Holly, HLS, HEP or HEP Logistics Holdings, L.P. (HLH), (ii) a majority of the members of Holly s board of directors is replaced by directors who were not endorsed by two-thirds of the board members prior to their appointment, (iii) the consummation of a merger of consolidation of Holly, HLS, HEP or any subsidiary of any of the foregoing other than (A) a merger or consolidation resulting in the voting securities of Holly, HLS, HLH or HEP, as applicable, outstanding immediately prior to the transaction continuing to represent at least 60% of the combined voting power of the voting

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securities of Holly, HLS, HLH, HEP or the surviving entity, as applicable, outstanding immediately after the transaction, or (B) a merger of consolidation effected to implement a recapitalization of Holly, HLS, HLH or HEP in which no person or group becomes the beneficial owner of securities of Holly, HLS, HLH or HEP representing more than 40% of the combined voting power of the then outstanding securities of Holly, HLS, HLH or HEP, or (iv) the stockholders or unit holders, as applicable, of Holly, HLS, HLH or HEP approve a plan of complete liquidation or dissolution of Holly, HLS, HLH or HEP or an agreement for the sale or disposition of all or substantially all of the assets of Holly, HLS, HLH or HEP.

The following table reflects the estimated payments due pursuant to the Change-In-Control Agreements and equity awards of each Named Executive Officer as of December 31, 2007, assuming, as applicable, that a Change-in-Control occurred (under both the Change-in-Control Agreements and the equity awards) and such executives were terminated effective December 31, 2007. For these purposes, our common unit price was assumed to be $43.75, which is the closing price on December 31, 2007. The amounts below have been calculated using numerous assumptions that we believe are reasonable. However, any actual payments that may be made pursuant to the agreements described above are dependent on various factors, which may or may not exist at the time a Change-in-Control actually occurs and the Named Executive Officer is actually terminated. Therefore, such amounts and disclosures should be considered forward looking statements.

	Cash Payments(1)	Value of Welfare Benefits(2)	Accelerated Vesting of Equity Awards	Excise Tax Gross Up or Cut Back	Total
Matthew P. Clifton	n/a	n/a	$ 823,475 (3)	n/a	$ 823,475
Stephen J. McDonnell	n/a	n/a	$ 147,461 (4)	n/a	$ 147,461
P. Dean Ridenour	n/a	n/a	$ 342,519 (4)	n/a	$ 342,519
David G. Blair	$664,341	$ 21,800	$ 333,485 (5)	n/a	$1,019,626
James G. Townsend (6)	n/a	n/a	$ 229,906 (4)	n/a	$ 229,906
Mark T. Cunningham	$198,975	$ 16,625	$ 45,500 (4)	n/a	$ 261,100

(1) Represents cash payments equal to (a) accrued vacation (none since no vacation carry over, plus (b) the executive s base salary as of December 31, 2007 and the average of the annual cash bonus paid for 2004, 2005 and 2006 times the multiplier identified above.

(2) Represents the value of the continuation of medical and dental benefits for the length of one year multiplied by the applicable multiplier identified above.

(3) Based upon (i) a payment of 100% of the units described at the Outstanding Equity Awards at Fiscal Year End Table and (ii) a payment of 150% of the units provided for under the terms of the long-term incentive equity agreements governing the awards.

(4) Based upon a payment of 100% of the units as provided for under the terms of the long-term incentive equity agreements governing the awards of the units.

(5) Mr. Blair held 3,049 shares of restricted stock, and 3,049 performance

units on December 31, 2007. The amount in the table was reached by multiplying his 3,049 shares of restricted stock by $43.75, to equal $133,394. Because Mr. Blair is eligible to receive 150% of the performance units under the terms of the long-term incentive compensation plan, his 3,049 performance units were first multiplied by 1.5, and then again by $43.75, to equal $200,091. These two amounts, $133,394 and $200,091, were added together to reach the total amount of $333,485 that is disclosed in the table above.

(6) Mr. Townsend no longer worked for HEP on December 31, 2007 and is not included in this summary of December 31, 2007 estimated payments. He was not entitled

to any payments
at the time he
left the employ
of HLS and
joined Holly.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters
The following table sets forth as of February 8, 2008 the beneficial ownership of units of HEP held by beneficial owners of 5% or more of the units, by directors of HLS, the general partner of our general partner, by each executive officer and by all directors and executive officers of HLS as a group. HEP Logistics Holdings, L.P. is an indirect wholly-owned subsidiary of Holly Corporation. Unless otherwise indicated, the address for each unitholder shall be c/o Holly Energy Partners, L.P., 100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Holly Corporation [1]	70,000	0.9	7,000,000	88.2	45.0
HEP Logistics Holdings, L.P. [1]	70,000	0.9	7,000,000	88.2	45.0
Fiduciary Asset Management, LLC [2]	691,698	8.5			4.3
Alon USA			937,500	11.8	5.8
Kayne Anderson Capital Advisors, L.P. [3]	758,600	9.3			4.7
Tortoise Capital Advisors LLC [4]	572,689	7.0			3.6
Matthew P. Clifton	36,802	*			*
Bruce R. Shaw [5]	1,359	*			*
W. John Glancy	1,000	*			*
David G. Blair	5,880	*			*
Mark T. Cunningham	1,390	*			*
P. Dean Ridenour [5]	20,698	*			*
Charles M. Darling, IV [5]	15,668	*			*
Jerry W. Pinkerton [5]	5,468	*			*
William P. Stengel [5]	4,468	*			*
All directors and executive officers as group (9 persons) [5]	92,733	1.1			*

* Less than 1%

(1) Holly Corporation is the ultimate parent company of HEP Logistics Holdings, L.P., and may, therefore, be deemed to beneficially own the units held by HEP Logistics Holdings, L.P.

Holly 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 total units beneficially owned includes a 2% general partner interest held by HEP Logistics Holdings, L.P.

(2) Fiduciary Asset Management, LLC has filed with the SEC a Schedule 13G/A, dated September 19, 2007. Based on this Schedule 13G/A, Fiduciary Asset Management, LLC has sole voting power and sole dispositive power with respect to zero units, and shared voting and dispositive power with respect to 691,698 units. The address of Fiduciary Asset Management, LLC is 8112 Maryland Avenue,

Suite 400 St. Louis, MO 63105.

(3) Kayne Anderson Capital Advisors, L.P. has filed with the SEC a Schedule 13G/A, dated January 23, 2008. Based on this Schedule 13G/A, Kayne Anderson Capital Advisors, L.P. has sole voting power and sole dispositive power with respect to zero units, and shared voting power and shared dispositive power with respect to 758,600 units. The address of Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, Second Floor, Los Angeles, CA 90067.

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(4) Tortoise Capital Advisors LLC has filed with the SEC a Schedule 13G/A, dated February 12, 2007. Based on this Schedule 13G/A, Tortoise Capital Advisors LLC has sole voting power and sole dispositive power with respect to zero units, shared voting power with respect to 534,637 units and shared dispositive power with respect to 572,689 units. The address of Tortoise Capital Advisors LLC is 10801 Mastin Blvd., Suite 222, Overland Park, Kansas 66210.

The number of units beneficially owned includes restricted common units granted as follows: 1,860 units each to Mr. Darling, Mr. Pinkerton and Mr. Stengel, 7,802 units to Mr. Clifton, 959 units to Mr. Shaw, 2,032 units to Mr. Blair, 643 units to Mr. Cunningham, 4,733 units to Mr. Ridenour and also includes performance units granted as follows: 17,174 to Mr. Clifton and 3,049 to Mr. Blair, a combined total of 41,972 units.

Equity Compensation Plan Table

The following table summarizes information about our equity compensation plans as of December 31, 2007:

	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 (excluding securities reflected)**

Equity compensation plans approved by security holders	
Equity compensation plans not approved by security holders.	260,115
Total	260,115

For more information about our Long-Term Incentive Plan, which did not require approval by our limited partners, refer to Item 11, Executive and Director Compensation Long-Term Incentive Plans .

Item 13. Certain Relationships, Related Transactions and Director Independence

Our general partner and its affiliates own 7,000,000 of our subordinated units and 70,000 of our common units, which combined represent a 43% limited partner interest in us. In addition, the general partner owns a 2% general partner interest in us. Transactions with the general partner are discussed below.

On February 28, 2005, we completed the transactions with Alon described on page 7 of this report, by which we acquired certain pipelines and terminals from Alon for $120.0 million in cash and 937,500 of our Class B subordinated units and entered into our pipelines and terminals agreement with Alon. Following this transaction, Alon owns all of our Class B subordinated units, which comprise approximately 5.7% of our total outstanding equity ownership. For the year ended December 31, 2007, we recognized revenues of $21.8 million from Alon pursuant to the pipelines and terminals agreement and $7.1 million from Alon pursuant to capacity lease arrangements on our Orla to El Paso pipeline.

See Item 10 for a discussion of Director Independence.

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

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payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Operational stage

Distributions of available cash to our general partner and its affiliates	We generally make cash distributions 98% to the unitholders, including our general partner and its affiliates as the holders of an aggregate of 7,000,000 of the subordinated units, 70,000 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 Holly or its affiliates an administrative fee, currently $2.1 million per year, for the provision of various general and administrative services for our benefit. The administrative fee may increase following the second and third anniversaries by the greater of 5% or the percentage increase in the consumer price index and may also increase if we make an acquisition that requires an increase in the level of general and administrative services that we receive from Holly 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

On July 13, 2004, we entered into the Omnibus Agreement with Holly and our general partner that addressed the following matters:

our obligation to pay Holly an annual administrative fee, currently in the amount of $2.1 million, for the provision by Holly of certain general and administrative services;

Holly s and its affiliates agreement not to compete with us under certain circumstances;

an indemnity by Holly for certain potential environmental liabilities;

our obligation to indemnify Holly for environmental liabilities related to our assets existing on the date of our initial public offering to the extent Holly is not required to indemnify us;

our three-year option to purchase the Intermediate Pipelines owned by Holly; and

Holly s right of first refusal to purchase our assets that serve Holly s refineries.

Payment of general and administrative services fee

Under the Omnibus Agreement we pay Holly an annual administrative fee, currently in the amount of $2.1 million, for the provision of various general and administrative services for our benefit. The contract provides that this amount may be increased on the third anniversary following our initial public offering by the greater of 5% or the percentage increase in the consumer price index for the applicable year. Our general partner, with the approval and consent of its conflicts committee, also has the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses. Following the initial three-year period under this agreement, our general partner will determine the general and administrative expenses that will be allocated to us.
The $2.1 million fee includes expenses incurred by Holly 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 or the cost of their employee benefits, such as 401(k), pension, and health insurance benefits which are separately charged to us by Holly. We also reimburse Holly and its affiliates for direct general and administrative expenses they incur on our behalf.

Noncompetition

Holly and its affiliates have agreed, for so long as Holly controls our general partner, not to engage in, whether by acquisition or otherwise, the business of operating crude oil pipelines or terminals, refined products pipelines or terminals, Intermediate Pipelines or terminals, truck racks or crude o