Energy Transfer Partners, L.P.
Form 10-K/A
December 12, 2005
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended August 31, 2005

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from ______ to ______

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1493906**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

2838 Woodside Street, Dallas, Texas 75204

(Address of principal executive offices and zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of class	Name of each exchange on which registered
Common Units	New York Stock Exchange

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

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 x No ¨

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes x No ¨

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

The aggregate market value as of February 28, 2005, of the registrant s Common Units held by non-affiliates of the registrant, based on the reported closing price of such units on the New York Stock Exchange on such date, was approximately $1,976,900,000. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At November 11, 2005, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	106,894,514 Common Units

Documents Incorporated by Reference: None

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We are filing this Amendment No. 1 on Form 10-K/A (the Amendment) to amend and supplement our Annual Report on Form 10-K for the fiscal year ended August 31, 2005, originally filed on November 14, 2005 (the Form 10-K). This Amendment is filed to provide the separate consolidated financial statements of our wholly-owned subsidiary, HPL Consolidation LP and its subsidiaries, included herein as Exhibit 99.3 in accordance with Rule 3-10 of Regulation S-X and to provide related consents of Independent Registered Public Accounting Firms included herein as Exhibits 23.1 and 23.2. HPL Consolidation LP became a wholly-owned subsidiary effective November 10, 2005. This Amendment does not reflect events occurring after November 14, 2005, or modify or update those disclosures that may have been affected by subsequent events. In addition, certifications from our Co-Chief Executive Officers and Chief Financial Officer, dated as of the filing of this Amendment, have been included as exhibits hereto.

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ENERGY TRANSFER PARTNERS, L.P.

2005 FORM 10-K ANNUAL REPORT

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PART I

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by us in periodic press releases and some oral statements of our officials during presentations about the Partnership, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified as any statement that does not related strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect , continue, estimate, goal, forecast, may, will, or similar ex forward-looking statements. Although we and our General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, neither we or our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. When considering forward-looking statements, please read the section titled Risk Factors included under Item 7 of this annual report.

ITEM 1. BUSINESS.

Overview

We are a publicly traded master limited partnership that is primarily engaged in the natural gas midstream and transportation and storage business through our operating subsidiary, La Grange Acquisition, L.P. (ETC OLP), and we also have a national retail propane marketing business in the United States through our operating subsidiary, Heritage Operating, L.P (HOLP). As of September 30, 2005, we had an equity market capitalization of approximately $3.8 billion, making us the third largest publicly traded master limited partnership in equity market capitalization.

Our midstream, transportation and storage business owns and operates approximately 11,700 miles of natural gas gathering and transportation pipelines, three natural gas processing plants, two of which are currently connected to our gathering systems, fourteen natural gas treating facilities and three natural gas storage facilities. Through ETC OLP, we conduct our natural gas midstream, transportation and storage business through two segments, the midstream segment and the transportation and storage segment. Our midstream segment focuses on the gathering, compression, treating, processing and marketing of natural gas and our operations are currently concentrated in the Austin Chalk trend of southeast Texas, the Permian Basin of west Texas, the Barnett Shale in north Texas and the Bossier Sands in east Texas. Our transportation and storage segment focuses on the transportation of natural gas between major markets from various natural gas producing areas through connections with other pipeline systems as well as through our Oasis Pipeline, our East Texas pipeline, our recently completed Fort Worth Basin Pipeline, our natural gas pipeline and storage assets that are referred to as the ET Fuel System, and our Houston Pipeline System, which are described below.

We are the fourth largest retail propane marketer in the United States, serving more than 700,000 customers from 315 customer service locations in 34 states. Our propane operations extend from coast to coast, with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States.

We are a publicly traded Delaware limited partnership originally formed as Heritage Propane Partners, L.P. (Heritage), which consummated its initial public offering in June 1996. In January 2004, the propane operations of Heritage were combined with the natural gas midstream and transportation operations of La Grange Acquisition, L.P. conducted under the name Energy Transfer Company. We refer to this combination, along with the incurrence of debt and the issuance of equity securities of Heritage in connection with that combination, as the Energy Transfer Transactions . In March 2004, the combined entity s name was changed to Energy Transfer Partners, L.P. (the Partnership or ETP)

For the year ended August 31, 2005, we had revenues of approximately $6.2 billion, operating income of approximately $312.1 million and net income of approximately $349.4 million.

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The following is a list of certain acronyms and terms generally used in the energy industry and throughout this document:

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement
Mcf	thousand cubic feet
MMBtu	million British thermal unit
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Energy Transfer Transactions

On January 20, 2004, Heritage and Energy Transfer Equity, L.P. (ETE), formerly known as La Grange Energy, L.P., completed a series of transactions whereby ETE contributed its subsidiary, ETC OLP, to Heritage in exchange for cash of $300.0 million less the amount of ETC OLP debt in excess of $151.5 million, less ETC OLP s accounts payable and other specified liabilities, plus agreed-upon capital expenditures paid by ETE relating to the ETC OLP business prior to closing, $433.9 million of Heritage Common and Class D Units, and the repayment of the ETC OLP debt of $151.5 million. These transactions and the other transactions described in the following paragraphs are referred to herein as the Energy Transfer Transactions. In conjunction with the Energy Transfer Transactions and prior to the contribution of ETC OLP to Heritage, ETC OLP distributed its cash and accounts receivables to ETE and an affiliate of ETE contributed an office building to ETC OLP. ETE also received 3,742,515 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline now referred to as the East Texas Pipeline. The Special Units converted to Common Units upon the East Texas Pipeline becoming commercially operational and such conversion being approved by our Unitholders. The East Texas Pipeline became commercially operational on June 21, 2004, and the Unitholders approved the conversion of the Special Units at a special meeting held on June 23, 2004.

Simultaneously with the transactions described in the preceding paragraph, ETE obtained control of Heritage by acquiring all of the interests in Energy Transfer Partners GP, L.P., (ETP GP), formerly U.S. Propane, L.P., the General Partner of Heritage, and ETP GP s general partner, Energy Transfer Partners, L.L.C., (ETP LLC) formerly U.S. Propane, L.L.C., from subsidiaries of AGL Resources, Atmos Energy Corporation, TECO Energy, Inc. and Piedmont Natural Gas Company, Inc. for $30.0 million (the General Partner Transaction). In conjunction with the General Partner Transaction, ETP GP contributed its 1.0101% General Partner interest in HOLP to Heritage in exchange for an additional 1% General Partner interest in Heritage. Simultaneously with these transactions, Heritage purchased the outstanding stock of Heritage Holdings, Inc. (Heritage Holdings) for $100.0 million.

Concurrent with the Energy Transfer Transactions, ETC OLP borrowed $325.0 million from financial institutions and Heritage raised $355.9 million of gross proceeds net of underwriter s discount through the sale of 9,200,000 Common Units at an offering price of $38.69 per unit. The net proceeds were used to finance the Energy Transfer Transactions and for general partnership purposes.

Recent Acquisitions, Dispositions, and Expansion

Devon Midstream Assets Acquisition. On November 1, 2004, we announced the closing of the acquisition of certain midstream natural gas assets of Devon Energy Corporation for approximately $63.0 million in cash after adjustments. The assets, known as the Texas Chalk and Madison Systems, include approximately 1,800 miles of gathering and mainline pipeline systems, four natural gas treating plants, condensate stabilization facilities, fractionation facilities and the 80 MMcf/d Madison gas processing plant.

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Houston Pipeline System Acquisition. In January 2005, we acquired controlling interests in the Houston Pipeline System and related storage facilities from American Electric Power Corporation for approximately $825.0 million plus $132.0 million in natural gas inventory, subject to working capital adjustments. This transaction was financed by us through a combination of borrowings under our credit facilities and a private placement of $350.0 million of Common Units with institutional investors. In addition, we acquired working inventory of natural gas stored in the Bammel storage facility and financed it through a short-term borrowing from an affiliate. The total purchase price of approximately $825.0 million plus working capital, was allocated to the assets acquired and liabilities assumed. Under the terms of the transaction, we acquired all but a 2% limited partner interest in HPL Consolidation, L.P., the entity that owns the companies that own the Houston Pipeline System. The Houston Pipeline System is comprised of approximately 4,200 miles of intrastate pipeline with aggregate capacity of 2.4 Bcf/d, substantial storage facilities and related transportation assets.

Disposition of Elk City Gathering System. On April 14, 2005, we announced that we had closed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City system, to Atlas Pipeline Partners, L.P. The sale price of $191.6 million was used to repay a portion of the indebtedness incurred by us in our recent acquisition of the Houston Pipeline System and related storage facilities.

Fort Worth Basin Expansion. In May 2005, we completed construction of a 55-mile, 24-inch natural gas pipeline in the Fort Worth Basin that connects various pipelines in north Texas and provides transportation for natural gas production from the Barnett Shale producing area. This pipeline has a capacity in excess of 400 MMcf/d. The expansion cost approximately $53.0 million, which was financed entirely with cash from operations.

Recent Propane Acquisitions. During the fiscal year ended August 31, 2005, HOLP acquired substantially all of the assets of ten propane businesses. The aggregate purchase price for these acquisitions totaled $30.8 million.

Recent Expansion Projects. Our recently announced current construction projects are major expansion projects involving several pipeline projects that are expected to increase pipeline transportation access for natural gas producers in the Bossier Sands and Barnett Shale basins in east and north Texas to various markets throughout Texas as well as to markets in the eastern United States through interconnects with other intrastate and interstate pipelines. The larger of the two expansion projects involves the construction of approximately 264 miles of 42-inch pipeline and the addition of approximately 40,000 horsepower of compression at a cost of approximately $535.5 million. The 264 mile pipeline will extend from the intersection of the Fort Worth Basin and North Texas Pipeline near Cleburne, Texas to our Texoma pipeline and on to the Carthage, Texas market hub. This expansion project is supported by a 10-year agreement with XTO Energy, Inc. pursuant to which XTO Energy has agreed to transport specified volumes of natural gas on an annual basis and is entitled to transport additional volumes under similar terms. We expect this project to be completed by December, 2006, although segments of the project will become operational prior to that date. Our other major expansion project involves the construction, on a joint venture basis with Atmos Energy Corp., of a 30-inch pipeline in the north Fort Worth Basin area that will provide an additional outlet for natural gas from the Barnett Shale area to several market hubs. Our share of the estimated cost is approximately $29.3 million. These expansion projects will continue the integration of several pipeline systems and natural gas storage facilities, including the integration of our Katy Pipeline and our Southeast Texas System with the recently acquired ET Fuel System and Houston Pipeline System.

Loop of Fort Worth Basin Expansion. In addition, in response to additional activity in the Barnett Shale, we have approved the looping of the first 24 miles of our existing 55-mile, 24-inch pipeline in the Fort Worth Basin. The Fort Worth Basin Pipeline became commercially operational on May 26, 2005, at nearly full capacity. The looping of the first 24 miles of the system with another 24-inch pipeline and the addition of up to 12,000 horsepower of incremental compression will provide additional upstream capacities needed to accommodate the increased volumes in the Fort Worth Basin production area. The estimated cost to complete this project is approximately $32.1 million and is expected to be completed prior to the end of fiscal year 2006.

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Other Developments

On June 20, 2005, we completed a private sale of 1,640,000 of our Common Units to a group of our executive managers. The Common Units were sold at a price of $31.95 per Common Unit, reflecting a discount from the closing price on the last trading day of June 17, 2005. The price received was based on the fair market value and we believe is comparable to the price that we would have received from an unaffiliated purchaser in a large block equity transaction. The sale was approved by both the special committee of independent directors and the audit committee. The Common Units were issued pursuant to our effective shelf registration statement. Of the proceeds of approximately $52.1 million, $30.0 million was used to repay existing indebtedness and the balance was used for general partnership purposes.

On July 26, 2005, we completed a private sale of 3,000,000 of Common Units to an institutional investor. The Common Units were sold at a price of $35.20 per Common Unit. The Common Units were issued pursuant to our effective shelf registration statement. The proceeds of approximately $105.6 million were used to retire a portion of our outstanding indebtedness under our revolving credit facility and for general partnership purposes.

On July 29, 2005, we completed a registered exchange offer to exchange our 5.95% Senior Notes due February 1, 2015 issued in a Rule 144A private placement offering on January 18, 2005 (the 2015 Unregistered Notes), for a like amount of 5.95% Senior Notes due February 1, 2015 that are registered under the Securities Act of 1933, as amended.

On July 29, 2005, we completed a Rule 144A private placement offering of 5.65% Senior Notes due 2012 (the 2012 Unregistered Notes). The net proceeds of approximately $397.1 million were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

On November 10, 2005 the Partnership purchased the 2% limited partner interest in HPL that it did not already own, from AEP for $16.6 million in cash. As a result HPL became a wholly-owned subsidiary of ETC OLP.

ETC OLP

The operations of ETC OLP consist of the following:

Midstream and Transportation and Storage Operations. Our midstream and transportation and storage operations are primarily located in major natural gas producing regions of Texas. Our midstream and transportation and storage assets consist of our interests in approximately 11,700 miles of natural gas pipelines, three natural gas processing plants, two of which are connected to our gathering systems, 14 natural gas treating facilities and three natural gas storage facilities.

Our midstream segment consists of the following:

the Southeast Texas System, a 4,186-mile integrated system located in southeast Texas that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. The system includes the La Grange processing plant, the Madison processing plant, and ten treating facilities. This system is connected to the Katy Hub through the 55-mile Katy Pipeline and is also connected to the Oasis Pipeline, as well as two power plants. The Southeast Texas system includes the assets acquired from Devon in November 2004.

The La Grange and Madison processing plants are cryogenic natural gas processing plants that processes the rich natural gas that flows through our system to produce residue gas and NGLs. The plants have a processing capacity of approximately 320 MMcf/d. Our ten treating facilities have an aggregate capacity of 740 MMcf/d. These treating facilities remove carbon dioxide and hydrogen sulfide from natural gas that is gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.

an interest in various midstream assets located in Texas and Louisiana, including the Vantex System, the Rusk County Gathering System, the Whiskey Bay System, the Dorado System and the Chalkley Transmission System. On a combined basis, these assets have a capacity of approximately 600 MMcf/d.

marketing operations through our producer services business, in which we market the natural gas that flows through our assets, referred to as on-system gas, and attracts other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell the natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

Substantially all of our on-system marketing efforts involve natural gas that flows through either the Southeast Texas System or our transportation pipelines. For the off-system gas, we purchase gas or act as an agent for small independent producers that do not have marketing operations. We develop relationships with natural gas producers to facilitate the purchase of their production on a long-term basis. We believe that this business provides us with strategic insights and valuable market intelligence, which may impact our expansion and acquisition strategy.

Our transportation and storage segment consists of the following:

the Oasis Pipeline, a 583-mile natural gas pipeline that directly connects the Waha Hub to the Katy Hub. The Oasis Pipeline is primarily a 36-inch diameter natural gas pipeline. It has bi-directional capability with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis Pipeline is currently flowing west-to-east with a current average throughput of approximately 1.6 Bcf/d. The Oasis Pipeline has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

The Oasis Pipeline is integrated with our Southeast Texas System and is an important component to maximizing our Southeast Texas System s profitability. The Oasis Pipeline enhances the Southeast Texas System by:

providing us with the ability to bypass the La Grange processing plant when processing margins are unfavorable;

providing natural gas on the Southeast Texas System access to other third party supply and market points and interconnecting pipelines; and

allowing us to bypass our treating facilities on the Southeast Texas System and blend untreated natural gas from the Southeast Texas System with gas on the Oasis Pipeline while continuing to meet pipeline quality specifications.

The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,000 miles of intrastate natural gas pipeline and related natural gas storage facilities. With approximately 460 receipt and/or delivery points, including interconnects with pipelines providing direct access to power plants and interconnects with other intrastate and interstate pipelines, the ET Fuel System is strategically located near high-growth production areas and provides access to the Waha Hub, the Katy Hub and the Carthage Hub, the three major natural gas trading centers in Texas. The ET Fuel System has total system throughput capacity of approximately 1.3 Bcf/d of natural gas and total working storage capacity of 12.4 Bcf of natural gas. The ET Fuel System s current average throughput is approximately 1.1 MMcf/d. Prior to our acquisition of it in June 2004, the ET Fuel System had been operated primarily as a natural gas transmission pipeline system to supply natural gas from various natural gas producing areas to electric generating power plants of TXU Corp. and its affiliates, which we collectively referred to as TXU. In connection with our acquisition of the ET Fuel System, we entered into an eight-year transportation agreement with TXU Portfolio Management Company, LP, which we refer to as TXU Shipper, a subsidiary of

TXU, to transport a minimum of 115.6 MMBtu per year, subject to certain adjustments as defined in the agreement, and TXU Shipper has elected, effective January 1, 2006, to reduce the minimum amount of natural gas that

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we are obligated to transport to not less than 100.0 MMBtu per year. This is a one-time election allowed under the contract. We also entered into two eight-year natural gas storage agreements with TXU Shipper to store gas at two natural gas storage facilities that were part of the ET Fuel System. The ET Fuel System operates our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d.

The East Texas Pipeline is a 148-mile natural gas pipeline that connects three treating facilities with our Southeast Texas System of which one treating facility is owned by us. This pipeline is the first phase of a multi-phased project that will service producers in East and North Central Texas providing access to the Katy Hub. The East Texas Pipeline expansion had an initial capacity of over 400 MMcf/d which increased to the current capacity of 675 MMcf/d with the addition of the Grimes Counter Compressor Station. The capacity will increase to 720 MMcf/d in February 2006, with the addition of approximately 5,000 horsepower of electric compression. Over 500 MMcf/d of pipeline capacity is contracted under long-term agreements with XTO Energy Inc. and other producers.

The Houston Pipeline System is comprised of approximately 4,200 miles of intrastate natural gas pipeline with an aggregate capacity of 2.4 Bcf/d, the underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast, east Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The Houston Pipeline System is well situated to gather gas in many of the major gas producing areas in Texas. The Houston Pipeline System has a particularly strong presence in the key Houston Ship Channel and Katy Hub markets, which significantly contribute to the Houston Pipeline System s overall ability to play an important role in the Texas natural gas markets. The Houston Pipeline System is also well positioned to capitalize upon off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and its operation of the Bammel storage facility. The Bammel storage facility has a total working gas capacity of approximately 65 Bcf. The field has a peak withdrawal rate of 1.3 Bcf/d. The field also has considerable flexibility during injection periods in that the Houston Pipeline System has engineered an injection well configuration to provide for a 0.6 Bcf/d peak injection rate. The Bammel storage facility is strategically located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers.

The recently completed Fort Worth Basin Pipeline, which became operational on May 26, 2005, is a 55-mile, 24-inch natural gas pipeline that connects our existing pipelines in north Texas and provides transportation for natural gas production from the Barnett Shale producing area. The completion of the Fort Worth Basin Pipeline is the first part of our previously disclosed expansion program that was implemented to integrate our 36-inch Katy Pipeline and Southeast Texas Pipeline assets with the ET Fuel System and the Houston Pipeline System.

Heritage Operating, L.P.

We believe we are the fourth largest retail propane marketer in the United States, serving more than 700,000 customers from 315 customer service locations in 34 states. Our operations extend from coast to coast, with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States. We are also a wholesale propane supplier in the southwestern and southeastern United States and in Canada, the latter through participation in M-P Energy Partnership. M-P Energy Partnership is a Canadian partnership in which we own a 60% interest that is engaged in wholesale distribution and in supplying our northern U.S. locations. Our propane business has grown primarily through acquisitions of retail propane operations and, to a lesser extent, through internal growth.

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Following is a summary of the retail sales volumes per fiscal year for the last three fiscal years:

	For the Years Ended August 31,		
	2003	2004	2005
Retail Gallons Sold (in millions):	375.9	397.9	406.3

Business Strategy

Our goal is to increase Unitholder distributions and the value of our Common Units. We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through acquisitions, internally generated expansion, and measures aimed at increasing the profitability of our existing assets.

We intend to continue to operate as a diversified, growth-oriented master limited partnership with a focus on increasing the amount of cash available for distribution on each Common Unit. We believe that by pursuing independent operating and growth strategies for our midstream and transportation and storage and propane businesses, we will be best positioned to achieve our objectives.

We expect that midstream and transportation and storage acquisitions, such as our recent acquisition of the ET Fuel System, the Devon midstream assets and the Houston Pipeline System, will be the primary focus of our acquisition strategy going forward, although we will also continue to pursue complementary propane acquisitions. We also anticipate that our midstream and transportation and storage business will provide internal growth projects of greater scale compared to those available in our propane business.

Midstream and Transportation and Storage Business Strategies

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes of natural gas, undertaking additional initiatives to enhance utilization and reducing costs by improving operations.

Engage in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for midstream services. These projects include expansion of existing systems, such as the East Texas Pipeline and the Fort Worth Basin project in North Texas, and construction of new facilities as discussed above. We expect that these expansions will lead to additional growth opportunities in this area.

Increase cash flow from fee-based businesses in our midstream segment. Excluding results from our marketing activities, the portion of our gross margin in the midstream segment attributable to fee-based business has continued to increase. We charge fees for providing midstream services, including gathering, compressing, treating, processing and transmitting natural gas for producers. These fee-based services are dependent on throughput volume and are typically less affected by short-term changes in commodity prices. We intend to seek to increase the percentage of our midstream business conducted with third parties under fee-based arrangements in order to reduce exposure to changes in the prices of natural gas and NGLs. For example, we converted a contract with a major producer in the third fiscal quarter of 2005 from a commodity based contract to a fee-based contract.

Growth through acquisitions. As demonstrated by our recent acquisitions of the ET Fuel System, the Devon midstream assets and the Houston Pipeline System, we intend to make strategic acquisitions of midstream, transportation and storage assets in our current areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing and acquired assets. We will also pursue midstream, transportation and storage asset acquisition opportunities in other regions of the U.S. with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas. We believe that we will be well positioned to benefit from the additional acquisition opportunities likely to arise as a result of the ongoing divestiture of midstream assets by large industry participants.

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Propane Business Strategies

Pursue internal growth opportunities. In addition to pursuing expansion through acquisitions, we have aggressively focused on high return internal growth opportunities at our existing customer service locations. We believe that by concentrating our operations in areas experiencing higher-than-average population growth, we are well positioned to achieve internal growth by adding new customers.

Growth through complementary acquisitions. We believe that our position as the fourth largest propane marketers provides us a solid foundation to continue our acquisition growth strategy through consolidation. We believe that the fragmented nature of the propane industry will continue to provide opportunities for growth through the acquisition of propane businesses that complement our existing asset base. In addition to focusing on propane acquisition candidates in our existing areas of operations, we will also consider core acquisitions in other higher-than-average population growth areas in which we have no presence in order to further reduce the impact adverse weather patterns and economic downturns in any one region may have on our overall operations.

Maintain low-cost, decentralized operations. We focus on controlling costs, and we attribute our low overhead costs primarily to our decentralized structure. By delegating all customer billing and collection activities to the customer service location level, as well as delegating other responsibilities to the operating level, we have been able to operate without a large corporate staff. In addition, our customer service location level incentive compensation program encourages employees at all levels to control costs while increasing revenues.

Competitive Strengths

We believe that we are well-positioned to compete in both the natural gas midstream and transportation and storage and propane industries based on the following strengths:

Our enhanced access to capital and financial flexibility will allow us to compete more effectively in acquiring assets and expanding our systems. We expect that our recently obtained credit facility and other recent financing transactions will increase our financial flexibility and enhance our access to capital. We believe this will allow us to implement our operating strategies in a timely manner and more effectively compete in acquiring additional assets or expanding our existing systems.

Our experienced management team has an established reputation as highly-effective, strategic operators within our operating segments. In the past, the management teams of each of our operating segments have been successful in identifying and consummating strategic acquisitions to enhance our businesses. In addition, our management team has a substantial equity ownership in us and is motivated through performance-based incentive compensation programs to effectively and efficiently manage our business operations.

Midstream and Transportation and Storage Business Strengths

We have a significant market presence in each of our operating areas. We have a significant market presence in each of our operating areas, which are located in major natural gas producing regions of the United States.

Our assets provide marketing flexibility through our access to numerous markets and customers. Our Oasis Pipeline combined with the Southeast Texas System provides our customers direct access to the Waha and Katy Hubs and to virtually all other market areas in the United States via interconnections with major intrastate and interstate natural gas pipelines. Furthermore, our Oasis Pipeline is tied directly or indirectly to a number of major power generation facilities in Texas as well as several industrial and utility end-users. With the acquisition of the ET Fuel System in June 2004, the HPL acquisition in January 2005, and the completion of the East Texas Pipeline system and the Fort Worth Basin pipeline, we have also enhanced our opportunities with additional power plants, industrial users, municipals, and co-operatives, and the added storage facilities add flexibility for fuel management services.

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Our Southeast Texas System has additional capacity, which provides opportunities for higher levels of utilization. We expect to connect new supplies of natural gas volumes by utilizing the available capacity on the Southeast Texas System. The available capacity also provides us with opportunities to extend the Southeast Texas System to additional natural gas producing areas, such as east Texas through the East Texas Pipeline.

Our ability to bypass our La Grange processing plant reduces our commodity price risk. A significant benefit of our ownership of the Oasis Pipeline is that we can elect not to process natural gas at our La Grange processing plant when processing margins (or the difference between NGL sales prices and the cost of natural gas) are unfavorable. Instead of processing the natural gas, we are able to deliver natural gas meeting pipeline quality specifications by blending rich gas, or gas with a high NGL content, from the Southeast Texas System with lean gas, or gas with a low NGL content, transported on the Oasis Pipeline. This enables us to sell the blended natural gas for a higher price than we would have been able to realize upon the sale of NGLs if we had to process the natural gas to extract NGLs.

Our acquisition of the Houston Pipeline System enables us to engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. The Bammel natural gas storage facility, acquired when we purchased the Houston Pipeline System, has a total working gas capacity of approximately 65 Bcf. The reservoir has a peak withdrawal rate of 1.3 Bcf/d and also has considerable flexibility during injection periods in that the Houston Pipeline System has engineered an injection well configuration to provide for a 600 MMcf/d peak injection rate. Therefore, we are able to purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. In addition, the Bammel natural gas storage facility is strategically located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers.

Propane Business Strengths

Geographically diverse retail propane network. We believe our geographically diverse network of retail propane assets reduces our exposure to unfavorable weather patterns and economic downturns in any one geographic region, thereby reducing the volatility of our cash flows.

Experience in identifying, evaluating and completing acquisitions. We follow a disciplined acquisition strategy that concentrates on propane companies that (1) are located in geographic areas experiencing higher-than-average population growth, (2) provide a high percentage of sales to residential customers, (3) have a strong reputation for quality service, and (4) own a high percentage of the propane tanks used by their customers. In addition, we attempt to capitalize on the reputations of the companies we acquire by maintaining local brand names, billing practices and employees, thereby creating a sense of continuity and minimizing customer loss. We believe that this strategy has also helped to make it an attractive buyer for many propane acquisition candidates from the seller s viewpoint.

Operations that are focused in areas experiencing higher-than-average population growth. We believe that our concentration in higher-than-average population growth areas provides a strong economic foundation for expansion through acquisitions and internal growth. We do not believe that we are more vulnerable than our competitors to displacement by natural gas distribution systems because the majority of our areas of operations are located in rural areas where natural gas is not readily available.

Low-cost administrative infrastructure. We are dedicated to maintaining a low-cost operating profile and have a successful track record of aggressively pursuing opportunities to reduce costs. Of the 2,642 full-time propane employees as of October 31, 2005, only 110, or approximately 4.2%, were general and administrative.

Decentralized operating structure and entrepreneurial workforce. We believe that our decentralized propane operations foster an entrepreneurial corporate culture by: (1) having operational decisions made at the customer service location and operating level, (2) retaining billing, collection and pricing responsibilities at the local and operating level, and (3) rewarding employees for achieving financial targets at the local level.

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Midstream Natural Gas Industry Overview

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry consists of natural gas gathering, compression, treating, processing and transportation and NGL fractionation and transportation, and is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

Natural gas has a widely varying quality and composition, depending on the field, the formation, or the reservoir from which it is produced. The principal constituents of natural gas are methane and ethane, though most natural gas also contains varying amounts of heavier components, such as propane, butane and natural gasoline that may be removed by a number of processing methods. Most raw materials produced at the wellhead are not suitable for long-haul pipeline transportation or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components and other contaminants that would interfere with pipeline transportation or the end use of the gas.

Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total domestic consumption of natural gas is expected to increase by over 2.2% per annum, on average, to 27.1 Tcf by 2010, from an estimated 22.2 Tcf consumed in 2001, representing approximately 25% of all total end-user energy requirements by 2010. During the last five years, the United States has on average consumed approximately 22.6 Tcf per year, with average domestic production of approximately 19.1 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

Natural gas gathering. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transportation.

Natural gas compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly more difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is high in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove carbon dioxide and hydrogen sulfide from natural gas to ensure that it meets pipeline quality specifications.

Natural gas processing. Some natural gas produced by a well does not meet the pipeline quality specifications established by downstream pipelines or is not suitable for commercial use and must be processed to remove the mixed NGL stream. In addition, some natural gas produced by a well, while not required to be processed, can be processed to take advantage of favorable processing margins. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream.

Natural gas transportation. Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the natural gas to industrial end-users, utilities and other pipelines.

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Propane Industry Overview

Propane, a by-product of natural gas processing and petroleum refining, is a clean-burning energy source recognized for its transportability and ease of use relative to alternative forms of stand-alone energy sources. Retail propane use falls into three broad categories: (1) residential applications, (2) industrial, commercial and agricultural applications and (3) other retail applications, including motor fuel sales. In our wholesale operations, we sell propane principally to governmental agencies and industrial end-users.

Propane is extracted from natural gas at processing plants or separated from crude oil during the refining process. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for ease of handling in shipping and distribution. When the pressure is released or the temperature is increased, it is usable as a flammable gas. Propane is naturally colorless and odorless. An odorant is added to allow its detection. Like natural gas, propane is a clean burning fuel and is considered an environmentally preferred energy source.

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. We compete for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources has been increasing as a result of reduced utility regulation. Except for certain industrial and commercial applications, propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a significantly less expensive source of energy than propane. The gradual expansion of natural gas distribution systems in the United States has resulted in the availability of natural gas in many areas that previously depended upon propane. Although the extension of natural gas pipelines tends to displace propane distribution in areas affected, we believe that new opportunities for propane sales arise as more geographically remote neighborhoods are developed. Even though propane is similar to fuel oil in certain applications and market demand, propane and fuel oil compete to a lesser extent primarily because of the cost of converting from one to another. Based upon industry publications, propane accounts for six and one-half percent of household energy consumption in the United States.

In addition to competing with alternative energy sources, we compete with other companies engaged in the retail propane distribution business. Competition in the propane industry is highly fragmented and generally occurs on a local basis with other large multi-state propane marketers, thousands of smaller local independent marketers and farm cooperatives. Most of our customer service locations compete with five or more marketers or distributors. Each retail distribution outlet operates in its own competitive environment because retail marketers tend to locate in close proximity to customers. The typical retail distribution outlet generally has an effective marketing radius of approximately 50 miles although in certain rural areas the marketing radius may be extended by satellite locations.

The ability to compete effectively further depends on the reliability of service, responsiveness to customers and the ability to maintain competitive prices. We believe that our safety programs, policies and procedures are more comprehensive than many of our smaller, independent competitors and give us a competitive advantage over such retailers.

The wholesale propane business is highly competitive. For fiscal year 2005, our domestic wholesale operations (excluding M-P Energy Partnership) accounted for only 3.0% of our total gallons sold in the United States and approximately 1.2% of our gross profit. We do not emphasize wholesale operations, but believe that limited wholesale activities enhance our ability to supply our retail operations.

The Midstream and Transportation and Storage Segments

Competition

The business of providing natural gas gathering, transmission, treating, transporting, storing and marketing services is highly competitive. Since pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our transportation and storage segment are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major

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integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely various sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

Credit Risk and Customers

We have a concentration of customers in natural gas transmission, distribution and marketing as well as industrial end-users and customers in the refining and petrochemical industries. We are diligent in attempting to ensure that we issue credit to credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

During the year ended August 31, 2005, we had one customer, BP Energy Company, that individually accounted for more than 10% of midstream and transportation and storage segment revenues. While this customer represents a significant percentage of midstream and transportation and storage segment revenues, the lost revenue from this customer would not have a material impact on our results of operations.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, transportation service includes storage service. We do not own any interstate natural gas transportation facilities, so FERC does not directly regulate any of our pipeline operations pursuant to its jurisdiction under the NGA. However, FERC s regulation influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;

the initiation and discontinuation of services; and

various other matters.

Failure to comply with the NGA can result in the imposition of administrative, civil and criminal remedies.

In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they are subject to regulation by various agencies in Texas, principally the Texas Railroad Commission (TRRC), where they are located. However, to the extent that our intrastate pipeline systems transport natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act (NGPA), which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service set forth in the pipeline s statement of operating conditions are subject to FERC review and approval. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply

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with the terms and conditions of service established in the pipeline s FERC approved Statement of Operating Conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Our intrastate pipeline and storage operations in Texas are subject to the Texas Utilities Code, as implemented by the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable and not discriminatory. The TRRC has authority to ensure that rates charged by intrastate pipelines for natural gas sales or transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines in Texas and Louisiana that we believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation.

In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Historically, apart from pipeline safety, it has not acted to exercise this jurisdiction respecting gathering facilities. Our Chalkley System is regulated as an intrastate transporter, and the Office of Conservation has determined that our Whiskey Bay System is a gathering system.

We are subject to state ratable take and common purchaser statutes in all of the states in which we operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and Federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. Sales for resale of natural gas in interstate commerce made by intrastate pipelines or their affiliates are subject to FERC regulation unless the gas is produced by the pipeline or affiliate. Under current federal rules, however, the price at which we sell natural gas currently is not regulated, insofar as the interstate

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market is concerned and, for the most part, is not subject to state regulation. Effective as of January 12, 2004, the FERC s rules require pipelines (including intrastate pipelines) and their affiliates who sell gas in interstate commerce subject to FERC s jurisdiction to adhere to a code of conduct prohibiting market manipulation and transactions that have no legitimate business purpose or result in prices not reflective of legitimate forces of supply and demand. Those who violate such code of conduct may be subject to suspension or loss of authorization to perform such sales, disgorgement of unjust profits, or other appropriate non-monetary remedies imposed by FERC. FERC denied rehearing of these rules on May 19, 2004, but the rules are still subject to possible court appeals. We cannot predict the outcome of these further proceedings, but do not believe we will be affected materially differently from other intrastate gas pipelines and their affiliates. In addition, our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that it will be affected by any such FERC action materially differently than other natural gas marketers with whom it competes.

Pipeline Safety. The states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended, (the NGPSA), which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal remedies. The rural gathering exemption under the presently exempts substantial portions of our gathering facilities from jurisdiction under that statute. The portions of our facilities that are exempt include those portions located outside of cities, towns or any area designated as residential or commercial, such as a subdivision or shopping center. The rural gathering exemption, however, may be restricted in the future, and it does not apply to our intrastate natural gas pipelines.

Propane Segment

Products, Services and Marketing

We distribute propane through a nationwide retail distribution network consisting of 315 customer service locations in 34 states. Our operations are concentrated in large part in the western, upper midwestern, northeastern and southeastern regions of the United States. We serve more than 700,000 active customers. Historically, approximately two-thirds of Heritage s retail propane volumes and in excess of 90% of its EBITDA, as adjusted, (please read footnote (c) under Item 6 Selected Historical Financial Data and Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations for a more detailed discussion of EBITDA, as adjusted) were attributable to sales during the six-month peak-heating season from October through March, as many customers use propane for heating purposes. Consequently, sales and operating profits are normally concentrated in the first and second fiscal quarters, while cash flows from operations are generally greatest during the second and third fiscal quarters when customers pay for propane purchased during the six-month peak season. To the extent necessary, we will reserve cash from peak periods for distribution to Unitholders during the warmer seasons.

Typically, customer service locations are found in suburban and rural areas where natural gas is not readily available. Generally, such locations consist of a one to two acre parcel of land, an office, a small warehouse and service facility, a dispenser and one or more 18,000 to 30,000 gallon storage tanks. Propane is generally transported from refineries, pipeline terminals, leased storage facilities and coastal terminals by rail or truck transports to our customer service locations where it is unloaded into storage tanks. In order to make a retail delivery of propane to a customer, a bobtail truck is loaded with propane from the storage tank. Propane is then delivered to the customer by the bobtail truck, which generally holds 2,500 to 3,000 gallons of propane, and pumped into a stationary storage tank on the customer s premises. We also deliver propane to retail customers in portable cylinders. We also deliver propane to certain other bulk end-users of propane in tractor-trailer transports, which typically have an average capacity of approximately 10,500 gallons. End-users receiving transport deliveries include industrial customers, large-scale heating accounts, mining operations and large agricultural accounts.

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We encourage our customers whose propane needs are temperature sensitive to implement a regular delivery schedule. Many of our residential customers receive their propane supply pursuant to an automatic delivery system, which eliminates the customer s need to make an affirmative purchase decision and allows for more efficient route scheduling. We also sell, install and service equipment related to our propane distribution business, including heating and cooking appliances.

We own, through our subsidiaries, a 60% interest in M-P Energy Partnership, a Canadian partnership that supplies us with propane as described below under Propane Supply and Storage.

Approximately 97% of the domestic gallons we sold in the fiscal year ended August 31, 2005 were to retail customers and 3% were to wholesale customers. Of the retail gallons we sold, approximately 56% were to residential customers, 29% were to industrial, commercial and agricultural customers, and 15% were to other retail users. Sales to residential customers in the fiscal year ended August 31, 2004 accounted for 55% of total domestic gallons sold but accounted for approximately 69% of our gross profit from propane sales. Residential sales have a greater profit margin and a more stable customer base than the other markets we serve. Industrial, commercial and agricultural sales accounted for 22% of our gross profit from propane sales for the fiscal year ended August 31, 2005, with all other retail users accounting for 9%. Additional volumes sold to wholesale customers contributed 1% of our gross profit from propane sales. No single customer accounts for 10% or more of revenues.

The propane business is very seasonal with weather conditions significantly affecting demand for propane. We believe that the geographic diversity of our operations helps to reduce our overall exposure to less than favorable weather conditions in any particular region of the United States. Although overall demand for propane is affected by climate, changes in price and other factors, we believe our residential and commercial business to be relatively stable due to the following characteristics:

- residential and commercial demand for propane has been relatively unaffected by general economic conditions due to the largely non-discretionary nature of most propane purchases;

- loss of customers to competing energy sources has been low due to the lack of availability or the high cost of alternative fuels;

- the tendency of our customers to remain with us due to the product being delivered pursuant to a regular delivery schedule and to our ownership as of August 31, 2005 of approximately 89% of the storage tanks utilized by our customers, which prevents fuel deliveries from competitors; and

- our historic ability to more than offset customer losses through internal growth of our customer base in existing markets.

Since home heating usage is the most sensitive to temperature, residential customers account for the greatest usage variation due to weather. Variations in the weather in one or more regions in which we operate can significantly affect the total volumes of propane that we sell and the margins realized thereon and, consequently, our results of operations. We believe that sales to the commercial and industrial markets, while affected by economic patterns, are not as sensitive to variations in weather conditions as sales to residential and agricultural markets.

Propane Supply and Storage

Supplies of propane from our sources historically have been readily available. We purchase from over 50 energy companies and natural gas processors at numerous supply points located in the United States and Canada. In the fiscal year ended August 31, 2005, Enterprise Products Operating L.P. (Enterprise) and Dynegy Liquids Marketing and Trade (Dynegy) provided approximately 23.7% and 20.6% of our combined total propane supply, respectively. In addition, M-P Energy Partnership, a Canadian partnership in which our wholly owned subsidiary M.P. Oils, Ltd. owns a 60% interest in, procured 23.0% of our combined total propane supply during the fiscal year ended August 31, 2005. M-P Energy Partnership buys and sells propane for its own account and supplies propane to us for our northern United States operations.

We believe that if supplies from Enterprise and Dynegy were interrupted we would be able to secure adequate propane supplies from other sources without a material disruption of our operations. Aside from Enterprise,

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Dynegy and the supply procured by M-P Energy Partnership, no single supplier provided more than 10% of our total domestic propane supply during the fiscal year ended August 31, 2005. We believe that our diversification of suppliers will enable us to purchase all of our supply needs at market prices without a material disruption of our operations if supplies are interrupted from any of our existing sources. Although we cannot assure you that supplies of propane will be readily available in the future, we expect a sufficient supply to continue to be available. However, increased demand for propane in periods of severe cold weather, or otherwise, could cause future propane supply interruptions or significant volatility in the price of propane.

We typically enter into one-year supply agreements. The percentage of contract purchases may vary from year to year. Supply contracts generally provide for pricing in accordance with posted prices at the time of delivery or the current prices established at major delivery or storage points, and some contracts include a pricing formula that typically is based on these market prices. Most of these agreements provide maximum and minimum seasonal purchase guidelines. We receive our supply of propane predominately through railroad tank cars and common carrier transport.

Because our profitability is sensitive to changes in wholesale propane costs, we generally seek to pass on increases in the cost of propane to customers. We have generally been successful in maintaining retail gross margins on an annual basis despite changes in the wholesale cost of propane, but there is no assurance that we will always be able to pass on product cost increases fully, particularly when product costs rise rapidly. Consequently, our profitability will be sensitive to changes in wholesale propane prices. See Management s Discussion and Analysis of Financial Condition and Results of Operations Overview.

We lease space in larger storage facilities in New York, Georgia, Michigan, Arizona, New Mexico, Texas, Alberta, Canada and smaller storage facilities in other locations and have the opportunity to use storage facilities in additional locations when we pre-buy product from sources having such facilities. We believe that we have adequate third party storage to take advantage of supply purchasing advantages as they may occur from time to time. Access to storage facilities allows us to buy and store large quantities of propane during periods of low demand, which generally occur during the summer months, or at favorable prices, thereby helping to ensure a more secure supply of propane during periods of intense demand or price instability.

Pricing Policy

Pricing policy is an essential element in the marketing of propane. We rely on regional management to set prices based on prevailing market conditions and product cost, as well as local management input. All regional managers are advised regularly of any changes in the posted price of each customer service location s propane suppliers. In most situations, we believe that our pricing methods will permit us to respond to changes in supply costs in a manner that protects our gross margins and customer base, to the extent such protection is possible. In some cases, however, our ability to respond quickly to cost increases could occasionally cause our retail prices to rise more rapidly than those of our competitors, possibly resulting in a loss of customers.

Billing and Collection Procedures

Customer billing and account collection responsibilities for our propane operations are retained at the local customer service locations. We believe that this decentralized approach is beneficial for several reasons:

the customer is billed on a timely basis;

the customer is more apt to pay a local business;

cash payments are received more quickly; and

local personnel have a current account status available to them at all times to answer customer inquiries.

Because propane sales to residential and commercial customers are affected by winter heating season requirements, our propane operations generally generate higher operating revenues and net income during the period from October through March of each year and lower operating revenues and, in some cases, net losses or lower net income during the period from April through September of each year. Sales to industrial and agricultural customers are much less weather-sensitive.

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Gross profit margins are not only affected by weather patterns but also by changes in customer mix. For example, sales to residential customers generate higher margins than sales to other customer groups, such as commercial or agricultural customers. Wholesale margins are substantially lower than retail margins. In addition, gross profit margins vary by geographic region. Accordingly, a change in customer or geographic mix can affect gross profit without necessarily affecting total revenues.

Government Regulation and Environmental Matters

The operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, or transporting natural gas, natural gas liquids and other 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. These laws and regulations can impair our business activities that affect the environment in many ways, such as:

- restricting the way we can release materials or waste products into the air, water, or soils;
- limiting or prohibiting construction activities in sensitive areas such as wetlands or areas of endangered species habitat, or otherwise constraining how or when construction is conducted;
- requiring remedial action to mitigate pollution from former operations, or requiring plans and activities to prevent pollution from ongoing operations; and
- imposing substantial liabilities on us for pollution resulting from our operations, including, for example, potentially enjoining the operations of facilities if it were determined that they were not in compliance with permit terms.

Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. We have implemented environmental programs and policies designed to avoid potential liability and cost under applicable environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. Moreover, risks of process upsets, accidental releases or spills are associated with our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such upsets, releases, or spills, including those relating to claims for damage to property and persons. In the event of future increases in costs, we may be unable to pass on those increases to our customers. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this trend will continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or Superfund, and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment, including those arising out of historical operations conducted by predecessors. Under CERCLA, these responsible persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. Although petroleum is excluded from the definition of hazardous substance under CERCLA, we will generate materials in the course of our operations that may be regulated as hazardous substances. We also may incur liability under the Resource Conservation and Recovery Act, also known as RCRA, which imposes requirements related to the management and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for drilling fluids, produced waters, and other wastes associated with the

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exploration, development, or production of crude oil, natural gas or geothermal energy, in the course of our operations, we may generate unrecovered petroleum product wastes as well as ordinary industrial wastes such as paint wastes, waste solvents, and waste compressor oils that may be regulated as hazardous or solid wastes.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination. A predecessor company acquired by us in July 2001 had previously received and responded to a request for information from the U.S. Environmental Protection Agency or EPA regarding its potential contribution to widespread groundwater contamination in San Bernardino, California, known as the Newmark Groundwater Contamination Superfund site. We have not received any follow-up correspondence from EPA on the matter since our acquisition of the predecessor company in 2001. In addition, through our acquisitions of ongoing businesses, we are currently involved in several remediation projects that have cleanup costs and related liabilities. As of August 31, 2005 an accrual of $2.0 million was recorded in our consolidated balance sheet to cover estimated environmental liabilities including certain matters assumed in connection with the HPL acquisition. We have also recorded a receivable of $0.4 million to account for the predecessor owner s share of certain environmental liabilities.

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accord with the terms of a permit issued by EPA or the state. Any unpermitted release of pollutants, including NGLs or condensates, from our systems or facilities could result in fines or penalties, as well as significant remedial obligations. We believe that we are in substantial compliance with the Clean Water Act. We currently expect to incur costs of approximately $0.1 million over the next year to upgrade or modify certain facilities as required under our spill prevention, control and countermeasures, or SPCC, plans.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including processing plants and compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Failure to comply with these laws and regulations could expose us to civil and criminal enforcement actions. We received a state-issued Pipeline Facilities air emissions permit on June 30, 2005 for our Prairie Lea Compressor Station in Caldwell County, Texas, which historically has been designated as a grandfathered facility and, thus, was excluded from state air emissions permitting requirements. In order to comply with the terms of this permit and associated regulations requiring specified reductions in nitrogen oxides or NOx emissions by March 1, 2007, we are planning to modify the compressor engines at the facility during 2006, at an estimated cost of $2.0 million. In addition, we are currently pursuing agency-approved baseline monitoring of NOx emissions from our Katy Compressor Station in Harris County, Texas, which is in a non-attainment area for ozone. Once we develop this NOx baseline, we have been planning to purchase a sufficient amount of NOx emission allowances that would allow the facility to continue at its current level of operation in the non-attainment area, at an estimated cost of $2.3 million. These plans are subject to possible change, however, as the non-attainment area is currently transitioning from a 1-hour ozone non-attainment area to an 8-hour ozone non-attainment area, which transition we expect will result in the adoption of further regulations that will perhaps change the extent to which NOx emissions reductions may be required.

Our operations are subject to regulation by the U.S. Department of Transportation or DOT under the Hazardous Liquid Pipeline Safety Act, or HLPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA requires any entity which owns or operates pipeline facilities to permit access to and allow copying of records and to make certain reports and provide information as required by DOT. While we believe that our

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pipeline operations are in substantial compliance with applicable HLPSA requirements, there can be no assurance that future compliance with the HLPSA will not have a material adverse effect on our operations or financial position. Moreover, the DOT, through the Office of Pipeline Safety, has promulgated rules requiring pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas, including areas with specified population densities. Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing, or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. We estimate that the cost of implementing these integrity management plans is $10 million per year, over the years 2006 to 2011.

We are subject to the requirements of the federal Occupational Safety and Health Act, also known as OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage, and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

Employees

As of October 31, 2005, we employ 551 people to operate our midstream and transportation and storage segments. We employ 2,642 full-time employees, of whom 54 are represented by labor unions to operate our propane segments. We believe that our relations with our employees are satisfactory. Historically, Heritage hires seasonal workers to meet peak winter demands in our propane operations.

SEC Reporting

We electronically file certain documents with the SEC. We file annual reports on Form 10-K; quarterly reports on Form 10-Q; current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.energytransfer.com, free of charge. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC.

ITEM 2. PROPERTIES.

Substantially all of our pipelines, which are located in Texas and Louisiana, are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee.

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Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that will be transferred to us will require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business in all material respects. With respect to any consents, permits or authorizations that have not been obtained, we believe that these consents, permits or authorizations will be obtained, or that the failure to obtain these consents, permits or authorizations will have no material adverse effect on the operation of our business.

We own two office buildings for our executive offices in Dallas, Texas. We also lease office facilities in Houston, Texas, San Antonio, Texas, Tulsa, Oklahoma, and Helena, Montana. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed. We are currently constructing new office facilities to replace our leased facility in Helena, Montana, which is for the administration of our propane operations.

We operate bulk storage facilities at over 315 customer service locations for our propane operations. We own substantially all of these facilities and have entered into long-term leases for those that we do not own. We believe that the increasing difficulty associated with obtaining permits for new propane distribution locations makes our high level of site ownership and control a competitive advantage. We own approximately 33.0 million gallons of aboveground storage capacity at our various propane plant sites and have leased an aggregate of approximately 42.3 million gallons of underground storage facilities in New York, Georgia, Michigan, Arizona, New Mexico, Texas and Alberta, Canada. We do not own or operate any underground propane storage facilities (excluding customer and local distribution tanks) or propane pipeline transportation assets (other than local delivery systems).

The transportation of propane requires specialized equipment. The trucks and railroad tank cars used for this purpose carry specialized steel tanks that maintain the propane in a liquefied state. As of August 31, 2005, we utilized approximately 50 transport truck tractors, 50 transport trailers, 16 railroad tank cars, 1,193 bobtails and 1,848 other delivery and service vehicles, all of which we own. As of August 31, 2005, we owned approximately 724,000 customer storage tanks with typical capacities of 120 to 1,000 gallons that are leased or available for lease to customers. These customer storage tanks are pledged as collateral to secure the obligations of HOLP to its banks and the holders of its notes.

We utilize a variety of trademarks and trade names in our propane operations that we own or have secured the right to use, including Heritage Propane. These trademarks and trade names have been registered or are pending registration before the United States Patent and Trademark Office or the various jurisdictions in which the trademarks or trade names are used. We believe that our strategy of retaining the names of the companies we have acquired has maintained the local identification of these companies and has been important to the continued success of these businesses. Some of our most significant trade names include Balgas, Bi-State Propane, Blue Flame Gas of Charleston, Blue Flame Gas of Mt. Pleasant, Blue Flame Gas, Carolane Propane Gas, Gas Service Company, EnergyNorth Propane, Gibson Propane, Guilford Gas, Holton s L.P. Gas, Ikard & Newsom, Northern Energy, Sawyer Gas, ProFlame, Rural Bottled Gas and Appliance, ServiGas, and V-1 Propane. We regard our trademarks, trade names and other proprietary rights as valuable assets and believe that they have significant value in the marketing of our products.

We believe that we have satisfactory title to or valid rights to use all of our material properties. Although some of our properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

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ITEM 3. LEGAL PROCEEDINGS.

Although our midstream operating partnership, ETC OLP, may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of its business, ETC OLP is not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against ETC OLP, or contemplated to be brought against ETC OLP, under the various environmental protection statutes to which it is subject.

At the time of the Houston Pipeline System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities) and the parent companies of the HPL Entities were engaged in ongoing litigation with Bank of America that related to AEP s acquisition of the Houston Pipeline in the Enron bankruptcy and Bank of America s financing of cushion gas stored in the Bammel Storage facility (Cushion Gas). At issue are matters relating to the ownership and certain rights to use the Cushion Gas. We refer to this litigation as the Cushion Gas Litigation . Under the terms of the purchase and sale agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory. The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the purchase and sale agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters.

Propane is a flammable, combustible gas. Serious personal injury and significant property damage can arise in connection with its storage, transportation or use. In the ordinary course of business, we are sometimes threatened with or are named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverages and deductibles we believe are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future. Although any litigation is inherently uncertain, based on past experience, the information currently available and the availability of insurance coverage, we do not believe that pending or threatened litigation matters will have a material adverse effect on our financial condition or results of operations.

Of the pending or threatened matters in which we or our subsidiaries are a party, none have arisen outside the ordinary course of our business except for an action filed by Heritage on November 30, 1999 against SCANA Corporation, Cornerstone Ventures, L.P. and Suburban Propane, L.P. in the Fifth Judicial Circuit Court of Common Pleas, Richland County, South Carolina (the SCANA litigation). In the SCANA litigation, Heritage sought to recover under various contract and fraud causes of action for damages incurred in connection with the 1999 breach of the agreement to sell SCANA s propane assets to Heritage. Prior to trial, a settlement was reached with Defendant Cornerstone Ventures, L.P. and they were dismissed from the litigation. The trial began on October 4, 2004 against the remaining defendants and testimony was concluded on October 20, 2004. On October 21, 2004, the jury returned a verdict in favor of Heritage against SCANA and in favor of defendant Suburban. The jury found in favor of Heritage on all four claims against SCANA, awarding a total of $48 million in actual and punitive damages. SCANA has appealed the jury s decision, and currently, the parties are involved in the appeal of a number of post-trial motions. We cannot predict whether the final judgment will affirm the jury verdict without any modification or whether any appeal of the final judgment by SCANA will be successful. As a result, we cannot yet predict whether we will receive any of the damages award covered by this verdict.

We are a party to various legal proceedings and/or regulatory proceedings incidental to our business. Certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against us. In the opinion of management, all such matters are either covered by insurance, are without merit or involve amounts, which, if resolved unfavorably, would not have a significant effect on our financial position or results of operations. Once management determines that information pertaining to a legal proceeding indicates that it is probable that a liability has been incurred, an accrual is established equal to management s estimate of the likely exposure. For matters that are covered by insurance, we accrue the related deductible. As of August 31, 2005, and 2004, accruals of $1.1 million and $0.9 million, respectively, were recorded as accrued and other current liabilities on our consolidated balance sheets.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None

PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Price of and Distributions on the Common Units and Related Unitholder Matters

Our Common Units are listed on the New York Stock Exchange under the symbol ETP . The following table sets forth, for the periods indicated, the high and low sales prices per Common Unit, as reported on the New York Stock Exchange Composite Tape, and the amount of cash distributions paid per Common Unit for the periods indicated. The table reflects the effect of the two-for-one unit split on March 15, 2005.

	Price Range		
	High	Low	Cash Distribution (1)
2005 Fiscal Year			
Fourth Quarter Ended August 31, 2005	$ 39.09	$ 31.69	$ 0.5000
Third Quarter Ended May 31, 2005	$ 33.13	$ 29.77	$ 0.48750
Second Quarter Ended February 29, 2005	$ 32.69	$ 25.80	$ 0.46250
First Quarter Ended November 30, 2004	$ 27.37	$ 21.51	$ 0.43750
2004 Fiscal Year			
Fourth Quarter Ended August 31, 2004	$ 21.69	$ 18.94	$ 0.41250
Third Quarter Ended May 31, 2004	$ 20.13	$ 17.25	$ 0.37500
Second Quarter Ended February 29, 2004	$ 21.33	$ 18.78	$ 0.35000
First Quarter Ended November 30, 2003	$ 19.35	$ 15.51	$ 0.32500

(1) Distributions are shown in the quarter with respect to which they were declared. For each of the indicated quarters for which distributions have been made, an identical per unit cash distribution was paid on any units subordinated to our Common Units outstanding at such time. Please see -Cash Distribution Policy for a discussion of our policy regarding the payment of distributions.

Description of Units

As of September 30, 2005, there were approximately 54,340 individual Common Unitholders, which includes Common Units held in Street name. Common Units and Class C Units represent limited partner interest in the Partnership s Amended and Restated Agreement of Limited

Partnership, as amended to date (the Partnership Agreement) that entitle the holders to the rights and privileges specified in the Partnership Agreement.

Common Units. As of August 31, 2005, we had 106,889,904 Common Units outstanding, of which 72,210,155 were held by the public, 32,773,840 were held by ETE or its affiliates, 1,308 were held by FHM Investments, L.L.C., and 1,904,601 were held by our officers and directors. As of such date, the Common Units represent an aggregate 98.0% limited partner interest in us. Our General Partner owns an aggregate 2.0% general partner interest in us. Our Common Units are registered under the Securities Exchange Act of 1934, as amended and are listed for trading on the New York Stock Exchange (the NYSE). Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any

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Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Class C Units. As of August 31, 2005, we had 1,000,000 Class C Units outstanding, all of which are held by FHS Investments, L.L.C. The Class C Units were issued to the former owners of our former general partner, Heritage Holdings, in conjunction with the August 2000 transaction we refer to as the U.S. Propane Transaction. The Class C Units were created to convert that portion of the former general partner s incentive distribution rights that would have entitled it to receive any distributions attributable to certain litigation filed prior to the U.S. Propane Transaction. See Item 3 Legal Proceedings for a more detailed description of the SCANA litigation. The Class C Units do not have any rights to share in any of our assets or distributions upon dissolution and liquidation of ETP except to the extent that such distributions consists of proceeds from the SCANA litigation to which the Class C Unitholders would otherwise have been entitled; generally have no voting rights except to the extent provided by law, in which case they will be entitled to one vote; and are not convertible into any other unit.

When the special litigation committee decides to distribute the distributable proceeds, the amount of such distribution will be deemed to be Available Cash under our Partnership Agreement and will be distributed as described below under Cash Distribution Policy. The amount of distributable proceeds that would have otherwise been distributed to holders of Incentive Distribution Rights will instead be distributed to the holders of the Class C Units, pro rata. We cannot predict whether any cash payments will be received as a result of the SCANA litigation and, if so, when these distributions might be made. The amount of cash distributions to which the Incentive Distribution Rights are entitled was not increased by the creation of the Class C Units; rather, the Class C Units are a mechanism for dividing the Incentive Distribution Rights to which Heritage Holdings and its former stockholders would have been entitled had the litigation been resolved and funds received in connection with such resolution of that time.

Class D Units. The Class D Units were issued to ETE in the Energy Transfer Transactions. The Class D Units generally had voting rights identical to the voting rights of the Common Units, and the Class D Units voted with the Common Units as a single class on each matter with respect to which the Common Units were entitled to vote. Each Class D Unit initially was entitled to receive 100% of the quarterly amount distributed on each Common Unit, for each quarter, provided that the Class D Units were subordinated to the Common Units with respect to the payment of the minimum quarterly distribution for such quarter (and any arrearage in the payment of the minimum quarterly distribution for all prior quarters). We were required, as promptly as practicable following the issuance of the Class D Units, to submit to a vote of our Unitholders a change in the terms of the Class D Units to provide that each Class D Unit would convert into one Common Unit immediately upon such approval. Holders of the Class D Units were entitled to vote upon the proposal to change the terms of the Class D Units and the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to ETE in connection with the Energy Transfer Transactions) with respect to this proposal. Our Unitholders approved this change in the terms of the Class D Units on June 23, 2004 at a special meeting of the Common Unitholders. Pursuant to the request of the holders of the Class D Units, these Class D Units were converted to an equal number of Common Units on June 24, 2004, and no Class D Units are outstanding.

Class E Units. As of August 31, 2005, we had 8,853,832 Class E Units outstanding, all of which are held by our former general partner, Heritage Holdings. Heritage Holdings became our wholly-owned subsidiary in conjunction with the Energy Transfer Transactions. Class E Units were converted from Common Units held by Heritage Holdings at that time. Class E Units generally do not have voting rights; are entitled to aggregate distributions equal to a percentage of the total amount of cash distributed to all Unitholders, up to a maximum of $1.41 per Class E Unit per year; and will be allocated 1% of any gain and an equivalent amount of any loss allocated to the Common Units in the event of a termination or liquidation of ETP. Because the owner of the Class E Units is our wholly-owned subsidiary, those units are treated as treasury stock. Although distributions on the Class E Units will be available to us as the owner of Heritage Holdings, this amount will be reduced by the annual tax payments at corporate federal income tax rates that Heritage Holdings is required to pay with respect to distributions on the Class E Units.

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Special Units. The Special Units were issued to ETE in the Energy Transfer Transactions as consideration for the East Texas Pipeline. The Special Units generally did not have any voting rights but were entitled to vote on the proposal to change the terms of the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to ETE in connection with the Energy Transfer Transactions) with respect to this proposal, and were not entitled to share in partnership distributions. We were required, as promptly as practicable following the issuance of the Special Units, to submit to a vote of our Unitholders the approval of the conversion of the Special Units into Common Units in accordance with the terms of the Special Units. Following Unitholder approval at a special meeting of the Unitholders on June 23, 2004 and upon the East Texas Pipeline becoming commercially operational on June 21, 2004, each Special Unit converted into one Common Unit on June 24, 2004 upon the request of the holder and no Special Units are outstanding.

Incentive Distribution Rights. Incentive Distribution Rights represent the contractual right to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read Quarterly Distributions of Available Cash below. The General Partner owns all of the Incentive Distribution Rights, except that in conjunction with the August 2000 U.S. Propane transaction we issued 1,000,000 Class C Units to Heritage Holdings, our general partner at that time, in conversion of that portion of Heritage Holdings Incentive Distribution Rights that entitled it to receive any distribution made by us of funds attributable to the net amount received in connection with the settlement, judgment, award or other final nonappealable resolution of the SCANA litigation.

Issuance of Additional Securities

Our Partnership Agreement authorizes us to issue an unlimited number of additional partnership securities and rights to buy partnership securities for the consideration and on the terms and conditions established by our General Partner in its sole discretion, without the approval of the Unitholders. Any such additional partnership securities may be senior to the Common Units.

It is possible that we will fund acquisitions through the issuance of additional Common Units or other equity securities. Holders of any additional Common Units we issue will be entitled to share equally with the then-existing holders of Common Units in our distributions of Available Cash. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of Common Units in our net assets.

In accordance with Delaware law and the provisions of our Partnership Agreement, we may also issue additional partnership securities that, in the sole discretion of the General Partner, have special voting rights to which the Common Units are not entitled.

Upon issuance of additional partnership securities, our General Partner will be required to make additional capital contributions to the extent necessary to maintain its 2.0% General Partner interest in us. Moreover, our General Partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase Common Units or other equity securities whenever, and on the same terms that, we issue those securities to persons other than the General Partner and its affiliates, to the extent necessary to maintain its percentage interest, including its interest represented by Common Units, that existed immediately prior to each issuance. The holders of Common Units will not have preemptive rights to acquire additional Common Units or other partnership securities.

Amendments of our Partnership Agreement Requiring Unitholder Approval

The following matters require the approval of the majority of the outstanding Common Units, including the Common Units owned by the General Partner and its affiliates:

- a merger of our Partnership;
- a sale or exchange of all or substantially all of our assets;
- dissolution or reconstitution of our Partnership upon dissolution;
- certain amendments to the Partnership Agreement;
- the transfer to another person of our General Partner interest before June 30, 2006 or the Incentive Distribution Rights at any time, except for transfers to affiliates of our General Partner or transfers in connection with the General Partner s merger or consolidation with or into, or sale of all or substantially all of its assets to, another person; and

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the withdrawal of the General Partner prior to June 30, 2006 in a manner that would cause the dissolution of our Partnership.

The removal of our General Partner requires the approval of not less than 66 2/3% of all outstanding units, including units held by our General Partner and its affiliates. Any removal is subject to the election of a successor General Partner by the holders of a majority of the outstanding Common Units, including units held by our General Partner and its affiliates.

Amendments to Our Partnership Agreement

Amendments to our Partnership Agreement may be proposed only by our General Partner. Certain amendments require the approval of a majority of the outstanding Common Units, including Common Units owned by the General Partner and its affiliates. Any amendment that materially and adversely affects the rights or preferences of any class of partnership interests in relation to other classes of partnership interests will require the approval of at least a majority of the class of partnership interests so affected. However, in some circumstances as more particularly described in our Partnership Agreement, our General Partner may make amendments to the Partnership Agreement without Unitholder approval to reflect, among other things:

a change in our name, the location of our principal place of business or our registered agent or office;

the admission, substitution, withdrawal or removal of partners;

a change to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability or to ensure that neither we nor our operating partnerships will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

a change that does not affect our Unitholders in any material respect;

a change to (i) satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute, (ii) facilitate the trading of Common Units or comply with any rule, regulation, guideline or requirement of any national securities exchange on which the Common Units are or will be listed for trading, (iii) that is necessary or advisable in connection with action taken by our General Partner with respect to subdivision and combination of our securities or (iv) that is required to effect the intent expressed in our Partnership Agreement;

a change in our fiscal year or taxable year and any changes that are necessary or advisable as a result of a change in our fiscal year or taxable year;

an amendment effected, necessitated or contemplated by a merger agreement approved in accordance with our Partnership Agreement;

an amendment that is necessary or advisable to reflect, account for and deal with appropriately our formation of, or investment in, any corporation, partnership, joint venture, limited liability company or other entity other than our Operating Partnerships, in connection with our conduct of activities permitted by our Partnership Agreement;

a merger or conveyance to effect a change in our legal form; or

any other amendment substantially similar to the foregoing.

Withdrawal or Removal of Our General Partner

Our General Partner has agreed not to withdraw voluntarily as our General Partner prior to June 30, 2006 without obtaining the approval of the holders of a majority of our outstanding Common Units, excluding those held by our General Partner and its affiliates, and furnishing an opinion of counsel stating that such withdrawal (following the selection of the successor general partner) would not result in the loss of the limited liability of any of our limited partners or of the limited partner of our operating partnership or cause us or our operating partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for federal income tax purposes (to the extent not previously treated as such).

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On or after June 30, 2006, our General Partner may withdraw as our General Partner without first obtaining approval of any Unitholder by giving 90 days written notice, and that withdrawal will not constitute a violation of our Partnership Agreement. In addition, our General Partner may withdraw without Unitholder approval upon 90 days notice to our limited partners if at least 50% of our outstanding Common Units are held or controlled by one person and its affiliates other than our General Partner and its affiliates.

Upon the voluntary withdrawal of our General Partner, the holders of a majority of our outstanding Common Units, excluding the Common Units held by the withdrawing general partner and its affiliates may elect a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within 90 days after that withdrawal, the holders of a majority of our outstanding units, excluding the Common Units held by the withdrawing general partner and its affiliates, agree to continue our business and to appoint a successor general partner.

Our General Partner may not be removed unless that removal is approved by the vote of the holders of not less than two-thirds of our outstanding units, including units held by our General Partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. In addition, if our General Partner is removed as our General Partner under circumstances where cause does not exist, our General Partner will have the right to receive cash in exchange for its partnership interest as a General Partner in us, its partnership interest as the General Partner of any member of the Energy Transfer partnership group and its incentive distribution rights. 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. Any removal of this kind is also subject to the approval of a successor general partner by the vote of the holders of the majority of our outstanding Common Units, including those held by our General Partner and its affiliates.

While our Partnership Agreement limits the ability of our General Partner to withdraw, it allows the general partner interest to be transferred to an affiliate or to a third party in conjunction with a merger or sale of all or substantially all of the assets of our General Partner. In addition, our Partnership Agreement expressly permits the sale, in whole or in part, of the ownership of our General Partner. Our General Partner may also transfer, in whole or in part, any Common Units it owns.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the person authorized to wind up our affairs (the liquidator) will, acting with all the powers of our General Partner that the liquidator deems necessary or desirable in its good faith judgment, liquidate our assets. The proceeds of the liquidation will be applied as follows:

first, towards the payment of all of our creditors and the creation of a reserve for contingent liabilities; and

then, to all partners in accordance with the positive balance in their respective capital accounts.

Under some circumstances and subject to some limitations, the liquidator may defer liquidation or distribution of our assets for a reasonable period of time. If the liquidator determines that a sale would be impractical or would cause a loss to our partners, our General Partner may distribute assets in kind to our partners.

Limited Call Right

If at any time less than 20% of the outstanding Common Units of any class are held by persons other than our General Partner and its affiliates, our General Partner will have the right to acquire all, but not less than all, of those Common Units at a price no less than their then-current market price. As a consequence, a Unitholder may be required to sell his Common Units at an undesirable time or price. Our General Partner may assign this purchase right to any of its affiliates or us.

Indemnification

Under our Partnership Agreement, in most circumstances, we will indemnify our General Partner, its

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affiliates and their officers and directors to the fullest extent permitted by law, from and against all losses, claims or damages any of them may suffer by reason of their status as general partner, officer or director, as long as the person seeking indemnity acted in good faith and in a manner believed to be in or not opposed to our best interest. Any indemnification under these provisions will only be out of our assets. Our General Partner shall not be personally liable for, or have any obligation to contribute or loan funds or assets to us to effectuate any indemnification. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our Partnership Agreement.

Cash Distribution Policy

General. We will distribute all of our Available Cash to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in our Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter:

- less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law or and debt instrument or other agreement (including reserves for future capital expenditures and for our future capital needs); or
  - provide funds for distributions to Unitholders and our General Partner in respect of 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 credit facilities and in all cases are used solely for working capital purposes or to pay distributions to partners.

Available Cash is more fully defined in the Partnership Agreement previously filed as an exhibit.

Operating Surplus and Capital Surplus

General. All cash distributed to our Unitholders is characterized as either operating surplus or capital surplus . We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. Our operating surplus for any period generally means:

- our cash balance on the closing date of our initial public offering in 1996; plus
- $10.0 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- our working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less
- all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

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Definition of Capital Surplus. Generally, our capital surplus will be generated only by:

- borrowings other than working capital borrowings;
- sales of our debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions. We will treat all Available Cash distributed as coming from operating surplus until the sum of all Available Cash distributed since we began operations equals the operating surplus as of the most recent date of determination of Available Cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As defined in our Partnership Agreement, operating surplus includes $10.0 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our Unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to $50.0 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and long-term borrowings, that would otherwise be distributed as capital surplus. We have not made, and we anticipate that we will not make, any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

We are required to make distributions of Available Cash from operating surplus for any quarter in the following manner:

First, 98% to all Common and Class E Unitholders, in accordance with their percentage interests, and 2% to the General Partner, until each Common Unit has received $0.25 per unit for such quarter (the minimum quarterly distribution);

Second, 98% to all Common and Class E Unitholders, in accordance with their percentage interests, and 2% to the General Partner, until each Common Unit has received $0.275 per unit for such quarter (the first target cash distribution);

Third, 85% to all Common and Class E Unitholders, in accordance with their percentage interests, 13% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner, until each Common Unit has received at least $0.3175 per unit for such quarter (the second target cash distribution);

Fourth, 75% to all Common and Class E Unitholders, in accordance with their percentage interests, 23% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner, until each Common Unit has received at least $0.4125 per unit for such quarter (the third target cash distribution); and

Fifth, thereafter, 50% to all Common and Class E Unitholders, in accordance with their percentage interests, 48% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner.

Notwithstanding the foregoing, any arrearage in the payment of the minimum quarterly distribution for all prior quarters and the distributions on each Class E unit may not exceed $1.41 per year.

Distributions of Available Cash from Capital Surplus

We will make distributions of available cash from capital surplus, if any, in the following manner:

First, 98% to all of our Unitholders, pro rata, and 2% to our General Partner, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and

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Thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Our Partnership Agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price per Common Unit less any distributions of capital surplus per unit is referred to as the unrecovered capital.

If we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust our minimum quarterly distribution; our target cash distribution levels; and our unrecovered capital.

For example, if a two-for-one split of our Common Units should occur, our unrecovered capital would each be reduced to 50% of our initial level. We will not make any adjustment by reason of our issuance of additional units for cash or property.

On January 14, 2005, our general partner announced a two-for-one split of our Common Units that was effected on March 15, 2005. As a result, our minimum quarterly distribution and the target cash distribution levels were reduced to 50% of their initial levels. Our adjusted minimum quarterly distribution and the adjusted target cash distribution levels are reflected in the discussion above under the caption Distributions of Available Cash from Operating Surplus.

In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce our minimum quarterly distribution and the target cash distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates.

The total amount of distributions declared for the year ended August 31, 2005 on Common Units, Class E Units, General Partner interests and the Incentive Distribution Rights totaled $190.4 million, $12.5 million, $4.9 million, and $38.5 million, respectively. All such distributions were made from Available Cash from operating surplus.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with our Partnership Agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to our Unitholders and our General Partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in our Partnership Agreement in the following manner:

First, to our General Partner and the holders of our units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

Second, 98% to our Common Unitholders, pro rata, and 2% to our General Partner, until the capital account for each Common Unit is equal to the sum of:

its unrecovered capital; and

the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

Third, 98% to all Unitholders, pro rata, and 2% to our General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the first target cash distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to our Unitholders, pro rata, and 2% to our General Partner, for each quarter of its existence;

Fourth, 85% to all Unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to the General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the second target cash distribution per unit over the first target cash distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the first target cash distribution per unit that it distributed 85% to the Unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner for each quarter of our existence;

Fifth, 75% to all Unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the third target cash distribution per unit over the second target cash distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the second target cash distribution per unit that it distributed 75% to the Unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner for each quarter of our existence; and

Sixth, thereafter, 50% to all Unitholders, pro rata, 48% to the holders of the incentive distribution rights pro rata, and 2% to our General Partner.

Manner of Adjustments for Losses. Upon our liquidation, we will generally allocate any loss to our General Partner and our unitholders in the following manner:

First, 98% to the holders of Common Units in proportion to the positive balances in their capital accounts and 2% to our General Partner, until the capital accounts of the Common Unitholders have been reduced to zero; and

Second, thereafter, 100% to our General Partner.

Adjustments to Capital Accounts upon the Issuance of Additional Units. We will make adjustments to our capital accounts upon issuance of additional units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to our Unitholders and our General Partner in the same manner as it allocates gain or loss upon liquidation. In the event that we make positive adjustments to our capital accounts upon the issuance of additional units, we will allocate any later negative adjustments to our capital accounts resulting from our issuance of additional units or upon liquidation in a manner which results, to the extent possible, in our General Partner s capital account balances equaling the amount which they would have been if no earlier positive adjustments to its capital accounts had been made.

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Changes in Securities and Recent Sales of Unregistered Securities

None

Equity Compensation Plan Information

At the time of our initial public offering, the shareholders of our General Partner adopted a Restricted Unit Plan, amended and restated as of February 4, 2002 as the Partnership s Second Amended and Restated Restricted Unit Plan (the Restricted Unit Plan), which provided for the awarding of Common Units to key employees. See Executive Compensation Restricted Unit Plan for a description of the Restricted Unit Plan. At the June 23, 2004 special meeting of our Common Unitholders, Common Unitholders approved our 2004 Unit Plan, which provides for awards of Common Units and other rights to our employees, officers and directors and the Restricted Unit Plan was terminated except for our future obligation to issue Common Units that have not previously vested.

The following table sets forth in tabular format, a summary of our equity plan information:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:			
Restricted Unit Plan	9,259	$ 315,732(1)	
2004 Unit Plan	276,835	9,440,074(1)	1,517,556
Equity compensation plans not approved by security holders:			
Total (2)	286,094	$ 9,755,806	1,517,556

(1) Valued as of October 31, 2005. Actual exercise price may differ depending on the Common Unit price on the date such units vest.
(2) As of August 31, 2005.

ITEM 6. SELECTED FINANCIAL DATA

Although Heritage Propane Partners, L.P. was the surviving parent entity for legal purposes in the Energy Transfer Transactions, ETC OLP was the acquirer for accounting purposes. As a result, following the Energy Transfer Transactions, the historical financial statements of ETC OLP for periods prior to the closing of the Energy Transfer Transactions became our historical financial statements. ETC OLP was formed on October 1, 2002 and has an August 31 year-end. ETC OLP s predecessor entities had a December 31 year-end. Accordingly, ETC OLP s 11-month period ended August 31, 2003 is treated as a transition period.

ETC OLP s historical financial information for the period from October 1, 2002 to August 31, 2003 has been derived from the historical financial statements of ETC OLP included elsewhere in this report. During this time period, ETC OLP owned the Southeast Texas System and the Elk City System. From October 1, 2002 through December 27, 2002, ETC OLP also owned a 50% equity interest in Oasis Pipe Line Company, which owns the Oasis Pipeline. After December 27, 2002, ETC OLP owned a 100% interest in Oasis Pipe Line. In addition, on December 27, 2002, an affiliate of ETE s general partner contributed to ETC OLP its marketing business and its interest in the Vantex System, the Rusk County Gathering System, the Whiskey Bay System and the Chalkley Transmission System. In April 2005, we sold the Elk City System and accounted for the sale as discontinued operations. As such, the results presented for the period form October 1, 2002 to August 31, 2004 below have been restated to account for the results of the Elk City System in discontinued operations.

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ETC OLP s historical financial information for periods prior to October 1, 2002 has been derived from the historical financial statements of Aquila Gas Pipeline. Prior to October 1, 2002, Aquila Gas Pipeline owned the Southeast Texas System, the Elk City System and a 50% equity interest in Oasis Pipe Line. All of these assets were acquired by ETC OLP effective on October 1, 2002.

The financial information below for Aquila Gas Pipeline for the nine months ended September 30, 2002 and the years ended December 31, 2001 and 2000 and as of September 30, 2002 and December 31, 2001 and 2000 has been derived from the audited consolidated financial statements of Aquila Gas Pipeline, which are not included in this report, but were included in previous filings.

The selected historical financial data should be read in conjunction with the financial statements of Energy Transfer Partners, L.P. included elsewhere in this report and with Management s Discussion and Analysis of Financial Condition and Results of Operations included in this report. The amounts in the table below, except per unit data, are in thousands.

	Aquila Gas Pipeline			Energy Transfer Partners		
	Year Ended December 31,		Nine Months Ended September 30,	Eleven Months Ended August 31,	Year Ended August 31,	
	2000	2001	2002	2003(a)	2004	2005
Statement of Operating Data:						
Revenues						
Midstream segment	$ 1,758,530	$ 1,813,850	$ 933,099	$ 899,086	$ 1,880,663	$ 3,246,772
Transportation and storage segment				41,500	113,938	2,608,108
Eliminations				(9,559)	(27,798)	(471,255)
Propane segments					376,689	778,306
Other segment					3,465	6,867
Total revenues	1,758,530	1,813,850	933,099	931,027	2,346,957	6,168,798
Gross margin	117,663	98,589	53,035	105,589	365,533	787,283
Depreciation and amortization	30,049	30,779	22,915	11,870	48,599	92,943
Operating income	31,024	42,990	2,862	55,595	139,089	312,051
Interest expense	12,098	6,858	3,931	12,456	41,190	93,017
Income from continuing operations before income tax expense	18,892	41,161	4,272	45,063	97,470	208,678
Income tax expense (b)	7,657	15,403	(467)	4,432	4,481	7,295
Income from continuing operations	11,235	25,758	4,739	40,631	92,989	201,383
Basic income from continuing operations share/unit (c)				3.01	1.62	1.79
Cash distribution share/unit					1.47	1.89
Balance Sheet Data (at period end):						
Current assets	231,260	144,396	116,831	$ 223,897	480,435	1,458,020
Total assets	724,161	633,260	601,528	602,103	2,327,104	4,426,906
Current liabilities	313,506	194,816	144,076	169,473	397,037	1,250,874
Long-term debt	110,721	66,250	66,250	196,000	1,070,871	1,675,705
Stockholders equity/Partners capital	254,248	249,520	254,259	181,088	746,980	1,326,192
Other Financial Data:						
EBITDA, as adjusted (unaudited) (d)	61,039	78,798	31,118	77,476	196,650	413,237

Cash flow provided by operating activities	76,011	65,198	12,987	70,206	162,695	169,418
Cash flow used in investing activities	(23,459)	(20,727)	(487)	(341,258)	(790,737)	(1,133,749)
Cash flow provided by (used in) financing activities	(52,552)	(44,471)	(12,500)	324,174	656,665	907,500
Capital expenditures						
Maintenance and growth	26,866	23,944	5,486	11,914	109,688	196,459
Acquisition				340,187	681,835	1,131,844

(a) On December 27, 2002, ETC OLP purchased the remaining 50% of Oasis Pipe Line. Prior to December 27, 2002, the interest in Oasis Pipe Line was treated as an equity method investment. After this date, Oasis Pipe Line s results of operations are consolidated with ETC OLP as a wholly-owned subsidiary.

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(b) As a partnership, we are not subject to income taxes. However, our subsidiaries, Oasis Pipe Line, Heritage Holdings and Heritage Service Corporation, are corporations that are subject to income taxes. Prior to 2003, Oasis Pipe Line was an equity method investment of ETC OLP, and taxes were netted against the equity method earnings. Aquila Gas Pipeline was a tax-paying corporation, and as such recognized income taxes related to its earnings in all periods presented.

(c) Net income per unit is computed by dividing the limited partners interest in net income by the weighted average number of units outstanding. For purposes of computing net income per limited partner unit, in periods when the Partnership s aggregate net income exceeds the aggregate distributions, for such periods, an increased amount of net income is allocated to the General Partner for the additional pro forma priority income attributable to the application of EITF 03-6. Although the equity accounts of ETC OLP survive the Energy Transfer Transactions, Heritage s partnership structure and partnership units survive. Accordingly, the equity accounts of ETC OLP have been restated based on general partner interest and Common Units received by ETC OLP in the Energy Transfer Transactions.

(d) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income such as the gain arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of the Partnership s fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to the Partnership s investors for trending, analyzing and benchmarking the operating results of the Partnership from period to period as compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view the Partnership s performance in a manner similar to the methods used by management and provides additional insight to the Partnership s operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of the Partnership s numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. The Partnership has a large number of business locations located in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the Partnership s business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare the Partnership s operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than the Partnership s. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in the Partnership s operating results but are not classified in interest, depreciation and amortization. We do not include gain on the sale of assets when determining EBITDA, as adjusted, since including non-cash income resulting from the sale of assets increases the

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performance measure in a manner that is not related to the true operating results of the Partnership s business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Description of Indebtedness.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us in the past. Management compensates for these limitations by considering EBITDA, as adjusted, in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities. A reconciliation of EBITDA, as adjusted, to net income (loss) is presented below. Please read Reconciliation of EBITDA, As Adjusted, to Net Income below.

Reconciliation of EBITDA, As Adjusted, to Net Income

The following tables set forth the reconciliation of EBITDA, as adjusted, to net income for the periods indicated:

	Aquila Gas Pipeline			Energy Transfer Partners		
	Year Ended August 31, 2000	Year Ended August 31, 2001	Nine Months Ended September 30, 2002	Eleven Months Ended August 31 2003	Year Ended August 31, 2004	Year Ended August 31, 2005
Net income reconciliation						
Net income	$ 11,235	$ 25,758	$ 4,739	$ 46,625	$ 99,152	$ 349,350
Gain on sale of discontinued operations, net of income tax expense						(142,469)
Depreciation and amortization	30,049	30,779	22,915	11,870	48,599	92,943
Interest	12,098	6,858	3,931	12,456	41,190	93,017
Income tax expense on continuing operations	7,657	15,403	(467)	4,432	4,481	7,295
Non-cash compensation expense					42	1,608
Other, net				(501)	(509)	(631)
Depreciation, amortization, and interest and taxes of investee				1,003	440	697
Depreciation, amortization and interest of discontinued operations				1,591	2,249	1,547
Loss on extinguishment of debt						9,550
Loss on disposal of assets					1,006	330
EBITDA, as adjusted (a)	$ 61,039	$ 78,798	$ 31,118	$ 77,476	$ 196,650	$ 413,237

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Overview

The following is a discussion of the historical financial condition and results of operations of the Partnership and its subsidiaries, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Form 10-K.

Energy Transfer Partners, L.P. (the Registrant or Partnership), is a Delaware limited partnership. Our Common Units are listed on the New York Stock Exchange under the symbol ETP . Our business activities are primarily conducted through our subsidiaries, ETC OLP, a Texas limited partnership, and HOLP, a Delaware limited partnership (the Operating Partnerships). The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as Energy Transfer or ETP .

Our primary objective is to increase the level of our cash distributions over time by pursuing a business strategy that is currently focused on growing our intrastate natural gas midstream business (including transportation, gathering, compression, treating, processing, storage and marketing) and our propane business through, among other things, pursuing certain construction and expansion opportunities relating to its existing infrastructure and acquiring certain additional businesses or assets.

Factors That Significantly Affect our Results. The actual amount of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

We have grown significantly through acquisitions and through internal growth projects. The significant acquisitions and internal construction projects that we have completed beginning in January 2004 include:

Energy Transfer Transactions. In January 2004, in a series of related transactions, the midstream and transportation operations of La Grange Acquisition, L.P. were combined with the retail propane operations of Heritage Propane Partners, L.P., a publicly traded limited partnership. These transactions, which we refer to as the Energy Transfer Transactions, were valued at approximately $1.0 billion and created ETP. Subsequent to these transactions, the combined partnership s name was changed to Energy Transfer Partners, L.P.

ET Fuel System. In June 2004, we acquired the midstream natural gas assets of TXU Fuel Company (now referred to as the ET Fuel System) from TXU Corp. for approximately $500 million. The ET Fuel System is comprised of approximately 2,000 miles of intrastate natural gas pipelines and related natural gas storage facilities that serve some of the most active natural gas drilling areas in Texas and provide direct access to power plants and interconnects with other intrastate and interstate pipelines that serve major markets.

East Texas Pipeline. In June 2004, we completed the construction of the Bossier Pipeline (now referred to as the East Texas Pipeline). The East Texas Pipeline is a 78-mile natural gas pipeline that provides transportation from the Bossier Sands drilling area in east and north central Texas to our Southeast Texas System. This pipeline cost approximately $71.4 million to construct.

Texas Chalk and Madison Systems. In November 2004, we acquired the Texas Chalk and Madison Systems from Devon Energy Corporation for approximately $65.0 million. These systems consist of approximately 1,800 miles of gathering and mainline pipelines, four natural gas treating facilities and a natural gas processing facility located in central Texas near our existing gathering and processing assets.

Houston Pipeline System. In January 2005, we acquired the Houston Pipeline System from American Electric Power Company, Inc. for approximately $825.0 million plus $132.0 million in natural gas inventory, subject to working capital adjustments. This system is comprised of six main transportation pipelines, three market area loops and a natural gas storage facility in Texas.

Fort Worth Basin. In May 2005, we completed the construction of the Fort Worth Basin Pipeline, a 55-mile pipeline that provides transportation for natural gas production from the Barnett Shale producing area in north central Texas to ETP s North Texas Pipeline. This pipeline cost approximately $53.0 million to construct.

Our results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate our midstream revenues and gross margins principally under fee-based arrangements or other arrangements. Under fee-based arrangements, we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue we earn from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. The terms of our contracts vary based upon gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Many of these contracts remain in effect for several years. The contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors. For additional information related to factors that affect the results of our midstream segment, please read Overview of Operations Midstream and Transportation and Storage Segments below.

Results from our transportation and storage segment are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through our transportation pipelines. Under transportation contracts, we charge our customers (1) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay us even if the customer does not transport natural gas on the respective pipeline, (2) a transportation fee, which is based on the actual throughput of natural gas by the customer, or (3) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly. We also generate revenue from fees charged for storing customers working natural gas in our storage facilities, primarily on the ET Fuel system and to a lesser extent at HPL.

The transportation and storage segment also generates its revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the Houston Pipeline System. Generally, HPL purchases its natural gas from either the market including purchases from the midstream s producer services, and from producers at the wellhead. To the extent the natural gas comes from producers, it is purchased at a discount to a specified price and resold to customers at the index price. For additional information related to factors that affect the results of our transportation and storage segment, please read Overview of Operations Midstream and Transportation and Storage Segments below.

Our propane-related segments are margin-based businesses in which gross profits depend on the excess of sales price over propane supply cost. The market price of propane is often subject to volatile changes as a result of supply or other market conditions over which we have no control. Product supply contracts are one-year agreements subject to annual renewal and generally permit suppliers to charge posted prices (plus transportation costs) at the time of delivery or the current prices established at major delivery points. Since rapid increases in the wholesale cost of propane may not be immediately passed on to retail customers, such increases could reduce gross profits. We generally have attempted to reduce price risk by purchasing propane on a short-term basis. We have on occasion purchased for storage significant volumes of propane during periods of low demand, which generally occur during the summer months, at the then current market price, both at our customer service locations and in major storage facilities, for future resale. In particular, our propane distribution business is largely seasonal and dependent upon weather conditions in our service areas. For additional information related to factors that affect the results of our propane-related segments, please read Overview of Operations Retail and Wholesale Propane Segments below.

None of our operations suffered any material damage or interruption from either Hurricane Katrina or Hurricane Rita, which landed in Louisiana and Texas, respectively, during September 2005.

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Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

We believe that current natural gas prices will continue to cause relatively high levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the number of natural gas wells drilled in the United States has increased overall in recent years, a corresponding increase in average annual production has not been realized, primarily as a result of smaller average discoveries and the decline in production from existing wells. We believe that an increase in United States drilling activity and imports of natural gas and liquefied natural gas will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the declining production of, natural gas in the United States. A number of the areas in which we operate are experiencing significant drilling activity as a result of recent high natural gas prices, new increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques.

While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil. Although the prevailing price of natural gas has less short term significance to our operating results than the price of NGLs, in the long term, the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. In the past, the prices of NGLs, crude oil and natural gas have been extremely volatile.

Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of worldwide economic growth. The number of active oil and gas rigs drilling in the United States were 223 and 1,219, respectively at August 31, 2005, compared to 166 and 1,082, respectively, at August 31, 2004. The increase in natural gas rigs is primarily attributable to recent significant increases in natural gas prices, which could result in continued sustained drilling activity for the remainder of 2005.

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 eleven-month period ended August 31, 2003 or the years ended August 31, 2004 and 2005. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Risk Factors

An investment in our common units involves risks. If any of these risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline, and you could lose all or part of your investment. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- **the general economic conditions in the United States of America as well as the general economic conditions and currencies in foreign countries;**

- **the amount of natural gas transported on our pipelines and gathering systems;**

the level and throughput in our natural gas processing and treating facilities;

the fees ETC OLP charges and the margins realized for its services;

the prices and market demand for, and the relationship between, natural gas and NGLs;

energy prices generally;

the price of propane to the consumer compared to the price of alternative and competing fuels;

the general level of petroleum product demand and the availability and price of propane supplies;

the level of domestic oil and natural gas production;

the availability of imported oil and natural gas;

the ability to obtain adequate supplies of propane for retail sale in the event of an interruption in supply or transportation and the availability of capacity to transport propane to market areas;

actions taken by foreign oil and gas producing nations;

the political and economic stability of petroleum producing nations;

the effect of weather conditions on demand for oil, natural gas and propane;

the weather in our operating areas;

availability of local, intrastate and interstate transportation systems;

the continued ability to find and contract for new sources of natural gas supply;

availability and marketing of competitive fuels;

the impact of energy conservation efforts;

energy efficiencies and technological trends;

the extent of governmental regulation and taxation;

hazards or operating risks incidental to the transporting, treating and processing of natural gas and NGLs or to the transporting, storing and distributing of propane that may not be fully covered by insurance;

the maturity of the propane industry and competition from other propane distributors;

competition from other midstream companies;

management has limited discretion under Board guidelines in conducting our risk management activities and may not accurately predict future price fluctuations and therefore expose us to financial risks and reduce our opportunity to benefit from price fluctuations;

changes in commodity prices may subject us to margin calls, which may adversely affect our liquidity;

loss of key personnel;

loss of key natural gas producers or the providers of fractionation services;

- **reductions in the capacity or allocations of third party pipelines that connect with Energy Transfer s pipelines and facilities;**

- **the effectiveness of risk-management policies and procedures and the ability of our marketing counterparties to satisfy their financial commitments and the nonpayment or nonperformance by our customers;**

- **the availability and cost of capital and our ability to access certain capital sources;**

- **changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations;**

- **the costs and effects of legal and administrative proceedings;**

- **the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results; and**

- **risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities.**

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described above.

Energy Transfer Transactions

On January 20, 2004, Heritage and ETE completed the series of transactions whereby ETE contributed its subsidiary, ETC OLP to Heritage in exchange for cash of $300.0 million less the amount of ETC OLP debt in excess of $151.5 million, less ETC OLP s accounts payable and other specified liabilities, plus agreed-upon capital expenditures paid by ETE relating to the ETC OLP business prior to closing, $433.9 million of Heritage Common and Class D Units, and the repayment of the ETC OLP debt of $151.5 million. These transactions and the other transactions described in the following paragraphs are referred to herein as the Energy Transfer Transactions. In conjunction with the Energy Transfer Transactions and prior to the contribution of ETC OLP to Heritage, ETC OLP distributed its cash and accounts receivables to ETE and an affiliate of ETE contributed an office building to ETC OLP. ETE also received 3,742,515 Special Units as consideration for the project it had in progress to construct the East Texas Pipeline. The Special Units converted to Common Units upon the East Texas Pipeline becoming commercially operational and such conversion being approved by Energy Transfer s Unitholders. The East Texas Pipeline became commercially operational on June 21, 2004, and the Unitholders approved the conversion of the Special Units at a special meeting held on June 23, 2004.

Simultaneously with the transactions described in the preceding paragraph, ETE obtained control of Heritage by acquiring all of the interest in ETP GP, the General Partner of Heritage, and ETP GP s general partner, ETP LLC, from subsidiaries of AGL Resources, Atmos Energy Corporation, TECO Energy, Inc. and Piedmont Natural Gas Company, Inc. for $30.0 million (the General Partner Transaction). In conjunction with the General Partner Transaction, ETP GP contributed its 1.0101% General Partner interest in HOLP to Heritage in exchange for an additional 1% General Partner interest in Heritage. Simultaneously with these transactions, Heritage purchased the outstanding stock of Heritage Holdings, Inc. (Heritage Holdings) for $100.0 million.

Concurrent with the Energy Transfer Transactions, ETC OLP borrowed $325.0 million from financial institutions and Heritage raised $355.9 million of gross proceeds through the sale of 9,200,000 Common Units at an offering price of $38.69 per unit. The net proceeds were used to finance the Energy Transfer Transactions and for general partnership purposes.

The Energy Transfer Transactions were accounted for as a reverse acquisition in accordance with Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141). Although Heritage was the surviving parent entity for legal purposes, ETC OLP was the acquiror for accounting purposes. As a result, ETC OLP s historical financial statements will be the historical financial statements of the registrant. The operations of Heritage prior to the Energy Transfer Transactions are referred to as Heritage.

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Other Recent Transactions

On October 17, 2005, we announced that the Board of Directors of our General Partner approved two new pipeline construction projects. The first project involves the expansion of our previously announced 264-mile intrastate pipeline project by increasing the pipeline s size to 42-inch for a larger portion of the project. The second project involves the construction of a new pipeline which will loop 24 miles of our existing 24-inch pipeline in the Fort Worth Basin production area.

These two recently announced major expansion projects involve several pipeline projects that are expected to increase pipeline transportation access for natural gas producers in the Bossier Sands and Barnett Shale basins in east and north Texas to various markets throughout Texas as well as to markets in the eastern United States through interconnects with other intrastate and interstate pipelines. The larger of the two expansion projects involves the construction of approximately 264 miles of 42-inch pipeline and the addition of approximately 40,000 horsepower of compression at a cost of approximately $535.5 million. The 264 mile pipeline will extend from the intersection of Fort Worth Basin and North Texas Pipeline near Cleburne, Texas to our Texoma pipeline and on to the Carthage, Texas market hub. This expansion project is supported by a 10-year agreement with XTO Energy, Inc. in which XTO Energy has agreed to transport specified volumes of natural gas on an annual basis and is entitled to transport additional volumes under similar terms. We expect this project to be completed by December 2006, although segments of the project will become operational prior to that date. Our other major expansion project involves the construction, on a joint venture basis with Atmos Energy Corp., of a 30-inch pipeline in the north Fort Worth Basin area that will provide an additional outlet for natural gas from the Barnett Shale area to several market hubs at a cost of approximately $29.3 million. These expansion projects will continue the integration of several pipeline systems and natural gas storage facilities, including the integration of our Katy Pipeline and Southeast Texas System with the recently acquired ET Fuel System and Houston Pipeline System. We expect this project to be completed in February 2006.

In addition, in response to additional activity in the Barnett Shale, we have approved the looping of the first 24 miles of our existing 55-mile, 24-inch pipeline in the Fort Worth Basin. The Fort Worth Basin Pipeline became commercially operational on May 26, 2005, at nearly full capacity. The looping of the first 24 miles of the system with another 24-inch pipeline and the addition of up to 12,000 horsepower of incremental compression will provide additional upstream capacities needed to accommodate the increased volumes in the Fort Worth Basin production area. The estimated cost to complete this project is approximately $32.1 million and is expected to be completed prior to the end of fiscal year 2006.

On November 10, 2005 the Partnership purchased the remaining 2% limited partner interest in HPL from AEP for $16.6 million in cash. As a result the Partnership now owns 100% of the general and limited interests in HPL.

Overview of Operations

Midstream and transportation and storage segments

Our midstream and transportation and storage segments are operated by ETC OLP. We own and operate approximately 11,700 miles of natural gas gathering and transportation pipelines, three natural gas processing plants, two of which are currently connected to our gathering systems, fourteen natural gas treating facilities and three natural gas storage facilities. Our midstream segment focuses on the transportation, gathering, compression, treating, processing and marketing of natural gas. Our operations are currently concentrated in the Austin Chalk trend of southeast Texas, the Permian Basin of west Texas, the Barnett Shale in north Texas and the Bossier Sands in east Texas. Our transportation and storage segment focuses on the transportation of natural gas through the Oasis Pipeline, our East Texas Pipeline, our natural gas pipeline and storage assets that are referred to as the ET Fuel System, and certain transportation assets of the recently acquired HPL System. The Oasis Pipeline is a

583-mile natural gas pipeline that directly connects the Waha Hub, a major natural gas trading center located in the Permian Basin of west Texas, to the Katy Hub, a major natural gas trading center near Houston, Texas. The East Texas Pipeline connects natural gas supplies in east Texas to the Katy Pipeline. The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,000 miles of intrastate natural gas pipeline and related natural gas storage facilities located in Texas. With approximately 460 receipt and/or delivery points, including interconnects with pipelines providing direct access to power plants and interconnects with other intrastate and interstate pipelines, the ET Fuel System is strategically located near high-growth production areas and major markets such as the Waha Hub, the Katy Hub and the Carthage Hub, three major natural gas trading centers located in Texas. Our transportation and storage segment also includes the recently acquired HPL System which is comprised of approximately 4,200 miles of intrastate natural gas pipeline, 65 Bcf of working gas underground Bammel storage reservoir and related transportation assets. The HPL System has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast, east Texas and the western Gulf of Mexico and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City, Baytown, Beaumont and Port Arthur. The HPL System consists of six main transportation pipelines and three market area loops and has direct access to multiple market hubs at Katy, the Houston Ship Channel, Ague Dulce and through its operations of the Bammel storage facility.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate our midstream gross margins under fee-based or other arrangements. Under fee-based arrangements, we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue we earn from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in the midstream segment, including (i) discount-to-index price arrangements which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed-upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based upon gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. The contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct our marketing operations through our producer services business, in which we market the natural gas that flows through our assets, which we refer to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, which we refer to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

During the fourth quarter of the year ended August 31, 2005, we adopted a new risk management policy that provides for our marketing operations to execute limited strategies. Certain strategies are considered trading activities for accounting purposes and are accounted for in net revenues on the consolidated statement of operations. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including NYMEX futures contracts, basis contracts and gas daily contracts. See further discussion regarding our risk management policies in Item 7a. Quantitative and Qualitative Disclosures about Market Risk found elsewhere in this report.

Results from our transportation and storage segment are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through our transportation pipelines. Under transportation contracts, we charge our customers (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay us even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, and (iii) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly. We also generate revenue from fees charged for storing customers working natural gas in our storage facilities, primarily on the ET Fuel system and to a lesser extent at HPL.

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The transportation and storage segment also generates its revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL System. Generally, HPL purchases its natural gas from either the market including purchases from the midstream s producer services, and from producers at the wellhead. To the extent the natural gas comes from producers, it is purchased at a discount to a specified price and resold to customers at the index price.

As a result of our acquisition of the HPL System, we now engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. The Bammel storage reservoir is one of the largest storage facilities in North America with a total working gas capacity of approximately 65 Bcf. The reservoir has a peak withdrawal rate of 1.3 Bcf/d and also has considerable flexibility during injection periods in that the HPL System has engineered an injection well configuration to provide for a 0.6 Bcf/d peak injection rate. Therefore, we purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. Since the acquisition, we have continually managed our positions to enhance the future profitability of our storage position. We may, from time to time, change our scheduled injection and withdrawal plans based on market conditions and adjust the level of working natural gas stored in the Bammel reservoir. We expect margins from the HPL System to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. As of August 31, 2005, we had approximately 28 Bcf of working natural gas stored in the Bammel storage facility. We intend to continue to purchase and store natural gas in our first quarter of 2006 in order to meet anticipated demand during the periods from November to March. However, we can not assure that management s expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Retail and Wholesale Propane segments

Our propane-related segments are operated by HOLP and its subsidiaries who are engaged in the sale, distribution and marketing of propane and other related products through its retail and wholesale segments, (the propane segments). HOLP derives its revenue primarily from the retail propane segment. We believe that we are the fourth largest retail marketer of propane in the United States, based on retail gallons sold. We serve more than 700,000 propane customers from 315 customer service locations in 34 states.

The propane segments are margin-based businesses in which gross profits depend on the excess of sales price over propane supply cost. The market price of propane is often subject to volatile changes as a result of supply or other market conditions over which we have no control. Product supply contracts are one-year agreements subject to annual renewal and generally permit suppliers to charge posted prices (plus transportation costs) at the time of delivery or the current prices established at major delivery points. Since rapid increases in the wholesale cost of propane may not be immediately passed on to retail customers, such increases could reduce gross profits. We generally have attempted to reduce price risk by purchasing propane on a short-term basis. We have on occasion purchased for storage significant volumes of propane during periods of low demand, which generally occur during the summer months, at the then current market price, both at our customer service locations and in major storage facilities, for future resale.

Our retail propane business consists principally of transporting propane purchased in the contract and spot markets, primarily from major fuel suppliers, to our customer service locations and then to propane tanks located on the customers premises, as well as to portable propane cylinders. In the residential and commercial markets, propane is primarily used for space heating, water heating, and cooking. In the agricultural market, propane is primarily used for crop drying, tobacco curing, poultry brooding, and weed control. In addition, propane is used for certain industrial applications, including use as an engine fuel to power vehicles and forklifts and as a heating source in manufacturing and mining processes.

Our propane distribution business is largely seasonal and dependent upon weather conditions in our service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements. Historically, approximately two-thirds of HOLP s retail propane volume and in excess of 80% of HOLP s EBITDA, as adjusted, is attributable to sales during the six-month peak-heating season of October through March. This generally results in higher operating revenues and net income in the propane segments during the period from October through March of each year, and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Consequently, sales and operating profits for the propane segments are concentrated in the first and second fiscal quarters, however, cash flow from operations is generally greatest during the second and third fiscal quarters when customers pay for propane purchased during the six-month peak-heating season. Sales to industrial and agricultural customers are much less weather sensitive.

A substantial portion of our propane is used in the heating-sensitive residential and commercial markets causing the temperatures realized in our areas of operations, particularly during the six-month peak-heating season, to have a significant effect on the financial performance in our propane operations. In any given area, sustained warmer-than-normal temperatures will tend to result in reduced propane use, while sustained colder-than-normal temperatures will tend to result in greater propane use. We use information on normal temperatures in understanding how temperatures that are colder or warmer than normal affect historical results of operations and in preparing forecasts related to our future operations.

The retail propane segment s gross profit margins are not only affected by weather patterns, but also vary according to customer mix. Sales to residential customers generate higher margins than sales to certain other customer groups, such as commercial or agricultural customers. The wholesale propane segment s margins are substantially lower than retail margins. In addition, propane gross profit margins vary by geographical region. Accordingly, a change in customer or geographic mix can affect propane gross profit without necessarily affecting total revenues.

Amounts discussed below reflect 100% of the results of MP Energy Partnership. MP Energy Partnership is a Canadian general partnership in which HOLP owns a 60% interest. Because MP Energy Partnership is primarily engaged in lower-margin wholesale distribution, its contribution to our net income is not significant, and the minority interest of this partnership is excluded from the EBITDA, as adjusted, calculation.

Analysis of Historical Results of Operations

The Energy Transfer Transactions affect the comparability of our financial statements for the year ended August 31, 2005 to the year ended August 31, 2004 because our consolidated financial statements for the year ended August 31, 2004 reflect the results of ETC OLP and its subsidiaries for the full period and the results of HOLP and HHI only from January 20, 2004 through August 31, 2004. The aggregate results in the propane segments disclosed below reflect Heritage s historical results for the year ended August 31, 2004 combined with the historical results of Energy Transfer Company for the year ended August 31, 2004, and are presented for comparability purposes only. This aggregate information (i) is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations and (ii) is not a measure of performance calculated in accordance with generally accepted accounting principles.

In addition to the Energy Transfer Transactions, the acquisition of the ET Fuel System affects the comparability of the historical results of operations in our transportation and storage segment for the year ended August 31, 2005 compared to the year ended August 31, 2004. We acquired the ET Fuel System in June 2004; therefore, the results of operations for the year ended August 31, 2004 do not reflect the impact of this acquisition for a full year. We also acquired the HPL System in January 2005. The acquisition of HPL affects the comparability of the historical results of operations in our transportation and storage operating segment for the year ended August 31, 2005 compared to the year ended August 31, 2004. The results of operations for the year ended August 31, 2004 do not reflect the impact of this acquisition and the results of operations for the year ended August 31, 2005 only include the results of operations of HPL from the date of acquisition to August 31, 2005.

In addition, we completed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, on April 14, 2005. These results are presented as net amounts in the Consolidated Statements of Operations, with prior periods restated to conform to the current presentation. Selected operating results for the midstream segment discussed below have been restated for the periods presented to reflect the discontinued operations.

Overall Increase in Results of Operations. We have experienced a significant increase in our results of operations for year ended August 31, 2005 when compared to last year. The increase is principally attributable to the following:

Energy Transfer Transactions noted above. The transactions were accounted for as a reverse acquisition and ETC OLP had no propane operations prior to the transaction;

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Acquisitions. We have been successful in completing various strategic acquisitions during the last twelve to eighteen months by both of our operating partnerships, ETC OLP and HOLP. As discussed above, we completed the acquisition of the ET Fuel System in June 2004 and the HPL System in January 2005. We also acquired the Texas Chalk and Madison System in November 2004. These acquisitions have significantly increased our asset base and operations for the 2005 periods presented. In addition, HOLP has made a number of propane acquisitions during the periods presented;

Completion of the East Texas Pipeline. We completed the East Texas Pipeline in June 2004. As a result, the 2004 period only contains the results of operations from June 2004 to August 2004, compared to a full year of operations for the 2005 period.

Increased volumes and prices. In addition to the acquisitions, we have also experienced increased volumes in our existing operating segments as a result of various strategies put in place by management. Commodity prices have also increased resulting in increased revenues and costs of sales, primarily in our midstream segment.

Fiscal Year Ended August 31, 2005 Compared to Fiscal Year Ended August 31, 2004

Volume. The following table presents selected volumetric information related to our operating segments for the years ended August 31, 2005 and 2004:

	August 31, 2005 (Actual)	August 31, 2004 (Actual)
Midstream		
Natural gas MMBtu/d sold	1,694,573	1,026,773
NGLs Bbls/d - sold	12,707	6,920
Transportation and storage		
Natural gas MMBtu/d - sold	1,361,729	
Natural gas MMBtu/d - transported	3,495,434	1,090,710
NGLs Bbls/d - sold	1,735	

Midstream. Natural gas sales volumes were 1,694,573 MMBtu/d for the year ended August 31, 2005 compared to 1,026,773 MMBtu/d for the year ended August 31, 2004, an increase of 667,800 MMBtu/d. NGLs sales volumes were 12,707 Bbls/d and 6,920 Bbls/d for the year ended August 31, 2005 and August 31, 2004, respectively. The increase in natural gas sales volumes was a result of our expanded marketing efforts, enhanced relationships with producers and expanded credit facilities with commodity counter parties. The increase was also attributable to the acquisition of the Texas Chalk and Madison Systems on November 1, 2004, as the Texas Chalk and Madison Systems essentially doubled the number of producing wells from 1,000 to 2,000. Our sales volumes of NGLs vary due to our ability to by-pass our processing plants when conditions exist that make it less favorable to process and extract NGLs from our processing plants. The increase in NGLs sales volumes is principally due to the increased natural gas sales volumes processed through our processing plants.

Transportation and Storage. Transportation natural gas volumes increased by 2,404,724 MMBtu/d from 1,090,710 MMBtu/d for the year ended August 31, 2004 to 3,495,434 MMBtu/d for the year ended August 31, 2005. The increase in transportation volumes is principally due to the increased volumes experienced on our Oasis Pipeline, the acquisition of the ET Fuel System in June 2004, the completion of the East Texas Pipeline in June 2004, and additional transportation volumes from the HPL System acquisition. As noted above, the transportation and storage segment also generates revenue and margin from the sale of natural gas on the HPL System to its customers. The HPL System s natural gas sales volumes were 1,361,729 MMbtu/d for the period from acquisition to August 31, 2005 and it processed 1,735 Bbls/d during the same period.

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	Year Ended		
	August 31, 2005	August 31, 2004	August 31, 2004
	(Actual)	(Actual)	(Aggregate)
Propane gallons			
(in thousands)			
Retail	406,334	226,209	397,862
Wholesale	70,047	35,719	64,399

Retail Propane. For the year ended August 31, 2005 total retail propane gallons sold were 406.3 million gallons, compared to 226.2 million retail propane gallons reflected in the year ended August 31, 2004. The difference in retail gallons sold is partially due to the fact that the Energy Transfer Transactions described above resulted in reverse acquisition accounting and ETC OLP had no propane operations prior to the Energy Transfer Transactions. As a comparison, we would have reflected an aggregate of 397.9 million retail gallons if the Energy Transfer Transactions would have occurred at the beginning of fiscal year 2004. The aggregate increase is due to a 23.0 million gallon increase resulting from volumes sold by customer services locations added through acquisitions, offset by a 14.5 million gallon decline in volumes sold due in part to warmer weather. We experienced temperatures that were 6.9% warmer than normal and 0.7% warmer than last year. We believe our volumes for the year ended August 31, 2005 were negatively impacted by the conservation efforts of our customers in reaction to record high energy prices. We have increased our marketing efforts to attain new customers, which partially offsets the negative factors described above.

Wholesale Propane. For the year ended August 31, 2005 we sold 70.0 million wholesale propane gallons as compared to 35.7 million in the year ended August 31, 2004. As a comparison, we would have reflected aggregate volumes of 64.4 million gallons for the year ended August 31, 2004. Of the 5.6 million gallon aggregate increase in domestic wholesale propane gallons, 0.8 million is primarily due to customers added from an acquisition in December 2003 and a 5.4 million gallon increase in our foreign operations offset by a decrease of 0.6 million gallons related to warmer weather.

Consolidated Results

	Year Ended	
	August 31, 2005	August 31, 2004
Consolidated Information:		
Revenues	$ 6,168,798	$ 2,346,957
Cost of sales	5,381,515	1,981,424
Gross margin	787,283	365,533
Operating expenses	319,554	147,374
Selling, general and administrative	62,735	30,471
Depreciation and amortization	92,943	48,599
Consolidated operating income	312,051	139,089
Equity in earnings (losses) of affiliates	(376)	363
Interest expense	(93,017)	(41,190)

Loss on extinguishment of debt	(9,550)	
Loss on disposal of assets	(330)	(1,006)
Other, net	631	509
Minority interests	(731)	(295)
Income tax expense	(7,295)	(4,481)
Income from continuing operations	201,383	92,989
Income from discontinued operations, net of income tax expense	147,967	6,163
Net income	$ 349,350	$ 99,152

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Equity in Earnings (Losses) of Affiliates. Equity in earnings (losses) of affiliates was $(0.4) million for the year ended August 31, 2005, compared to $0.4 million for the year ended August 31, 2004. In connection with the HPL acquisition, we acquired a 50% interest in an unconsolidated affiliate. Our share of losses from this affiliate was $(0.7) million for the year ended August 31, 2005.

Interest Expense. Interest expense was $93.0 million for the year ended August 31, 2005 as compared to $41.2 million for the year ended August 31, 2004. Of the $51.8 million increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004, $12.7 million is the interest of our propane segments prior to the Energy Transfer Transactions which is not included in expense for the year ended August 31, 2004, $43.5 million is the result of the borrowings on the Senior Notes and the Revolving Credit Facility in January 2005, $1.0 million is related to the amortization of financing costs and the bond discount related to the Senior Notes and the Revolving Credit Facility, offset by a decrease of $1.5 million from gains on interest rate swaps that was included in interest expense during the year ended August 31, 2005 and was not present in 2004, $2.0 million that is attributed to reduced interest in our midstream and transportation and storage segments due to the reduction of long term debt in January 2005 and the effects of interest rate swaps accounted for at ETC OLP, and a $1.9 million decrease in interest expense in our propane segments which is primarily due to the reduction of principal on several of HOLP s Senior Secured Notes from annual payments during the year ended August 31, 2005.

Loss on Extinguishment of Debt. As a result of refinancing certain debt during the year ended August 31, 2005, we wrote off $8.0 million of debt issuance costs associated with the debt that was repaid with the proceeds from the issuance of $750 million of Senior Notes. We also wrote off $1.5 million of deferred debt costs during the year ended August 31, 2005 as a result of repaying the debt with ETE that we incurred to purchase the working inventory of natural gas related to the acquisition of the HPL System. The write-off was accounted for as a loss on extinguishment of debt.

Income Tax Expense. Income tax expense was $7.3 million for the year ended August 31, 2005 as compared to $4.5 million for the year ended August 31, 2004. As a partnership, we are not subject to income taxes. However, Oasis Pipe Line Company, Heritage Service Company, and HHI, wholly-owned subsidiaries are corporations that are subject to income taxes. The increase in income tax expense is due to income tax expense recorded in HHI for the entire period in the year ended August 31, 2005 as compared with the year ended August 31, 2004, when tax expense related to HHI was only included in our results of operations after the Energy Transfer Transactions, and increased income from acquisitions, partially offset by lower taxes on the Oasis Pipeline due to lower taxable income for that entity.

Income from Continuing Operations. Income from continuing operations for the year ended August 31, 2005 was $201.4 million as compared to income from continuing operations of $93.0 million for the year ended August 31, 2004. The increase from the 2004 periods to the 2005 periods is principally due to acquisition-related income.

Income from Discontinued Operations. On April 14, 2005, we completed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, for total cash proceeds of $191.6 million, including certain adjustments as defined in the purchase and sale agreement. Revenues from the Elk City System were $105.5 million for the period from September 1, 2004 to April 14, 2005 as compared to $135.3 million for the year ended August 31, 2004. Costs and expenses were $100.0 million for the period from September 1, 2004 to April 14, 2005 and $129.1 million for the year ended August 31, 2004. Income from discontinued operations for the period from September 1, 2004 to April 14, 2005 and for the year ended August 31, 2004 was $5.5 million and $6.2 million, respectively. The decrease in revenues, expenses and income was principally due to the sale occurring in April 2005. The gain on the sale of the Elk City System was $142.5 million, net of related income tax expense of $1.8 million recorded by HHI.

Net Income. Net income was $349.4 million for the year ended August 31, 2005, as compared to $99.2 million for the year ended August 31, 2004. The increase in net income for the year ended August 31, 2005 compared to August 31, 2004 is largely due to the effect of the Energy Transfer Transactions, acquisition-related income, and the divestiture of the Elk City System.

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EBITDA, as adjusted. EBITDA, as adjusted, increased $216.5 million to $413.2 million for the year ended August 31, 2005 as compared to EBITDA, as adjusted, of $196.7 million for the year ended August 31, 2004. This increase is due to the operating results of our segments described below.

EBITDA, as adjusted, is computed as follows:

	Year Ended	
	August 31, 2005	August 31, 2004
Net income reconciliation		
Net income	$ 349,350	$ 99,152
Gain on sale of discontinued operations, net of income tax expense	(142,469)	
Depreciation and amortization	92,943	48,599
Interest expense	93,017	41,190
Income tax expense on continuing operations	7,295	4,481
Non-cash compensation expense	1,608	42
Other (income) expense, net	(631)	(509)
Depreciation, amortization, and interest of investee	697	440
Depreciation, amortization, and interest of discontinued operations	1,547	2,249
Loss on extinguishment of debt	9,550	
Loss on disposal of assets	330	1,006
EBITDA, as adjusted (a)	$ 413,237	$ 196,650
Heritage EBITDA, as adjusted (b)		$ 52,845
Aggregate EBITDA, as adjusted (b)		$ 249,495

(a) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, gain or loss on discontinued operations, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income or loss such as the gain or loss arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of our fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to our investors for trending, analyzing and benchmarking the operating results of our partnership from period to period as compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view our performance in a manner similar to the methods used by management and provides additional insight to our operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of our numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. We have a large number of business locations located in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. To present EBITDA, as adjusted, on a full Partnership basis, we add back the minority interest of the general partner because net income is reported net of the general partner s minority interest. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the our business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare our operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than ours. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in our operating results but are not classified in interest, depreciation and amortization. We do not include gain or loss on the sale of assets when determining EBITDA, as adjusted, since including non-cash income or loss resulting from the sale of assets increases/decreases the performance measure in a manner that is not related to the true operating results of our business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read Financing and Sources of Liquidity in this Form 10-K.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us and Heritage in the past. Management compensates for these limitations by considering EBITDA, as adjusted in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities.

(b) The business combination of Energy Transfer Company and Heritage Propane Partners, L.P. and subsidiaries (Heritage), (the Energy Transfer Transaction), on January 20, 2004 resulted in a change of control for accounting purposes, causing Energy Transfer s financial statements to become those of the registrant. Because of the accounting treatment applied in the Energy Transfer Transaction, the reported first quarter fiscal 2004 actual results reflect the operations of Energy Transfer s midstream and transportation and storage businesses for the entire reporting period but not Heritage s propane business for that period. The aggregate results disclosed reflect Heritage s historical results for the period ended January 19, 2004 combined with the historical results of Energy Transfer Company for the nine months ended August 31, 2004, and are presented for comparability purposes only. This aggregate information (i) is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations and (ii) is not a measure of performance calculated in accordance with generally accepted accounting principles.

The following reconciliation of Aggregate EBITDA, as adjusted, to net income is presented for comparability purposes only, and is comprised of the aggregate of Energy Transfer Company and Heritage s historical results for the periods presented.

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	For the Period Ended January 19, 2004	Year Ended August 31, 2004
	(Heritage)	(Aggregate)
Net income reconciliation		
Net income	$ 22,644	$ 121,796
Depreciation and amortization	15,389	63,988
Interest expense	12,754	53,944
Income tax expense	20	4,501
Non-cash compensation expense	1,232	1,274
Other, net	66	(443)
Depreciation, amortization, and interest of investee	322	762
Depreciation, amortization, and interest of discontinued operations		2,249
Minority interests in Operating Partnership	178	178
(Gain) loss on disposal of assets	240	1,246
Heritage EBITDA, as adjusted (b)	$ 52,845	
Aggregate EBITDA, as adjusted (b)		$ 249,495

OPERATING RESULTS BY SEGMENT

Midstream Segment

	Year Ended	
	August 31, 2005	August 31, 2004
	(Actual)	(Actual)
Revenues	$ 3,246,772	$ 1,880,663
Cost of sales	3,102,539	1,787,849
Gross Margin	144,233	92,814
Operating expenses	22,835	12,541
Selling, general and administrative	9,685	10,387
Depreciation and amortization	12,580	9,637
Segment operating income	$ 99,133	$ 60,249

Gross Margin. Midstream s gross margin increased $51.4 million from $92.8 million for the year ended August 31, 2004 to $144.2 million for the year ended August 31, 2005. The increase is principally due to increases in margin pertaining to increased volumes experienced on our Southeast Texas System as noted above, and increased marketing efforts by our producer services. In addition, fee-based revenue increased principally due to increased processing, treating and gathering fees resulting from the increased throughput volumes and the acquisition of the Texas Chalk and Madison System in November 2004. The increase in fee based revenue was also due to a change in the contract mix with a major producer during the third quarter of our 2005 fiscal year; however, this change should have no effect on overall midstream margins. The increase in margin during the year ended August 31, 2005 was also due to mark-to-market gains resulting from favorable price movements in relation to our overall derivative positions. The price movements were a result of the effects of Hurricane Katrina during the latter part of August 2005. We expect the effects of Hurricanes Katrina and Rita to have a positive impact on our earnings in our first quarter of fiscal 2006.

Operating Expenses. For the year ended August 31, 2005, Midstream operating expenses increased $10.3 million to $22.8 million from $12.5 million for the year ended August 31, 2004. The increase was principally due to $3.1 million in increased compressor and pipeline maintenance, $1.8 million in increased measurement expenses, $1.8 million in increased property taxes, and $3.6 million in the aggregate, of other operating expenses such as chemicals, electricity, and other plant operating expenses primarily due to the Texas Chalk and Madison Systems acquisition and increased throughput experienced on our existing systems.

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Selling, General and Administrative Expenses. Midstream general and administrative expenses decreased from $10.4 million for the year ended August 31, 2004 to $9.7 million for the year ended August 31, 2005. The decrease was principally due to $9.5 million in certain departmental costs incurred by the midstream segment and allocated to the transportation and storage operating segment. The decrease was offset by increases of $6.7 million in employee-related expenses such as salary, incentive compensation and health care cost, and $2.1 million in other general and administrative costs such as office, legal, and insurance expense.

Depreciation and Amortization. Midstream depreciation and amortization was $12.6 million for the year ended August 31, 2005 compared to $9.6 million for the year ended August 31, 2004, an increase of $3.0 million or 31%. The increase was principally due to the Texas Chalk and Madison Systems acquisition in November 2004.

Transportation and Storage Segment

	Year Ended	
	August 31, 2005	**August 31, 2004**
	(Actual)	**(Actual)**
Transportation and Storage Segment:		
Revenues	$ 2,608,108	$ 113,938
Cost of sales	2,280,082	11,270
Gross Margin	328,026	102,668
Operating expenses	113,166	30,571
Selling, general and administrative	27,020	8,372
Depreciation and amortization	27,742	7,426
Segment operating income	$ 160,098	$ 56,299

Gross Margin. Transportation and storage gross margin was $328.0 million for the year ended August 31, 2005 as compared to $102.7 million for the year ended August 31, 2004, an increase of $225.3 million. The increase in transportation and storage gross margin is principally due to the following:

Increased volumes on our Oasis Pipeline. The increase is principally due to the increase in average natural gas prices period to period which promotes shippers to transport natural gas to more liquid markets such as the Katy Hub and our strategy to pursue additional volumes in the middle and west end of the Oasis Pipeline System. Additionally, the average differential between the Waha market hub and Katy market hub increased $0.051 from $0.249 for the year ended August 31, 2004 to $0.30 for the year ended August 31, 2005, thereby influencing shippers to transport natural gas to regions where natural gas prices are more favorable.

ET Fuel System acquisition in June 2004. In connection with the acquisition of the ET Fuel System in June of 2004, we entered into an eight-year transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 115.6 MMBtu per year. We also entered into two eight-year natural gas storage agreements with TXU Shipper to store gas at two natural gas storage facilities that are part of the ET Fuel System. During the third fiscal quarter of 2005, we were entitled to receive additional fees for the difference between the actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above. As a result, we recognized an additional $14.7 million in fees during the third fiscal quarter of 2005. TXU Shipper has notified us that it has elected to reduce the minimum transport volume to 100.0 MMBtu per year beginning in January 2006. The ability to reduce the minimum transport volume was limited to a one-time election. The increase in margin was also due to the Fort Worth Basin expansion completed in May 2005. We expect margins from our ET Fuel System to increase in fiscal 2006 as a result of this expansion and the recently announced expansion projects discussed herein.

East Texas System. We completed the East Texas System in June 2004.

HPL System acquired in January 2005. As discussed above, we expect significant fluctuations in our margins from period to period on the HPL System due to the timing of injections and withdrawals of working natural gas. We expect our margins to increase in the first quarter of fiscal 2006 as a result of the effects of Hurricanes Katrina and Rita in the region where we own these assets.

Operating Expenses. For the year ended August 31, 2005, transportation and storage operating expenses were $113.2 million as compared to $30.6 million for the year ended August 31, 2004, an increase of $82.6 million. The increase was principally attributable to the ET Fuel System acquisition in June 2004, the completion of the East Texas Pipeline in June 2004 and the acquisition of HPL in January 2005. In addition, Oasis Pipeline s operating expenses increased $9.1 million as a result of increased gas consumption required to transport natural gas through its pipeline and increases in other operating expenses such as compressor and pipeline maintenance and ad valorem taxes.

Selling, General and Administrative Expenses. Transportation and storage general and administrative expenses increased $18.6 million to $27.0 million for the year ended August 31, 2005 from $8.4 million for the year ended August 31, 2004. The increase was principally due to $9.0 million in general and administrative expenses related to the HPL acquisition, $1.4 million in general and administrative expenses relating to the ET Fuel acquisition, and $9.5 million related to certain department costs allocated from the midstream segment offset by a $1.0 million decrease in legal fees related to a lawsuit that was settled in January 2004 and a $0.3 million decrease in other expenses.

Depreciation and Amortization. For the year ended August 31, 2005 transportation and storage depreciation and amortization increased $20.3 million from $7.4 million for the year ended August 31, 2004 to $27.7 million for the year ended August 31, 2005. The increase was principally attributable to the acquisitions of the ET Fuel System and HPL System during the 2005 fiscal period and the completion of the East Texas Pipeline in June 2004.

Retail Propane Segment

	Year Ended		
	August 31, 2005	August 31, 2004	August 31, 2004
	(Actual)	(Actual)	(Aggregate)
Retail propane revenues	$ 641,071	$ 315,177	$ 536,636
Other propane related revenues	68,402	34,167	60,646
Retail propane cost of sales	384,186	174,769	296,206
Other propane related cost of sales	19,554	9,602	17,512
Operating expenses	176,277	100,093	158,471
Selling, general and administrative	11,067	6,746	11,080
Depreciation and amortization	51,487	30,925	45,979
Segment operating income	$ 66,902	$ 27,209	$ 68,034

Revenues. For the year ended August 31, 2005, we had retail propane revenues of $641.1 million as compared to retail propane revenues of $315.2 million for the year ended August 31, 2004, due in part to the fact that the Energy Transfer Transactions described above resulted in reverse acquisition accounting, and ETC OLP had no propane operations. As a comparison, for the year ended August 31, 2004, aggregate retail propane revenues would have been $536.6 million. Of the $104.5 million aggregate increase, $36.3 million is due to the increase in volumes sold by customer service locations added through acquisitions, $91.1 million is due to higher selling prices which were a result of higher fuel costs that we have passed to our consumer base; offset by a decrease of $22.9 million due to the adverse impact weather related volumes and customer conservation efforts described above. We had other propane related revenues of $68.4 million for the year ended August 31, 2005 compared to $34.2 for the year ended August 31, 2004. As a comparison, aggregate other propane related revenues would have been $60.6 million for the year ended August 31, 2004. The aggregate increase of $7.8 million for the year ended August 31, 2005 compared to the year ended August 31, 2004 is primarily due to other propane revenue from companies acquired during the year ended August 31, 2005 and higher cost of propane related resale items which we have recovered through an increase to our selling prices.

Costs of Sales. For the year ended August 31, 2005, we had retail propane cost of sales of $384.2 million compared to retail propane cost of sales of $174.8 million for the year ended August 31, 2004. As a comparison, for the year ended August 31, 2004, aggregate retail propane cost of sales would have been $296.2 million. Of the $88.0 million aggregate increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004, $80.0 million reflects the increase due to higher cost of fuel, and $8.0 million is due to the increase in volumes described above. We had other propane related cost of sales of $19.5 million for the year ended August 31, 2005 as compared to $9.6 million for the year ended August 31, 2004. As a comparison, we had aggregate other propane related cost of sales of $17.5 million. The aggregate increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004 is primarily due to acquisition related cost of sales for the year ended August 31, 2005 and higher cost of resale items.

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Operating Expenses. For the year ended August 31, 2005, operating expenses for the retail propane segment were $176.3 million and $100.1 million for the year ended August 31, 2004. As a comparison, aggregate retail propane operating expenses would have been $158.5 million for the year ended August 31, 2004, or an aggregate increase of $17.8 million. Of this aggregate increase, approximately $8.7 million related to an increase in our employee base from acquisitions, $3.1 million is due to higher fuel costs to run our vehicles and other vehicle expenses, net business insurance increased $3.1 million, and the remaining increase of $2.9 million is primarily due to a general increase in other operating expenses also from acquisitions.

Selling, General and Administrative Expenses. For the year ended August 31, 2005, selling, general and administrative expenses for our retail propane segment were $11.1 million as compared to aggregate retail propane selling, general and administrative expenses of $11.1 million for the year ended August 31, 2004.

Depreciation and Amortization. For the year ended August 31, 2005, depreciation and amortization in our retail propane segment was $51.5 million as compared $30.9 million for the year ended August 31, 2004. We would have had aggregate depreciation and amortization of $46.0 million for the year ended August 31, 2004. The aggregate increase of $6.1 million is due primarily to the increase in depreciation of assets and amortization of intangible assets added through acquisitions and the additional depreciation and amortization of the assets stepped up to fair market value as a result of the Energy Transfer Transactions.

Operating Income. For the year ended August 31, 2005, we had retail propane operating income of $66.9 million as compared to retail propane operating income of $27.2 million for the year ended August 31, 2004. Aggregate total operating income for the year ended August 31, 2004 was $68.0 million. These variances are primarily due to changes in revenues and expenses described above.

Wholesale Propane Segment

	Year Ended		
	August 31, 2005 (Actual)	**August 31, 2004 (Actual)**	**August 31, 2004 (Aggregate)**
Wholesale Propane Segment:			
Revenues	$ 68,833	$ 27,345	$ 47,941
Cost of sales	64,667	24,871	43,410
Operating expenses	3,139	1,936	2,912
Selling, general and administrative	1,564	918	1,443
Depreciation and amortization	754	432	626
Segment operating loss	$ (1,291)	$ (812)	$ (450)

Revenues. For the year ended August 31, 2005, wholesale propane revenues were $68.8 million, compared to $27.3 million for the year ended August 31, 2004. Aggregate wholesale propane revenues were $47.9 million for the year ended August 31, 2004. Of the aggregate increase of $20.9 million, $0.9 million is due to the increase in gallons due to acquisitions, and a $15.5 million is related to higher selling prices, $5.1 million is due to increased marketing efforts in our foreign operations, offset by the decrease of $0.6 million due to weather related gallons described above.

Costs of Sales. For the year ended August 31, 2005, wholesale propane cost of sales was $64.7 million and $24.8 million for the year ended August 31, 2004. As a comparison, aggregate wholesale propane cost of sales would have been $43.4 million for the year ended August 31, 2004. The aggregate increase of $21.3 million is due to a $17.1 million increase from higher selling prices, $4.8 increase due to the increase in volumes in our foreign market described above, offset by a $0.6 million decrease due to weather related volumes described above.

Operating Expenses. For the year ended August 31, 2005, operating expenses for our wholesale propane segment were $3.1 million and $1.9 million for the year ended August 31, 2004. As a comparison, we had aggregate wholesale propane operating expenses of $2.9 million for the year ended August 31, 2004, or an increase of $0.2 million.

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Selling, General and Administrative Expenses. Selling, general and administrative expenses for our wholesale propane segment were $1.6 million for the year ended August 31, 2005, compared to wholesale selling, general, and administrative expenses of $0.9 for the year ended August 31, 2004. As a comparison, we had aggregate wholesale selling, general, and administrative expenses of $1.4 million for the year ended August 31, 2004.

Depreciation and Amortization. For the year ended August 31, 2005, depreciation and amortization in our wholesale propane segments was $0.7 million as compared to aggregate depreciation of $0.6 million for the year ended August 31, 2004. The aggregate increase of $0.1 million is due primarily to the increase in depreciation of assets added through acquisitions.

Operating Loss. For the year ended August 31, 2005, we had domestic wholesale propane operating loss of $1.3 million as compared to operating loss of $0.8 million for the year ended August 31, 2004. Aggregate total operating loss for the year ended August 31, 2004 would have been $0.4 million.

Other

	Year Ended		
	August 31, 2005 (Actual)	August 31, 2004 (Actual)	August 31, 2004 (Aggregate)
Other			
Revenue	$ 6,867	$ 3,464	$ 5,283
Cost of sales	1,742	861	1,304
Operating expenses	4,137	2,233	3,614
Depreciation and amortization	380	179	321
Other operating income	$ 608	$ 191	$ 44
Unallocated selling, general and administrative expenses	$ 13,399	$ 4,047	$ 9,288

Unallocated Selling, General and Administrative Expenses. The selling, general and administrative expenses that relate to the general operations of the Partnership are not allocated to our segments.

For the year ended August 31, 2005, the total unallocated selling, general, and administrative expenses were $13.4 million as compared to $4.0 million unallocated selling, general, and administrative expense for the year ended August 31, 2004. Aggregate total unallocated selling, general, and administrative expense for the year ended August 31, 2004 would have been $9.3 million. The aggregate increase of $4.1 million in unallocated selling, general, and administrative expenses is primarily related to the $4.4 million expense related to our ongoing efforts to comply with the Sarbanes Oxley Act and additional executive wages charged to unallocated selling, general and administrative expenses during fiscal year 2005, offset by approximately $4.5 million of transaction costs related to the Energy Transfer Transactions.

Fiscal Year Ended August 31, 2004 Compared to the Eleven Months Ended August 31, 2003

The Energy Transfer Transactions affect the comparability of our financial statements for the fiscal year ended August 31, 2004 to the eleven months ended August 31, 2003 because our consolidated financial statements for the fiscal year ended August 31, 2004 include the twelve month results for ETC OLP and its subsidiaries and the results of HOLP, its subsidiaries, and Heritage Holdings only for the period from January 20, 2004 through August 31, 2004. The financial statements of ETC OLP for the eleven months ended August 31, 2003 reflect only the results of ETC OLP and its subsidiaries, and the financial statements of Heritage reflect the results of HOLP and its subsidiaries. The changes in the line items discussed below are a result of these transactions. The aggregate results disclosed below reflect Heritage s historical results from September 1, 2003 until the closing of the Energy Transfer Transactions on January 19, 2004, Heritage s historical results for the fiscal year ended August 31, 2003, and the actual results for the year ended August 31, 2004, for comparability purposes only. This aggregate information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

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Volume. Total volumes of natural gas sales, NGL sales including propane, and natural gas transported by our midstream, transportation and storage, retail propane, domestic wholesale propane, and foreign wholesale propane segments for the fiscal year ended August 31, 2004 and eleven months ended August 31, 2003 are as follows:

	Year Ended August 31, 2004 (actual)	Eleven Months Ended August 31, 2003 (ETC OLP actual)
Midstream		
Natural gas MMBtu/d	1,026,773	505,725
NGLs bbls/d	6,920	9,332
Transportation and storage		
Natural gas MMBtu/d	1,090,710	921,352

Natural gas sales volumes were 1,026,773 MMBtu/d for the year ended August 31, 2004 compared to 505,725 MMBtu/d for the eleven months ended August 31, 2003, an increase of 521,048 MMBtu/d. NGLs sales volumes decreased from 9,332 Bbls/d for the eleven months ended August 31, 2003 to 6,920 Bbls/d for the year ended August 31, 2004. The increased natural gas sales volumes are the result of our expanded marketing efforts, enhanced relationships with producers and expanded credit facilities with commodity counter parties. As previously discussed, our sales volumes of NGLs vary due to our ability to by-pass our processing plants during unfavorable conditions to process and extract NGLs from our processing plants. The decrease in NGLs sales volumes was attributable to the bypassing of our La Grange plant.

Transportation natural gas volumes increased 169,358 MMBtu/d from 921,352 MMBtu/d for the eleven months ended August 31, 2003 to 1,090,710 for the year ended August 31, 2004. The increase in transportation volumes in principally due to the increased volumes experienced on our Oasis Pipeline and an increase in the differential between the Waha and Katy market hub. The average differential increased $0.093 from $0.156 for the eleven months ended August 31, 2003 to $0.249 for the year ended August 31, 2004 thereby influencing shippers to transport natural gas to regions where natural gas prices were more favorable. The increase was also attributable to the ET Fuel acquisition in June 2004 and the completion of the East Texas Pipeline also in June 2004.

	Year Ended August 31, 2004 (actual)	Year Ended August 31, 2004 (aggregate)	Eleven Months Ended August 31 2003 (actual)	Eleven Months Ended August 31 2003 (aggregate)
Propane gallons				
(in thousands)				
Retail	226,209	397,862		375,939
Domestic wholesale	7,071	12,452		15,343
Foreign wholesale	28,648	51,947		58,958

Total gallons	261,928	462,261		450,240

A total of $226.2 million retail propane gallons were sold in the twelve months ended August 31, 2004, with no sales of retail propane gallons reflected in the eleven months ended August 31, 2003. The difference in retail gallons sold is due to the Energy Transfer Transactions described above. We also sold approximately 7.1 million and 28.6 million domestic and foreign wholesale propane gallons, respectively, in the fiscal year ended August 31, 2004, with no sales of domestic or foreign wholesale propane gallons reflected for the eleven months ended August 31, 2003. As a comparison, Heritage would have reflected aggregate volumes of 397.9 million retail propane gallons for the fiscal year ended August 31, 2004 and historical volumes of 376.0 million gallons for the fiscal year ended August 31, 2003. Of the 21.9 million gallon aggregate increase, 27.8 million gallons are the result of volumes sold by customer service locations added through acquisitions, offset by a decrease of 5.9 million gallons that were weather related. We experienced temperatures that were on average, 2.73% warmer in the twelve months ended August 31, 2004 compared to last year and 6.47% warmer than normal during fiscal 2004. Also, as a

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comparison, Heritage would have reflected aggregated volumes of 12.5 million and 52.0 million domestic wholesale and foreign wholesale propane gallons, respectively, for the fiscal year ended August 31, 2004 as compared to historical volumes of 15.3 million and 59.0 million domestic and foreign wholesale propane gallons for the fiscal year ended August 31, 2003. The 2.8 million gallon decrease in domestic wholesale propane gallons is primarily the effect of the loss of two commercial customers to alternative fuel sources, and the 7.0 million gallon decrease in foreign wholesale volumes is due to an exchange contract that was in effect during the fiscal year ended August 31, 2003, which was not economical to renew during fiscal 2004.

Consolidated Results

	Year Ended August 31, 2004 (Actual)	Eleven Months Ended August 31, 2003 (ETC OLP)
Consolidated Information:		
Revenues	$ 2,346,957	$ 931,027
Cost of sales	1,981,424	825,438
Gross profit	365,533	105,589
Operating expenses	147,374	25,046
Selling, general and administrative	30,471	13,078
Depreciation and amortization	48,599	11,870
Consolidated operating income	$ 139,089	$ 55,595
Equity in earnings of affiliates	363	1,423
Interest expense	(41,190)	(12,456)
Gain (loss) on disposal of assets	(1,006)	
Other income (expense)	509	501
Minority interests	(295)	
Income tax expense	(4,481)	(4,432)
Income from continuing operations	92,989	40,631
Income from discontinued operations, net of income tax expense	6,163	5,994
Net income	$ 99,152	$ 46,625

Equity Income in Affiliates. Equity income in affiliates was $1.4 million for the eleven months ended August 31, 2003 compared to $0.4 million for the fiscal year ended August 31, 2004. The decrease was principally due to the consolidation of the Oasis Pipeline in December 2002.

Interest Expense. Interest expense was $41.2 million for the fiscal year ended August 31, 2004 as compared to $12.5 million for the eleven months ended August 31, 2003. This interest expense reflects the full fiscal year of ETC OLP s interest expense consolidated with the interest expense of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Of this increase, $20.7 million is related to the interest expense of HOLP after the Energy Transfer Transactions and $5.9 million is the result of additional interest in our midstream and transportation and storage segments due to the Energy Transfer Transactions and the acquisition of ET Fuel System in June 2004. In addition, we incurred $8.2 million in deferred financing costs during the year ended August 31, 2004, which we are amortizing on a straight-line basis over the remaining term of the related credit facility and accounting for it in interest expense.

Income Tax Expense. Income tax expense was $4.5 million for the fiscal year ended August 31, 2004 compared to $4.4 million for the eleven months ended August 31, 2003. As a partnership, we are not subject to income taxes. However, Oasis Pipeline, Heritage Service Company, and Heritage Holdings, wholly-owned subsidiaries are corporations that are subject to income taxes. The decrease in income taxes is due to lower taxable income in Oasis Pipeline offset by the increase from the income taxes in Heritage Holdings after the Energy Transfer Transactions.

Income from continuing operations. Income from continuing operations was $93.0 million for the year ended August 31, 2004 compared to $40.6 million for the eleven months ended August 31, 2003. The increase from fiscal 2003 compared to fiscal year 2004 is principally due to the affects of the Energy Transfer Transactions described above together with the increase in acquisition related income.

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Discontinued operations. Income from discontinued operations was $6.2 million for the year ended August 31, 2004 compared to $6.0 million for the eleven months ended August 31, 2003.

Net Income. Net income for the year ended August 31, 2004 was $99.2 million compared to $46.6 million for the eleven months ended August 31, 2003. The affects of the Energy Transactions described above together with the increase in acquisition related income, attributed to this increase.

EBITDA, as adjusted. EBITDA, as adjusted, increased $119.2 million to $196.7 million for the fiscal year ended August 31, 2004 as compared to EBITDA, as adjusted, of $77.5 million for the eleven months ended August 31, 2003. This increase is due to the Energy Transfer Transactions and operating performance described above. This EBITDA, as adjusted, reflects the full twelve months of ETC OLP s EBITDA, as adjusted, consolidated with the EBITDA, as adjusted, of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total EBITDA, as adjusted, for the periods presented, would have been $249.5 million for the fiscal year ended August 31, 2004 as compared to the aggregate EBITDA, as adjusted, of $188.4 million for the eleven months ended August 31, 2003, which includes the effect of $3.3 million of transaction costs, net of non-cash compensation, which were expensed due to the Energy Transfer Transactions. EBITDA, as adjusted, is computed as follows:

	Fiscal Year Ended	
	August 31, 2004	August 31, 2003
Net income reconciliation		
Net income	$ 99,152	$ 46,625
Depreciation and amortization	48,599	11,870
Interest	41,190	12,456
Taxes	4,481	4,432
Non-cash compensation expense	42	
Other, net	(509)	(501)
Depreciation, amortization, and interest of investee	440	1,003
Depreciation, amortization, and Interest of discontinued operations	2,249	1,591
Minority interests in Operating Partnership		
(Gain) loss on disposal of assets	1,006	
EBITDA, as adjusted (a)	$ 196,650	$ 77,476
Heritage EBITDA, as adjusted (b)	$ 52,845	$ 110,963
Aggregate EBITDA, as adjusted (c)	$ 249,495	$ 188,439

(a) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income or loss such as the gain or loss arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

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EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of our fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to our investors for trending, analyzing and benchmarking the operating results of our partnership from period to period as compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view our performance in a manner similar to the methods used by management and provides additional insight to our operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of our numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. We have a large number of business locations located in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. To present EBITDA, as adjusted, on a full Partnership basis, we add back the minority interest of the general partner because net income is reported net of the general partner s minority interest. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the our business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare our operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than ours. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in our operating results but are not classified in interest, depreciation and amortization. We do not include gain or loss on the sale of assets when determining EBITDA, as adjusted, since including non-cash income or loss resulting from the sale of assets increases/decreases the performance measure in a manner that is not related to the true operating results of our business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read - Financing and Sources of Liquidity in this Form 10-K.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us and Heritage in the past. Management compensates for these limitations by considering EBITDA, as adjusted in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities.

The following reconciliation of Aggregate EBITDA, as adjusted, to net income is presented for comparability purposes only, and is comprised of the aggregate of Energy Transfer Company and Heritage s historical results for the periods presented.

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	For the Period Ended January 19, 2004 (Heritage)	Year Ended August 31, 2004 (Aggregate)	Year Ended August 31, 2003 (Heritage Historical)	Year Ended August 31, 2003 (Aggregate)
Net income reconciliation				
Net income	$ 22,644	$ 121,796	31,142	77,767
Depreciation and amortization	15,389	63,988	37,959	49,829
Interest expense	12,754	53,944	35,740	48,196
Income tax expense	20	4,501	1,023	5,455
Non-cash compensation expense	1,232	1,274	1,159	1,159
Other, net	66	(443)	3,213	2,712
Depreciation, amortization, and interest of investee	322	762	901	1,904
Depreciation, amortization, and interest of discontinued operations		2,249		1,591
Minority interests in Operating Partnership	178	178	256	256
(Gain) loss on disposal of assets	240	1,246	(430)	(430)
Heritage EBITDA, as adjusted (b)	$ 52,845		110,963	
Aggregate EBITDA, as adjusted (b)		$ 249,495		188,439

OPERATING RESULTS BY SEGMENT

Midstream Segment

	Year Ended August 31, 2004 (Actual)	Eleven Months Ended August 31, 2003 (ETC OLP)
Midstream Segment:		
Revenues	$ 1,880,663	$ 899,086
Cost of sales	1,787,849	832,874
Gross Margin	92,814	66,212
Operating expenses	12,541	11,193
General and administrative	10,387	8,057
Depreciation and amortization	9,637	9,056

Segment operating income	$ 60,249	$ 37,906

Gross Margin. Midstream gross margin increased $26.6 million from $66.2 million for the eleven months ended August 31, 2003 to $92.8 million for the year ended August 31, 2004. the increase is principally attributable to expanding our producer services activities and increases in sales volumes during the year ended August 31, 2004. We also had the benefit of one additional month for the 2004 period compared to the 2003 period.

Operating Expenses. Midstream operating expenses increased from $11.2 million for the eleven months ended August 31, 2003 to $12.5 million for the year ended August 31, 2004. The increase was principally attributable to a $1.2 million effect of reporting on an additional month and $0.1 increase in miscellaneous expenses during the year ended August 31, 2004 compared to the eleven months ended August 31, 2003.

Selling, General and Administrative Expenses. Midstream general and administrative expenses increased $2.3 million from $8.1 million for the eleven months ended August 31, 2003 to $10.4 million principally due to a $1.2 million effect of reporting on an additional month for the year ended August 31, 2004, a $2.7 million increase in compensation expense and a $0.4 million increase in merger and reporting compliance expenses. The increase was offset by a $2.0 million increase in costs allocated to the transportation and storage segment for certain management services provided by the midstream.

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Depreciation and Amortization. Midstream depreciation and amortization increased $0.5 million from $9.1 million for the eleven months ended August 31, 2003 to $9.6 million for the year ended August 31, 2004 due to an additional month in the 2004 reporting period.

Transportation and Storage Segment

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
	(Actual)	(ETC OLP)
Transportation and Storage Segment:		
Revenues	$ 113,938	$ 41,500
Cost of sales	11,270	2,123
Gross Margin	102,668	39,377
Operating expenses	30,571	13,853
General and administrative	8,372	5,021
Depreciation and amortization	7,426	2,814
Segment operating income	$ 56,299	$ 17,689

Gross Margin. Transportation and storage gross margin was $102.7 million for the year ended August 31, 2004 compared to $39.4 million for the eleven months ended August 31, 2003. The significant increase in transportation and storage revenues is principally due to the following:

Accounting for Oasis Pipeline. As discussed above, we accounted for the Oasis Pipeline as an equity method investment prior to December 27, 2002 when we purchased the remaining 50% in Oasis Pipeline. As a result, the eleven months ended August 31, 2003 only includes the results of operations subsequent to December 27, 2002.

Increased volumes. During the year ended August 31, 2004, we transported 1,090,710 MMBtu/d through our transportation pipelines compared to 921,352 MMBtu/d during the period from December 27, 2002 to August 31, 2003, an increase of 169,358 MMBtu/d or 18.4%. The volume increase is a result of our decision to pursue additional volumes on the middle and west end of the system on the Oasis Pipeline, the acquisition of the ET Fuel System in June 2004, and the completion of the East Texas Pipeline in June 2004. We believe that we will be able to increase throughput on, and therefore gross margin from, the ET Fuel System in future years through the addition of interconnects with other pipelines and other industrial end-users, the addition of new customers and more active management of the ET Fuel System and storage facilities to capitalize market opportunities. In addition, a wide basis differential between the Waha and Katy market hubs provides an incentive to transport increased volumes of natural gas to a more attractive marketplace.

Operating Expenses. Transportation and storage operating expenses were $30.6 million for the year ended August 31, 2004 compared to $13.9 million for the eleven months ended August 31, 2003, an increase of $16.7 million or 120.1%. The increase was principally attributable to the Oasis Pipeline being accounted for as an equity method investment prior to December 27, 2002, $11.0 million in additional operating expenses related to the acquisition of the ET Fuel System in June 2004, and the completion of the East Texas Pipeline in June 2004.

Selling, General and Administrative Expenses. Transportation and storage general and administrative expenses increased $3.4 million during the eleven months ended August 31, 2003 from $5.0 million to $8.4 million for the year ended August 31, 2004. The increase is principally attributable to the 2003 reporting period not including general and administrative expenses for the Oasis Pipeline prior to December 27, 2002 as it was accounted for as an equity method investment.

Depreciation and Amortization. Transportation and storage depreciation and amortization increased $4.6 million from $2.8 million for the eleven months ended August 31, 2003 to $7.4 million for the year ended August 31, 2004. The increase was attributable to increased depreciation as a result of the consolidation of the Oasis Pipeline in December 2002 and the acquisition of the ET Fuel System in June 2004.

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Retail Propane Segment

	Year Ended August 31, 2004	Year Ended August 31, 2004	Year Ended August 31, 2003
		(Aggregate)	(Aggregate)
	(Actual)	(unaudited)	(unaudited)
Retail Propane Segment:			
Retail propane revenues	$ 315,177	$ 536,636	$ 463,392
Other propane related revenues	34,167	60,646	55,557
Retail propane cost of sales	174,769	296,206	236,307
Other propane related cost of sales	9,602	17,512	16,073
Operating expenses	100,093	158,471	144,929
Selling General and administrative	6,746	11,080	12,825
Depreciation and amortization	30,925	45,979	37,113
Segment operating income	$ 27,209	$ 68,034	$ 71,702

Revenues. For the year ended August 31, 2004, we had retail propane revenues of $315.2 million with no retail propane sales reflected in the fiscal year ended August 31, 2003. These revenues reflect only the amounts earned after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). As a comparison, for the fiscal ended August 31, 2004, Heritage would have reflected aggregate retail propane revenues of $536.6 million as compared to aggregate revenues of $463.4 million in the fiscal year ended August 31, 2003 for Heritage. Of the $73.2 million increase from Heritage, $37.4 million is due to the increase in volumes sold by customer service locations added through acquisitions, $43.7 million is due to higher selling prices, offset by a decrease of $7.9 million due to the decrease in weather related volumes described above. We had other propane related revenues of $34.2 million for the year ended August 31, 2004 with no other propane related revenues for fiscal year 2003. As a comparison for the fiscal year ended August 31, 2004, we would have reflected aggregate other propane related revenues of $60.6 million compared to aggregate other propane related revenues of $55.6 million for the year ended August 31, 2003. The aggregate increase of $5.0 million is primarily increases from acquisitions.

Costs of Sales. For the fiscal year ended August 31, 2004, we had retail propane cost of sales of $174.8 million, with no retail propane cost of sales reflected in the fiscal year ended August 31, 2003 These costs reflect only the amounts that were incurred after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). As a comparison, for the fiscal year ended August 31, 2004, aggregated retail propane cost of sales would have been $296.2 million as compared to the historical cost of sales of $236.3 million in the fiscal year ended August 31, 2003. Of the $59.9 million aggregate increase from Heritage, $16.3 million reflects changes in volumes described above and $43.6 reflects the increase due to higher selling prices. We had other propane related cost of sales of $9.6 million for the year ended August 31, 2004 with no other propane related cost of sales reflected for the fiscal year ended August 31, 2003. As a comparison, we would have reflected aggregated other propane related cost of sales of $17.5 million for the year ended August 31, 2004 with aggregate other propane related cost of sales of $16.1 million for the year ended August 31, 2003. The increase of $6.4 million is primarily related to increases from acquisitions.

Operating Expenses. Total operating expenses for the retail propane operations were $100.1 million for the fiscal year ended August 31, 2004, which reflects from the date of the Energy Transfer Transaction. Our retail propane operations would have reflected total aggregate operating expense of $158.5 million for the full year as compared to Heritage s historical total operating expenses of $144.9 million for the year ended August 31, 2003, or an increase of $13.6 million. Of this aggregate increase approximately $12.4 million related to employee related expenses due to an increase in our employee base from acquisitions. During fiscal 2004, Heritage purchased the other 50% of Bi-State Partnership, which accounted for as an equity method investment prior to the purchase in December 2003.

Selling, General and Administrative Expenses. For the year ended August 31, 2004, selling, general and administrative expenses for our retail propane segment were $6.7 million with no retail propane selling general and administrative expenses for the year ended August 31, 2003. As a comparison, aggregate retail propane selling, general and administrative expenses would have been $11.1 million for the year ended August 31, 2004 compared to aggregate retail propane selling, general and administrative expenses of $12.8 million for the fiscal year ended August 31, 2003.

Depreciation and Amortization. For the year ended August 31, 2004, depreciation and amortization in our retail propane segment was $30.9 with no depreciation expense reflected for the year ended August 31, 2003. As a comparison, we would have had aggregate depreciation and amortization of $46.0 million for the year ended August 31, 2004 compared to aggregate depreciation and amortization of $37.1 million for the year ended August 31, 2003. The aggregate increase of $8.9 million is due primarily to the increase in depreciation of assets and amortization of intangible assets added through acquisitions and the additional depreciation and amortization of the assets stepped up to fair market value as a result of the Energy Transfer Transactions.

Operating Income. For the year ended August 31, 2004, we had retail propane operating income of $27.2 with no retail propane operating income reflected for the year ended August 31, 2003. As a comparison, we would have had aggregate operating income for the year ended August 31, 2004 of $68.0 million compared to aggregate operating income of $71.7 million for the year ended August 31, 2003. This aggregate decrease is due to changes in revenues and expenses described above.

Wholesale Propane Segment

	Year Ended August 31, 2004 (Actual)	Year Ended August 31, 2004 (Aggregate) (unaudited)	Year Ended August 31, 2003 (Aggregate) (unaudited)
Wholesale Propane Segment:			
Revenues	$ 27,345	$ 47,941	$ 47,366
Cost of sales	24,871	43,410	43,636
Operating expenses	1,936	2,912	3,508
Selling, general and administrative	918	1,443	1,213
Depreciation and amortization	432	626	517
Segment operating loss	$ (812)	$ (450)	$ (1,508)

Revenues. For the fiscal year ended August 31, 2004, we had wholesale propane revenues of $27.3 million, with no wholesale propane revenues reflected in the eleven months ended August 31, 2003. These revenues reflect only the amounts that were incurred after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate wholesale propane revenues would have been $47.9 million for the fiscal year ended August 31, 2004 as compared to aggregate revenues of $47.4 million for the fiscal year ended August 31, 2003.

Costs of Sales. For the fiscal year ended August 31, 2004, we had wholesale propane cost of sales of $24.8 million, with no wholesale propane cost of sales reflected in the fiscal year ended August 31, 2003. These costs reflect only the amounts that were incurred after the Energy Transfer

Transactions (from January 20, 2004 through August 31, 2004). Aggregate wholesale propane cost of sales would have been $43.4 million as compared to historical cost of sales of $43.6 million for the fiscal year ended August 31, 2003.

Operating Expenses. For the year ended August 31, 2004, operating expenses for our wholesale propane segment were $1.9 million with no wholesale propane operating expenses reflected for the year ended August 31, 2003. As a comparison, we had aggregate wholesale propane operating expenses of $2.9 million for the year ended August 31, 2004, compared to aggregated wholesale propane operating expenses of $3.5 million for the fiscal year ended August 31, 2003.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for our wholesale propane segment were $0.9 for the year ended August 31, 2004 with no wholesale propane selling, general and administrative expenses reflected in the year ended August 31, 2003. As a comparison, we had aggregate wholesale selling, general, and administrative expenses of $1.4 million for the year ended August 31, 2004 compared to aggregate wholesale selling, general and administrative expenses of $1.2 million for the year ended August 31, 2003.

Depreciation and Amortization. For the year ended August 31, 2004, depreciation and amortization in our wholesale propane segments was $0.4 million with no wholesale depreciation and amortization reflected in the year ended August 31, 2003. As a comparison, we had aggregate depreciation of $0.6 million for the year ended August 31, 2004 compared to aggregate wholesale deprecation of $0.5 million for the year ended August 31, 2003.

Operating Loss. For the year ended August 31, 2004, we had domestic wholesale propane operating loss of $0.8 million compared to aggregate total operating loss of $1.5 million for the year ended August 31, 2003.

Other

	Year Ended		
	August 31, 2004 (Actual)	August 31, 2004 (Aggregate)	August 31, 2003 (Aggregate)
Other			
Revenue	$ 3,465	$ 5,283	$ 5,161
Cost of sales	861	1,304	1,139
Operating expenses	2,234	3,614	3,694
Depreciation and amortization	179	321	329
Other operating income (loss)	$ 191	$ 44	$ (1)
Unallocated selling, general and administrative expenses	$ 4,047	$ 9,288	$

Unallocated Selling, General and Administrative Expenses. The selling, general and administrative expenses that related to the general operations of the Partnership are not allocated to our segments.

For the year ended August 31, 2004, the total unallocated selling, general, and administrative expenses were $4.0 million with no unallocated selling, general, and administrative expense reflected for the year ended August 31, 2003. Aggregate total unallocated selling, general, and administrative expense for the year ended August 31, 2004 would have been $9.3 million with no aggregate total unallocated selling, general and administrative expenses for the year ended August 31, 2003.

Liquidity and Capital Resources

Our ability to satisfy our obligations will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management s control.

Future capital requirements of our business will generally consist of:

- maintenance capital expenditures, which include capital expenditures made to connect additional wells to our natural gas systems in order to maintain or increase throughput on existing assets for which we expect to expend $21.3 million in the next fiscal year and capital expenditures to extend the useful lives of our propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet for which we expect to expend $16.0 million in the next fiscal year;

- growth capital expenditures, mainly for constructing new pipelines, processing plants and treating plants for which we expect to expend $534.0 million in the next fiscal year; and customer propane tanks for which we expect to expend $18.9 million in the next fiscal year; and

- acquisition capital expenditures including acquisition of new pipeline systems and propane operations.

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We believe that cash generated from the operations of our businesses will be sufficient to meet anticipated maintenance capital expenditures. We will initially finance all capital requirements by cash flows from operating activities. To the extent that our future capital requirements exceed cash flows from operating activities:

maintenance capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities described below, which will be repaid by subsequent season reductions in inventory and accounts receivable;

growth capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities and the issuance of additional Common Units or a combination thereof; and

acquisition capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities, other lines of credit, long-term debt, the issuance of additional Common Units or a combination thereof.

The assets utilized in our propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our propane business. In addition, we do not experience any significant increases attributable to inflation in the cost of these assets or in our propane operations. The assets used in our midstream and transportation and storage segments, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than new well connects.

In connection with the HPL acquisition, we now engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. Natural gas is typically purchased and held in storage during the summer months and sold during the winter months. Although we intend to fund natural gas purchases with cash generated from operations, from time to time we may need to finance the purchase of natural gas to be held in storage with borrowings from our current credit facilities. We intend to repay these borrowings with cash generated from operations when the gas is sold.

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, including the recently acquired HPL System, and other factors.

Operating Activities. Cash provided by operating activities during the year ended August 31, 2005, was $169.4 million as compared to cash provided by operating activities of $162.7 million for the year ended August 31, 2004. The net cash provided by operations for the year ended August 31, 2005 consisted of net income of $349.3 million, non-cash charges of $(28.7) million, principally gain on the sale of discontinued operations and depreciation and amortization, and a decrease in working capital of $151.2 million. Various components of working capital changed significantly from the prior period due to factors such as the variance in the timing of accounts receivable collections, payments on accounts payable, purchase of inventories related to the propane and transportation and storage operations, and the Energy Transfer Transactions.

Investing Activities. Cash used in investing activities during the year ended August 31, 2005 of $1,133.7 million is comprised of cash paid for acquisitions of $1,131.8 million, $196.5 million invested for maintenance and growth capital expenditures needed to sustain operations at current levels and to support growth of operations, and cash invested in affiliates of $2.3 million. Cash used in investing activities also includes proceeds from the sale of discontinued operations of $191.6 million and proceeds from the sale of idle property of $5.3 million. The cash paid for acquisitions included $1,039.5 million paid for the acquisition of the HPL System, $63.0 million for the Texas Chalk and Madison Systems acquisitions and $3.8 million for the purchase of the remaining interests in Vantex that we did not previously own. Cash paid for acquisitions also included $25.5 million expended for retail propane acquisitions. In addition to cash paid for acquisitions, we also issued $2.5 million of Common Units in connection with two propane acquisitions.

Financing Activities. Cash provided by financing activities during the year ended August 31, 2005 was $0.9 million. In January 2005, we successfully completed our issuance of $750.0 million in Rule 144A private placement

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Senior Notes. Net proceeds of approximately $741.0 million were used to repay borrowings of $725.0 million and accrued interest outstanding under our then existing ETC OLP Term Loan Facility and ETC OLP Revolving Credit Facility. We also entered into a $700.0 million Revolving Credit Facility in January 2005. Effective June 2, 2005 we increased the amount available under the Revolving Credit Facility from $700.0 million to $800.0 million. The Revolving Credit Facility had net borrowings $186.0 million outstanding as of August 31, 2005, of which the majority was used to finance the purchase of natural gas inventory to be stored in our Bammel storage facility and margin calls with our brokers. The Swingline loan option of the Revolving Credit Facility provided $15.0 million of net proceeds that were used for general partnership purposes. On July 29, 2005 in a Rule 144A private placement offering, we issued $400.0 million in aggregate principal amount of Senior Notes. The net proceeds of approximately $397.1 million from the sale of the 2012 Unregistered Notes were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

ETC OLP borrowed $80.0 million under its Revolving Credit Facility of which $60.0 million was used to fund the acquisition of the Texas Chalk and Madison Systems. The remaining $20.0 million was used for general partnership purposes. The $80.0 million was repaid during the second quarter of fiscal year 2005. Net cash provided by financing activities also included $174.6 million of proceeds from a short-term loan with ETE, whereby ETC OLP borrowed the funds to acquire the working natural gas inventory stored in the Bammel storage facilities in connection with the HPL acquisition. The loan was paid in full during the third quarter of fiscal year 2005. ETC OLP incurred $3.1 million in debt issuance costs associated with the loan agreement which were amortized into interest expense or written off at the time of the repayment of the loan.

Cash provided by financing activities includes the net increase in HOLP s Working Capital Facility of $2.1 million, a net increase in HOLP s Acquisition Facility of $19.0 million and a net decrease in HOLP s long-term debt of $31.0 million. The increase in the Acquisition Facility is due to funding of acquisitions of propane businesses and other growth capital. The decrease in HOLP s long-term debt is due to the re-payment of required principal on HOLP s senior secured notes.

On January 26, 2005, we placed $350.0 million of Common Units in a private placement to institutional investors as part of the financing of the acquisition of HPL. In this private placement we issued 6,296,294 (post-split) unregistered Common Units for total consideration of $170.0 million, and we became obligated under a Units Purchase Agreement dated January 14, 2005 to issue an additional 6,666,666 (post-split) Common Units for total consideration of $180.0 million. These Common Units were issued pursuant to an effective shelf registration statement on March 18, 2005. The proceeds from these private placements were used to finance a portion of the HPL acquisition. On June 20, 2005 we issued 1,640,000 Common Units to a group of our executive managers for $52.4 million, On July 26, 2005, we completed the sale of 3,000,000 Common Units in a private sale to an institutional investor. The Common Units were issued pursuant to the Partnership s effective shelf registration statement and the proceeds of $105.6 million were used by the Partnership to retire a portion of the outstanding indebtedness on its revolving credit facility. We paid $0.3 million in equity issue costs associated with the issuance of Common Units. The General Partner contributed $10.4 million to maintain its 2% interest in the Partnership in connection with the Common Units issued in the private placements and $2.5 million units issued in connection with certain acquisitions.

Cash received from financing activities is reduced by the distributions we paid to our Common Unitholders and the General Partner s 2% interest of $207.0 million, and other financing costs of $19.7 million related to the issuance of the $750.0 million Senior Notes, the $400 million Senior Notes, and other debt.

Financing and Sources of Liquidity

Cash Distributions

We will use our cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders. Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for the Partnership s operations. Heritage (the predecessor to

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ETP) paid all quarterly distributions since its inception in 1996 up to and including the quarterly distribution of $0.325 per unit paid on January 14, 2004. Heritage had raised its quarterly distribution over the years from $0.25 per unit in 1996 to $0.325 per unit as of the quarterly distribution paid on January 14, 2004. On October 15, 2004, we paid a quarterly distribution of $0.4125 per unit, or $1.65 per unit annually, to our Unitholders of record at the close of business on October 7, 2004. On January 14, 2005, we paid a quarterly distribution of $0.4375 per unit, or $1.75 per unit annually, to our Unitholders of record at the close of business on January 5, 2005. On April 14, 2005, we paid a quarterly distribution of $0.4625 per unit, or $1.85 per unit annually, an increase of $0.025 per unit per quarter, or $0.10 annually. On July 15, 2005, we paid a quarterly distribution of $0.4875 per Common Unit, or $1.95 per unit annually, an increase of $0.10 per Common Unit on an annualized basis. On September 2, 2005, we declared a distribution for the fourth quarter ended August 31, 2005 of $0.500 per Common Unit, or $2.00 per unit annually, an increase of $0.05 per Common Unit on an annualized basis. The distribution was paid on October 14, 2005 to Unitholders of record at the close of business on September 30, 2005. In addition to these quarterly distributions, our General Partner received quarterly distributions for its general partner interest in us, and incentive distributions to the extent the quarterly distribution exceeded $0.275 per unit.

Description of Indebtedness

The Partnership s indebtedness consists of $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012 and a Revolving Credit Facility that allows for borrowings of up to $800.0 million through January 18, 2010. We also currently maintain separate credit facilities for HOLP. Prior to January 18, 2005, we maintained a separate credit facility for ETC OLP, which was paid off using net proceeds received from us pursuant to our offering of 5.95% Senior Notes due 2015. The terms of our indebtedness and our Operating Partnerships are described in more detail below. Failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability our subsidiaries to incur additional debt and our ability to pay our distributions. We are required to measure these financial tests and covenants quarterly and, as of August 31, 2005, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

Senior Notes.

On January 18, 2005, in a Rule 144A private placement offering, we issued $750.0 million in aggregate principal amount of 5.95% Senior Notes due on February 1, 2015 (the 2015 Unregistered Notes). We recorded a discount of $2.2 million and debt issue costs of $7.4 million in connection with the issuance of the 2015 Unregistered Notes. The net proceeds of approximately $741.0 million were used to repay the indebtedness and accrued interest outstanding under the then existing credit facilities that were previously secured by the assets of ETC OLP. On July 29, 2005, we completed the exchange of the 2015 Unregistered Notes for substantially similar notes registered under the Securities Act of 1933, as amended.

On July 29, 2005, in a Rule 144A private placement offering, we issued $400.0 million in aggregate principal amount of 5.65% Senior Notes due on August 1, 2012 (the 2012 Unregistered Notes and together with the 2015 Unregistered Notes, the ETP Senior Notes). We recorded a discount of $0.4 million in connection with the issuance of the 2012 Unregistered Notes. The net proceeds of approximately $397.1 million from the sale of the 2012 Unregistered Notes were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

The ETP Senior Notes represent senior unsecured obligations of the Partnership and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The ETP Senior Notes are jointly and severally guaranteed by ETC OLP and all of the direct and indirect wholly-owned and majority-owned subsidiaries of ETC OLP. The subsidiary guarantees rank equally in right of payment with all of the existing and future unsubordinated indebtedness of our guarantor subsidiaries. The ETP Senior Notes and each guarantee will effectively rank junior to any future indebtedness of ours or our subsidiary guarantors that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes will effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries that are not subsidiary guarantors.

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The ETP Senior Notes were issued under an indenture containing covenants, which include covenants that restrict our ability to, subject to certain exceptions, incur debt secured by liens, engage in sale and leaseback transactions or merge or consolidate with another entity or sell substantially all of our assets.

Revolving Credit Facility.

On January 18, 2005 we entered into a $700.0 million Revolving Credit Facility available through January 18, 2010. Effective June 2, 2005, the Revolving Credit Facility was amended to increase the borrowing capacity from $700.0 million to $800.0 million. The Revolving Credit Facility also offers a Swingline loan option the maximum borrowing of $30.0 million and a daily rate based on the London market. Amounts borrowed under the Credit Facility bear interest at a rate based on either a Eurodollar rate, or a prime rate. The weighted average interest rate was 4.827% as of August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.30%. As of August 31, 2005, $201.0 million was outstanding under the Revolving Credit Facility which includes $15.0 million under the Swingline loan option. There was also $11.3 million in letters of credit outstanding as of August 31, 2005, which reduced the amount available for borrowing under the Revolving Credit Facility. Total amount available under the Credit Agreement as of August 31, 2005 was $587.7 million after deducting $11.3 million in letters of credit.

The ETP Revolving Credit Facility requires that, on the last day of each of our fiscal quarters, the ratio of our Consolidated Funded Debt (as defined in the credit agreement relating to the ETP Revolving Credit Facility) to our Consolidated EBITDA (as defined in the credit agreement relating to the ETP Revolving Credit Facility) for the four fiscal quarters most recently ended must be no greater than 4.5 to 1.0 except that, on the last day of any fiscal quarter in which we or our subsidiaries makes an acquisition with a purchase price of $50.0 million or more, such ratio must be no greater than 5.0 to 1.0. In addition, this facility requires that the ratio of our Consolidated EBITDA (as defined in the credit agreement relating to the ETP Revolving Credit Facility) to our Consolidated Interest Expense (as defined in the credit agreement relating to the ETP Revolving Credit Facility) for the four fiscal quarters most recently ended must not be less than 3.0 to 1.0. We satisfied our leverage ratio covenants for the fiscal years ended August 31, 2005 and 2004 and therefore were able to make the cash distributions at the levels we distributed during these periods.

ETC OLP and its designated subsidiaries act as guarantors of the debt obligations under the ETP Revolving Credit Facility. If we were to default on the ETP Revolving Credit Facility, ETC OLP and its designated subsidiaries would be responsible for full repayment of our debt obligations under the ETP Revolving Credit Facility. The ETP Revolving Credit Facility is unsecured and the lenders thereunder have equal rights to holders of our other current and future unsecured senior debt.

HOLP Facilities

Working Capital Facility. Effective March 31, 2004, HOLP entered into the Third Amended and Restated Credit Agreement, which includes a $75.0 million senior revolving working capital facility available through December 31, 2006 (the HOLP Working Capital Facility). Amounts borrowed under the working capital facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.308% for the amount outstanding at August 31, 2005. HOLP must reduce the principal amount of working capital borrowings to $10.0 million for a period of not less than 30 consecutive days at least one time during each fiscal year. HOLP completed the 30-day clean down requirement under the HOLP Working Capital Facility on June 14, 2005. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Working Capital Facility. A $5.0 million Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the Working Capital Facility. As of August 31, 2005, the HOLP Working Capital Facility had a balance outstanding of $26.7 million and $1.0 million of outstanding letters of credit. Letter of Credit Exposure plus the Working Capital Loan cannot exceed the $75,000 maximum Working Capital Facility.

Acquisition Facility. The Third Amended and Restated Credit Agreement also includes a $75.0 million senior revolving acquisition facility that is available through December 31, 2006 (the HOLP Acquisition Facility). Amounts borrowed under the HOLP Acquisition Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.182% for the amount outstanding at August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.50%. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Acquisition Facility. As of August 31, 2005, the HOLP Acquisition Facility had a balance outstanding of $42.0 million.

Effective September 1, 2005, HOLP entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The amendment in its entirety states as follows: In no event shall the Letter of Credit Exposure exceed $15.0 million at any time . All of the remaining terms, provisions and conditions of the existing Credit Agreement continue in full force and effect as within the March 31, 2004 Third Amended and Restated Credit Amendment noted above.

Senior Secured Notes. In connection with our initial public offering, on June 25, 1996, HOLP entered into a Note Purchase Agreement whereby HOLP issued $120 million principal amount of 8.55% Senior Secured Notes (the HOLP Notes) with institutional investors. Interest is payable semi-annually in arrears on each December 31 and June 30. The HOLP Notes have a final maturity of June 30, 2011, with ten equal mandatory repayments of principal, which began on June 30, 2002. At August 31, 2005, $72 million of principal debt was outstanding under the HOLP Notes.

On November 19, 1997, HOLP entered into a Note Purchase Agreement that provided for the issuance of up to $100 million of senior secured promissory notes (HOLP Medium Term Note Program) if certain conditions were met. An initial placement of $32 million (Series A and B), at an average interest rate of 7.23% with an average 10-year maturity, was completed at the closing of the HOLP Medium Term Note Program. Interest is payable semi-annually in arrears on each November 19 and May 19. An additional placement of $15 million (Series C, D and E), at an average interest rate of 6.59% with an average 12-year maturity, was completed in March 1998. Interest is payable on Series C and D semi-annually in arrears on each September 13 and March 13. The proceeds of the placements were used to refinance amounts outstanding under the HOLP Acquisition Facility. No future placements are permitted under the unused portion of the HOLP Medium Term Note Program. During the fiscal year ended August 31, 2003, Heritage used $3.9 million and $5.0 million of the proceeds from the issuance of 1,610,000 of Common Units to retire the balance of the Series D and Series E Senior Secured Notes, respectively. At August 31, 2005, $28.7 million of principal debt was outstanding under the HOLP Medium Term Note Program.

On August 10, 2000, HOLP entered into a Note Purchase Agreement (HOLP Senior Secured Promissory Notes) that provided for the issuance of up to $250 million of fixed rate senior secured promissory notes if certain conditions were met. An initial placement of $180 million (Series A through F) at an average rate of 8.66% with an average 13-year maturity was completed in conjunction with the merger with U.S. Propane. Interest is payable quarterly. The proceeds were used to finance the transaction with U.S. Propane and retire a portion of existing debt. On May 24, 2001, HOLP issued an additional $70 million (Series G through I) of the Senior Secured Promissory Notes to a group of institutional lenders with 7-, 12- and 15-year maturities and an average coupon rate of 7.66%. HOLP used the net proceeds from the Senior Secured Promissory Notes to repay the balance outstanding under the HOLP Acquisition Facility and to reduce other debt. Interest is payable quarterly. During the fiscal year ended August 31, 2003, HOLP used $7.5 million and $19.5 million of the proceeds from the issuance of 1,610,000 of Common Units to retire a portion of the Series G and Series H Senior Secured Promissory Notes, respectively. At August 31, 2005, $196.7 million of principal debt was outstanding under the HOLP Senior Secured Promissory Notes.

Covenants Related to HOLP Credit Agreements. The Note Agreements for each of the HOLP Notes, the HOLP Medium Term Note Program and the HOLP Senior Secured Promissory Notes, and HOLP s bank credit facilities contain customary restrictive covenants applicable to HOLP, changes in ownership of HOLP, including limitations on the level of additional indebtedness, creation of liens, and substantial disposition of assets. These covenants require HOLP to maintain ratios of Consolidated Funded Indebtedness to Consolidated EBITDA (as defined in the Note Purchase Agreements of HOLP) of not more than 4.75 to 1.00 and Consolidated EBITDA to Consolidated Interest Expense (as defined in the Note Purchase Agreements of HOLP) of not less than 2.25 to 1. For purposes of calculating the ratios under the Note Purchase Agreements of HOLP, Consolidated EBITDA is based upon the HOLP s EBITDA, as adjusted, during the most recent four quarterly periods and modified to give pro forma effect for acquisitions and divestures made during the test period, and is compared to Consolidated Funded Indebtedness as of the test date and the Consolidated Interest Expense for the most recent twelve months. The Note Purchase Agreements also provide that HOLP may declare, make, or incur a liability to make, a restricted

payment during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed Available Cash (As defined in the Note Purchase Agreements of HOLP) with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payment; and (c) HOLP s restricted payments are not greater than the product of HOLP s Percentage of Aggregate Partner Obligations (as defined in the Note Purchase Agreements). The Note Purchase Agreements further provide that HOLP s Available Cash is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes. In addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the notes, Available Cash is required to reflect a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates.

Failure to comply with the various restrictive and affirmative covenants of HOLP s bank credit facilities and the Note Agreements could negatively impact our ability to incur additional debt and our ability to pay distributions. We are required to measure these financial tests and covenants quarterly and were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under the Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the bank credit facilities at August 31, 2005. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the Senior Secured, Medium Term, and Senior Secured Promissory Notes. In addition to the stated interest rate for the Notes, we are required to pay an additional 1% per annum on the outstanding balance of the Notes at such time as the Notes are not rated investment grade status or higher. Since April 18, 2004 the Notes have rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

ETC OLP Facilities

In January 2005, ETC OLP repaid in full the amounts borrowed under its $725.0 million term loan facility and its $225.0 million revolving credit facility using net proceeds received from our private placement of $750.0 million of 5.95% Senior Notes due 2015.

Loan from affiliate. In January 2005, ETC OLP entered into a short-term loan agreement with ETE, whereby ETC OLP borrowed approximately $174.6 million in connection with the acquisition of the Houston Pipeline System to purchase from the sellers the working gas inventory of natural gas stored in the Bammel storage facility. The six-month note provided for the payment of interest based on the Eurodollar Rate plus 3.0% per annum. The loan was repaid in full during the quarter ended May 31, 2005 and the unamortized debt issuance costs were written off and accounted for as loss on extinguishment of debt in the consolidated statements of operations for the year ended August 31, 2005.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of August 31, 2005:

In thousands	**Payments Due by Period**				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1 3 Years**	**3 5 Years**	**More Than 5 Years**
Long-term debt	$ 1,715,054	$ 39,349	$ 137,123	$ 285,075	$ 1,253,507
Interest on fixed rate long-term debt (a)	706,551	92,940	176,374	162,350	274,887

Purchase commitments	52,196	52,196			
Operating lease obligations	15,592	5,881	5,435	3,298	978
Totals	$ 2,489,393	$ 190,366	$ 318,932	$ 450,723	$ 1,529,372

(a) Fixed rate interest on long-term debt includes the amount of interest due on our fixed rate long-term debt. These amounts do not include interest on our variable rate debt obligations which include our Revolving Credit Facility, Revolving Credit Facility Swingline loan option, long term portion of our Senior Revolving Working Capital Facility or our Senior Revolving Acquisition Facility. As of August 31, 2005, variable rate interest on our outstanding balance of variable rate debt of $269.6 million would be $13.3 million on an annual basis. See Note 7 Working Capital Facility and Long-Term Debt to the Consolidated Financial Statements beginning on Page F-1 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

New Accounting Standards

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). In March 2005, the Financial Accounting Standards Board (FASB) published FIN 47, which requires companies to record a liability for those asset retirement obligations in which the timing or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS 143. FIN 47 will require us to accrue a liability when a range of scenarios can be determined. Management intends to adopt FIN 47 no later than the end of the fiscal year ending August 31, 2006, and has not yet determined the impact, if any, that this pronouncement will have on our financial statements.

SFAS No. 123 (Revised 2004) (SFAS 123R), Share-Based Payment. In December 2004, the FASB issued SFAS 123R, which replaces SFAS 123 and supercedes Accounting Principles Board (APB) Opinion No. 25. SFAS 123R requires an entity to recognize the grant-date fair-value of stock options and other equity-based compensation issued to employees in the income statement. The revised statement requires that an entity account for those transactions using the fair-value-based method, and eliminates the intrinsic value method of accounting in APB 25, *Accounting for Stock Issued to Employees*, which was permitted under SFAS No. 123 , as originally issued. The revised statement also requires entities to disclose information about the nature of the share-based payment transactions and the effects of those transactions on the financial statements. SFAS 123R is effective for public companies, that are not small business issuers, beginning with their next fiscal year. All public companies must use either the modified prospective or modified retrospective transition method. On March 29, 2005, the SEC staff issued SAB No. 107, Share-Based Payment, to express the views of the staff regarding the interaction between SFAS 123R and certain SEC rules and regulations and to provide the staff s views regarding the valuation of share-based payment arrangements for public companies. We have considered the additional guidance provided by SAB 107 in connection with our implementation of SFAS 123R as of September 1, 2005, which did not have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 151 (SFAS 151), Inventory Costs an amendment of ARB No. 43, Chapter 4. In November 2004, the FASB issued SFAS 151 which amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing. ARB No. 43 previously required that certain costs associated with inventory be treated as current period charges if they were determined to be so abnormal as to warrant it. SFAS 151 amends this removing the so abnormal requirement and stating that unallocated overhead costs and other items such as abnormal handling costs and amounts of wasted materials (spoilage) require treatment as current period charges rather than a portion of inventory cost. SFAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, with earlier application permitted. The provisions of this statement need not be applied to immaterial items. We do not allocate overhead costs to inventory and we have determined that there are no other material items which require the application of SFAS 151.

SFAS No. 153 (SFAS 153), Exchanges of Nonmonetary Assets-an amendment of APB Opinion No. 29. In December 2004, the FASB issued SFAS 153, which amends APB Opinion No. 29 by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS 153 also eliminates APB 29 s concept of culmination of an earnings process. SFAS 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The impact of SFAS 153 will depend on the nature and extent of any exchanges of nonmonetary assets after the effective date, but management does not currently expect SFAS 153 to have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 154 (SFAS 154), Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3. In May 2005, the FASB issued SFAS 154 which requires that the direct effect of voluntary changes in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Indirect effects of a change should be recognized in the period of the change. SFAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005.

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The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS 154 to have a material impact on our consolidated results of operations, cash flows or financial position.

EITF Issue No. 03-13 (EITF 03-13), Applying the Conditions in Paragraph 42 of SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations. In November 2004, the EITF reached a consensus with respect to evaluating whether the criteria in SFAS 144 has been met for classifying as a discontinued operation a component of an entity that either has been disposed of or is classified as held for sale. To qualify as a discontinued operation, SFAS 144 requires that the cash flows of the disposed component be eliminated from the operations of the ongoing entity and that the ongoing entity not have any significant continuing involvement in the operations of the disposed component after the disposal transaction. The consensus is to be applied prospectively to a component of an entity that is either disposed or classified held for sale in fiscal periods beginning after December 15, 2004. We accounted for the sale of our discontinued operations in accordance with SFAS 144 and EITF 03-13 as of August 31, 2005.

EITF Issue No.04-1 (EITF 04-1). Accounting for Preexisting Relationships between the Parties to a Business Combination. EITF 04-1 requires that pre-existing contractual relationships between two parties involved in a business combination be evaluated to determine if a settlement of the pre-existing contracts is required separately from the accounting for the business combination. This consensus is effective for business combinations consummated and goodwill impairment tests performed in reporting periods beginning after October 13, 2004. We adopted EITF 04-1 during the quarter ended February 28, 2005, without a material effect on our financial position, results of operations and cash flows.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to establish accounting policies and make estimates and assumptions that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 3 Summary of Significant Accounting Policies and Balance Sheet Detail to the Consolidated Financial Statements beginning on page F-1 of this report. We believe the following are critical accounting policies:

Revenue Recognition. Revenues for sales of natural gas, natural gas liquids (NGLs) including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenue from service labor, transportation, treating, compression, and gas processing, is recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based arrangements or other arrangements. Under fee-based arrangements, we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and processes natural gas

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on behalf of producers, selling the resulting residue gas and NGL volumes at market prices and remitting to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

Primarily the amount of capacity customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines determines transportation and storage segment results. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay us even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly. The transportation and storage segment also generates its revenues and margin from the sale and marketing of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL system.

We account for our trading activities under the provisions of EITF Issue No. 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF No. 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the income statement.

Impairment of Long-Lived Assets and Goodwill. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability, we must make estimates of projected cash flows related to the asset which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset s existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas and propane supply, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other midstream companies, including major energy producers. Due to the subjectivity of the assumptions used to test for recoverability and to determine fair value, significant impairment charges could result in the future, thus affecting our future reported net income.

Stock Based Compensation Plans. We account for our stock compensation plans following the fair value recognition method. This method was adopted as we believe it is the preferable method of accounting for stock based compensation. Please see the caption Stock Based Compensation Plans in Note 3 Summary of Significant Accounting Policies and Balance Sheet Detail to the Consolidated Financial Statements beginning on page F-1 of this report for additional information about this adoption.

Property, Plant, and Equipment. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Maintenance capital expenditures also include capital expenditures made to connect additional wells to our systems in order to maintain or increase throughput on our existing assets. Growth or expansion capital expenditures are capital expenditures made to expand the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses as we incur them. Upon disposition or retirement of pipeline components or gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful life ranging from 5 to 65 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful live of our property, plant, and equipment.

Amortization of Intangible Assets. We calculate amortization using the straight-line method over periods ranging from 2 to 15 years. We use amortization methods and determine asset values based on management s best estimate using reasonable and supportable assumptions and projections. Changes in the amortization methods or asset values could have a material effect on our results of operations. We do not anticipate future changes in the estimated useful lives of our intangible assets.

Fair Value of Derivative Commodity Contracts. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and propane prices and in our trading activities. These contracts consist primarily of commodity forward, future, swaps, options and certain basis contracts as cash flow hedging instruments. Certain contracts, which, in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities , are not accounted for as hedges, but are marked to fair value on the income statement. In our retail propane business, we classify all gains and losses from these derivative contracts entered into for risk management purposes as liquids marketing revenue in the consolidated statement of operations. On our contracts that are designated as cash flow hedging instruments in accordance with SFAS No. 133, the effective portion of the hedged gain or loss is initially reported as a component of other comprehensive income and is subsequently reclassified into earnings when the physical transaction settles. The ineffective portion of the gain or loss is reported in earnings immediately. We utilize published settlement prices for exchange-traded contracts, quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. We also use the Black Scholes valuation model to estimate the value of certain embedded derivatives. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts.

Natural Gas Exchanges. We record exchange receivables and payables when a customer delivers more or less gas into our pipelines than they take out. We primarily estimate the value of our exchanges at prices representing the value of the commodity at the end of the accounting reporting period. Changes in natural gas prices may impact our valuation. Based on our net receivable position of $1.9 million as of August 31, 2005, a change in natural gas prices of 10 percent could positively or negatively affect our results of operations by $0.2 million.

Volume Measurement. We record amounts for natural gas gathering and transportation revenue, liquid transportation and handling revenue, natural gas sales and natural gas purchases, and the sale of production based on volumetric calculations. Variances resulting from such calculations are inherent in our business.

Asset Retirement Obligation. An entity is required to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate cannot be made in the period the asset retirement obligation is incurred, the liability should be recognized when a reasonable estimate of fair value can be made.

In order to determine fair value, management must make certain estimates and assumptions including, among other things, projected cash flows, a credit-adjusted risk-free rate, and an assessment of market conditions that could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective. We have determined that we are obligated by contractual or regulatory requirements to remove assets or perform other remediation upon retirement of certain assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. We will record an asset retirement obligation in the periods in which it can reasonably determine the settlement dates.

Income Per Limited Partner Unit. Basic net income per limited partner unit is determined by dividing limited partners interest in net income by the weighted average number of Common Units outstanding. In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present earnings per unit as if all of the earnings for the periods were distributed. Diluted net income per limited partner unit is computed by dividing limited partners interest in net income, after considering the General Partner s interest, by the weighted average number of Common Units outstanding and the weighted average number of restricted units (Unit Grants) granted under the Restricted Unit Plan and the 2004 Unit Plan.

ITEM 7a. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity variations, risks related to interest rate variations, and to a lesser extent, credit risks. From time to time, we may utilize derivative financial instruments as described below to manage our exposure to such risks.

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Commodity Price Risk

We are exposed to commodity price risk from the risk of price changes in the natural gas and NGLs that we buy and sell and in our midstream, transportation and storage activities. We control the scope of risk management, marketing and trading activities through a comprehensive set of policies and procedures involving senior levels of management. The audit committee of our Board of Directors has oversight responsibilities for our risk management limits and policies. A risk oversight committee, comprised of the co-chief executive officers, chief financial officer, treasurer, president of our midstream and transportation and storage operations, controller of our midstream and transportation and storage operations, and risk manager of our midstream and transportation and storage operations, sets forth risk management policies and objectives and establishes procedures for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of derivative activity and risk exposures. The trading activities are subject to the commodity risk management policy that includes risk management limits, including volume and stop-loss limits, to manage exposure to market risk.

In our retail propane business, the market price of propane is often subject to volatile changes as a result of supply or other market conditions over which we have no control. In the past, price changes have generally been passed along to our propane customers to maintain gross margins, mitigating the commodity price risk. In order to help ensure adequate supply sources are available to us during periods of high demand, we will at times purchase significant volumes of propane during periods of low demand, which generally occur during the summer months, at the then current market price, for storage both at our customer service locations and in major storage facilities and for future resale.

Non-trading activities

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis trades to manage our exposure to market fluctuations in the prices of natural gas, NGLs and propane. Swaps and futures allow us to protect our margins because corresponding losses or gains in the value of financial instruments are generally offset by gains or losses in the physical market.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly protected against decreases in such prices for hedged transactions.

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in prices. However, we are subject to counterparty risk for both the physical and financial contracts. We account for such physical contracts under the normal purchases and sales exception in accordance with SFAS 133.

In connection with the acquisition of HPL, we acquired certain physical forward contracts that contain embedded options that we have not designated as a normal purchase and sale nor were they designated as hedges under SFAS 133. These contracts are marked to market, along with the financial options that offset them, and are recorded in the statement of operations and on our consolidated balance sheet as a component of price risk management assets and liabilities.

In our midstream and transportation and storage segments, we account for certain of our derivatives as cash flow hedges under SFAS 133. All derivatives are recognized in the balance sheet as price risk management assets and liabilities measured at fair value. For those instruments that do not qualify for hedge accounting, the change in market value is recorded as cost of products sold in the consolidated statement of operations in cost of products sold. The fair value of price risk management assets and liabilities that are designated and documented as cash flow hedges and determined to be effective are recorded through other comprehensive income (loss). The effective portion of the hedge gain or loss is initially reported as a component of other comprehensive income (loss) and when the physical transaction settles, any gain or loss previously recorded in other comprehensive income (loss) on the derivative is recognized in earnings in the consolidated statement of operations. The ineffective portion of the gain or loss is reported immediately in cost of products sold in the consolidated statement of operations.

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We also attempt to maintain balanced positions in our midstream and transportation and storage segments to protect us from the volatility in the energy commodities markets. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial results either favorably or unfavorably.

Trading activities

During the fourth fiscal quarter of 2005, we adopted a new risk management policy that provides for our marketing operations to execute limited strategies. Certain strategies are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to futures and basis trades. These instruments are within the guidelines of the risk management policy which has been approved by our Board of Directors. The trading activities are a compliment to the producer services operations and are accounted for in net revenues on the consolidated statement of operations. We follow the applicable provisions of EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), which requires that gains and losses on derivative instruments be shown net in the statement of operations if the derivative instruments are held for trading purposes. Net realized and unrealized gains and losses from the financial contracts and the impact of price movements are recognized in the consolidated statement of operations as other revenue. Changes in the assets and liabilities from the trading activities result primarily from changes in the market prices, newly originated transactions, and the timing and settlement of contracts. Physical contracts associated with the trading activities are accounted for on an accrual basis as they do not meet normal purchases and sales exception of SFAS 133.

Our price risk management assets and liabilities as of August 31, 2005 were as follows:

August 31, 2005:	**Commodity**	**Notional Volume MMBTU**	**Maturity**	**Fair Value**
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/Nymex	Gas	(16,775,767)	2005	$ (5,462)
Basis Swaps IFERC/Nymex	Gas	(15,377,347)	2006	5,524
Basis Swaps IFERC/Nymex	Gas	(2,043,000)	2007	584
				$ 646
Swing Swaps IFERC	Gas	(11,986,504)	2005	(6,580)
Swing Swaps IFERC	Gas	(13,650,000)	2006	180
				$ (6,400)
Fixed Swaps/Futures	Gas	(2,150,000)	2005	$ (8,562)
Fixed Swaps/Futures	Gas			